COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

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In the Matter of:

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

ATTORNEY GENERAL'S PRE-FILED TESTIMONY

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

Respectfully submitted,
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this 23rd day of April, 2010

Assistant Attorney General

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

AFFIDAVIT OF GLENN A. WATKINS

Commonwealth of Virginia)

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

Glenn A. Watkins

SUBSCRIBED AND SWORN to before me this 19th day of April, 2010.

NOTARY PUBLIC

My Commission Expires: 10-13-14
Registration No: 7315146

JENNIFER R. DOLEN
COMMONWEALTH OF VIRGINIA
NOTARY PUBLIC
Expires 10-31-14
ID# 7315146

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

PREPARED DIRECT TESTIMONY AND SCHEDULES

OF

GLENN A. WATKINS

ON BEHALF OF THE

KENTUCKY OFFICE OF THE ATTORNEY GENERAL

APRIL 23, 2010

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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 James Center III, 1051 East Cary Street, Suite 601, Richmond, VA 23219.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Principal and Senior Economist with Technical Associates, Inc., which is an economic and financial consulting firm with offices in Richmond, Virginia.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Office of Rate Intervention of the Kentucky Office of Attorney General ("OAG").

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS.

A. Except for a six-month period during 1987 in which I was employed by Old Dominion Electric Cooperative as its forecasting and rate economist, I have been employed by Technical Associates continuously since 1980.

During my career at Technical Associates, I have conducted marginal and embedded cost of service, rate design, cost of capital, and load forecasting studies involving numerous electric, gas, water/wastewater, and telephone utilities, and have provided expert testimony in Alabama, Arizona, Georgia, Kansas, Kentucky, Maine, Maryland, Massachusetts, Michigan, North Carolina, New Jersey, Ohio, Illinois, Pennsylvania, Vermont, Virginia, South Carolina, Washington, and West Virginia. I hold an M.B.A. and B.S. in economics from Virginia Commonwealth University. I am a member of several professional organizations as well as a Certified Rate of Return Analyst. A more complete description of my education and experience is provided in my Schedule GAW-1 to my testimony.

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

A. Technical Associates has been retained by the OAG to evaluate the reasonableness of Louisville Gas & Electric Company's ("LG&E" or "Company") proposed electric weather normalization adjustment, electric and natural gas class cost of service studies (CCOSS), proposed distribution of revenues by class, and residential electric and natural gas rate designs. The purpose of my testimony, therefore, is to comment on LG&E's proposals on these issues and to present my findings and recommendations based on the results of the studies I have undertaken on behalf of the OAG.

II. ELECTRIC WEATHER NORMALIZATION

Q. IS LG&E PROPOSING A WEATHER NORMALIZATION ADJUSTMENT FOR ITS ELECTRIC OPERATIONS IN THIS CASE?

A. Yes. Consistent with LG&E's last several rate increase applications, the Company is proposing a weather normalization adjustment for this case.

Q. HAS THIS COMMISSION EVER APPROVED AN ELECTRIC WEATHER NORMALIZATION ADJUSTMENT?

A. To the best of my knowledge, this Commission has not approved an electric weather normalization adjustment.

Q. WHAT EFFECT DOES LG&E'S PROPOSED ELECTRIC WEATHER NORMALIZATION HAVE ON ITS REQUESTED INCREASE?

A. In this particular rate case, LG&E's proposed electric weather normalization has the effect of reducing its requested revenue increase. That is, as a result of Mr. Seelye's proposed methodology and analysis, he concludes that actual test year sales and revenues were less than what would be expected under a more normal weather pattern. Specifically, Mr. Seelye's proposed weather adjustment results in an increase to test year revenue of $5.751 million and an increase to variable expenses of $1.899 million. The net effect of Mr. Seelye's weather adjustment is to increase test year operating income, before income taxes of $3.252 million.

Q. DO YOU AGREE WITH MR. SEELYE'S PROPOSED ELECTRIC WEATHER NORMALIZATION ADJUSTMENT?

A. No.

Q. PLEASE EXPLAIN.

A. Although a portion of Residential and Commercial electricity usage is sensitive to temperature for heating and cooling, over the course of an entire year short term increased sales (due to colder than average temperatures in winter and warmer than average temperatures in summer) are generally offset by short-term weather conditions in the opposite direction. Furthermore, and unlike weather sensitive natural gas sales that are entirely weather dependent for heating load, electricity serves both heating and cooling (air conditioning) load. As such, even if a winter is somewhat milder than normal (and heating sales are less than expected), the following summers are often somewhat more severe than normal (and cooling sales are more than expected). Under these conditions, an electric utility's energy sales are evened out over the course of an entire year. For this reason, many, if not most, state utility Commissions do not recognize weather normalization for ratemaking purposes.

In this case, Mr. Seelye has developed a methodology that evaluates whether individual monthly sales are greater than or less than an outside band of weather normalcy. If an individual month's expected heating degree days (HDD) or cooling degree days (CDD) fall outside of Mr. Seelye's band of what would be expected under relatively normal weather conditions, that month's sales are adjusted upward or downward.

The flaw in Mr. Seelye's logic is that each month's analysis and determination of weather normalcy is independent and mutually exclusive of all other months within the same heating or cooling season.

Mr. Seelye's Exhibit 15 shows how his monthly sales adjustments are determined. Using Mr. Seelye's definition of LG&E's cooling season running from May 1 through October 31 as an example, we see that the month of May is evaluated to determine if that single month's weather pattern was outside of a band of normal weather. In this instance, the weather in May 2009 was not deemed to be abnormally warm (outside the band of normalcy), such that no adjustment was made to actual May sales. The same was true for June, August, and September 2009. However, Mr. Seelye determined that the month of July 2009 was cooler than normal (and outside of his normalcy band) so this month's sales were adjusted upward. Although Mr. Seelye's mutually exclusive analysis is conducted on a month by month basis, one could also apply the same logic on a weekly, daily, or even hourly basis.

The flaw in using any of the sub-sets (partial periods) of an entire heating or cooling season is that while a short-term period may fall outside of Mr. Seelye's weather normalcy band such as more severe weather than expected the remaining sub-sets (partial periods) within the same overall heating or cooling season may have been somewhat milder than average and hence not subject to adjustment. However, when these somewhat milder sub-sets (partial periods) are consolidated, we find that the entire heating or cooling season overall cannot be said to be abnormal. For example, consider the following hypothetical example: suppose July was abnormally cool and its weather pattern (CDD) fell outside of Mr. Seelye's band of normalcy. Also assume that June, August, and September were just marginally warmer than average such that these month's did not fall outside of the normalcy bands. Even though the total cooling degree days over the entire summer period (cooling season) were the same as the historical average (cooler July, yet somewhat warmer June, August and September), Mr. Seelye's approach would result in a weather adjustment (an increase to sales) simply because one month of the entire season was beyond a range of normal weather.

Q. WHAT WAS THE ACTUAL COOLING SEASON EXPERIENCE DURING THE TEST YEAR?

A. Mr. Seelye defines LG&E's cooling season as May through October. I disagree with the inclusion of May and October for reasons that I will explain later. For the test year months of June through September (2009), the 30-year average cooling degree days are 1,360. The standard deviation of this 30-year average, is 202. As such, using Mr. Seelye's banding approach of defining a range of normal weather, a normal weather range is between 1,158 CDDs and 1,562 CDD. The actual cooling degree days during the June through September 2009 (test-year) period were 1,142 which is 16 CDD beyond the "normal" band. As such, one may conclude that the test year cooling season was just slightly cooler (milder) than the range of expected normal weather. However, the above determination is only true by accepting the subjective banding definition of plus or minus one standard deviation from the thirty-year average. What this means is that about 68% of observations are expected to fall within the plus or minus one standard deviation and would be considered as the limits of normalcy. The remaining 32% would be considered "abnormal" under Mr. Seelye's approach. Although there are no established parameters as to exactly what percentage should be considered to fall within an expected normal range, extremes are often defined as those that are expected to occur less than 5% of the time. This 5% level of significance is by statistical definition approximately plus or minus two standard deviations. As such, if the definition of normal weather is expanded from 68% (plus or minus one standard deviation) to 95% (plus or minus two standard deviations) we see that the test year experience falls well within the band of normalcy.

It is not my intention to question whether one or two standard deviations are appropriate, but rather that Mr. Seelye's pre-selected definition of one standard deviation results in the test year being considered just slightly beyond his range of normalcy. In my opinion, this minor difference is not reason for this Commission to alter its long standing practice of not considering weather adjustments for electric utilities.

Q. MR. SEELYE INCLUDED THE MONTHS OF MAY AND OCTOBER AS COOLING SEASON MONTHS. SHOULD THESE MONTHS BE INCLUDED AS "COOLING MONTHS"?

A. No. These months are considered shoulder months. Days in May and October can be cool or fairly warm such that these months are comprised of heating degree days and cooling degree days. As such, heating and air conditioning loads are not predictable in May and October. To illustrate, consider Mr. Seelye's Exhibit 15. On average, May has 72 HDDs throughout the month and 123 CDDs. Similarly, October is historically comprised of 221 HDDs and only 40 CDDs. Indeed, October tends to have significantly more heating load than air conditioning load.

III. ELECTRIC CLASS COST OF SERVICE

Q. PLEASE EXPLAIN THE CONCEPT OF A CLASS COST OF SERVICE STUDY ("CCOSS").

A. First, I note that there are two general types of cost of service studies used for public utility ratemaking: marginal cost studies; and embedded, fully allocated cost studies. LG&E has utilized a traditional embedded cost of service concept in this case for purposes of establishing its overall retail revenue requirement, as well as for its class cost of service study ("CCOSS"). As such, I will limit my explanation to embedded class cost of service studies.

Embedded cost of service studies are often referred to as fully allocated cost studies. This is because the vast majority of an electric utility's plant investment serves all customers, and the majority of expenses are incurred in a joint manner such that these costs cannot be specifically attributed to any individual customer or group of customers. To the extent that certain costs can be specifically attributable to a particular customer (or group of customers), these costs are often directly assigned in a CCOSS. However, the vast majority of LG&E's Production, Transmission, and Distribution plant and expenses are incurred jointly to serve all (or most) customers. These joint costs are then allocated to rate classes. It is generally recognized that to the extent possible, joint costs should be allocated to classes based on the concept of cost causation; i.e., costs are allocated based on specific factors that cause costs to be incurred by the utility. Although cost analysts generally strive to abide by the concept of cost causation to the greatest extent practical, some costs (particularly overhead costs), cannot be attributed to specific exogenous factors and must be subjectively assigned or allocated to rate classes. With regards to those costs in which cost causation can be attributed, cost of service experts often disagree as to what is the most cost causative factor; e.g., peak demand, energy usage, number of customers, etc.

Q. PLEASE EXPLAIN HOW CCOSS RESULTS SHOULD BE USED IN THE RATEMAKING PROCESS.

A. Although there are certain principles used by all cost of service analysts, there are often significant disagreements on the specific factors that drive certain costs. These disagreements can and do arise as a result of the quality of data and level of detail available from financial records, as well as fundamental differences in opinions regarding the design or cost causation factors that should be considered to properly allocate costs to rate schedules or customer classes. Furthermore, and as mentioned earlier, cost causation factors cannot be realistically ascribed to some costs such that subjective decisions are required. In this regard, two different cost studies conducted for the same utility and time period can, and often do, yield different results. As such, regulators should consider CCOSS results as one of many tools in assigning revenue responsibility.

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

A. The process in which I conducted my analysis in this case was identical to how I evaluate all CCOSSs. First, I reviewed the structure and organization of the Company's CCOSS sponsored by Mr. Seelye. Once the basic structure was understood, I reviewed the accuracy and completeness of the primary drivers (allocators) used to assign costs to rate schedules and classes. Next, I reviewed Mr. Seelye's selection of allocators to specific rate base, revenue and expense accounts. Finally, I adjusted certain aspects of the Company's study to better reflect cost causation and cost incidence by rate schedule and customer class.

Q. DID YOU FIND THE COMPANY'S STUDY TO BE MATHEMATICALLY ACCURATE?

A. Yes. Perhaps the most fundamental requirement of an embedded CCOSS is that the sum of the parts (classes) must equal the whole (system). This is true with respect to the allocation of financial accounts, as well as the various allocation factors. Furthermore, certain costs previously allocated are carried forward for other purposes such as for the development of composite or internal allocators and for the assignment of income taxes. In all regards, I found Mr. Seelye's CCOSS to be mathematically accurate.

Q. DID YOUR EXAMINATION RESULT IN ANY DISAGREEMENTS WITH THE ASSUMPTIONS OR METHODOLOGIES USED BY MR. SEELYE?

A. Yes. Although I have two material disagreements with Mr. Seelye's CCOSS, my ultimate findings are not significantly different from Mr. Seelye's, with the possible exception of the lighting classes.

Q. PLEASE PROVIDE A SUMMARY OF MR. SEELYE'S AND YOUR CCOSS FINDINGS.

A. The following is a summary comparison of Mr. Seelye's and my class rates of return at current rates:

	Class ROR At Current Rates	
Class	Seelye	Watkins
Residential	3.19%	4.01%
General Service	9.12%	9.89%
PS-Primary	4.86%	4.01%
PS-Secondary	6.62%	6.06%
CTOD-Primary	4.47%	2.67%
CTOD-Secondary	4.42%	3.57%
ITOD-Primary	3.31%	1.69%
ITOD-Secondary	5.27%	3.90%
RTS-Transmission	2.91%	1.47%
Sp. Contract-Ft. Knox	-0.16%	-0.48%
Sp. Contract-Water Companies	-0.34%	-1.44%
Lighting-RLS & LS	8.88%	7.43%
Lighting-LE	3.38%	-2.72%
Lighting-Traffic	4.25%	-0.21%
Total Company	4.77%	4.77%

Q. PLEASE OUTLINE THE TWO MATERIAL DISAGREEMENTS YOU HAVE WITH MR. SEELYE'S CCOSS.

A. The two substantial disagreements that I have with Mr. Seelye are his "Modified Base-Intermediate-Peak" method used to allocate generation costs and his classification of distribution facilities between customer-related and demand-related portions.

A. Generation

Q. YOU INDICATE THAT ONE OF YOUR DISAGREEMENTS WITH MR. SEELYE IS HIS USE OF WHAT HE REFERS TO AS A MODIFIED BASE-INTERMEDIATE-PEAK METHOD TO ALLOCATE GENERATION COSTS. ARE THERE OTHER METHODOLOGIES WHICH MAY BE USED TO ALLOCATE GENERATION- RELATED PLANT AND EXPENSES?

A. Yes. There are several demand allocation methods utilized in the electric industry. The current National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual discusses at least thirteen embedded demand allocation methods, while Dr. James Bonbright noted the existence of at least 29 demand allocation methods in his treatise, Principles of Public Utilities Rates.

Q. WHY DO SO MANY GENERATION ALLOCATION METHODS EXIST FOR THE ELECTRIC INDUSTRY?

A. Utilities design and build generation facilities to meet the energy and demand requirements of their customers on a collective basis. Because of this, and the physical laws of electricity, it is impossible to determine which customers are being served by which facilities. As such, production facilities are joint costs; i.e., used by all customers. Because of this commonality, production-related costs are not directly known for any customer or customer group and must somehow be allocated.

If all customer classes used electricity at a constant rate throughout the year, there would be no disagreement as to the proper assignment of generation-related costs: all analysts would agree that energy usage in terms of kWh would be the proper approach to reflect cost causation and cost incidence. However, such is not the case in that LG&E experiences periods (hours) of much higher demand during certain times of the year and across various hours of the day. Moreover, all customer classes do not contribute in equal proportions to these varying demands placed on the generation system. To complicate matters, the electric utility industry is somewhat unique in that there is a distinct energy/capacity trade-off relating to generation costs. That is, utilities design their mix of production facilities (generation and power supply) to minimize the total costs of energy and capacity, while also ensuring there is enough available capacity to meet peak demands. The trade-off occurs between the level of fixed investment per unit of capacity (KW) and the variable cost of producing a unit of output (kWh). Coal and nuclear units require high capital expenditures resulting in large investments per KW, whereas smaller units with higher variable production costs generally require significantly less investment per KW. Due to varying levels of demand placed on the system over the course of each day, month, and year there is a unique optimal mix of production facilities for each utility that minimizes the total cost of capacity and energy; i.e., its cost of service.

Therefore, as a result of the energy/capacity cost trade-off, and the fact that the service requirements of each utility are unique, many different allocation methodologies have evolved in an attempt to equitably allocate joint production costs to individual classes.

Q. PLEASE EXPLAIN.

A. Total production costs vary each hour of the year. Theoretically, energy and capacity costs should be allocated to classes each and every hour of the year. This would result in 8,760 hourly allocations during non-leap years. Although such an analysis is certainly possible with today's technology, the time and cost necessary for such an undertaking would likely exceed the additional benefits obtained over simpler methods. This is because the analyst does not know precise class loads each and every hour, and subjective decisions must still be made regarding the assignment of fixed investment (capacity costs) to individual hours. With this practical constraint in mind, each method has its strengths and weaknesses regarding its reasonableness in reflecting cost causation as well as the cost and effort required to produce a study.

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

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

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

The 1-CP method has several shortcomings, however. First, and foremost, is the fact that the 1-CP method totally ignores the capacity/energy trade-off inherent in the electric utility industry. That is, the sole criterion for assigning one hundred percent of fixed capacity costs is the classes' relative contributions to load during a single hour of the year. This method does not consider, in any way, the extent to which customers use these facilities during the other 8,759 hours of the year. This may have severe consequences because a utility's planning decisions regarding the amount and type of generation capacity to build and install is predicated not only on the maximum system load, but also on how customers demand electricity throughout the year, i.e., load duration. To illustrate, if a utility had a peak load of 15,000 MW and its actual optimal generation mix included an assortment of nuclear, coal, hydro, combined cycle and combustion turbine units, the total cost of capacity is significantly higher than if the utility only had to consider meeting 15,000 MW for 1 hour of the year. This is because the utility would install the cheapest type of plant, (i.e., peaker units) if it only had to consider one hour a year.

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

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 characteristic. This method is essentially the same as the 1-CP method except that two hours of load are considered instead of one. This method has essentially the same strengths and weaknesses as the 1-CP method, and in my opinion, is only marginally more reasonable than the 1-CP method.

Twelve Monthly Coincident Peak ("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.

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

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

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

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

Although the recognition of the capacity/energy trade-off is admittedly arbitrary under the P&A method, most other allocation methods also suffer to some degree of arbitrariness.

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

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

A potential shortcoming of this method is that customers that only use power during off-peak periods will be overburdened with costs. Under the A&E method, off-peak customers will be assigned a higher percentage of capacity costs because their non-coincident load factor may be very low even though they call on the utility's resources only during less costly off-peak periods.

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

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

Base-Intermediate-Peak ("BIP") -- The BIP method is an accepted allocation approach that attempts to recognize the capacity/energy trade-off that actually exists within a utility's portfolio of generation assets. A utility's base load units tend to run during all (or most) periods of the year; i.e., both peak load periods as well as to satisfy energy requirements in the most efficient manner possible during minimum demand periods (e.g., during the middle of the night). Because base load units operate regardless of peak requirements, they are most appropriately classified as energy-related. At the opposite end of the spectrum are peaking units, such as combustion turbines. These units operate with high variable costs and are only utilized to help meet peak period demands. As such, peakers are classified as peak demand-related. Intermediate plants (e.g., many combined cycle units) are not as efficient as large base load plants but more efficient than peaking units. For this reason, Intermediate plants are not called upon (dispatched) during periods of minimum (base) load but are dispatched before, and more frequently, than peaker units. Therefore, Intermediate plants can be said to serve a dual purpose: partially energy-related and partially demand-related. Intermediate plants are typically classified as partially energy-related and partially demand-related based on their respective capacity or availability factors.[1] In my opinion, the BIP method is an excellent cost allocation approach for many utilities as it captures the actual differences in the capacity/energy trade-off that exist across a utility's generation mix. The BIP method may not be appropriate for utilities that purchase the majority of their energy needs or for utilities with an inefficient mix of generating resources.

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

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

Q. MR. SEELYE HAS USED WHAT HE REFERS TO AS A MODIFIED BIP METHOD TO ALLOCATE GENERATION COSTS. DID HE CALCULATE THE BIP METHOD IN A REASONABLE MANNER?

A. Mr. Seelye's Modified BIP method does not follow the generally accepted BIP approach, and in fact, I have never seen Mr. Seelye's method used in any other cases or utilities. However, I would be reluctant to say his approach is totally unreasonable.

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1 Capacity factor is the ratio of average utilization (output) over a year to peak hour output. Availability factor is the ratio of average utilization during periods when a unit is available for dispatch (i.e., excludes outages) to peak hour output.

Whereas Mr. Seelye's Modified BIP method does allocate a portion of generation facilities based on energy (34.89%) and a portion on peak demands (65.11%), his approach does not reflect the actual mix of supply resources utilized by LG&E. At this point, it should be noted that LG&E's and Kentucky Utilities' ("KU") generation resources are centrally dispatched. Both Mr. Seelye and I have recognized this combined central dispatch in our allocation studies. When I refer to LG&E's actual generation resources, I am referring to the joint resources of LG&E and KU and not the individual legal ownership of these plants for booking purposes.

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

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

Q. PLEASE EXPLAIN THE ACTUAL COMPOSITION OF EON'S GENERATION RESOURCES.

A. With the addition of Trimble County Unit #2, EON's generation capacity will be about 9,600 MW. The following is a summary of this generation portfolio by Fuel Type:

Fuel	MW Capacity	% Of Total
Coal	6,998	73%
Gas/Oil	2,499	26%
Hydro	113	1%
Total	9,610	100%

As can be seen above, about 73% of EON's generation comes from very low cost coal plants. Furthermore, the combined LG&E and KU peak native load is about 6,550 MW, which is lower than the capacity of EON's coal plants. This is especially relevant for cost allocation purposes since EON's coal plants tend to be base load plants in nature. That is, they operate with low variable operating expenses per unit (KWH) and have very high availability factors in the 80% to 90% range. This actual mix of generation assets is dissimilar to most electric utilities in the United States which rely on a much higher percentage of intermediate (high variable cost) plants primarily utilizing natural gas for fuel. Indeed, Kentucky ratepayers and shareholders alike are very fortunate to have an abundance of low cost electric energy resources.

Q. DOES MR. SEELYE'S COST ALLOCATION METHODOLOGY REFLECT THE FACT THAT EON'S GENERATION PORTFOLIO IS COMPRISED PRIMARILY OF BASE LOAD UNITS?

A. No.

Q. PLEASE EXPLAIN HOW YOU CONDUCTED YOUR TRADITIONAL BIP METHOD.

A. During the discovery phase of this proceeding, LG&E provided the order of economic dispatch for each of its generation units.[2] With this information, along with generating plant information provided in EON's 2008 Integrated Resource Plan ("IRP"), such as fuel type, nameplate capacity (MW), annual KWH generation, capacity factors, and availability factors, I was able to separate each generation unit into Base,

[2] Economic Order of dispatch is based on variable running costs. That is, the unit with the lowest running costs (primarily fuel) per unit of KWH output is dispatched first, followed by the next least expensive generation facility, and so forth.

Intermediate, Peak, or Hydro. Base load units are classified as 100% energy-related as they are designed and utilized to meet energy requirements throughout the year; i.e., they are low-cost units that serve energy needs and are not installed to meet short time period peak load requirements. Conversely, peak load (peaker) units are classified as 100% demand-related because of their high cost of output; i.e., they are dispatched and utilized only to meet peak load requirements. Intermediate plants operate at higher variable costs per unit than base load units yet are considerably less costly to operate than peak units, and are dispatched during periods of Intermediate demand (higher than base load but lower than peak period loads). I have followed the industry practice of classifying these units between energy and peak demand based on each facility's capacity factor. Finally, I have classified EON's Hydro facilities as 100% energy-related as they are run of the river or flood control facilities and have little or no ability to reliably meet peaking requirements.

The results of my BIP generation classification is presented in my Schedule GAW-2. My BIP generation classification study results in the following aggregate generation classification:

Energy-related:	82.12%
Demand-related:	17.88%

Q. IN HIS REBUTTAL TO YOUR CCOSS FINDINGS IN LG&E'S 2008 RATE CASE (CASE NO. 2008-000252), MR. SEELYE INDICATED THAT HE COULD NOT RECALL EVER SEEING COST OF SERVICE STUDIES THAT ALLOCATE SUCH A LARGE PERCENTAGE (82%) OF PRODUCTION AND TRANSMISSION CAPACITY COSTS ON THE BASIS OF ENERGY. ARE YOU AWARE OF OTHER UTILITY STUDIES WITH SIMILARLY HIGH PRODUCTION AND TRANSMISSION PLANT ENERGY CLASSIFICATIONS?

A. Yes. Electric energy produced in the Pacific Northwest is comprised of a high percentage of base load hydro generation (primarily from the Columbia River System) as well as significant contributions from very large coal facilities in Western Montana (Colstrip, MT). As a result of this disproportionate mix of base load generation, all of the major investor-owned utilities in this region classify the vast majority of generation and transmission rate base (capacity costs) as energy-related. In its 2009 rate case, Puget Sound Energy sponsored class cost of service study classified its generation and transmission assets as 79% energy and 21% demand. Avista's developed 2009 study classified generation assets as 76% energy-related, and PacifiCorp's 2009 CCOSS classified generation rate base as 88% energy-related.[3]

Q. HOW DO THESE LOW ENERGY COST ELECTRIC UTILITIES IN THE PACIFIC NORTHWEST RELATE TO THE COAL DOMINATED GENERATION MIX OF EON?

A. What is important to understand is that neither the Pacific Northwest utilities nor EON are "typical" U.S. utilities in terms of generation mix. Ratepayers and shareholders are fortunate to reap the benefit of low energy cost generation for each of these utilities. All ratepayers benefit from the low cost energy produced from their respective base load dominated utility. In turn, all ratepayers should share in the costs required to provide this low cost energy in a proportionate and fair manner. Remembering that base load units have a much higher capacity cost per KW than less efficient peaker units, all ratepayers should proportionately share in the fixed costs associated with those base load units that make low cost energy possible. In other words, it is not reflective of cost causation nor is it fair for all customers to reap the benefits of low variable cost output (energy KWH) yet ask certain groups of customers to pay a disproportionate share of the fixed capacity costs that make this low cost energy possible. In my opinion, and as evidenced from the actual cost structure of EON's generation facilities, Mr. Seelye's 35% energy classification does not adequately reflect cost causation nor reasonably assign costs to classes proportionate to the benefits received.

Q. WHAT ARE THE CLASS RATES OF RETURN ON RATE BASE AT CURRENT RATES UTILIZING YOUR TRADITIONAL BIP METHOD TO CLASSIFY GENERATION PLANT?

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[3] Puget Sound Energy, Washington Utilities and Transportation Commission ("WUTC") Docket No. UE-090704; Avista, WUTC Docket No. UE-090134; and, PacifiCorp, WUTC Docket No. UE-090205.

A. Individual class rates of return utilizing the traditional BIP classification method, compared to Mr. Seelye's Modified BIP are presented below. It should be noted that the following OAG results only reflect adjustments to generation and production costs, they do not reflect my other CCOSS adjustments that I will also explain in my testimony:

Class	OAG Traditional BIP	Seelye Modified BIP
Residential	3.66%	3.19%
General Service	10.09%	9.12%
PS-Primary	4.38%	4.86%
PS-Secondary	-6.50%	6.62%
CTOD-Primary	3.00%	4.47%
CTOD-Secondary	-3.94%	4.42%
ITOD-Primary	-1.97%	3.31%
ITOD-Secondary	-4.32%	5.27%
RTS-Transmission	1.47%	2.91%
Sp. Contract-Ft. Knox	-0.24%	-0.16%
Sp. Contract-Water Companies	-1.23%	-0.34%
Lighting-RLS & LS	7.10%	8.88%
Lighting-LE	-2.50%	3.38%
Lighting-Traffic	-0.27%	4.25%
Total Company	4.77%	4.77%

B. <u>Distribution</u>

Q. AS WE MOVE DOWNSTREAM FROM GENERATION THROUGH TRANSMISSION TO THE DISTRIBUTION SYSTEM, HOW HAS MR. SEELYE ASSIGNED DISTRIBUTION COSTS TO RATE SCHEDULES AND CUSTOMER CLASSES?

A. Mr. Seelye has allocated Distribution plant and expenses partially on the basis of number of customers and partially on the basis of peak demand. I concur with Mr. Seelye's selection of customer and demand allocators for Distribution plant. However, there is often controversy regarding the portion of Distribution plant that should be allocated on number of customers and the portion that should be allocated on demand. This separation between customer-related and demand-related Distribution plant is referred to as the classification of Distribution plant.

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

A. In the broadest sense, an embedded CCOSS is undertaken using a three-tiered approach. First, costs are functionalized as Production, Transmission, Distribution, General, and/or customer. These functionalized costs are then classified as energy, demand, or customer-related. Finally, classified costs are then allocated to individual classes. With respect to the classification of Distribution plant, it is generally recognized that there are no energy-related costs. That is, the distribution system is designed to meet localized peak demands. However, largely as a result of differences in customer densities throughout a utility's service area, electric utility Distribution plant often is classified as partially demand-related and partially customer-related.

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

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

Q. WHY ARE THE DIFFERENCES IN CUSTOMER DENSITIES IMPORTANT IN THE ASSIGNMENT OF DISTRIBUTION COSTS TO INDIVIDUAL CLASSES?

A. Possibly the best way to answer this question is by way of example. Consider two different electric utilities: one similar to LG&E with urban, suburban, and rural service areas and one similar to Consolidated Edison Company, which is mainly urban. With respect to the utility with a rural service area, many miles of conductors and associated plant must be installed in order to serve the demands of relatively few customers. Conversely, many more customers are served on a per mile basis for the urban utility. For the urban utility, it may be fair and reasonable to allocate Distribution plant solely on the basis of peak demands. However, with respect to the utility with a rural service area, such an allocation may be unfair if some classes are located mainly in urban or suburban areas, while other classes of customers are located in urban, suburban, and rural areas. As a result, many utilities classify Distribution plant as partially demand- related and partially customer-related. In this manner, a portion of Distribution plant is allocated based on a peak demand, and a portion allocated based on number of customers.

Q. HOW DOES ONE DETERMINE HOW MUCH DISTRIBUTION PLANT SHOULD BE CLASSIFIED AS DEMAND-RELATED AND HOW MUCH AS CUSTOMER-RELATED?

A. Once the decision is made that Distribution plant should be allocated considering both peak demand and number of customers, there are two generally accepted methods for determining the portions or percentages that should be allocated on each basis. These two methods are known as the minimum size and zero-intercept approaches. Under both methods, a study is conducted for each major plant account within the distribution system. That is, each account is studied and assigned its own customer and demand components.

The minimum size method rests on the premise that the minimum, or smallest size, installed equipment makes up the distribution network to connect customers to the distribution system, and that all larger sizes of equipment serve peak demands. In practice, the cost per unit of the smallest sized installed equipment is determined. This minimum cost per unit is then multiplied by the total number units in the system to arrive at a total customer amount. The total customer amount is then divided by the total cost for the account to determine the customer percentage. As the compliment, one minus the customer percentage equals the demand percentage.

The zero-intercept method is similar to the minimum size method, except for the determination of the minimum cost per unit. The zero-intercept method recognizes that even the smallest installed piece of equipment has a demand component, because it too is designed and installed to meet the peak load placed on that equipment. The zero-intercept method attempts to arrive at the "theoretical" cost of a piece of plant or equipment capable of carrying zero load. This is accomplished using statistical regression techniques whereby the per unit costs of various sizes of equipment are determined and a best fitting line is fitted into an equation form. The point at which the fitted line intersects the cost axis at zero size is called the zero-intercept. The zero-intercept cost then serves as the minimum, or zero size, cost per unit.

Q. IS ONE METHOD PREFERRED OVER THE OTHER?

A. In general, I prefer to use the zero-intercept method when possible and appropriate. However, as with most aspects of ratemaking where there is not a universally accepted formula, each approach has its advantages and disadvantages. The major criticisms I have regarding the minimum size method is that this method tends to overstate the customer percentage because even the smallest installed size is used to meet some level of peak demand. The primary weaknesses of the zero-intercept method are that more data and a good working knowledge of statistical linear regression analyses are required, and sometimes there is no strong correlation between costs and sizes (capacity) of distribution equipment.

Q. HOW APPROPRIATE IS EITHER METHOD FROM A DESIGN OR OPERATIONAL PERSPECTIVE?

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

There are three major factors the analyst should keep in mind when classifying Distribution plant. First, there are often alternatives across plant and equipment. For example, the need for a particular transformer may be erased if a larger size conductor is used. Alternatively, fewer and smaller poles may be required if lighter conductors are used. Second, and more importantly, is the fact that purchasing economies are usually present. For example, there are dozens of various types of overhead conductors manufactured. However, due to purchasing economies, a utility may only purchase a few different sizes of conductor. This may result in some "over capacity", yet, the total installed cost is less than if every segment of the system is optimally designed. Third, most components of the distribution system are somewhat oversized for other reasons such as safety, reliability, current looping and growth uncertainty.

Although, these three factors are reflective of how distribution systems are actually designed and installed, neither the minimum size nor the zero-intercept method account for these factors. In fact, the presence of these three factors can seriously skew the results of either method. If the weakness is not captured or recognized, inequitable class allocations may result.

Q. HOW DID MR. SEELYE CLASSIFY DISTRIBUTION PLANT BETWEEN CUSTOMER-RELATED AND DEMAND-RELATED COMPONENTS?

A. My Seelye claims to have conducted a zero-intercept analysis to develop customer/demand classifications for distribution Overhead lines, underground lines, and transformers. I take exception to Mr. Seelye's reference to his proposed classifications as a "zero-intercept" derived study, and I disagree with his approach.

Q. PLEASE EXPLAIN HOW AN INDUSTRY ACCEPTED ZERO-INTERCEPT STUDY IS CONDUCTED.

A. Under accepted industry practices, which are well documented in various cost allocation manuals,[4] the zero-intercept method is very straight-forward. First, various types of equipment are separated by capacity size and type. Next, historical accounting costs are trended by vintage year to reflect cost differences over time. For each size and type of equipment, the total dollars and total units (feet or number of units) are considered as well as the capacity (size) of each type of equipment. Because the overall objective is to estimate the cost of a "zero-size" piece of equipment, total costs are divided by total units (feet or unit) for each type of equipment to derive an average cost per foot or per unit. A regression model is then developed based on the following general form:

cost/unit = a + b (size)

[4] See for example the National Association of Regulatory Utility Commissions ("NARUC") Electric Utility Cost Allocation Manual, 1992, pages 92 through 94.

The resulting intercept (a) produces the estimated cost per unit of a "zero-size" piece of equipment. This estimated zero-size cost per unit is then multiplied by the total units in the system to estimate a zero-size total cost. The ratio of total zero size costs to trended total actual costs represents the percentage of zero-size equipment and serves as the customer percentage.

The above industry standard is in stark contrast to Mr. Seelye's method presented in his Seelye Exhibits 25, 26, and 27. Mr. Seelye refers to his approach as a "weighted regression analysis." Although this "weighted regression analysis" is a clever arithmetic exercise, it violates theoretical statistical principles of linear regression and skews his results. Moreover, on page 91 of his direct testimony, Mr. Seelye states:

> "Like most electric utilities, the feet of conductors and number of transformers on LG&E's system is not uniformly distributed over all sizes of wire and transformer. For this reason, it was necessary to use a weighted regression analysis, instead of a standard least-squares analysis, in the determination of the zero intercept."

It is interesting that Mr. Seelye finds LG&E's system to be typical of other utilities, yet, his approach varies dramatically from the industry practice that has been used by countless utilities, commissions, and analysts for decades.

To understand the bias in Mr. Seelye's "weighted regression analysis," we must fully understand the mathematical model he derives. Using Overhead Conductors as an example, consider Mr. Seelye's analysis presented in his Exhibit 25. Although not shown in his exhibit, Mr. Seelye's equation for Overhead Conductors is:

$$(\text{cost per foot x feet}^{0.5}) = 0 + 0.75697(\text{feet}^{0.5}) + 0.00366(\text{size x feet}^{0.5})$$

Notice that the equation's true intercept is forced to zero. However, if capacity is set to zero, the second term [$0.00366(\text{size x feet}^{0.5})$] becomes zero. If we then ask what is the cost for a foot of a zero size conductor we see that $\text{feet}^{0.5} = 1^{0.5} = 1$, such that the cost for one foot becomes \$0.75697. This is the zero-intercept used by Mr. Seelye.

To illustrate the bias in Mr. Seelye's analysis, consider the following hypothetical example of his approach for a system "not uniformly distributed over all sizes of wire":

Total Cost	Cost Per Foot (y)	Capacity (x)	Feet (n)	$y(n^{0.5})$	$n^{0.5}$	$x(n^{0.5})$
$350.00	3.50	2.00	100	35	10.00	20.00
250.00	5.00	4.00	50	35.355339	7.07	28.28
62,500.00	6.25	6.00	10,000	625	100.00	600.00
164.00	8.20	8.00	20	36.671515	4.47	35.78
$99.50	9.95	10.00	10	31.464663	3.16	31.62

Under the correct, and accepted zero-intercept method, the following regression equation results:

$$\text{cost/feet} = 1.75 + 0.805(\text{size})$$

Therefore, a zero-size cost is estimated to be $1.75 per foot. Using the same data, the following equation is produced using Mr. Seelye's approach:

$$\text{cost per foot x feet}^{0.5} = 0 + 1.9815(\text{feet}^{0.5}) + 0.7120(\text{size x feet}^{0.5})$$

Mr. Seelye's approach results in a zero cost per foot of $1.9815 as compared to the industry accepted cost per foot of $1.75.

Q. WHAT ARE THE RESULTS OF MR. SEELYE'S CLASSIFICATION OF DISTRIBUTION PLANT?

A. Mr. Seelye classifies distribution plant as follows:

	Percentage	
Account	Customer	Demand
Overhead Conductors	54.45%	45.55%
Underground Conductors	30.81%	69.19%
Line Transformers	45.67%	54.33%

Q. HAVE YOU UNDERTAKEN AN INDEPENDENT ANALYSIS OF THE CLASSIFICATION OF ELECTRIC DISTRIBUTION PLANT FOR LG&E?

A. Yes. I have taken a traditional zero-intercept approach to the analyses of LG&E Accounts 365 (Overhead Conductors), 367 (Underground Conductors), and 368 (Line

Transformers). In my analyses, I have relied on Mr. Seelye's account data provided in Seelye Exhibits 25, 26 and 27, except for one significant revision.

Q. PLEASE DISCUSS THE SIGNIFICANT REVISION YOU HAVE INCORPORATED IN YOUR ZERO-INTERCEPT ANALYSES OF ACCOUNTS 365, 367 AND 368.

A. In his regression formulations of "average cost" as a function of "size," Mr. Seelye's representation of "size" for the units of plant is a physical measurement (circular-mils). As an example, with regard to Account 365 (Overhead Conductors), Mr. Seelye's representation of the "size" of 1/0 Conductor and 2/0 Conductor is, respectively, 105.6 and 133.1. These are the physical sizes of the conductor and not the load carrying capacity of these wires. While I have used Mr. Seelye's 21 categories of LG&E's various sizes and types of overhead conductors; e.g., average cost, quantity, etc., I have not used Mr. Seelye's representation of "size" in my analyses. I have used the electrical load capability (ampacity) of each size and type of overhead conductor.

Q. WHY HAVE YOU INCORPORATED THE CAPACITY (AMPACITY) RATHER THAN SIMPLY THE SIZE OF CONDUCTORS IN YOUR ANALYSES?

A. The purpose of the zero-intercept analysis is to calculate the average cost of a zero load conductor in order to evaluate the customer portion as I have discussed previously. In my zero-intercept analyses, therefore, I have incorporated the ampacity (capacity or load capability) of LG&E's overhead conductors, rather than merely the physical size of these conductors.

Q. HAVE YOU INCORPORATED THIS AMPACITY OR LOAD CAPABILITY IN ALL OF YOUR ZERO-INTERCEPT ANALYSES?

A. Yes. I have incorporated an ampacity measurement for each of the overhead conductors and underground conductors and KVA capacity for line transformers in my zero-intercept analyses.

Q. PLEASE PROVIDE A COMPARISON OF THE RESULTS OF YOUR ZERO-INTERCEPT ANALYSES TO THAT OF MR. SEELYE'S.

A. The following table summarizes the results of my analyses and that of Mr. Seelye for LG&E's three electric distribution accounts for which classification analyses were performed:

	Customer Portion		Demand Portion	
	Watkins	Seelye	Watkins	Seelye
Account 365 (Overhead Conductors)	26%	54%	74%	46%
Account 367 (Underground Conductors)	19%	31%	81%	69%
Account 368 (Transformers)	46%	46%	54%	54%

The details supporting my classification of distribution plant are provided in my Schedule GAW-3 which consists of three pages.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING ZERO-INTERCEPT ANALYSES OF LG&E'S DISTRIBUTION PLANT ACCOUNTS?

A. Yes. While I have used the account data presented by Mr. Seelye, as I discussed above, I question why the data Mr. Seelye used for his Overhead Conductors (Account 365) and Underground Conductors (Account 367) analyses are exactly the same for LG&E and KU, and different for Line Transformers (Account 368). The data used for the analyses clearly should be different between LG&E and KU, and in fact, the data were different data presented in the last case.

Q. WHAT ARE YOUR CCOSS RESULTS USING THESE CUSTOMER/DEMAND CLASSIFICATIONS?

A. My recommended distribution plant classifications coupled with a traditional BIP approach to classify generation resources are reflected in my recommended CCOSS. The detail of this CCOSS is provided in my Schedule GAW-4 and are summarized below:

	ROR At Current Rates	
Class	OAG Recommended	Seelye
Residential	4.01%	3.19%
General Service	9.89%	9.12%
PS-Primary	4.01%	4.86%
PS-Secondary	6.06%	6.62%
CTOD-Primary	2.67%	4.47%
CTOD-Secondary	3.57%	4.42%
ITOD-Primary	1.69%	3.31%
ITOD-Secondary	3.90%	5.27%
RTS	1.47%	2.91%
Sp. Contract-Ft. Knox	-0.48%	-0.16%
Sp. Contract-Water Companies	-1.44%	-0.34%
Lighting-RLS & LS	7.43%	8.88%
Lighting-LE	-2.72%	3.38%
Lighting-Traffic	-0.21%	4.25%
Total Company	4.77%	4.77%

As can be seen above, although there are some differences in individual class rates of return, our studies produce relatively similar results.

IV. ELECTRIC CLASS REVENUE INCREASE DISTRIBUTION

Q. HOW DOES MR. SEELYE PROPOSE TO ASSIGN LG&E'S PROPOSED OVERALL $94.6 MILLION INCREASE ACROSS RATE CLASSES?

A. Mr. Seelye proposes to assign the Company's overall requested revenue increase to individual classes on an equal percentage basis. That is, all rate classes would receive the same percentage increase in revenue responsibility (12.2%).

Q. IS MR. SEELYE'S PROPOSED CLASS REVENUE DISTRIBUTION REASONABLE?

A. Yes, given the fairly narrow range of achieved class rates of return under my CCOSS as well as under Mr. Seelye's analysis, an across the board (equal percentage) increase is fair and reasonable. In this regard, it should be remembered that allocated cost of service results are not surgically precise and should, therefore, serve only as a guide in evaluating class revenue responsibility.

V. NATURAL GAS CLASS COST OF SERVICE

Q. HAVE YOU EXAMINED MR. SEELYE'S NATURAL GAS CLASS COST OF SERVICE STUDY?

A. Yes.

Q. WHAT METHODOLOGY DID MR. SEELYE USE FOR PURPOSES OF HIS NATURAL GAS CCOSS?

A. Mr. Seelye used what is known as the Peak Responsibility method to allocate Mains costs. Furthermore, Mr. Seelye separated LG&E's Mains into "high pressure" and "low pressure" systems. Finally, Mr. Seelye classified both high pressure and lower pressure Mains as partially customer-related and partially demand-related. In short, Mr. Seelye has allocated Mains investment costs based partially on customer counts and partially on contributions to estimated design day demand.

Q. DO YOU HAVE ANY MAJOR DISAGREEMENTS WITH MR. SEELYE'S NATURAL GAS CCOSS?

A. Yes.

Q. PLEASE OUTLINE YOUR DISAGREEMENTS.

A. I disagree with Mr. Seelye's use of the Peak Responsibility method to allocate distribution Mains (low and high pressure).

Q. PLEASE EXPLAIN PEAK RESPONSIBILITY METHOD.

A. The Peak Responsibility method is similar in concept to the 1-CP method previously discussed for the electric industry. The major difference is that whereas the 1-CP electric method is generally based on actual loads and demands, the Peak Responsibility method is based on estimated loads at design day temperatures. In other words, design day demands are not known historical loads, but rather estimated class demands under the most extreme weather conditions.

Q. IS THERE A METHOD THAT IS PREFERRED OVER THE PEAK RESPONSIBILITY METHOD FOR LG&E'S NATURAL GAS OPERATIONS?

A. Yes. The Peak and Average method is far superior for LG&E's natural gas operations.

Q. PLEASE EXPLAIN WHY THE PEAK AND AVERAGE METHOD IS PREFERRED.

A. There are several reasons why the Peak and Average Method is preferred and why the Peak Responsibility method is not appropriate for LG&E. The first is the recognition of how and why natural gas consumers are customers of LG&E. Customers connect to LG&E's system in order to meet their natural gas needs throughout the year. Indeed, the Company's Mains are utilized each and every day of the year and recognition of annual usage (throughput) is a logical basis for cost assignment.

Another shortcoming of the Peak Responsibility method using design day demand is that the "design day" is a moving target over time. That is, whereas natural gas Mains are planned and installed to serve customers in excess of fifty years into the future, design day demand (as used by Mr. Seelye) is a function of the mix, usage per customer, and number of customers today. In addition LG&E's commercial customers have obviously changed over the last few decades. Yet, Mr. Seelye assumes the entire Company system was optimally designed and installed to meet today's mix and level of customers.

Q. HAVE YOU CONDUCTED A CLASS COST OF SERVICE STUDY THAT UTILIZES THE PEAK AND AVERAGE METHOD?

A. Yes. I have accepted all other aspects (allocators and classifications) of Mr. Seelye's natural gas CCOSS except for his use of the Peak Responsibility method. It should be noted that while I disagree conceptually with Mr. Seelye that <u>any</u> portion of distribution Mains should be classified as partially customer related, I have accepted his classification since his recommended customer percentages of Mains are relatively small.[5]

Q. PLEASE PRESENT THE RESULTS OF YOUR NATURAL GAS CCOSS UTILIZING THE PEAK AND AVERAGE METHOD.

A. The following is a summary of class rates of return at current rates utilizing my recommended Peak and Average method to allocate distribution Mains. Also provided are Mr. Seelye's results using his Peak Responsibility method.

	ROR at Current Rates	
Class	OAG Peak & Average	Seelye Peak Responsibility
RSG	4.53%	3.90%
CGS	7.61%	7.01%
IGS	4.28%	4.36%
AAGS	3.27%	16.85%
FT	2.32%	25.71%
SP	1.25%	25.05%
Total Company	5.06%	5.06%

The details of my recommended natural gas CCOSS are provided in my Schedule GAW-5.

VI. NATURAL GAS CLASS REVENUE DISTRIBUTION

Q. PLEASE DESCRIBE LG&E'S PROPOSED DISTRIBUTION OF ITS REQUESTED OVERALL NATURAL GAS REVENUE INCREASE TO INDIVIDUAL CUSTOMER CLASSES.

A. LG&E witness Seelye presents the Company's proposed distribution of requested $22.59 million revenue increase to customer classes. A summary of Mr. Seelye's proposed natural gas revenue increase for each customer class is shown below. Note, that the percentage increases reflect increases to Base (non-gas) rates.

[5] Mr. Seelye customer percentage of high pressure mains is 6.97% while high customer percentage of low pressure mains is 14.82%.

Rate Class	Current Base Rate (Non-Gas) Revenue	LG&E Proposed Natural Gas Increases ($000) Amount	Percent
Sales:			
Residential (RGS)	$76,545	$16,197	21.2%
Commercial (CGS)	$27,700	$5,362	19.4%
Industrial (IGS)	$1,759	$363	20.4%
As-Available (AAGS)	$198	$0	0%
Transportation:			
Firm Transportation (FT)	$4,364	$0	0%
Special Contracts:			
Intra-Company	$7,381	$665	21.8%
Special Contract A	$263	$0	0%
Special Contract B	$179	$0	0%
Total LG&E	$118,448	$22,588	19.1%

Q. ARE MR. SEELYE'S PROPOSED CLASS REVENUE INCREASES REASONABLE?

A. When all factors are considered, I do not object to Mr. Seelye's class revenue increases. Although the results of my CCOSS indicate that the Transportation and Special Contract customers are providing significantly lower rates of return than other classes, Mr. Seelye's study indicates exactly the opposite; i.e., these classes are over contributing. Notwithstanding the differences in our CCOSS results, Mr. Seelye also claims that there is a potential for by-pass for transportation and Special Contract customers if their rates are increased.

While Mr. Seelye provides no evidence as to whether any of these customers have a realistic ability to by-pass the LG&E system, I acknowledge that this is a valid concern when a real potential for by-pass exists. Mr. Seelye indicates that a natural gas transmission pipe runs through LG&E's service area. However, this is in no way indicative of any customers having a realistic ability to by-pass LG&E. In order for an end user to by-pass its local distribution gas company, it must secure easements and/or rights of way to run a service lateral (pipe) to the transmission pipeline. Even if such easements and/or rights of way can be secured, the transmission pipeline must agree to a new interconnection point. Finally, and perhaps most importantly, the distance between the end-user and the transmission pipeline must be close enough such that the capital costs to the customer constructing a service line make such a project economically viable. For some Industrial end-users whose facilities are adjacent to transmission pipelines, by-pass is a rather simple and economically viable alternative. However, as the distance between the end-user and transmission pipeline increases, the realistic threat of by-pass decreases. In this regard, I recommend that in its next case LG&E present detailed evidence of any specific customer's potential for by-pass, if special price considerations are requested for that customer.

In agreeing to accept Mr. Seelye's recommendation for no increase to Transportation and Special Contract customers in this case, I recommend that even if these customers' revenue were increased, the corresponding required increase to other customers would be de minimus in percentage terms. As such, I do not object to Mr. Seelye's proposed revenue increase allocation in this case, with the caveats noted for future rate cases.

VII. RESIDENTIAL RATE DESIGN

Q. DOES LG&E PROPOSE ANY SIGNIFICANT CHANGES TO ITS ELECTRIC AND GAS RESIDENTIAL RATE STRUCTURES?

A. Yes. LG&E proposes to substantially change its electric Residential base rate structure from a largely volumetric basis to a largely fixed fee charge per month basis. That is, whereas LG&E currently collects approximately 15% of its non-fuel base rate revenue from fixed monthly customer charges, (85% from energy charges) its proposed changes to rate design would collect approximately 33% of non-fuel base rate revenues from fixed customer charges. In order to accomplish this shift in revenue collection, LG&E proposes to increase its monthly electric Residential customer charge from $5.00 to $15.00 and at the same time, reduce its base rate energy charge from 6.7140¢ per KWH to 6.6100¢ per KWH.

With regard to LG&E Residential natural gas rates, the Company proposes to collect 100% of its distribution (non-gas margin) revenue from fixed monthly charges thereby eliminating the variable usage (per MCF) component of its rates.

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

A. Yes. It is clear from the testimony of Mr. Seelye that the primary objective of LG&E's Residential rate design is to guarantee revenue collection and profitability associated with fixed monthly customer charges. Indeed, as stated on page 39 of his direct testimony, Mr. Seelye claims that "by recovering its fixed distribution [gas] costs through a fixed monthly charge, the Company would be severing the relationship between its natural gas delivery revenue and its sales of natural gas.

Q. WHY DOES LG&E DESIRE MORE ELECTRIC AND ALL NATURAL GAS RESIDENTIAL REVENUE RECOGNITION FROM CUSTOMER CHARGES?

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

Q. OTHER THAN DECOUPLING THE LINK BETWEEN PROFITABILITY AND VOLUMETRIC SALES, DOES MR. SEELYE PROVIDE OTHER JUSTIFICATIONS FOR HIS PROPOSAL TO COLLECT SUBSTANTIALLY MORE OF ITS ELECTRIC RESIDENTIAL AND 100% OF ITS GAS RESIDENTIAL BASE RATE REVENUES FROM FIXED MONTHLY CHARGES?

A. Yes. Mr. Seelye provides two underlying reasons for his partial electric, and total natural gas, revenue decoupling rate design proposals. Mr. Seelye claims that traditional volumetric based rate design provides a disincentive for the Company to promote conservation and because of the high percentage of fixed cost inherent in providing electric and natural gas service, prices (rate design) should reflect the Company's relationship between fixed and variable costs.

Q. IS LG&E CURRENTLY COMPENSATED FOR ITS CONSERVATION EFFORTS?

A. Yes. LG&E currently has a Demand Side Management surcharge for both electric and natural gas service, which compensates the Company for its conservation program costs. In fact, not only is LG&E compensated for its costs to administer conservation efforts, it is also allowed an extra profit incentive over and above the costs of its DSM programs and compensation for its lost sales.

Q. NOTWITHSTANDING LG&E'S RECENT DSM INCENTIVES AND ATTENDANT RATE RIDERS, HAVE RESIDENTIAL CUSTOMERS BEEN USING ELECTRICITY AND NATURAL GAS IN A MORE EFFICIENT MANNER OVER THE LAST COUPLE OF DECADES?

A. Absolutely. Virtually all Residential electric and natural gas appliances are much more energy efficient than they were even ten years ago. As a result, the average Residential energy consumption per appliance has been declining steadily over the last decade or two. These market-based conservation measures have prevailed in spite of the so-called "disincentives" to conserve energy resources as alluded to by Mr. Seelye.

Q. DOES THE LONG-TERM DECLINE IN THE RESIDENTIAL AVERAGE USAGE PER CUSTOMER SUPPORT THE NEED FOR GUARANTEED REVENUE RECOVERY?

A. No. While LG&E's electric and natural gas declining usage per appliance is similar to that experienced by other utilities, LG&E's Residential rates (prices) have reflected this decline in usage in every rate case. Secondly, there is no doubt that both Residential electric usage per appliance and total natural gas usage per customer have been declining over the last ten to twenty years; this declining use has been true for LG&E as well as the electric and natural gas industry in general. Indeed, this change in usage is nothing new to LG&E or the industry.

Q. HAVE THE ELECTRIC AND NATURAL GAS UTILITY INDUSTRIES BEEN ABLE TO REMAIN FINANCIALLY VIABLE OVER THE YEARS ABSENT A FIXED CHARGE RATE DESIGN?

A. Yes. For decades the pricing structure of electric and natural gas LDC's have been largely volume based. These industries have remained viable and have achieved at the very least, respectable returns on their investments with this volumetric based rate structure. For example, faced with declining Residential usages per customer and largely volumetric rate structures, the Value Line group of natural gas utility companies have achieved the following average rates of return on common equity each year since 2000:

Year	Value Line Natural Gas Utility Rate of Return on Common Equity a/
2000	12.4%
2001	12.8%
2002	12.3%
2003	12.1%
2004	11.2%
2005	12.0%
2006	12.4%
2007	11.6%
2008	11.8%
2009	12.4%
10-yr. Avg.	12.1%

a/ Calculated per Schedule GAW-6.

Similarly, the electric utility industry has achieved the following annual rates of return:

Year	Value Line Electric Utility Rate of Return on Common Equity a/
2000	11.3%
2001	12.2%
2002	8.4%
2003	9.5%
2004	9.9%
2005	10.4%
2006	11.0%
2007	11.2%
2008	10.3%
2009	9.6%
10-yr. Avg.	10.3%

a/ Calculated per Schedule GAW-7.

As such while it is true that the electric and natural gas industries have been faced with declining usages per appliance or customer due to improvements in appliance efficiency, earnings (with revenue calculated largely from volumetric based prices) have been achieved at high levels. These high earnings are largely a result of periodic rate increases, cost savings from technological advances, and economies of scale due to mergers.

Q. DOES LG&E'S PROPOSAL TO COLLECT A SUBSTANTIAL PORTION OF ITS ELECTRIC NON-FUEL REVENUE AND 100% OF ITS RESIDENTIAL NATURAL GAS MARGIN REVENUE FROM FIXED MONTHLY CHARGES COMPORT WITH THE ECONOMIC THEORY OF COMPETITIVE MARKETS OR THE ACTUAL PRACTICES OF SUCH COMPETITIVE MARKETS?

A. No. 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 the duplication of 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.[6] As such, the pricing policy for a regulated public utility should mirror those of competitive firms to the greatest extent practical.

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

A. Economic theory tells us that efficient price signals result when prices are equal to long-run marginal costs. It is well known that in the long-run all costs are variable and, hence, 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 EXPLAIN HOW THIS THEORY OF COMPETITIVE PRICING SHOULD BE APPLIED TO REGULATED PUBLIC UTILITIES, SUCH AS LG&E.

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 always address fairness or equity. From a perspective of fair and equitable pricing of a regulated monopoly's products and services, it is generally agreed that payments for a good or service should be in accordance with the benefits received. In this regard, those that receive more benefits should pay more in total than those who receive fewer benefits. With respect to electric and natural gas usage, the volume of consumption is the most direct, and in my opinion the best indicator of benefits received, such that volumetric pricing promotes the fairest pricing mechanism to customers and to the utility.

The above philosophy is, and has been, the belief of economists, regulators, and the marketplace for many years. As an illustration, consider utility industry pricing in its

[6] James C. Bonbright, et al Principles of Public Utility Rates at 141 (2d ed. 1988).

infancy (1800s). In the beginning, 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 the 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 than others paid more in total for the utility service because they used more of the commodity.

Furthermore, virtually every capital intensive industry is faced with a high percentage of fixed costs in the short-run. This includes the manufacturing and transportation industries. Prices for competitive products and services in these industries are invariably established on a volumetric basis, including those that were once regulated; e.g., motor transportation, airline travel, and rail service.

Accordingly, the position of Mr. Seelye that LG&E's fixed costs should be recovered through fixed monthly charges, in my view, is incorrect since pricing should reflect long-run cost incidence wherein all costs are variable or volumetric in nature, and that users requiring more of LG&E's products and services pay more than customers who use less of these products and services.

Q. DOES LG&E'S PROPOSAL TO COLLECT A SUBSTANTIALLY GREATER PORTION OF ITS ELECTRIC RESIDENTIAL REVENUES AND 100% OF ITS NATURAL GAS MARGIN REVENUES FROM FIXED MONTHLY CUSTOMER CHARGES COMPORT WITH PROPER RATEMAKING PRINCIPLES?

A. No. Perhaps the most highly regarded, and certainly the most commonly used reference to ratemaking principles is Dr. James Bonbright's treatise entitled Principles of Public Utility Rates. With regard to the collection of revenue solely (or largely) through a fixed customer charge, Dr. Bonbright states:

> . . . there remains a choice as to the unit of service to which the uniform rate shall be applied. Among a variety of alternatives, three receive closest consideration: a uniform charge per customer; a uniform charge per unit of energy (kilowatt-hour); and a uniform charge per unit of the customer's maximum monthly kilowatt demand.
>
> **Uniformity of charge per customer (say, $10 per month for any desired quantity of service) has charm in avoiding metering costs. Nevertheless, it is soon rejected because of its utter failure to**

recognize either cost differences or value-of-service differences between large and small customers. [Page 396] **[Emphasis added].**

Q. MR. SEELYE CHARACTERIZES LG&E'S PROPOSED NATURAL GAS RATE DESIGN AS A "STRAIGHT-FIXED VARIABLE" RATE DESIGN. IS IT CORRECT TO CHARACTERIZE THIS RATE STRUCTURE AS STRAIGHT-FIXED VARIABLE?

A. No. The straight-fixed variable (SFV) term was coined and adopted by the FERC in its famous Order 636 in which fixed pipeline costs are recovered through demand charges. The concepts of demand charges and customer charges are entirely different. First, demand charges vary by customer based on their self determined contract entitlements to pipeline capacity. Although a customer's demand charges are fixed during a given year, each pipeline shipper (often LDCs) determines its own level of contract demand that can and do vary from year to year. As such, the total pipeline demand charges incurred by individual customers vary tremendously based on the size and needs of each customer. Such is not the case with fixed customer charges since small residential customers pay the same as large residential customers regardless of the demands placed on the system.

Another fundamental difference between a demand charge based rate structure (i.e., true straight-fixed variable) and a fixed customer charge rate structure is that customers purchasing pipeline capacity under the SFV method have the ability to shed unwanted (unneeded) demand charge costs through capacity release to other users. Obviously such revenue (cost) shifting is not possible under a fixed customer charge rate structure.

Q. PLEASE EXPLAIN WHY THE FERC ADOPTED ITS STRAIGHT-FIXED VARIABLE RATE DESIGN IN ITS ORDER 636.

A. FERC Order 636 had two primary goals. The first was to enhance gas competition at the wellhead by completely unbundling the merchant and transportation functions of pipelines.[7] The second goal was to encourage the increased consumption of natural gas in the United States. In the introductory statement of the Order, the 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 . . . ." [Order at 8].

With specific regard to the SFV rate design adopted in Order 636, the 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" [Order at 128-129].

Q. HOW DOES FERC'S OBJECTIVE TO INCREASE NATURAL GAS CONSUMPTION USING THE SFV RATE DESIGN COMPORT WITH THE LDC INDUSTRY'S CLAIMED SOCIETAL NEED FOR REVENUE DECOUPLING AND GUARANTEED REVENUE RECOVERY?

A. The FERC's objective for SFV is diametrically in opposition to a major claimed need for revenue decoupling and/or guaranteed revenue recovery. That is, the LDC industry claims that because retail rates have been historically volumetric based, there has been a disincentive for LDCs to promote conservation or encourage reduced consumption of natural gas. As is clearly discussed in the FERC Order, the price signal that results from SFV pricing is meant to promote additional natural gas consumption, not reduce consumption. A rate structure, therefore, that is based on a fixed monthly customer charge sends an even stronger price signal to consumers to use more natural gas. Indeed, a rate structure comprised of fixed monthly customer charges is even more at odds with conservation and efficient pricing than a demand charge based (true SFV such as the one adopted by the FERC) rate structure. Whereas a demand charge rate does recognize relative customer size and allows customers to decide how much service is desired,

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[7] Federal Energy Regulatory Commission, Docket Nos. RM91-11-001 and RM87-34-065, Order No. 636, page 7.

coupled with the ability to shed revenue responsibility (through capacity release), such characteristics are not present or possible with fixed customer charge pricing.

Q. IN CASE IT IS NOT OBVIOUS, WHY DO SFV AND FIXED CUSTOMER CHARGE RATE STRUCTURES PROMOTE ADDITIONAL CONSUMPTION?

A. These rate structures promote consumption because the consumers' price of incremental consumption is de minimus, or at the very least, less than what an efficient price structure would otherwise be. As discussed in its Order 636, the FERC's adoption of the SFV pricing method was a result of national policy (primarily that of Congress) to promote the additional use of domestic natural gas by promoting additional interruptible (and incremental firm) gas usage. Furthermore, when Order 636 was issued, the electric industry was actively promoting the need for additional natural gas supplies at lower prices to fuel the need for additional capacity and movement away from its reliance on coal and nuclear generation. As such, the FERC's SFV pricing mechanism greatly reduced the price of incremental (additional) natural gas consumption thereby significantly increasing the demand for, and use of, natural gas in the United States subsequent to 1992 (when Order 636 was issued).

Q. MR. WATKINS, A CUSTOMER'S TOTAL ELECTRIC OR NATURAL GAS BILL IS COMPRISED OF A BASE RATE COMPONENT AND A FUEL OR GAS COMMODITY COST COMPONENT. FUEL AND GAS COSTS ARE VOLUMETRICALLY PRICED AND REPRESENT THE MAJORITY OF A CUSTOMER'S BILL. DOES THE VOLUMETRIC PRICING OF FUEL OR GAS COSTS OVERSHADOW THE NEED FOR A PROPER PRICING SIGNAL FROM BASE RATES?

A. No. The rationale of the SFV pricing approach escapes me as an economist and policy advisor. This notion implies that even though marginal rates may be inefficiently structured, this error is acceptable due to other aspects within a customer's bill. To me, this argument is no more plausible than establishing rates that provide for clearly excessive monopolistic profits under the notion that the additional cost to consumers only represents a small portion of their energy bills and/or cost of living.

Q. EARLIER IN YOUR TESTIMONY YOU EXPLAINED THAT VOLUMETRIC PRICING PREDOMINATES IN COMPETITIVE MARKETS. IS THERE ANY DATA OR EXPERIENCE REGARDING THE PRICING OF FIXED PUBLIC UTILITY SERVICES THAT HAVE RECENTLY BEEN DEREGULATED?

A. Yes. There is a limited amount of data available. Retail electric competition for generation services exists in several states. Invariably, customer choice for generation supply is volumetrically priced. However, competition in electric generation alone does not necessarily provide a good apples-to-apples comparison with bundled electric service or natural gas LDC distribution base rates.

However, Texas has implemented total retail electric competition for consumers for most of the States' ratepayers, including distribution service. Under the Texas model, consumers select their electricity provider for all bundled electric services including generation, transmission, distribution and metering. The customers' selected service provider supplies all services from the generator to the meter box. Electric providers compete for customers and are free to set their own prices and pricing structure.

Q. HOW ARE COMPETITIVE RESIDENTIAL ELECTRIC RATES STRUCTURED IN TEXAS?

A. Every electric service provider in Texas has a volumetric component within their rate structure. With regard to Residential fixed monthly customer charges, there are three different pricing structures: those with no fixed monthly charge; those that have a minimum bill amount; and, those with traditional fixed monthly customer charges (regardless of consumption). The following is a summary of the rate structures regarding customer charges for the 30 providers that offer competitive residential electric service in Texas:

	Number Of Providers	Percentage Of Providers
No fixed charge	4	13%
Fixed charge waived with usage threshold	11	37%
Traditional fixed monthly customer charge	15	50%
Total	30	100%

Of the 15 providers that utilize a traditional fixed monthly customer charge the minimum charge is $2.15 per month, the maximum customer charge is $11.69 per month, with an average customer charge of $6.24 per month. The details supporting these amounts are provided in my Schedule GAW-8.

From this data, half of the providers have maintained the traditional fixed monthly customer charge, an eighth of the companies have abandoned fixed charge pricing altogether, and somewhat more than a third of the providers waive any fixed fees once a minimum level of consumption (KWH) is achieved.[8] The conclusions that can be drawn from this data are:

(1) half of the competitive service providers (15) have abandoned traditional fixed customer charge pricing in favor of no customer charges at all or waiver of such with reasonably low levels of consumption;

(2) of the 15 providers that continue to utilize a traditional fixed monthly customer charge, variable energy charges recover more than just generation and transmission (i.e., they include a substantial portion of distribution) costs as the maximum customer charge is only $11.69 with an average customer charge of $6.24; and,

(3) no competitor relies on fixed customer charge pricing for the majority of its revenue.

From this data and analysis, it is clear that when prices for a service identical to LG&E's electric operations and similar to LG&E's natural gas operations are established based on competition and determined by the market (customers and sellers), the resulting rate structure is similar to that found for most other competitive goods and services, i.e., predominantly based on volumetric pricing, and not fixed charge pricing.

Q. HAS MR. SEELYE CONDUCTED AN ANALYSIS OF COSTS THAT HE CONTENDS SHOULD BE CONSIDERED IN DEVELOPING THE RESIDENTIAL CUSTOMER CHARGE FOR ELECTRIC SERVICE?

A. Yes.

[8] As indicated in the notes to Schedule GAW-8 customer charges are waived with a minimum monthly usage of 500 KWH or 1,000 KWH. For purposes of comparison, LG&E's average residential customer usage is about 1,000 KWH per month.

Q. DO YOU AGREE WITH MR. SEELYE'S CUSTOMER COST ANALYSIS?

A. No.

Q. PLEASE EXPLAIN.

A. Mr. Seelye estimates LG&E's monthly electric Residential customer "cost" to be $15.80. However, Mr. Seelye's analysis includes a significant level of distribution, administrative, general, and other overhead costs. Electric utilities are in the business of providing electric energy to customers. Administrative, general and other overhead costs are a normal cost of business for any enterprise and should be recovered based on the level of service provided (i.e., on a volumetric basis). That is, these costs are incurred in the provision of services rendered. As such, these costs should be recovered in relation to the level of services provided.

Q. HOW ARE ADMINISTRATIVE, GENERAL AND OVERHEAD EXPENSES TYPICALLY RECOVERED IN COMPETITIVE MARKETS?

A. As discussed previously, the pricing structures in competitive markets are predominately volumetrically priced. This volumetric pricing recovers all of a business's costs: fixed; variable; administrative; general; overhead; profit; etc.

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. Such is obviously not the case with regulated monopoly utilities. Consumers and the market have a clear preference for volumetric pricing. Utility customers are not so fortunate in that the local utility is a monopolist. 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. That is, competitive markets and consumers in the

U.S. have demanded volumetric based prices for generations: 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. HAVE YOU CONDUCTED AN ANALYSIS OF THE COSTS THAT SHOULD BE CONSIDERED IN DETERMINING LG&E'S RESIDENTIAL CUSTOMER CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE?

A. Yes. As I discussed earlier, there is no doubt that the majority of LG&E's non-fuel or non-gas costs are fixed in the short-run and that efficient, competitive pricing dictates volumetric pricing. However, traditional ratemaking has recognized a minimum level of fixed customer charges to reflect the direct costs of maintaining a customer's account. These direct customer costs include the Company's investment in meters and service lines as well as the operating expenses associated with meter reading, customer service, accounting and customer records and collections. I have conducted a traditional direct customer cost analysis for LG&E which is presented in my Schedules GAW-9 (Electric) and GAW-10 (Gas). These studies indicate a monthly LG&E customer cost of $3.58 per month for electric service and $6.86 for natural gas service.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING LG&E'S RESIDENTIAL CUSTOMER CHARGES?

A. Although my customer cost analyses indicate that reductions to LG&E's electric and natural gas customer charges are warranted, in the interest of gradualism and rate continuity I recommend that LG&E's current Residential electric and natural gas customer charges be maintained at the current levels of $5.00/mth for electric service and $9.50/mth for natural gas service.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

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

EDUCATION

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

POSITIONS

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

EXPERIENCE

I. <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.

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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

EXPERT T. .ONY
PROVIDED BY
GLENN A. WATKINS

YEAR	CASE NAME	PRE-FILED	JURISDICTION	DOCKET NO.	SUBJECT OF TESTIMONY
1985	SAVANNAH ELECT. & PWR CO.	YES	GA. PSC	3523U	SALES FORECAST, RATE DESIGN ISSUES
1990	CENTRAL MAINE PWR CO.	YES	ME. PUC	89-68	MARGINAL COST OF SERVICE
1990	COMMONWEALTH GAS SERVICES (Columbia Gas)	YES	VA. SCC	PUE900034	CLASS COST OF SERVICE
1990	WARNER FRUEHAUF	NO	U.S. BANKRUPTCY CT.	n/a	VALUE OF STOCK, COST OF CAPITAL
1991	W. VA. WATER	YES	WVA PSC	91-140-W-42T	RATE DESIGN
1992	S.C. WORKERS COMPENSATION	YES	SC DEPT OF INSUR	92-034	INTERNAL RATE OF RETURN
1992	GRASS v. ATLAS PLUMBING, et.al.	NO	RICHMOND CIRCUT CT	n/a	DAMAGES, BREACH OF COVENANT NOT TO COMPETE (PROFFERED TEST)
1992	VIRGINIA NATURAL GAS	YES	VA SCC	PUE920031	JURISDICTIONAL & CLASS COST OF SERVICE
1992	ALLSTATE INSURANCE COMPANY (DIRECT)	YES	N.J. DEPT OF INSUR	INS 06174-92	COST ALLOCATIONS, PROFITABILITY
1992	ALLSTATE INSURANCE COMPANY (REBUTTAL)	YES	N.J. DEPT OF INSUR	INS 06174-92	COST ALLOCATIONS, PROFITABILITY
1993	MOUNTAIN FORD v FORD MOTOR COMPANY	NO	FEDERAL DISTRICT CT	n/a	VEHICLE ALLOCATIONS, INVENTORY LEVELS, INCREMENTAL PROFIT, & DAMAGES
1993	SOUTH WEST GAS CO.	YES	AZ. CORP COMM	U-1551-92-253	DIRECT: CLASS COST ALLOCATIONS
1993	SOUTH WEST GAS CO.	YES	AZ. CORP COMM	U-1551-92-253	SURREBUTTAL: CLASS COST ALLOCATIONS
1993	POTOMAC EDISON CO.	YES	VA. SCC	PUE930033	COST ALLOCATIONS,RATE DESIGN
1995	VIRGINIA AMERICAN WATER CO.	YES	VA. SCC	PUE950003	JURISDICTIONAL ALLOCATIONS
1995	NEW JERSEY AMERICAN WATER COMPANY	YES	N.J. B.P.U.	WR95040165	COST ALLOCATIONS,RATE DESIGN
1995	PIEDMONT NATURAL GAS COMPANY	YES	S.C. P.S.C.	95-715-G	COST ALLOCATIONS,RATE DESIGN,WEATHER NORMALIZATION
1995	CYCLE WORLD v. HONDA MOTOR CO.	NO	VA. DMV	None	MARKET PERFORMANCE, FINANCIAL IMPACT OF NEW DEALER
1996	HOUSE BILL # 1513	NO	VA. GEN'L ASSEMBLY	N/A	WATER / WASTEWATER CONNECTION FEES
1996	VIRGINIA AMERICAN WATER CO.	YES	VA. SCC	PUE950003	JURISDICTIONAL ALLOCATIONS
1996	ELIZABETHTOWN WATER CO.	YES	N.J. B.P.U.	WR95110557	COST ALLOCATIONS,RATE DESIGN
1996	ELIZABETHTOWN WATER CO.	NO	N.J. B.P.U.	WR95110557	SURREBUTTAL COST ALLOCATIONS,RATE DESIGN
1996	SOUTH JERSEY GAS CO.	YES	N.J. B.P.U.	GR96010032	CLASS COST OF SERVICE
1996	VIRGINIA LIABILITY INSURANCE COMPETITION	YES	VA. SCC	INS960164	COST ALLOCATIONS, INSURANCE PROFITABILITY
1996	SOUTH JERSEY GAS CO.	YES	N.J. B.P.U.	GR96010032	REBUTTAL - CLASS COST OF SERVICE
1996	HOUSE BILL # 1513	NO	VA. GEN'L ASSEMBLY	N/A	WATER / WASTEWATER CONNECTION FEES
1997	NISSAN v. CRUMPLER NISSAN	NO	VA. DMV	None	MARKET DETERMINATION & PERFORMANCE
1997	PHILADELPHIA SUBURBAN WATER CO. (DIRECT)	YES	PA. PUC	R-00973952	COST ALLOCATIONS,RATE DESIGN,RATE DISCOUNTS
1997	PHILADELPHIA SUBURBAN WATER CO. (REBUTTAL)	YES	PA. PUC	R-00973952	COST ALLOCATIONS,RATE DESIGN,RATE DISCOUNTS
1997	PHILADELPHIA SUBURBAN WATER CO. (SURREBUTTAL)	YES	PA. PUC	R-00973952	COST ALLOCATIONS,RATE DESIGN,RATE DISCOUNTS
1997	VIRGINIA AMERICAN WATER CO.	YES	VA. SCC	PUE970523	JURISDICTIONAL/CLASS ALLOCATIONS
1998	VIRGINIA ELECTRIC POWER COMPANY	YES	VA. SCC	PUE960296	CLASS COST OF SERVICE and TIME DIFFERENTIATED FUEL COSTS
1998	NEW JERSEY AMERICAN WATER COMPANY	YES	N.J. B.P.U.	WR98010015	CLASS COST OF SERVICE,RATE DESIGN, REVENUES
1998	AMERICAN ELECTRIC POWER COMPANY	YES	VA. SCC	PUE960296	CLASS COST OF SERVICE and TIME DIFFERENTIATED FUEL COSTS
1998	FREEMAN WRONGFUL DEATH	YES	FIEDERAL DISTRICT CT.		LOST INCOME, WORK EXPECTANCY
1998	EASTERN MAINE ELECTRIC COOPERATIVE	YES	MAINE PUC	98-596	REVENUE REQUIREMENT
1998	CREDIT LIFE/AH RATE FILING	YES	VA. SCC		PRIMA FACIA RATES, LEVEL OF COMPETITION
1999	CREDIT LIFE & A&H LEGISLATION	NO	VA. GEN'L ASSEMBLY	N/A	COST ALLOCATIONS, INSURANCE PROFITABILITY
1999	MILLER VOLKSWAGEN v. VOLKSWAGEN oF AMERICA	YES	VA. DMV	None	VEHICLE ALLOCATIONS/CSI
1999	COLUMBIA GAS of VIRGINIA	YES	VA. SCC	PUE980287	RATE STRUCTURE
1999	NCCI (WORKERS COMPENSATION INSURANCE)	YES	VA. SCC	INS990165	WORKERS COMPENSATION RATES
1999	ROANOKE GAS	YES	VA. SCC	PUE980626	Rate Design/ Weather Norm
2000	PERSON-SMITH v. DOMINION REALITY	NO	RICHMOND CIRCUIT	n/a	LOST INCOME
2000	CREDIT LIFE/AH RATE FILING	YES	VA. SCC		PRIMA FACIA RATES, LEVEL OF COMPETITION
2000	UNITED CITIES GAS	YESW	VA. SCC		Cost Allocations/ Rate Design
2001	VERMONT WORKERS COMPENSATION RATE CASE	YES	VT. INSURANCE COMM.	n/a	WORKERS COMPENSATION RATES
2001	SERRA CHEVROLET v. GENERAL MOTORS CORP.	NO	ALABAMA CIRCUIT CT.	98-2089	ECONOMIC DAMAGES
2001	VIRGINIA POWER ELECTRIC RESTRUCTURING	YES	VA. SCC	PUE000584	RATE Design (UNBUNDLING)
2001	AMERICAN ELECTRIC POWER RESTRUCTURING	YES	VA. SCC	PUE010011	RATE Design (UNBUNDLING)
2001	NCCI (WORKERS COMPENSATION INSURANCE)	YES	VA. SCC	INS010190	WORKERS COMPENSATION RATES
2002	PHILADELPHIA SUBURBAN WATER CO. (DIRECT)	YES	PA. PUC	R00016750	COST ALLOCATIONS AND RATE DESIGN
2002	HAROLD MORRIS PERSONAL INJURY	YES	FED. DIST CT (RICHMOND)	n/a	LOST WAGES
2002	PIEDMONT NATURAL GAS	YES	S.C. PSC	2002-63-G	REVENUE RQMT, COST OF CAPITAL
2002	VIRGINIA AMERICAN WATER COMPANY	YES	VA. SCC	PUE-2002-00375	JURISDICTIONAL/CLASS ALLOCATIONS
2002	ROANOKE GAS COMPANY	YES	VA. SCC	PUE-2002-00373	WEATHER NORMALIZATION RIDER
2002	SOUTH CAROLINA ELECTRIC & GAS (ELECTRIC)	YES	S.C. PSC	2002-223-E	REVENUE RQMT.
2003	NCCI (WORKERS COMPENSATION INSURANCE)	YES	VA. SCC	INS-2003-00157	WORKERS COMPENSATION RATES
2003	CREDIT LIFE/AH RATE FILING	YES	VA. SCC		PRIMA FACIA RATES, LEVEL OF COMPETITION
2003	ROANOKE GAS	YES	VA. SCC	PUE-2003-00425	WEATHER NORMALIZATION ADJUSTMENT RIDER

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YEAR	CASE NAME	PRE-FILED	JURISDICTION	DOCKET NO.	SUBJECT OF TESTIMONY
2003	SOUTHWESTERN VIRGINIA GAS CO.	YES	VA. SCC	PUE-2003-00426	WEATHER NORMALIZATION ADJUSTMENT RIDER
2004	SOUTH CAROLINA PIPELINE COMPANY	YES	S.C. PSC	2004-6-G	COST OF GAS AND INTERUPT. SALES PROGRAM
2004	VIRGINIA AMERICAN WATER COMPANY	YES	VA. SCC	PUE-2003-00539	JURISDICTIONAL/CLASS ALLOCATIONS
2004	SCE&G FUEL CONTRACT	YES	S.C. PSC	2004-126-E	GAS CONTRACT FOR COMBINED CYCLE PLANT
2004	WASHINGTON GAS LIGHT	YES	VA. SCC	PUE-2003-00603	RATE DESIGN/ WNA RIDER
2004	ATMOS ENERGY	YES	VA. SCC	PUE-2003-00507	RATE DESIGN/ WNA RIDER
2004	SCE&G RATE CASE (ELECTRIC)	YES	S.C. PSC	2004-178-E	COST OF CAPITAL/ REV RQMT.
2004	MEDICAL MALPRACTICE LEGISLATION	NO	VA. GENERAL ASSEMBLY	N/A	INDUSTRY RESTRUTURE/ PROFITABILITY
2004	ATLAS HONDA v. HONDA MOTOR CO.	YES	VA. DMV	None	NEW DEALER PROTEST
2004	NCCI (WORKERS COMPENSATION INSURANCE)	YES	VA. SCC	INS-2004-00124	WORKERS COMPENSATION RATES
2004	NATIONAL FUEL GAS DISTRIBUTION	YES	PA. PUC	R00049656	COST ALLOCATIONS/ RATE DESIGN
2005	WASHINGTON GAS LIGHT	YES	VA SCC	PUE-2005-00010	WEATHER NORMALIZATION ADJUSTMENT RIDER
2005	Serra Chevrolet	Yes	US Federal Ct.	CV-01-P-2682-S	Dealer incremental profits and costs
2005	NEWTOWN ARTESIAN WATER		PA. PUC		REV. RQMT./ RATE STRUCTURE
2005	CITY OF BETHLEHEM WATER RATE CASE		PA. PUC		REV. RQMT./ RATE STRUCTURE
2005	NCCI (WORKERS COMPENSATION INSURANCE)	YES	VA SCC	INS-2005-00159	WORKERS COMPENSATION RATES
2005	Virginia Natural Gas	YES	VA SCC	PUE-2005-00057	Revenue Requirement/ Alt/ Regulation Plan
2006	Olathe Hyundai v. Hyundai Motors of America	YES	KS DMV	None	Dealer impact analysis
2006	Virginia Credit Life & A&H Prima Facia Rates	YES	VA SCC	INS-2006-00013	Market Structure
2006	Columbia Gas of Virginia	YES	VA SCC	PUE-2005-00098	Revenue Requirements/ Alt. Regulation Plan
2006	PPL Gas	YES	PA. PUC	R-00061398	COST ALLOCATIONS/ RATE DESIGN
2006	NCCI (WORKERS COMPENSATION INSURANCE)	YES	VA SCC	INS-2006-00197	WORKERS COMPENSATION RATES
2007	Level of Private Pass. Auto Competition	YES	Ma. Dept of Insur	N/A	Private Pass Auto level of competition
2007	WASHINGTON GAS LIGHT	YES	VA SCC	PUE-2006-00059	Cost Allocations/ Rate Design/ Alt Regulation Plan
2007	Valley Energy	YES	PA. PUC	R-00072349	Cost of Capital/Rate Design
2007	Wellsboro Electric	YES	PA. PUC	R-00072350	Cost of Capital/Rate Design
2007	Citizens' Electric Of Lewisburg, Pa	YES	PA. PUC	R-00072348	Cost of Capital/Rate Design
2007	NCCI (WORKERS COMPENSATION INSURANCE)	YES	VA SCC	INS-2007-00224	WORKERS COMPENSATION RATES
2007	Georgia Power	YES	Ga.PSC	25060-U	Cost Allocations/Rate Design
2008	Columbia Gas of Pennsylvania	YES	PA. PUC	R-2008-2011621	COST ALLOCATIONS/ RATE DESIGN
2008	Greenway Toll Road Investigation	YES	VA. GENERAL ASSEMBLY	N/A	Affiliate Transactions
2008	Puget Sound Energy (Electric)	YES	Wa. UTC	UE-072300	Cost Allocations/Rate Design
2008	Puget Sound Energy (Gas)	YES	Wa. UTC	UE-072301	Cost Allocations/Rate Design
2008	Blue Grass Electric Cooperative	YES	Ky PSC	2008-00011	Cost Allocations/Rate Design
2008	Columbia Gas of Ohio	YES	OH PUC	08-72-GA-AIR, et. a	Cost Allocations/Rate Design
2008	Virginia Natural Gas	YES	Va SCC	PUE-2008-00060	Natl Gas Conservation/ Revenue Decoupling
2008	Equitable Natural Gas	YES	PA. PUC	R-2008-2029325	Cost Allocations/Rate Design/ Discounted Rates
2008	LG&E (Electric)	YES	Ky PSC	2008-000252	Cost Allocations/Rate Design/ Weather Normalization
2008	LG&E (Natural Gas)	YES	Ky PSC	2008-000252	Cost Allocations/Rate Design
2008	Kentucky Utilities	YES	Ky PSC	2008-00251	Cost Allocations/Rate Design/ Weather Normalization
2008	Pike County Natural Gas	YES	PA. PUC	R-2008-2046520	Cost Allocations/Rate Design
2008	Pike County Electric	YES	PA. PUC	R-2008-2046518	Cost Allocations/Rate Design
2008	Newtown Artesian Water	YES	PA. PUC	R-2008-2042293	Revenue Requirement
2009	Leesburg Water & Sewer	YES	Va. Circuit Ct.	Civil Action 42736	Revenue Requirement/ Excess Rates
2009	Central Penn Gas, Inc.	YES	PA. PUC	R-02008-2079675	Cost Allocation/Rate Design
2009	Penn Natural Gas, Inc.	YES	PA. PUC	R-2008-2079660	Cost Allocation/Rate Design
2009	Credit Life/ A&H ratemaking	YES	Va. SCC	n/a	Market Structure and Availability
2009	Fairfax County v. City of Falls Church Virginia	YES	Fairfax Circuit Ct. (Va.)	CL-2008-16114	Water Revenue Requirement
2009	Avista Utilities (Electric)	YES	Wa. UTC	UE-090134	Electric rate Design
2009	Avista Utilities (Gas)	YES	Wa. UTC	UE-090135	Gas Rate design
2009	Columbia Gas of Kentuky	YES	Ky PSC	2009-00141	Cost Allocations/Rate Design
2009	NCCI (Workers Compensation Rates)	YES	VA SCC	INS-2009-00142	Workers Compensation Rates
2009	Duke Energy of Kentucky (Gas)	YES	Ky. PSC	2009-00202	Rate Design
2009	Duke Energy Carolinas (Electric)	YES	NC UC	E-7 Sub 909	Cost Allocations/Rate Design
2009	PacifiCorp	YES	Wa. UTC	UE-090205	Rate Design/Low Income
2009	Puget Sound Energy (Electric)	YES	Wa. UTC	UE-090704	Cost Allocations/Rate Design
2009	Puget Sound Energy (Gas)	YES	Wa. UTC	UG-090705	Cost Allocations/Rate Design
2010	Aqua Virginia, Inc.	YES	VA SCC	PUE-2009-00059	Rate Design
2010	Philadelphia Gas Works	YES	PA. PUC	R-2009-2139884	Cost Allocations/Rate Design

Note: Does not include Expert Reports submitted to Courts or Regulatory agencies in which cases that settled prior to testimony. Testimony prior to 2003 may be incomplete.

Schedule GAW-2

Kentucky Utilities and Louisville Gas & Electric
Test Year Generation Statistics

Generating Unit	Fuel	Generator Nameplate (MW)	Net MWH Produced	Generation Order	Total Gross Investment	Net Investment	Capacity Factor Avg	Availability Factor Avg	B/I/P	Pct Energy	Pct Demand	Net Investment Energy	Net Investment Demand
Mill Creek 1	Coal	356	2,060,877	1	$163,196,129	$54,631,912	77.9	85.6	Base	100.00%	0.00%	$54,631,912	$0
Trimble County 1	Coal	566	3,559,440	2	$607,594,315	$342,381,617	89.6	90.1	Base	100.00%	0.00%	$342,381,617	$0
Mill Creek 4	Coal	544	3,596,774	3	$504,316,481	$251,798,310	81.3	87.5	Base	100.00%	0.00%	$251,798,310	$0
Mill Creek 3	Coal	463	2,768,596	4	$277,074,472	$129,748,881	81.2	89	Base	100.00%	0.00%	$129,748,881	$0
Mill Creek 2	Coal	356	2,084,795	5	$124,822,261	$43,236,558	70.9	86.3	Base	100.00%	0.00%	$43,236,558	$0
Ghent 2	Coal	556	2,362,899	7	$193,971,163	$77,347,614	69.7	82.4	Base	100.00%	0.00%	$77,347,614	$0
Ghent 1	Coal	557	2,950,195	8	$493,607,411	$271,159,395	84.2	87.9	Base	100.00%	0.00%	$271,159,395	$0
Ghent 4	Coal	556	2,941,478	9	$393,801,651	$208,887,124	83	85.1	Base	100.00%	0.00%	$208,887,124	$0
Cane Run 4	Coal	164	966,602	11	$72,507,681	$14,641,808	51.3	86.9	Base	100.00%	0.00%	$14,641,808	$0
Ghent 3	Coal	557	3,363,968	12	$784,290,812	$533,549,718	78	85.5	Base	100.00%	0.00%	$533,549,718	$0
Cane Run 6	Coal	272	1,350,253	13	$141,803,002	$54,133,803	51.2	84	Base	100.00%	0.00%	$54,133,803	$0
Cane Run 5	Coal	209	933,114	14	$93,964,064	$29,847,094	38.7	84.7	Intermediate	38.70%	61.30%	$11,550,825	$18,296,269
Green River 4	Coal	114	396,032	15	$44,909,090	$9,568,636	31.9	85.9	Intermediate	31.90%	68.10%	$3,052,395	$6,516,241
Green River 3	Coal	75	226,460	16	$20,882,040	$4,223,762	21.2	83	Intermediate	21.20%	78.80%	$895,438	$3,328,324
Brown 3	Coal	446	1,834,351	17	$167,769,218	$61,483,147	52.9	81.3	Intermediate	52.90%	47.10%	$32,524,585	$28,958,562
Brown 2	Coal	180	627,235	18	$51,604,493	$19,960,742	37.7	86	Intermediate	37.70%	62.30%	$7,525,200	$12,435,542
Brown 1	Coal	114	289,333	19	$58,239,565	$19,914,445	41	83.4	Intermediate	41.00%	59.00%	$8,164,922	$11,749,523
Tyrone 3	Coal	75	68,321		$26,123,876	$6,142,131	20.9	81.6	Intermediate	20.90%	79.10%	$1,283,705	$4,858,426
Trimble County 5	Gas	199	43,621	20	$63,318,704	$47,453,510	17.4	82.8	Peak	0.00%	100.00%	$0	$47,453,510
Trimble County 6	Gas	199	24,504	21	$59,494,178	$44,963,635	14.9	83.4	Peak	0.00%	100.00%	$0	$44,963,635
Trimble County 7	Gas	199	38,658	22	$52,344,925	$42,578,406	10.4	83.4	Peak	0.00%	100.00%	$0	$42,578,406
Trimble County 8	Gas	199	34,284	23	$51,954,657	$42,261,302	8.6	83.4	Peak	0.00%	100.00%	$0	$42,261,302
Trimble County 9	Gas	199	23,995	24	$52,109,272	$42,802,901	7.1	83.4	Peak	0.00%	100.00%	$0	$42,802,901
Trimble County 10	Gas	199	19,039	25	$58,438,142	$48,466,389	5.5	83.4	Peak	0.00%	100.00%	$0	$48,466,389
Brown 6	Gas,Oil	177	34,203	26	$64,152,496	$54,834,899	9	82.2	Peak	0.00%	100.00%	$0	$54,834,899
Brown 7	Gas,Oil	177	40,139	27	$65,080,354	$53,169,501	10.6	82.2	Peak	0.00%	100.00%	$0	$53,169,501
Brown 8	Gas,Oil	128	7,547	28	$36,379,638	$23,135,828	1.4	88	Peak	0.00%	100.00%	$0	$23,135,828
Brown 9	Gas,Oil	126	1,524	29	$48,505,028	$26,291,775	1	85.7	Peak	0.00%	100.00%	$0	$26,291,775
Brown 10	Gas,Oil	126	2,504	30	$29,531,409	$16,272,357	0.8	85.7	Peak	0.00%	100.00%	$0	$16,272,357
Brown 11	Gas,Oil	126	4,493	31	$44,435,742	$27,303,037	0.5	89.1	Peak	0.00%	100.00%	$0	$27,303,037
Brown 5	Gas	123	2,592	32	$47,749,126	$35,132,623	1.9	89.1	Peak	0.00%	100.00%	$0	$35,132,623
Paddys Run 13	Gas	178	1,262	33	$64,913,860	$49,849,554	10.3	88.6	Peak	0.00%	100.00%	$0	$49,849,554
Paddys Run 11	Gas	16	20	34	$1,609,957	($28,342)	0.1	50	Peak	0.00%	100.00%	$-0	($28,342)
Cane Run 11	Gas,Oil	16	212	35	$3,249,070	$1,357,866	0.1	50	Peak	0.00%	100.00%	$0	$1,357,866
Paddys Run 12	Gas	33	0	36	$3,183,011	($213,388)	0.1	50	Peak	0.00%	100.00%	$-0	($213,388)
Zorn 1	Gas	18	231	37	$1,899,048	($31,433)	0.1	50	Peak	0.00%	100.00%	$-0	($31,433)
Haefling 1-3	Gas,Oil	63	-439	38	$5,695,570	$1,417,461	0.2	50	Peak	0.00%	100.00%	$0	$1,417,461
Dix Dam 1-3	Hydro	27	56,130	-	$12,391,689	$3,980,168	28.8	none	Hydro	100.00%	0.00%	$3,980,168	$0
Ohio Falls 1-8	Hydro	86	230,869	-	$41,596,196	$33,670,611	68.3	none	Hydro	100.00%	0.00%	$33,670,611	$0
				Projected Top 6									
Trimble County 2	Coal	838			$870,200,000	$870,200,000	89.7	89.4	Base	100.00%	0.00%	$870,200,000	$0
Total		9610				$3,597,525,357						$2,954,364,689	***************
												82.12%	17.88%

Source: KU Responses to AG 1-219 through AG1-222

Louisville Gas & Electric Co.
Overhead Lines Classification

Exclude small Quantities

	Size	Ampacity	Avg cost/ft	Quantity	Ln Avg cost/ft	Total Cost
6	26.24	105	0.19	18421	-1.660731	3499.99
4	41.74	140	0.24	89519	-1.427116	21484.56
2	66.36	184	0.67	971519	-0.400478	650917.73
1	83.69	212	1.31	88940	0.2700271	116511.4
1/0	105.6	242	1.38	39898	0.3220835	55059.24
2/0	133.1	276	1.44	713507	0.3646431	1027450.1
3/0	167.8	315	1.6	1954687	0.4700036	3127499.2
4/0	211.6	357	1.63	112230	0.48858	182934.9
266	266	449	1.8	288794	0.5877867	519829.2
266.8	266.8	450	1.85	20263	0.6151856	37486.55
300 MCM	300	492	3.57	9557	1.2725656	34118.49
397 MCM	397	576	0.86	265460	-0.150823	228295.6
500 MCM	500	690	6.95	7511	1.9387417	52201.45
795 MCM	795	884	4	113204	1.3862944	452816
				4,693,510		6,510,104

Regression Output:

Constant		-1.0112	0.3637823
Std Err of Y Est		0.6552882	
R Squared		0.590519	
No. of Observations		14	
Degrees of Freedom		12	
X Coefficient(s)	0.0033942		
Std Err of Coef.	0.0008159		

Intercept	0.3637823
Q	4,693,510
Zero load Cost	1,707,416
Total Cost	6,510,104
Pct Cust	26.23%

Ampacty Source: Southwire ACSR

Louisville Gas & Electric Co.
Underground Lines Classification

Excludes Small Quantities

	Size	Ampacity	Avg cost/ft	Quantity	Ln Avg cost/ft	Total Cost
12	6.53	20	0.17	102463	-1.771957	17418.71
6 Cu	26.24	65	0.31	147560	-1.171183	45743.6
2 Cu	66.36	115	1.4	807125	0.3364722	1129975
1	83.69	100	0.94	9181	-0.061875	8630.14
1/0	105.6	120	1.35	95476	0.3001046	128892.6
2/0 Cu	133.1	175	1.44	2768745	0.3646431	3986992.8
4/0 Cu	211.6	230	2	1164717	0.6931472	2329434
350 MCM Cu	350	310	2.92	20435	1.0715836	59670.2
1000 MCM	1000	445	10.5	10980	2.3513753	115290
				5126682		7822047.1

Regression Output:			Anti-log
Constant		-1.228544	0.2927183
Std Err of Y Est		0.479928	
R Squared		0.8599632	
No. of Observations		9	
Degrees of Freedom		7	
X Coefficient(s)	0.0083349		
Std Err of Coef.	0.0012713		

Intercept	0.2927183
Q	5126682
Zero load Cost	1500673.8
Total Cost	7822047.1
Pct Cust	19.19%

Ampacity Source: National Electric Code Table 310-16

Louisville Gas & Electric Co.
Transformer Classification

OH 1P
Eliminate small Observations

Size	Quantity	total Cost	Avg Cost	Ln Avg cost/ft
15	1526	1549125	$1,015.15	6.9227956
25	3191	4839002	$1,516.45	7.3241294
37.5	2612	4456030	$1,705.98	7.4418973
50	1903	4443475	$2,334.98	7.7557604
75	611	1773189	$2,902.11	7.9731932
100	408	1279833	$3,136.85	8.050973
167	265	929949	$3,509.24	8.1631552
	10516	19270603		

Regression Output:		
Constant		1223.7422
Std Err of Y Est		399.83394
R Squared		0.8446052
No. of Observations		7
Degrees of Freedom		5
X Coefficient(s)	16.090686	
Std Err of Coef.	3.0866039	
		12868873
		0.6677981

Pad 1 P

Size	Quantity	total Cost	Avg Cost	Ln Avg cost/ft
25	610	1155666	1894.5344	7.5467284
37.5	1509	3798390	2517.1571	7.8308854
50	2503	8797798	3514.9013	8.1647667
75	1791	5928607	3310.2217	8.1047704
100	556	2134604	3839.2158	8.2530234
150	174	1045866	6010.7241	8.7013005
167	139	662878	4768.9065	8.4698723
225	104	981881	9441.1635	9.1528345
	7386	24505690		

Regression Output:		
Constant		1132.5527
Std Err of Y Est		919.68546
R Squared		0.8739168
No. of Observations		8
Degrees of Freedom		6
X Coefficient(s)	31.629177	
Std Err of Coef.	4.9046251	
		8365034.5
		0.3413507

Pad 3 P

Size	Quantity	total Cost	Avg Cost	Ln Avg cost/ft
150	101	811424	8033.901	8.9914255
225	50	502613	10052.26	9.2155528
300	265	3252302	12272.838	9.4151438
500	143	2015204	14092.336	9.5533864
750	169	3363344	19901.444	9.8985476
1000	98	2386094	24347.898	10.100201
1500	53	1551916	29281.434	10.284709
2000	39	1714574	43963.436	10.691114
2500	32	1410663	44083.219	10.693834
	950	17008134		

Regression Output:		
Constant		6811.3849
Std Err of Y Est		2439.9074
R Squared		0.9725983
No. of Observations		9
Degrees of Freedom		7
X Coefficient(s)	16.215832	
Std Err of Coef.	1.0287553	
		6470815.7
		0.3804542

Use Linear	Pct	Total Cost	Weighted Pct
OH 1P	0.6677981	19270603	21.17%
Pad 1P	0.3413507	24505690	13.76%
Pad 3P	0.3804542	17008134	10.65%
Total		60784427	45.58%

Louisville Gas & Electric
Electric Cost of Service Study
(Summary)

Acct. No.	Account Description	Allocator	Total System	Residential Rate-RS	Gen. Service GSS	Rate PS Primary	Rate PS Secondary	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Secndary	Rate RTS Transmission	Sp. Contract Ft. Knox	Sp. Contract Water Co.	St. Lighting RLS & LS	St. Lighting LE	Traffic SL TLE
	Cost of Service Summary -- Pro-Forma																
	Total Operating Revenue		$958,491,752	$382,037,590	$137,184,375	$20,622,875	$199,798,423	$23,737,046	$28,229,215	$102,334,431	$3,197,444	$26,722,557	$14,005,641	$3,519,708	$16,551,683	$243,100	$309,881
	Pro-Forma Adjustments:																
	Eliminate Unbilled Revenue	74	($2,871,000)	($1,158,313)	($423,291)	($60,157)	($597,677)	($68,781)	($82,743)	($290,605)	($9,415)	($74,300)	($39,241)	($9,751)	($55,139)	($669)	($917)
	Mismatch in Fuel Cos Recovery	1	($32,833,346)	($11,844,697)	($4,094,614)	($793,088)	($7,109,030)	($962,456)	($1,093,290)	($4,442,711)	($121,894)	($1,244,460)	($626,953)	($164,548)	($312,344)	($11,819)	($11,442)
	To Reflect a Full Year of the FAC Roll-In	48	($3,104,008)	($1,421,315)	$971,372	($173,599)	($838,308)	($125,200)	($160,865)	($766,612)	($12,975)	($499,146)	($34,076)	($22,230)	($18,204)	($1,561)	($1,286)
	Remove ECR Revenue	49	($8,394,624)	($3,345,623)	($1,239,000)	($175,921)	($1,760,923)	($202,980)	($243,550)	($862,594)	($27,998)	($229,933)	($116,433)	($27,441)	($157,765)	($1,851)	($2,613)
	To Reflect a full Year of the ECR Roll-In	50	$6,853,924	$2,304,814	$2,479,866	$114,151	$1,107,744	$109,136	$125,583	$385,791	$12,447	$129,292	$85,991	$0	($438)	($452)	$0
	Remove Off-System ECR Revenues	81	($2,033,628)	($751,473)	($256,326)	($48,477)	($437,283)	($58,076)	($66,905)	($266,540)	($7,428)	($73,905)	($38,659)	($9,860)	($17,363)	($657)	($676)
	Eliminate Brokered Sales	1	($10,165,209)	($3,667,120)	($1,267,693)	($245,540)	($2,200,957)	($297,976)	($338,483)	($1,375,464)	($37,738)	($385,285)	($194,105)	($50,944)	($96,702)	($3,659)	($3,543)
	Eliminate DSM Revenue	48	($12,207,246)	($9,197,044)	($1,115,653)	($111,611)	($1,289,906)	($229,587)	($263,446)	$-0	$-0	$-0	$-0	$-0	$-0	$-0	$-0
	Year End Revenue Adjustment	42	$11,451,462	$8,138,925	$973,726	$2,107	$71,725	$492	$1,967	$1,054	$398	$117	$23	$47	$2,237,605	$2,529	$20,747
	Adjustment for Customer Billing and Rate Switching	82	($875,110)	$-0	$-0	($55,033)	($654,521)	($71,266)	($94,290)	$-0	$-0	$-0	$-0	$-0	$-0	$-0	$-0
	Eliminate ECR, MSR, DSM, FAC, GSC	74	$3,333,166	-$1,344,775	$491,432	$69,841	$693,890	$79,854	$96,063	$337,386	$10,931	$86,260	$45,558	$11,321	$64,015	$777	$1,065
	Weather Normalized Electric Operating Revenues	40	$5,151,223	$4,284,606	$475,872	$24,653	$258,591	$27,262	$40,404	$0	$0	$0	$39,835	$0	$0	$0	$0
	Adjustment for Merger Surcredit	43	$2,323,679	$1,012,681	$325,693	$48,204	$464,561	$43,486	$65,523	$216,289	$6,584	$60,481	$27,090	$9,172	$41,840	$954	$1,122
	USGC Settlement	51	($654,800)	($246,163)	($83,159)	($15,450)	($140,029)	($18,326)	($21,341)	($83,729)	($2,362)	($23,029)	($12,402)	($3,095)	($5,114)	($194)	($210)
	VDT Surcredit Revenues	47	($395)	$0	($395)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Pro-Forma Operating Revenue		$914,466,040	$367,491,643	$134,422,206	$19,202,954	$187,384,298	$21,962,628	$26,193,642	$95,186,697	$3,007,994	$24,488,650	$13,142,269	$3,252,377	$18,232,074	$226,498	$311,809
	Operating Expenses																
	Operation and Maintenance Expenses		$842,628,776	$250,673,608	$79,587,312	$14,582,616	$132,443,125	$17,560,327	$20,096,448	$80,815,067	$2,262,737	$22,366,863	$11,500,176	$2,993,408	$7,287,013	$214,908	$242,968
	Depreciation and Amortization Expenses		$109,158,113	$45,850,753	$13,806,137	$2,253,931	$20,844,484	$2,682,256	$3,145,617	$12,051,765	$355,604	$2,986,666	$1,799,603	$445,865	$2,870,390	$32,648	$52,373
	Regulatory Credits		($1,724,280)	($651,686)	($219,006)	($40,476)	($367,143)	($48,004)	($55,934)	($219,248)	($6,195)	($60,079)	($32,488)	($8,104)	($14,845)	($510)	($584)
	Accretion Expense		$1,501,895	$567,985	$190,756	$35,233	$319,610	$41,784	$48,690	$190,832	$5,393	$52,289$28,276		$7,053	$13,076	$444	$493
	Depreciation for Asset Retirement Costs	71	$222,385	$93,411	$28,127	$4,592	$42,466	$5,424	$6,408	$24,553	$724	$6,085	$3,666	$908	$5,848	$67	$107
	Amortization Expense	71	$5,626,250	$2,363,249	$711,599	$116,173	$1,074,371	$137,219	$162,132	$621,176	$18,329	$153,939	$92,756	$22,981	$147,946	$1,683	$2,699
	Property and Other Taxes		$18,568,593	$7,883,577	$2,347,457	$377,769	$3,501,943	$445,980	$527,862	$2,016,666	$59,822	$493,118	$301,427	$74,617	$523,581	$5,560	$9,214
	Amortization of Investment Tax Credit		$1,861,232	$790,214	$235,299	$37,866	$351,019	$44,703	$52,911	$202,142	$5,996	$49,428$30,214		$7,479	$52,481	$557	$924
	Gain on Disposition of Allowances		($66,274)	($28,138)	($8,378)	($1,348)	($12,499)	($1,592)	($1,884)	($7,198)	($214)	($1,760)	($1,076)	($268)	($1,869)	($20)	($33)
	State and Federal Income Taxes		$46,763,814	$19,089,397	$11,893,271	$809,702	$11,370,116	$632,261	$1,028,567	$683,075	$121,273	($153,104)	($138,143)	($66,134)	$1,508,704	($8,472)	($8,700)
	Specific Assignment of Interruptible Credit		($2,667,453)	$0	$0	$0	$0	$0	$0	($1,765,763)	$0	($901,690)	$0	$0	$0	$0	$0
	Allocation of Interruptible Credit	32	$2,667,453	$1,190,545	$367,394	$56,178	$538,713	$58,529	$78,437	$250,479	$8,341	$60,487	$48,713	$9,129	$0	$0	$509
	Adjustments to Operating Expenses:																
	Eliminate mismatch in fuel cost recovery	1	($27,088,657)	($9,771,567)	($3,377,950)	($654,277)	($5,864,765)	($794,001)	($901,936)	($3,665,121)	($100,559)	($1,026,647)	($517,220)	($135,748)	($257,676)	($9,750)	($9,440)
	Remove ECR expenses	49	($3,707,947)	($1,477,778)	($547,272)	($77,705)	($777,809)	($89,657)	($107,577)	($381,012)	($12,367)	($101,562)	($51,429)	($12,121)	($69,686)	($818)	($1,154)
	Reflect full year of ECR roll-in	50	$3,377,839	$1,135,888	$1,222,160	$56,257	$545,933	$53,786	$61,891	$190,130	$6,134	$63,719	$42,379	$0	($216)	($223)	$0
	Eliminate brokered sales expenses	1	($248,375)	($89,602)	($30,975)	($5,999)	($53,778)	($7,281)	($8,270)	($33,608)	($922)	($9,414)	($4,743)	($1,245)	($2,363)	($89)	($87)
	Eliminate DSM Expenses	48	($7,314,564)	($5,510,855)	($668,497)	($66,877)	($772,910)	($137,568)	($157,856)	$-0	$-0	$-0	$-0	$-0	$-0	$-0	$-0
	Year end Expense adjustment	42	$7,956,625	$5,655,031	$676,558	$1,464	$49,835	$342	$1,367	$732	$277	$81	$16	$33	$1,554,717	$1,757	$14,415
	Depreciation adjustment	71	$6,204,918	$2,606,313	$784,788	$128,121	$1,184,871	$151,332	$178,808	$685,064	$20,214	$169,772	$102,296	$25,345	$163,163	$1,856	$2,977
	Labor adjustment	72	$1,827,123	$823,660	$225,293	$36,036	$336,980	$42,557	$49,731	$194,242	$5,761	$51,315	$28,309	$7,197	$24,654	$528	$861
	Adjustment for pension/post retir benefit	72	$314,825	$141,922	$38,819	$6,209	$58,064	$7,333	$8,569	$33,469	$993	$8,842	$4,878	$1,240	$4,248	$91	$148
	Adjustment for increase in property insurance	22	$355,686	$151,338	$44,962	$7,214	$66,911	$8,516	$10,083	$38,500	$1,143	$9,388	$5,756	$1,425	$10,166	$107	$178
	Adjustment for increase in liability insurance	22	$514,982	$219,106	$65,096	$10,445	$96,873	$12,330	$14,599	$55,741	$1,655	$13,592	$8,333	$2,062	$14,719	$154	$257
	Adjustment for Hazard Tree program	39	$1,759,303	$1,110,011	$241,749	$18,375	$205,619	$21,086	$29,243	$87,918	$3,742	$0	$14,123	$3,277	$23,325	$400	$436
	Storm Damage Adjustment	39	($670,600)	($423,107)	($92,148)	($7,004)	($78,376)	($8,037)	($11,147)	($33,512)	($1,426)	$-0	($5,383)	($1,249)	($8,891)	($152)	($166)
	Eliminate advertising expenses	74	($404,623)	($163,246)	($59,656)	($8,478)	($84,233)	($9,694)	($11,661)	($40,956)	($1,327)	($10,471)	($5,530)	($1,374)	($7,771)	($94)	($129)
	Adjustment for retired mainframe	69	($1,048,815)	($444,730)	($132,468)	($21,374)	($198,064)	($25,252)	($29,856)	($114,253)	($3,384)	($28,043)	($17,045)	($4,228)	($29,282)	($315)	($519)
	Adjustment for MISO Exit Fee	62	($157,117)	($59,084)	($19,960)	($3,708)	($33,610)	($4,399)	($5,122)	($20,097)	($567)	($5,527)	($2,977)	($743)	($1,227)	($46)	($50)
	Adjustment for 2008 Wind Storm	39	$27,630,386	$17,433,051	$3,796,741	$288,592	$3,229,305	$331,157	$459,271	$1,380,773	$58,772	$0	$221,812	$51,464	$366,320	$6,282	$6,844
	Adjustment for 2009 Winter Storm	39	$8,734,140	$5,510,698	$1,200,174	$91,226	$1,020,804	$104,681	$145,179	$436,471	$18,578	$0	$70,116	$16,268	$115,796	$1,986	$2,164
	Adjustment for KCCS Asset	51	$343,330	$129,109	$43,616	$8,103	$73,444	$9,612	$11,193	$43,915	$1,239	$12,078	$6,505	$1,623	$2,682	$101	$110
	Adjustment for CMRG Asset	51	($1,940)	($730)	($246)	($46)	($415)	($54)	($63)	($248)	($7)	($68)	($37)	($9)	($15)	($1)	($1)
	Amortization of rate case expenses	78	$324,253	$126,484	$40,158	$7,358	$66,827	$8,860	$10,140	$40,777	$1,142	$11,286	$5,803	$1,510	$3,677	$108	$123
	Adjustment for SW Power Pool Expense	51	($583,743)	($219,517)	($74,157)	($13,777)	($124,872)	($16,342)	($19,031)	($74,665)	($2,106)	($20,536)	($11,060)	($2,760)	($4,560)	($173)	($187)
	Adjustment for MISO RSG Settlement	52	($429,911)	($161,668)	($54,615)	($10,147)	($91,965)	($12,036)	($14,016)	($54,989)	($1,551)	($15,124)	($8,145)	($2,032)	($3,359)	($127)	($138)
	Adjustment for USGC Settlement	51	$480,212	$180,584	$61,005	$11,334	$102,725	$13,444	$15,656	$61,423	$1,733	$16,894	$9,098	$2,270	$3,752	$142	$154

Louisville Gas & Electric
Electric Cost of Service Study
(Summary)

Acct. No.	Account Description	Allocator	Total System	Residential Rate RS	Gen. Service GSS	Rate PS Primary	Rate PS Secondary	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Secndary	Rate RTS Transmission	Sp. Contract Ft. Knox	Sp. Contract Water Co.	St. Lighting RLS & LS	St. Lighting LE	Traffic SL TLE
	Adjustment to Remove FERC Hydropower Program Change	51	($157,135)	($59,091)	($19,962)	($3,709)	($33,614)	($4,399)	($5,123)	($20,099)	($567)	($5,528)	($2,977)	($743)	($1,228)	($46)	($50)
	Adjustment for Injuries and Damages	22	$313,993	$133,598	$39,692	$6,369	$59,067	$7,518	$8,901	$33,987	$1,009	$8,287	$5,081	$1,258	$8,974	$94	$157
	Adjustment for Interest Rate Swap Amortization	22	$205,798	$87,563	$26,015	$4,174	$38,714	$4,927	$5,834	$22,276	$662	$5,432	$3,330	$824	$5,882	$62	$103
	Adjustment to Correct Edison Electric Institute Invoice	69	$62,735	$26,602	$7,924	$1,279	$11,847	$1,510	$1,786	$6,834	$202	$1,677	$1,020	$253	$1,752	$19	$31
	Adjustment for property tax expense	22	$815,861	$347,048	$103,107	$16,544	$153,440	$19,529	$23,123	$88,289	$2,622	$21,528	$13,199	$3,267	$23,313	$244	$407
	Adjustment for EKPC settlement charges	1	$904,386	$326,259	$112,785	$21,845	$195,816	$26,511	$30,114	$122,373	$3,358	$34,278	$17,269	$4,532	$8,603	$326	$315
	Reflect Weather Normalized Electric Sales Margins	77	$1,899,644	$1,452,124	$142,855	$18,978	$199,060	$20,957	$31,060	$0	$0	$0	$34,610	$0	$0	$0	$0
	Federal & State Income Tax Adjustment	25	($24,635,520)	($12,556,271)	($2,438,911)	($478,555)	($4,468,100)	($562,215)	($691,855)	($2,317,791)	($72,115)	($542,678)	($308,970)	($85,141)	($100,074)	($7,075)	($5,769)
	Federal & State Income Tax Interest Adjustment	24	($153,688)	($62,736)	($39,086)	($2,661)	($37,367)	($2,078)	($3,380)	($2,245)	($399)	$503	$454	$217	($4,958)	$28	$22
	Prior income tax adjustments	24	$2,641,449	$1,078,263	$671,790	$45,736	$642,240	$35,713	$58,098	$38,583	$6,850	($8,648)	($7,803)	($3,736)	$85,219	($479)	($378)
	Adjustment for domestic production activities	24	($1,259,667)	($514,207)	($320,367)	($21,811)	($306,274)	($17,031)	($27,706)	($18,400)	($3,267)	$4,124	$3,721	$1,781	($40,640)	$228	$180
	Adjustment for tax basis depreciation reduction	22	($87,982)	($37,435)	($11,122)	($1,785)	($16,551)	($2,107)	($2,494)	($9,523)	($283)	($2,322)	($1,424)	($352)	($2,515)	($26)	($44)
	Adjustment for Amortization of Investment Tax Credit	22	$345,849	$147,152	$43,718	$7,015	$65,060	$8,281	$9,804	$37,435	$1,112	$9,128	$5,597	$1,385	$9,885	$104	$173
	Total Expense Adjustments		($935,165)	$7,270,179	$1,701,610	($585,240)	($4,539,268)	($802,169)	($832,843)	($3,187,586)	($63,649)	($1,334,845)	($341,038)	($124,248)	$1,896,388	($4,799)	$11,943
	Total Operating Expenses		$823,603,339	$335,093,294	$110,641,576	$17,646,995	$165,566,936	$20,736,717	$24,256,610	$91,675,980	$2,768,162	$23,717,577	$13,292,089	$3,362,688	$14,288,715	$242,067	$313,932
	Net Operating Income -- Pro-Forma		$90,862,701	$32,398,349	$23,780,630	$1,555,960	$21,797,362	$1,225,911	$1,937,232	$3,510,717	$239,832	$751,072	($149,819)	($110,311)	$3,943,359	($15,569)	($2,023)
	Net Cost Rate Base		******************	$807,662,866	$240,572,450	$38,817,435	$359,699,329	$45,859,507	$54,220,821	$207,492,762	$6,145,724	$50,928,344	$30,954,691	$7,677,754	$53,178,529	$572,888	$943,010
	Adjustment to Reflect Depreciation Reserve	71	($6,204,918)	($2,606,313)	($784,788)	($128,121)	($1,184,871)	($151,332)	($178,808)	($685,064)	($20,214)	($169,772)	($102,296)	($25,345)	($163,163)	($1,856)	($2,977)
	Cash Working Capital	45	$6,025,602	$2,373,057	$745,285	$135,584	$1,233,512	$163,153	$186,834	$750,662	$21,070	$207,456	$106,855	$27,806	$70,024	$2,001	$2,306
	Adjusted Net Cost Rate Base		******************	$807,429,611	$240,632,947	$38,824,898	$359,747,970	$45,871,328	$54,228,847	$207,558,359	$6,146,579	$50,966,028	$30,959,250	$7,680,215	$53,085,390	$573,033	$942,339
	Rate of Return		4.77%	4.01%	9.89%	4.01%	6.06%	2.67%	3.57%	1.69%	3.90%	1.47%	-0.48%	-1.44%	7.43%	-2.72%	-0.21%

Louisville Gas & Electric
Electric Cost of Service Study
(Rate Base)

Acct. No.	Account Description	Allocator	Total System	Residential Rate RS	Gen. Service GSS	Rate PS Primary	Rate PS Secondary	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Secndary	Rate RTS Transmission	Sp. Contract Ft. Knox	Sp. Contract Water Co.	St. Lighting RLS & LS	St. Lighting LE	Traffic SL TLE
	RATE BASE																
	Plant-in-Service																
	Intangible Plant																
301.00	ORGANIZATION	54	$2,240	$954	$283	$45	$421	$54	$63	$242	$7	$59	$36	$9	$65	$1	$1
302.00	FRANCHISE AND CONSENTS	54	$100	$43	$13	$2	$19	$2	$3	$11	$0	$3	$2	$0	$3	$0	$0
303.00	SOFTWARE	54	$44,745,233	$19,065,137	$5,655,868	$905,762	$8,403,304	$1,069,125	$1,266,163	$4,832,612	$143,614	$1,176,215	$722,561	$178,815	$1,290,204	$13,404	$22,449
301.00	ORGANIZATION - COMMON	54	$81,999	$26,417	$7,837	$1,255	$11,644	$1,481	$1,754	$6,696	$199	$1,630	$1,001	$248	$1,788	$19	$31
302.00	FRANCHISE AND CONSENTS - COMMON	54	$3,108	$1,324	$393	$63	$584	$74	$88	$336	$10	$82	$50	$12	$90	$1	$2
	Sub-total		$44,812,680	$19,093,875	$5,664,383	$907,128	$8,415,971	$1,070,737	$1,268,072	$4,839,896	$143,831	$1,177,988	$723,650	$179,084	$1,292,149	$13,425	$22,483
	Production Plant																
	Steam Production Generation																
	Energy	1	$1,636,952,501	$590,533,986	$204,142,708	$39,540,533	$354,430,648	$47,984,583	$54,507,507	$221,497,564	$6,077,178	$62,044,302	$31,257,614	$8,203,785	$15,572,371	$589,241	$570,479
	Demand	32	$356,362,120	$159,052,561	$49,082,457	$7,505,139	$71,970,148	$7,819,228	$10,478,865	$33,463,099	$1,114,386	$8,080,819	$6,507,937	$1,219,542	$0	$0	$67,937
330	Hydro Baseload Generation																
	Energy	1	$34,145,762	$12,318,154	$4,258,284	$824,790	$7,393,192	$1,000,927	$1,136,991	$4,620,295	$126,766	$1,294,204	$652,013	$171,126	$324,830	$12,291	$11,900
	Demand	32	$7,433,482	$3,317,733	$1,023,828	$156,552	$1,501,250	$163,104	$218,582	$698,018	$23,245	$168,561	$135,751	$25,439	$0	$0	$1,417
340	Other Production Generation																
	Energy	1	$189,907,274	$68,509,440	$23,683,146	$4,587,204	$41,118,455	$5,566,821	$6,323,563	$25,696,530	$705,030	$7,197,927	$3,626,280	$951,743	$1,806,593	$68,359	$66,183
	Demand	32	$41,342,530	$18,452,117	$5,694,188	$870,691	$8,349,451	$907,130	$1,215,681	$3,882,144	$129,283	$937,478	$755,003	$141,482	$0	$0	$7,882
	Total Production Plant		$2,266,143,689	$852,183,991	$287,884,611	$53,484,910	$484,763,145	$63,441,793	$73,881,191	$289,857,651	$8,175,888	$79,723,290	$42,934,600	$10,713,118	$17,703,793	$869,891	$725,788
	Transmission Plant																
	Transmission Plant	51	$241,924,058	$90,975,613	$30,733,362	$5,709,826	$51,751,294	$6,772,781	$7,887,248	$30,943,995	$872,824	$8,510,926	$4,583,519	$1,143,688	$1,889,983	$71,515	$77,483
	Total Transmission Plant		$241,924,058	$90,975,613	$30,733,362	$5,709,826	$51,751,294	$6,772,781	$7,887,248	$30,943,995	$872,824	$8,510,926	$4,583,519	$1,143,688	$1,889,983	$71,515	$77,483
	Distribution Plant																
360-362	TOTAL ACCTS 360-362	28	$88,269,208	$42,730,403	$11,550,281	$1,846,725	$15,937,319	$2,124,504	$2,277,997	$8,861,011	$282,761	$0	$1,423,873	$330,249	$861,409	$29,207	$13,470
364-365	OVERHEAD LINES																
	Primary																
	Customer	19	$64,223,135	$55,361,707	$6,623,374	$14,335	$487,877	$3,345	$13,380	$7,168	$2,708	$0	$159	$319	$1,691,244	$1,911	$15,610
	Demand	28	$182,788,924	$88,486,627	$23,918,458	$3,824,221	$33,003,189	$4,399,448	$4,717,303	$18,349,486	$585,545	$0	$2,948,572	$683,883	$1,783,816	$60,483	$27,893
	Secondary																
	Customer	18	$20,548,691	$17,720,396	$2,120,036	$0	$156,162	$0	$4,283	$0	$867	$0	$0	$0	$541,340	$612	$4,996
	Demand	29	$58,484,735	$37,238,625	$12,152,544	$0	$7,411,695	$0	$1,115,620	$0	$155,334	$0	$0	$0	$391,520	$13,275	$6,122
366-367	UNDERGROUND LINES																
	Primary																
	Customer	19	$33,704,689	$29,054,141	$3,475,984	$7,523	$256,041	$1,755	$7,022	$3,762	$1,421	$0	$84	$167	$887,574	$1,003	$8,192
	Demand	28	$143,688,326	$69,558,346	$18,802,032	$3,006,177	$25,943,437	$3,458,357	$3,708,219	$14,424,326	$460,290	$0	$2,317,840	$537,592	$1,402,238	$47,545	$21,927
	Secondary																
	Customer	18	$264,963	$228,494	$27,337	$0	$2,014	$0	$55	$0	$11	$0	$0	$0	$6,980	$8	$64
	Demand	29	$1,129,680	$719,230	$234,715	$0	$143,150	$0	$21,547	$0	$3,000	$0	$0	$0	$7,562	$256	$118
368	TRANSFORMERS																
	Customer	18	$58,052,106	$50,061,890	$5,989,313	$0	$441,172	$0	$12,099	$0	$2,449	$0	$0	$0	$1,529,340	$1,728	$14,115
	Demand	29	$88,148,124	$43,391,536	$14,160,499	$0	$8,636,324	$0	$1,299,953	$0	$180,999	$0	$0	$0	$456,211	$15,468	$7,134
369	SERVICES	27	$25,016,081	$22,105,235	$2,644,625	$0	$194,800	$0	$5,353	$0	$2,852	$0	$0	$0	$0	$6,879	$56,336
370	METERS	28	$36,348,005	$30,569,462	$4,022,994	$62,879	$1,346,111	$11,267	$45,069	$129,028	$47,977	$14,175	$2,908	$6,906	$0	$9,450	$77,780
373	STREET LIGHTING	7	$68,350,905	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$67,647,227	$76,456	$627,222
374	ASSET RETIRE OBLIGATIONS DIST PLANT	55	$37,874	$22,972	$5,178	$444	$4,744	$509	$676	$2,121	$86	$0	$341	$79	$509	$9	$6
	Total Distribution Plant		$849,053,125	$487,249,063	$105,727,371	$8,762,304	$93,964,035	$9,899,185	$13,228,675	$41,778,902	$1,728,299	$14,175	$6,693,776	$1,559,184	$77,206,870	$284,282	$880,986
	General Plant																
	Total General Plant	54	$18,821,680	$7,167,415	$2,126,287	$340,515	$3,159,168	$401,931	$476,006	$1,816,789	$53,991	$442,190	$271,642	$67,224	$485,044	$5,039	$8,439
	TOTAL COMMON PLANT	54	$122,360,846	$52,135,751	$15,466,603	$2,476,908	$22,979,775	$2,923,643	$3,462,465	$13,215,318	$392,729	$3,216,491	$1,975,923	$488,988	$3,528,208	$36,656	$61,388
106	COMPLETED CONSTR NOT CLASSIFIED	54	$43,594,015	$18,574,624	$5,510,352	$882,459	$8,187,101	$1,041,619	$1,233,587	$4,708,277	$139,919	$1,145,953	$703,971	$174,214	$1,257,010	$13,060	$21,871
105	PLANT HELD FOR FUTURE USE	53	$649,014	$372,452	$80,818	$6,698	$71,826	$7,643	$10,112	$31,934	$1,320	$11	$5,117	$1,192	$59,017	$202	$673
105	PLANT HELD FOR FUTURE USE	51	$4,182,560	$1,572,853	$531,341	$98,716	$894,714	$117,093	$136,361	$534,982	$15,090	$147,143	$79,243	$19,773	$32,675	$1,236	$1,340
	PROPERTY HELD UNDER CAPITAL LEASE		$0														
	OTHER		$0														
	Construction Work in Progress																
	CWIP Production	51	$199,499,749	$75,021,939	$25,343,895	$4,708,539	$42,676,079	$5,585,092	$6,504,124	$25,517,592	$719,764	$7,018,432	$3,779,744	$943,128	$1,558,552	$58,974	$63,896
	CWIP Transmission	52	$42,811,947	$16,099,445	$5,438,711	$1,010,436	$9,158,137	$1,198,541	$1,395,762	$5,475,986	$154,459	$1,506,131	$811,120	$202,392	$334,460	$12,656	$13,712
	CWIP Distribution Plant	53	$42,933,183	$24,638,203	$5,346,203	$443,074	$4,751,379	$505,618	$668,915	$2,112,488	$87,292	$717	$338,477	$78,842	$3,904,042	$13,364	$44,548
	CWIP Common Plant	54	$9,249,889	$3,941,211	$1,169,200	$187,242	$1,737,160	$221,013	$261,746	$999,014	$29,688	$243,151	$149,370	$36,965	$266,715	$2,771	$4,641
	Total CWIP		$294,494,748	$119,700,789	$37,298,010	$6,349,291	$58,322,755	$7,510,265	$8,830,547	$34,105,079	$991,203	$8,768,431	$5,078,710	$1,261,328	$6,063,769	$87,765	$126,798
	TOTAL PLANT-IN-SERVICE		$3,589,541,649	$1,529,325,637	$463,725,137	$72,669,464	$674,187,027	$85,776,425	$101,583,616	$387,725,744	$11,521,890	$94,378,168	$57,971,440	$14,346,475	$103,454,849	$1,075,315	$1,800,482
	TOTAL UTILITY PLANT		$3,884,036,397	$1,649,026,436	$491,023,147	$79,018,755	$732,509,782	$93,286,690	$110,414,163	$421,830,824	$12,513,093	$103,146,598	$63,050,151	$15,607,803	$109,518,619	$1,163,080	$1,927,257

Louisville Gas & Electric
Electric Cost of Service Study
(Rate Base)

Acct. No.	Account Description	Allocator	Total System	Residential Rate RS	Gen. Service GSS	Rate PS Primary	Rate PS Secondary	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Secndary	Rate RTS Transmission	Sp. Contract Ft. Knox	Sp. Contract Water Co.	St. Lighting RLS & LS	St. Lighting LE	Traffic SL TLE
	Accumulated Reserve for Depreciation																
	Production	51	$1,132,202,431	$425,765,056	$143,831,859	$26,721,935	$242,195,594	$31,696,557	$36,912,251	$144,817,622	$4,084,807	$39,831,059	$21,450,828	$5,352,449	$8,845,105	$334,689	$362,621
	Transmission	51	$132,956,587	$49,998,364	$16,890,436	$3,138,005	$28,441,468	$3,722,184	$4,334,673	$17,006,196	$479,686	$4,677,434	$2,519,010	$628,548	$1,038,697	$39,303	$42,583
	Distribution	53	$397,101,732	$227,886,149	$49,448,640	$4,098,125	$43,946,933	$4,676,614	$6,186,998	$19,539,037	$807,389	$6,630	$3,130,676	$729,234	$36,109,662	$123,609	$412,037
	General & Common Plant	64	$89,953,313	$38,327,485	$11,370,240	$1,820,894	$16,893,532	$2,149,310	$2,545,424	$9,715,212	$288,714	$2,364,596	$1,452,596	$359,479	$2,593,755	$26,947	$45,130
	Intangible Plant	64	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL ACCUMULATED RESERVE FOR DEPRECIATION		$1,752,214,063	$741,977,054	$221,541,175	$35,778,980	$331,477,527	$42,244,665	$49,979,345	$191,078,067	$5,660,597	$46,879,719	$28,553,109	$7,069,710	$48,587,218	$524,548	$862,370
	Net Utility Plant		$2,131,822,334	$907,049,382	$269,481,972	$43,239,795	$401,032,255	$51,042,025	$60,434,818	$230,752,757	$8,852,496	$58,268,879	$34,497,041	$8,538,093	$80,831,401	$638,632	$1,084,687
	Rate Base Adjustments and Working Capital																
	Working Capital Assets																
	Cash Working Capital - Operation and Maintenance Expenses	67	$70,625,892	$27,814,523	$8,735,459	$1,589,171	$14,457,951	$1,912,311	$2,189,870	$8,798,482	$246,955	$2,431,586	$1,252,444	$325,914	$820,747	$23,453	$27,026
	Materials and Supplies	57	$78,422,832	$33,412,079	$9,912,800	$1,587,653	$14,729,361	$1,874,008	$2,219,357	$8,470,873	$251,726	$2,061,935	$1,266,536	$313,436	$2,260,239	$23,493	$39,336
	Prepayments	57	$3,238,899	$1,379,082	$409,150	$65,530	$607,954	$77,350	$91,604	$349,635	$10,390	$85,106	$52,276	$12,937	$93,291	$970	$1,624
	Mill Creek Ash Dredging Project	51	$1,028,827	$386,891	$130,699	$24,282	$220,082	$28,803	$33,542	$131,595	$3,712	$36,194	$19,492	$4,864	$8,038	$304	$330
	Sub-total		$153,314,450	$62,892,574	$19,188,110	$3,268,638	$30,015,348	$3,892,471	$4,534,373	$17,760,585	$512,783	$4,614,822	$2,590,748	$857,150	$3,182,315	$48,220	$68,316
	Other Rate Base Items																
	Less:																
	Accumulated Deferred Income Taxes	57	$338,601,920	$144,261,482	$42,799,950	$6,854,920	$63,596,148	$8,091,301	$9,582,395	$36,574,219	$1,086,861	$8,902,704	$5,468,453	$1,353,305	$9,758,909	$101,435	$169,838
	FAS 109 Deferred Income Taxes	67	$37,321,382	$15,900,794	$4,717,497	$755,563	$7,009,697	$891,840	$1,056,191	$4,031,285	$119,796	$981,274	$602,744	$149,164	$1,075,647	$11,180	$18,720
	Asset Retirement Obligations - Net Assets	57	$3,342,287	$1,423,974	$422,469	$67,663	$627,744	$79,867	$94,586	$361,016	$10,728	$87,877	$53,978	$13,358	$96,328	$1,001	$1,676
	Asset Retirement Obligations - Regulatory Liabilities	57	($703,629)	($299,739)	($88,927)	($14,243)	($132,137)	($16,812)	($19,910)	($75,992)	($2,258)	($18,498)	($11,362)	($2,812)	($20,277)	($211)	($353)
	Sub-total		$378,562,050	$161,286,511	$47,850,989	$7,663,904	$71,101,452	$9,046,197	$10,713,263	$40,890,528	$1,215,127	$9,953,358	$6,113,813	$1,513,015	$10,910,607	$113,405	$189,881
	Less:																
	Customer Advances	68	$1,848,625	$1,092,579	$246,642	$25,092	$246,822	$28,793	$35,108	$120,053	$4,428	$0	$19,286	$4,475	$24,579	$458	$311
	TOTAL RATE BASE		$1,904,726,109	$807,662,866	$240,572,450	$38,817,435	$359,699,328	$45,859,507	$54,220,821	$207,492,782	$6,145,724	$50,928,344	$30,954,691	$7,877,754	$53,178,529	$572,868	$943,010

Louisville Gas & Electric
Electric Cost of Service Study
(Expenses)

Acct. No.	Account Description	Allocator	Total System	Residential Rate RS	Gen. Service GSS	Rate PS Primary	Rate PS Secondary	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Seondary	Rate RTS Transmission	Sp. Contract Ft. Knox	Sp. Contract Water Co.	St. Lighting RLS & LS	St. Lighting LE	Traffic SL TLE
O & M Expenses																	
	Steam Production O&M																
500	OPERATION SUPERVISION & ENGINEERING	60	$2,317,003	$865,973	$293,533	$54,878	$496,551	$65,325	$75,782	$298,946	$8,396	$82,462	$43,950	$11,053	$18,694	$707	$752
501	FUEL	1	$329,480,255	$118,864,288	$41,090,400	$7,958,826	$71,340,766	$9,658,468	$10,971,419	$44,583,633	$1,223,231	$12,488,446	$6,291,618	$1,651,280	$3,134,449	$118,604	$114,828
502	STEAM EXPENSES-- Labor	51	$11,242,697	$4,227,820	$1,428,241	$265,347	$2,404,987	$314,745	$366,536	$1,438,030	$40,562	$395,520	$213,005	$53,149	$87,831	$3,323	$3,601
	STEAM EXPENSES— Other	1	$24,586,658	$8,862,436	$3,063,671	$593,404	$5,319,117	$720,128	$818,021	$3,324,124	$91,203	$931,130	$469,099	$123,118	$233,702	$8,843	$8,561
505	ELECTRIC EXPENSES-Labor	51	$563,732	$211,992	$71,615	$13,305	$120,591	$15,782	$18,379	$72,106	$2,034	$19,832	$10,681	$2,665	$4,404	$167	$181
	ELECTRIC EXPENSES-- Other	1	$177,937	$64,191	$22,190	$4,298	$38,527	$5,216	$5,925	$24,077	$661	$6,744	$3,398	$892	$1,693	$64	$62
506	MISC. STEAM POWER EXPENSES	51	$18,305,637	$7,259,890	$2,452,535	$455,646	$4,129,774	$540,471	$629,406	$2,469,343	$69,652	$679,175	$365,767	$91,267	$150,821	$5,707	$6,183
507	RENTS	51	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
509	ALLOWANCES	51	$4,878	$1,759	$594	$110	$1,001	$131	$153	$598	$17	$165	$89	$22	$37	$1	$1
510	MAINTENANCE SUPERVISION & ENGINEERING	61	$2,618,047	$953,065	$329,199	$63,672	$570,951	$77,211	$87,779	$356,287	$9,784	$99,742	$50,360	$13,195	$24,942	$944	$917
511	MAINTENANCE OF STRUCTURES	51	$2,262,456	$850,797	$287,416	$53,398	$483,974	$63,339	$73,761	$289,386	$8,163	$79,594	$42,865	$10,696	$17,675	$669	$725
512	MAINTENANCE OF BOILER PLANT	1	$34,630,824	$12,493,141	$4,318,775	$836,506	$7,498,217	$1,015,146	$1,153,143	$4,685,929	$128,567	$1,312,589	$661,276	$173,557	$329,444	$12,466	$12,069
513	MAINTENANCE OF ELECTRIC PLANT	1	$7,280,413	$2,626,424	$907,933	$175,858	$1,576,345	$213,413	$242,424	$985,119	$27,028	$275,945	$139,020	$36,487	$69,259	$2,621	$2,537
514	MAINTENANCE OF MISC STEAM PLANT	1	$1,572,978	$567,455	$196,165	$37,995	$340,579	$46,109	$52,377	$212,841	$5,840	$59,620	$30,036	$7,883	$14,964	$566	$548
	Sub-total		$438,053,215	$167,849,232	$64,462,267	$10,513,245	$94,321,378	$12,735,484	$14,495,105	$58,740,418	$1,615,137	$16,430,962	$8,321,161	$2,176,264	$4,087,915	$154,882	$150,965
	Hydraulic Production O&M																
535	OPERATION SUPERVISION & ENGINEERING	62	$96,788	$36,397	$12,296	$2,284	$20,704	$2,710	$3,155	$12,380	$349	$3,405	$1,834	$458	$756	$29	$31
536	WATER FOR POWER	51	$39,044	$14,683	$4,960	$922	$8,352	$1,093	$1,273	$4,994	$141	$1,374	$740	$185	$305	$12	$13
537	HYDRAULIC EXPENSES	51	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
538	ELECTRIC EXPENSES	51	$164,110	$61,714	$20,848	$3,873	$35,106	$4,594	$5,350	$20,991	$592	$5,773	$3,109	$776	$1,282	$49	$53
539	MISC. HYDRAULIC POWER EXPENSES	51	$118,533	$44,574	$15,058	$2,798	$25,356	$3,318	$3,864	$15,161	$428	$4,170	$2,246	$560	$926	$35	$38
540	RENTS	51	$378,801	$142,448	$48,122	$8,940	$81,031	$10,605	$12,350	$48,452	$1,367	$13,326	$7,177	$1,791	$2,959	$112	$121
541	MAINTENANCE SUPERVISION & ENGINEERING	63	$101	$37	$13	$2	$22	$3	$3	$13	$0	$4	$2	$0	$1	$0	$0
542	MAINTENANCE OF STRUCTURES	51	$203,930	$76,688	$25,907	$4,813	$43,624	$5,709	$6,649	$26,084	$736	$7,174	$3,864	$964	$1,593	$60	$65
543	MAINT. OF RESERVES, DAMS, AND WATERWAYS	61	$88,508	$32,531	$10,989	$2,042	$18,505	$2,422	$2,820	$11,065	$312	$3,043	$1,639	$409	$676	$26	$28
544	MAINTENANCE OF ELECTRIC PLANT	1	$200,808	$72,442	$25,043	$4,851	$43,479	$5,886	$6,687	$27,172	$745	$7,611	$3,834	$1,006	$1,910	$72	$70
545	MAINTENANCE OF MISC HYDRAULIC PLANT	1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub-total		$1,288,621	$481,513	$163,235	$30,525	$276,179	$36,340	$42,152	$188,312	$4,670	$45,881	$24,444	$6,149	$10,409	$384	$418
	Other Power Generation Operation Expense																
546	OPERATION SUPERVISION & ENGINEERING	51	$31,105	$11,697	$3,951	$734	$6,654	$871	$1,014	$3,979	$112	$1,094	$589	$147	$243	$9	$10
547	FUEL	1	$11,186,602	$4,035,590	$1,395,070	$270,212	$2,422,107	$327,917	$372,493	$1,513,670	$41,530	$423,998	$213,608	$56,063	$106,418	$4,027	$3,899
548	GENERATION EXPENSE	51	$127,492	$47,943	$16,196	$3,009	$27,273	$3,569	$4,157	$16,307	$460	$4,485	$2,415	$603	$996	$38	$41
549	MISC OTHER POWER GENERATION	51	$41,162	$15,479	$5,229	$971	$8,805	$1,152	$1,342	$5,265	$149	$1,448	$780	$195	$322	$12	$13
550	RENTS	51	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
551	MAINTENANCE SUPERVISION & ENGINEERING	51	$40,120	$15,087	$5,097	$947	$8,582	$1,123	$1,308	$5,132	$145	$1,411	$760	$190	$313	$12	$13
552	MAINTENANCE OF STRUCTURES	51	$65,277	$24,547	$8,293	$1,541	$13,964	$1,827	$2,128	$8,349	$236	$2,296	$1,237	$309	$510	$19	$21
553	MAINTENANCE OF GENERATING & ELEC PLANT	51	$1,480,185	$556,624	$188,039	$34,935	$316,634	$41,438	$48,257	$189,327	$5,340	$52,073	$28,044	$6,998	$11,564	$438	$474
554	MAINTENANCE OF MISC OTHER POWER GEN PLT	51	$161,443	$60,711	$20,509	$3,810	$34,535	$4,520	$5,263	$20,650	$582	$5,680	$3,059	$763	$1,261	$48	$52
	Sub-total		$13,133,386	$4,787,678	$1,642,384	$318,159	$2,838,554	$382,418	$435,963	$1,762,679	$48,554	$492,488	$250,492	$85,268	$121,627	$4,602	$4,622
	Other Power Supply Expense																
555	PURCHASED POWER																
	Demand	51	$10,209,122	$3,839,143	$1,296,939	$240,953	$2,183,889	$285,809	$332,839	$1,305,827	$36,833	$359,159	$193,423	$48,263	$79,757	$3,018	$3,270
	Energy	1	$87,410,519	$24,318,484	$8,406,698	$1,628,299	$14,595,631	$1,976,029	$2,244,646	$9,121,380	$250,261	$2,555,015	$1,287,204	$337,836	$641,278	$24,265	$23,493
555	PURCHASED POWER OPTIONS		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
555	BROKERAGE FEES		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
555	MISO TRANSMISSION EXPENSES		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
556	SYSTEM CONTROL AND LOAD DISPATCH	51	$1,445,355	$543,526	$183,614	$34,113	$309,184	$40,463	$47,122	$184,872	$5,215	$50,848	$27,384	$6,833	$11,292	$427	$463
557	OTHER EXPENSES	51	$2,008,235	$755,197	$255,121	$47,398	$429,592	$56,222	$65,473	$256,869	$7,245	$70,650	$38,048	$9,494	$15,689	$594	$643
558	DUPLICATE CHARGES	1	($3,972,034)	($1,432,919)	($495,348)	($95,944)	($860,019)	($116,434)	($132,261)	($537,460)	($14,746)	($150,549)	($75,846)	($19,906)	($37,786)	($1,430)	($1,384)
	Sub-total		$77,101,197	$28,023,431	$9,647,023	$1,854,818	$16,658,277	$2,242,090	$2,557,819	$10,331,489	$284,808	$2,885,122	$1,470,213	$382,520	$710,228	$26,874	$28,484
Transmission Expenses																	
560	OPERATION SUPERVISION AND ENG	51	$888,384	$251,338	$84,907	$15,775	$142,973	$18,711	$21,790	$85,489	$2,411	$23,513	$12,663	$3,160	$5,221	$198	$214
561	LOAD DISPATCHING	51	$932,847	$350,797	$118,506	$22,017	$199,550	$26,116	$30,413	$119,318	$3,366	$32,818	$17,674	$4,410	$7,288	$276	$299
562	STATION EXPENSES	51	$1,257,574	$472,911	$159,759	$29,681	$269,015	$35,206	$41,000	$160,854	$4,537	$44,242	$23,826	$5,945	$9,825	$372	$403
563	OVERHEAD LINE EXPENSES	51	$136,420	$50,925	$17,203	$3,196	$28,968	$3,791	$4,415	$17,321	$489	$4,764	$2,566	$640	$1,058	$40	$43
565	TRANSMISSION OF ELECTRICITY BY OTHERS	51	$4,130,106	$1,553,128	$524,677	$97,478	$883,493	$115,624	$134,650	$528,273	$14,901	$145,298	$78,249	$19,525	$32,266	$1,221	$1,323
566	MISC. TRANSMISSION EXPENSES	51	$3,168,816	$1,190,882	$402,304	$74,742	$677,431	$88,657	$103,245	$405,061	$11,425	$111,409	$59,999	$14,971	$24,740	$936	$1,014
567	RENTS	51	$22,287	$8,381	$2,831	$526	$4,768	$624	$727	$2,851	$80	$784	$422	$105	$174	$7	$7
568	MAINTENACE SUPERVISION AND ENG		$0											$0	$0	$0	$0
569	STRUCTURES	51	$17,207	$6,471	$2,186	$406	$3,681	$482	$561	$2,201	$62	$605	$326	$81	$134	$5	$6
570	MAINT OF STATION EQUIPMENT	51	$1,195,088	$449,412	$151,820	$28,206	$255,647	$33,457	$38,962	$152,861	$4,312	$42,043	$22,642	$5,650	$9,336	$353	$383
571	MAINT OF OVERHEAD LINES	51	$513,643	$193,156	$65,252	$12,123	$109,876	$14,380	$16,746	$65,699	$1,853	$18,070	$9,732	$2,428	$4,013	$152	$165
572	UNDERGROUND LINES		$0											$0	$0	$0	$0
573	MISC PLANT	51	$1,388	$522	$176	$33	$297	$39	$45	$178	$5	$49	$26	$7	$11	$0	$0
575	MARKET FACILITATION, MONITORING & COMPLIANCE	51	$925,090	$347,880	$117,521	$21,834	$197,891	$25,898	$30,160	$118,326	$3,338	$32,545	$17,527	$4,373	$7,227	$273	$296
	Sub-total		$12,965,828	$4,875,803	$1,647,143	$306,016	$2,773,591	$362,985	$422,714	$1,658,432	$46,779	$458,140	$245,652	$61,296	$101,293	$3,833	$4,153
	Distribution Expense - Operating																
580	OPERATION SUPERVISION AND ENGI	64	$1,650,124	$1,346,074	$214,656	$11,763	$135,933	$11,535	$14,602	$50,774	$3,212	$461	$7,578	$1,961	$48,032	$525	$3,019
581	LOAD DISPATCHING	28	$384,127	$185,953	$50,264	$8,037	$69,355	$9,245	$9,913	$38,561	$1,231	$0	$6,196	$1,437	$3,749	$127	$59
582	STATION EXPENSES	28	$1,009,374	$488,630	$132,080	$21,118	$182,246	$24,294	$26,049	$101,327	$3,233	$0	$16,282	$3,776	$9,850	$334	$154
583	OVERHEAD LINE EXPENSES	55	($2,168,951)	($1,321,306)	($297,844)	($25,512)	($272,884)	($29,262)	($38,884)	($122,001)	($4,948)	$-0	($19,598)	($4,547)	($29,296)	($507)	($363)

Louisville Gas & Electric
Electric Cost of Service Study
(Expenses)

Acct. No.	Account Description	Allocator	Total System	Residential Rate RS	Gen. Service GSS	Rate PS Primary	Rate PS Secondary	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Secndary	Rate RTS Transmission	Sp. Contract Ft. Knox	Sp. Contract Water Co.	St. Lighting RLS & LS	St. Lighting LE	Traffic SL TLE
584	UNDERGROUND LINE EXPENSES	58	$331,165	$184,414	$41,751	$5,582	$48,798	$6,409	$6,922	$26,725	$861	$0	$4,293	$996	$4,268	$90	$56
585	STREET LIGHTING EXPENSE	15	$10,273	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,273	$0	$0
586	METER EXPENSES	28	$6,014,822	$5,058,958	$665,768	$10,406	$222,769	$1,865	$7,459	$21,353	$7,940	$2,346	$481	$1,143	$0	$1,564	$12,872
586	METER EXPENSES - LOAD MANAGEMENT		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
587	CUSTOMER INSTALLATIONS EXPENSE	7	($172,883)	$-0	$-0	$-0	$-0	$-0	$-0	$-0	$-0	$-0	$-0	$-0	($171,083)	($193)	($1,586)
588	MISCELLANEOUS DISTRIBUTION EXP	53	$2,843,085	$1,631,571	$354,032	$29,341	$314,642	$33,483	$44,296	$139,891	$5,781	$47	$22,414	$5,221	$258,530	$885	$2,950
588	MISC DISTR EXP -- MAPPIN		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
589	RENTS	53	$14,189	$8,128	$1,764	$146	$1,567	$167	$221	$697	$29	$0	$112	$26	$1,288	$4	$15
590	MAINTENANCE SUPERVISION AND EN	65	$3,451	$3,513	$709	($7)	$256	($9)	$37	($36)	$5	($0)	($6)	($1)	($1,010)	$0	$0
591	STRUCTURES	28	$770,034	$372,767	$100,761	$16,110	$139,032	$18,534	$19,873	$77,301	$2,467	$0	$12,421	$2,881	$7,515	$255	$118
592	MAINTENANCE OF STATION EQUIPME	28	$957,159	$463,353	$125,247	$20,025	$172,818	$23,037	$24,702	$96,086	$3,066	$0	$15,440	$3,581	$9,341	$317	$146
593	MAINTENANCE OF OVERHEAD LINES	65	($5,345,079)	($3,259,180)	($734,672)	($62,928)	($673,106)	($72,178)	($95,913)	($300,933)	($12,204)	$-0	($48,341)	($11,217)	($72,262)	($1,251)	($895)
594	MAINTENANCE OF UNDERGROUND LIN	68	$1,623,097	$903,843	$204,627	$27,359	$239,166	$31,412	$33,924	$130,983	$4,219	$0	$21,043	$4,882	$20,920	$443	$275
595	MAINTENANCE OF LINE TRANSFORME	70	($487,253)	($360,819)	($77,797)	$-0	($35,048)	$-0	($5,066)	$-0	($708)	$-0	$-0	$-0	($7,666)	($66)	($82)
596	MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	15	$508,593	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$508,593	$0	$0
597	MAINTENANCE OF METERS	28	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
598	MISCELLANEOUS DISTRIBUTION EXPENSES	53	$280,282	$166,574	$36,145	$2,996	$32,123	$3,418	$4,522	$14,282	$590	$5	$2,288	$533	$26,394	$90	$301
	Sub-total		$8,437,683	$5,872,472	$817,486	$84,435	$577,668	$61,950	$52,657	$275,010	$14,772	$2,660	$40,606	$10,872	$827,438	$2,618	$17,038
	Customer Accounts Expense																
901	SUPERVISION/CUSTOMER ACCTS	6	$800,912	$633,950	$83,973	$1,632	$55,552	$762	$3,047	$1,632	$617	$181	$36	$73	$19,257	$22	$178
902	METER READING EXPENSES	6	$2,113,947	$1,673,264	$221,641	$4,308	$146,625	$2,011	$8,042	$4,308	$1,628	$479	$96	$191	$50,828	$57	$469
903	RECORDS AND COLLECTION	6	$5,314,316	$4,206,469	$557,191	$10,831	$368,604	$5,054	$20,217	$10,831	$4,092	$1,203	$241	$481	$127,778	$144	$1,179
904	UNCOLLECTIBLE ACCOUNTS	6	$2,405,783	$1,904,262	$252,239	$4,903	$166,867	$2,288	$9,152	$4,903	$1,852	$545	$109	$218	$57,845	$65	$534
905	MISC CUST ACCOUNTS	6	$379,346	$300,266	$39,773	$773	$26,312	$361	$1,443	$773	$292	$86	$17	$34	$9,121	$10	$84
	Sub-total		$11,014,304	$8,718,212	$1,154,818	$22,447	$763,959	$10,475	$41,902	$22,447	$8,480	$2,494	$488	$998	$264,829	$299	$2,444
	Customer Service & Information Expense																
907	SUPERVISION	6	$119,732	$94,772	$12,554	$244	$8,305	$114	$455	$244	$92	$27	$5	$11	$2,879	$3	$27
908	CUSTOMER ASSISTANCE EXPENSES	6	$6,415,901	$5,078,413	$672,689	$13,076	$445,011	$6,102	$24,408	$13,076	$4,940	$1,453	$291	$581	$154,265	$174	$1,424
908	CUSTOMER ASSISTANCE EXP-INCENTIVES		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
909	INFORMATIONAL AND INSTRUCTIONA	6	$158,029	$125,086	$16,569	$322	$10,961	$150	$601	$322	$122	$36	$7	$14	$3,800	$4	$35
909	INFORM AND INSTRUC -LOAD MGMT		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
910	MISCELLANEOUS CUSTOMER SERVICE	6	$2,330,329	$1,844,538	$244,328	$4,749	$161,633	$2,216	$8,865	$4,749	$1,794	$528	$106	$211	$56,031	$63	$517
911	DEMONSTRATION AND SELLING EXP		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
912	DEMONSTRATION AND SELLING EXP	6	$7,980	$6,301	$835	$16	$552	$8	$30	$16	$6	$2	$0	$1	$191	$0	$2
913	ADVERTISING EXPENSES	6	$42,908	$33,962	$4,499	$87	$2,976	$41	$163	$87	$33	$10	$2	$4	$1,032	$1	$10
915	MDSE-JOBBING-CONTRACT		$0														
916	MISC SALES EXPENSE		$0														
	Sub-total		$9,074,857	$7,183,071	$951,472	$18,495	$629,438	$8,631	$34,524	$18,495	$6,987	$2,055	$411	$822	$218,197	$247	$2,014
	General Expenses																
920	ADMIN. & GEN. SALARIES-	68	$14,156,874	$6,399,488	$1,743,225	$278,811	$2,608,329	$329,278	$384,506	$1,503,676	$44,591	$398,882	$218,849	$55,718	$179,794	$4,082	$6,644
921	OFFICE SUPPLIES AND EXPENSES	68	$4,344,577	$1,964,066	$535,013	$85,570	$800,522	$101,059	$118,009	$461,493	$13,685	$122,421	$67,167	$17,100	$55,180	$1,253	$2,039
922	ADMINISTRATIVE EXPENSES TRANSFERRED	68	($2,258,053)	($1,019,901)	($277,822)	($44,435)	($415,695)	($52,478)	($61,280)	($239,644)	($7,107)	($63,571)	($34,879)	($8,880)	($28,654)	($651)	($1,059)
923	OUTSIDE SERVICES EMPLOYED	68	$5,390,844	$2,437,100	$663,868	$106,179	$993,323	$125,398	$146,430	$572,641	$16,981	$151,905	$83,344	$21,219	$68,470	$1,555	$2,530
924	PROPERTY INSURANCE	23	$3,341,145	$1,418,534	$422,390	$67,974	$630,123	$80,248	$94,981	$362,869	$10,764	$88,729	$54,237	$13,426	$94,211	$1,001	$1,658
925	INJURIES AND DAMAGES - INSURAN	68	$1,718,338	$776,814	$211,605	$33,844	$316,617	$39,970	$46,674	$182,527	$5,413	$48,419	$26,565	$6,763	$21,825	$495	$807
926	EMPLOYEE BENEFITS	68	$35,383,805	$15,986,930	$4,354,852	$696,513	$6,516,017	$822,588	$960,557	$3,756,421	$111,395	$996,471	$546,720	$139,192	$449,153	$10,197	$16,599
927	FRANCHISE REQUIREMENTS	23	$25,547	$10,846	$3,230	$520	$4,818	$614	$726	$2,775	$82	$678	$415	$103	$720	$8	$13
928	REGULATORY COMMISSION FEES	23	$1,119,103	$475,132	$141,478	$22,768	$211,057	$26,879	$31,814	$121,542	$3,605	$29,720	$18,167	$4,497	$31,555	$335	$555
929	DUPLICATE CHARGES	68	($27,402)	($12,388)	($3,374)	($540)	($5,049)	($637)	($744)	($2,911)	($86)	($772)	($424)	($108)	($348)	($8)	($13)
930	MISCELLANEOUS GENERAL EXPENSES	68	$1,623,174	$733,793	$199,886	$31,970	$299,082	$37,756	$44,089	$172,418	$5,113	$45,738	$25,094	$6,389	$20,616	$468	$762
931	RENTS AND LEASES	59	$1,387,133	$591,032	$175,336	$28,079	$260,508	$33,144	$39,252	$149,814	$4,452	$36,463	$22,400	$5,543	$39,997	$416	$696
935	MAINTENANCE OF GENERAL PLANT	59	$7,371,700	$3,140,948	$931,794	$149,223	$1,384,430	$176,137	$208,598	$796,164	$23,660	$193,779	$119,041	$29,459	$212,559	$2,208	$3,698
	Sub-total		$73,557,885	$32,602,398	$9,101,481	$1,458,475	$13,604,082	$1,719,954	$2,013,813	$7,839,785	$232,550	$2,048,863	$1,148,697	$290,422	$1,146,078	$21,359	$34,930
	TOTAL O & M EXPENSES		$642,626,776	$250,673,808	$79,587,312	$14,582,616	$132,443,125	$17,580,327	$20,096,448	$80,815,067	$2,262,737	$22,368,883	$11,500,178	$2,993,408	$7,287,013	$214,808	$242,988
	TOTAL O&M EXPENSE Less PURCHASED POWER		$585,007,135	$222,518,181	$69,883,675	$12,713,384	$115,863,606	$15,298,489	$17,518,982	$70,387,859	$1,975,643	$19,452,690	$10,018,548	$2,607,309	$8,565,979	$187,624	$218,208
	Depreciation Expense																
	Power Production - Energy	1	$85,053,049	$23,468,021	$8,112,701	$1,571,354	$14,085,194	$1,906,924	$2,166,147	$8,802,389	$241,509	$2,465,662	$1,242,188	$326,021	$618,851	$23,417	$22,671
	Power Production - Demand	32	$14,161,952	$6,320,803	$1,950,554	$298,257	$2,860,118	$310,739	$416,434	$1,329,835	$44,286	$321,135	$258,628	$48,465	$0	$0	$2,700
	Transmission - Energy	1	$4,858,170	$1,679,723	$580,666	$112,470	$1,008,147	$136,488	$155,042	$630,031	$17,286	$176,480	$88,910	$23,335	$44,294	$1,676	$1,623
	Transmission - Demand	32	$1,013,841	$452,411	$139,611	$21,348	$204,713	$22,241	$29,806	$95,183	$3,170	$22,985	$18,511	$3,469	$0	$0	$193
	Dist. Poles - Specific	28	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Dist Substation - General	28	$2,523,489	$1,221,605	$330,207	$52,795	$455,627	$60,737	$65,125	$253,324	$8,084	$0	$40,707	$9,441	$24,627	$835	$385
	Dist. Primary Lines	84	$12,133,992	$6,932,099	$1,510,151	$195,910	$1,706,588	$224,805	$241,474	$937,335	$30,019	$0	$150,577	$34,937	$164,821	$3,172	$2,105
	Dist. Secondary Lines - Demand	85	$2,289,690	$1,598,481	$415,573	$0	$220,530	$0	$32,638	$0	$4,552	$0	$0	$0	$27,088	$405	$323
	Dist. Line Transformers - Demand	88	$3,607,897	$2,671,709	$576,056	$0	$259,514	$0	$37,510	$0	$5,245	$0	$0	$0	$56,764	$492	$607
	Dist. Services - Customer	27	$715,177	$631,960	$75,606	$0	$5,569	$0	$153	$0	$82	$0	$0	$0	$0	$197	$1,611
	Dist. Meters - Customer	28	$1,039,084	$873,940	$115,012	$1,798	$38,484	$322	$1,288	$3,689	$1,372	$405	$83	$197	$0	$270	$2,224
	Dist Street & Customer Lighting	7	$1,954,062	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,933,945	$2,186	$17,931
	TOTAL DEPRECIATION EXPENSES		$109,158,113	$45,850,753	$13,806,137	$2,253,931	$20,844,484	$2,682,258	$3,145,617	$12,051,785	$355,604	$2,966,866	$1,799,803	$445,865	$2,870,390	$32,648	$52,373

Other Expenses

Louisville Gas & Electric
Electric Cost of Service Study
(Expenses)

Acct. No.	Account Description	Allocator	Total System	Residential Rate RS	Gen. Service GSS	Rate PS-Primary	Rate PS-Secondary	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Secndary	Rate RTS Transmission	Sp. Contract Ft. Knox	Sp. Contract Water Co.	St. Lighting RLS & LS	St. Lighting LE	Traffic SL TLE
	Regulatory Credits																
	Production	51	($1,705,393)	($641,314)	($216,648)	($40,250)	($364,810)	($47,743)	($55,600)	($218,133)	($6,153)	($59,996)	($32,311)	($8,062)	($13,323)	($504)	($546)
	Transmission	52	($1,467)	($552)	($186)	($35)	($314)	($41)	($48)	($188)	($5)	($52)	($28)	($7)	($11)	($0)	($0)
	Distribution	53	($16,231)	($9,315)	($2,021)	($168)	($1,796)	($191)	($253)	($799)	($33)	($0)	($128)	($30)	($1,476)	($5)	($17)
	Common	69	($1,189)	($507)	($150)	($24)	($223)	($28)	($34)	($128)	($4)	($31)	($19)	($5)	($34)	($0)	($1)
	Accretion Expense																
	Production	51	$1,483,472	$557,860	$188,456	$35,013	$317,338	$41,531	$48,364	$189,748	$5,352	$52,189	$28,106	$7,013	$11,589	$439	$475
	Transmission	52	$1,395	$525	$177	$33	$298	$39	$45	$178	$5	$49	$26	$7	$11	$0	$0
	Distribution	53	$15,865	$9,105	$1,976	$164	$1,756	$187	$247	$781	$32	$0	$125	$29	$1,443	$5	$16
	Common	69	$1,163	$496	$147	$24	$218	$28	$33	$126	$4	$31	$19	$5	$34	$0	$1
	Property Taxes & Other	23	$18,568,593	$7,883,577	$2,347,457	$377,769	$3,501,943	$445,980	$527,862	$2,016,666	$59,822	$493,118	$301,427	$74,617	$523,581	$5,560	$9,214
	Amortization of Investment Tax Credit	23	$1,881,232	$790,214	$235,299	$37,866	$351,019	$44,703	$52,911	$202,142	$5,996	$49,428	$30,214	$7,479	$52,481	$557	$924
	Gain on Disposition of Allowances	23	($68,274)	($28,138)	($8,378)	($1,348)	($12,499)	($1,592)	($1,884)	($7,198)	($214)	($1,760)	($1,076)	($266)	($1,869)	($20)	($33)
	Interest	23	$48,502,810	$20,592,602	$6,131,766	$986,765	$9,147,387	$1,164,939	$1,378,823	$5,267,711	$156,260	$1,288,067	$787,353	$194,906	$1,367,639	$14,524	$24,067
	Other Expenses		$0														
	Total Other Expenses		$68,643,678	$29,154,554	$8,677,893	$1,395,808	$12,940,317	$1,647,811	$1,950,467	$7,450,905	$221,063	$1,821,042	$1,113,709	$276,688	$1,940,064	$20,658	$34,100
TOTAL EXPENSES			$820,428,865	$325,679,115	$102,071,342	$18,232,356	$166,227,826	$21,870,393	$25,182,532	$100,317,757	$2,839,404	$27,174,572	$14,413,488	$3,714,858	$12,097,488	$268,112	$328,441
Calculation of Taxable Income and Allocation of Income Taxes:																	
	Total Operating Revenue		$958,491,762	$382,037,690	$137,184,376	$20,622,875	$199,798,423	$23,737,046	$28,229,215	$102,334,431	$3,197,444	$28,722,557	$14,005,641	$3,519,708	$16,551,683	$243,100	$309,661
	Operating Expenses		$771,928,055	$305,086,512	$95,939,576	$17,245,590	$157,080,540	$20,705,454	$23,813,710	$95,050,046	$2,883,144	$28,888,505	$13,628,134	$3,520,053	$10,729,829	$253,588	$305,374
	Interest Expense		$48,502,810	$20,592,602	$8,131,766	$986,765	$9,147,387	$1,184,939	$1,378,823	$5,267,711	$158,260	$1,288,067	$787,353	$194,906	$1,367,639	$14,524	$24,067
	Taxable Income		$138,062,887	$56,358,476	$35,113,033	$2,390,520	$33,568,497	$1,866,653	$3,036,683	$2,016,674	$358,040	($452,015)	($407,846)	($195,251)	$4,454,214	($25,012)	($19,780)
	Income Taxes																
	State & Federal Income Taxes		$48,783,814	$19,089,397	$11,893,271	$809,702	$11,370,115	$632,261	$1,028,587	$683,075	$121,273	($153,104)	($138,143)	($68,134)	$1,508,704	($8,472)	($6,700)

Louisville Gas & Electric
Electric Cost of Service Study
(Labor)

Acct. No.	Account Description	Allocator	Total System	Residential Rate RS	Gen. Service GSS	Rate PS Primary	Rate PS Secondary	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Secndary	Rate RTS Transmissio	Sp. Contract Ft. Knox	Sp. Contract Water Co.	St. Lighting RLS & LS	St. Lighting LE	Traffic SL TLE
	Labor O & M Expenses																
	Labor Expenses																
	Steam Power Generation Operation Expenses																
500	OPERATION SUPERVISION & ENGINEERING	60	$1,490,340	$557,010	$188,806	$35,299	$319,391	$42,019	$48,744	$192,287	$5,400	$53,041	$28,270	$7,109	$12,025	$455	$484
501	FUEL	1	$2,869,025	$1,035,087	$357,793	$69,301	$621,197	$84,101	$95,533	$388,210	$10,651	$108,743	$54,784	$14,378	$27,293	$1,033	$1,000
502	STEAM EXPENSES	51	$11,242,697	$4,227,820	$1,428,241	$265,347	$2,404,987	$314,745	$366,536	$1,438,030	$40,562	$395,520	$213,005	$53,149	$87,831	$3,323	$3,601
505	ELECTRIC EXPENSES	51	$563,732	$211,992	$71,615	$13,305	$120,591	$15,782	$18,379	$72,106	$2,034	$19,832	$10,681	$2,665	$4,404	$167	$181
506	MISC. STEAM POWER EXPENSES	51	$4,379,139	$1,646,777	$556,314	$103,355	$936,765	$122,596	$142,769	$560,126	$15,799	$154,059	$82,968	$20,702	$34,211	$1,295	$1,403
507	RENTS	51	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Steam Power Operation Expenses		$20,544,933	$7,678,604	$2,602,769	$486,607	$4,402,931	$579,242	$671,962	$2,650,760	$74,447	$731,195	$389,707	$98,004	$165,764	$6,272	$6,667
	Steam Power Generation Maintenance Expenses																
510	MAINTENANCE SUPERVISION & ENGINEERING	61	$1,419,243	$512,740	$177,106	$34,255	$307,166	$41,539	$47,224	$191,679	$5,264	$53,660	$27,093	$7,099	$13,419	$508	$493
511	MAINTENANCE OF STRUCTURES	51	$282,445	$106,214	$35,881	$6,666	$60,419	$7,907	$9,208	$36,127	$1,019	$9,936	$5,351	$1,335	$2,207	$83	$90
512	MAINTENANCE OF BOILER PLANT	1	$6,424,675	$2,317,715	$801,215	$155,188	$1,391,062	$188,329	$213,930	$869,329	$23,852	$243,510	$122,679	$32,198	$61,118	$2,313	$2,239
513	MAINTENANCE OF ELECTRIC PLANT	1	$1,483,608	$535,215	$185,019	$35,837	$321,229	$43,490	$49,401	$200,748	$5,508	$56,232	$28,330	$7,435	$14,114	$534	$517
514	MAINTENANCE OF MISC STEAM PLANT	1	$43,556	$15,713	$5,432	$1,052	$9,431	$1,277	$1,450	$5,894	$162	$1,651	$832	$218	$414	$16	$15
	Total Steam Power Generation Maintenance Expense		$9,653,527	$3,487,595	$1,204,653	$232,997	$2,089,306	$282,541	$321,214	$1,303,776	$35,804	$364,990	$184,285	$48,286	$91,271	$3,454	$3,355
	Total Steam Power Generation Expense		$30,198,460	$11,166,200	$3,807,422	$719,605	$6,492,237	$861,783	$993,177	$3,954,536	$110,251	$1,096,184	$573,992	$146,290	$257,035	$9,726	$10,022
	Hydraulic Power Generation Operation Expenses																
535	OPERATION SUPERVISION & ENGINEERING	62	$76,594	$28,803	$9,730	$1,808	$16,385	$2,144	$2,497	$9,797	$276	$2,695	$1,451	$362	$598	$23	$25
536	WATER FOR POWER	51	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
537	HYDRAULIC EXPENSES	51	$0	$0	$0	$0	$0	$0	$0	.$0	$0	$0	$0	$0	$0	$0	$0
538	ELECTRIC EXPENSES	51	$135,663	$51,016	$17,234	$3,202	$29,020	$3,798	$4,423	$17,352$489		$4,773	$2,570	$641	$1,060	$40	$43
539	MISC. HYDRAULIC POWER EXPENSES	51	$9,267	$3,485	$1,177	$219	$1,982	$259	$302	$1,185	$33	$326	$176	$44	$72	$3	$3
540	RENTS	51	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Hydraulic Power Operation Expenses		$221,524	$83,304	$28,142	$5,228	$47,387	$6,202	$7,222	$28,335$799		$7,793	$4,197	$1,047	$1,731	$65	$71
	Hydraulic Power Generation Maintenance Expenses																
541	MAINTENANCE SUPERVISION & ENGINEERING	63	$76	$28	$10	$2	$16	$2	$3	$10	$0	$3	$1	$0	$1	$0	$0
542	MAINTENANCE OF STRUCTURES	51	$22,785	$8,568	$2,895	$538	$4,874	$638	$743	$2,914	$82	$802	$432	$108	$178	$7	$7
543	MAINT. OF RESERVES, DAMS, AND WATERWAYS	51	$49,157	$18,486	$6,245	$1,160	$10,515	$1,376	$1,603	$6,288	$177	$1,729	$931	$232	$384	$15	$16
544	MAINTENANCE OF ELECTRIC PLANT	1	$110,859	$39,993	$13,825	$2,678	$24,003	$3,250	$3,691	$15,000$412		$4,202	$2,117	$556	$1,055	$40	$39
545	MAINTENANCE OF MISC HYDRAULIC PLANT	1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Hydraulic Power Generation Maint. Expense		$182,877	$67,074	$22,974	$4,378	$39,409	$5,266	$6,039	$24,212$671		$6,736	$3,481	$896	$1,617	$61	$62
	Total Hydraulic Power Generation Expense		$404,401	$150,378	$51,116	$9,606	$86,796	$11,468	$13,262	$52,547	$1,471	$14,529	$7,678	$1,943	$3,348	$127	$133
	Other Power Generation Operation Expense																
546	OPERATION SUPERVISION & ENGINEERING	51	$22,899	$8,611	$2,909	$540	$4,898	$641	$747	$2,929	$83	$806	$434	$108	$179	$7	$7
547	FUEL	1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
548	GENERATION EXPENSE	51	$77,953	$29,314	$9,903	$1,840	$16,675	$2,182	$2,541	$9,971	$281	$2,742	$1,477	$369	$609	$23	$25
549	MISC OTHER POWER GENERATION	51	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
550	RENTS	51	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Other Power Generation Expenses		$100,852	$37,925	$12,812	$2,380	$21,574	$2,823	$3,288	$12,900$364		$3,548	$1,911	$477	$788	$30	$32
	Other Power Generation Maintenance Expense																
551	MAINTENANCE SUPERVISION & ENGINEERING	51	$38,860	$14,613	$4,937	$917	$8,313	$1,088	$1,267	$4,971	$140	$1,367	$736	$184	$304	$11	$12
552	MAINTENANCE OF STRUCTURES	51	$48,205	$18,128	$6,124	$1,138	$10,312	$1,350	$1,572	$6,166	$174	$1,696	$913	$228	$377	$14	$15
553	MAINTENANCE OF GENERATING & ELEC PLANT	51	$215,080	$80,881	$27,323	$5,076	$46,009	$6,021	$7,012	$27,510$776		$7,567	$4,075	$1,017	$1,680	$64	$69
554	MAINTENANCE OF MISC OTHER POWER GEN PLT	51	$33,614	$12,641	$4,270	$793	$7,191	$941	$1,096	$4,299	$121	$1,183	$637	$159	$263	$10	$11
	Total Other Power Generation Maintenance Expense		$335,759	$126,262	$42,654	$7,924	$71,824	$9,400	$10,946	$42,946	$1,211	$11,812	$6,361	$1,587	$2,623	$99	$108
	Total Other Power Generation Expense		$436,611	$164,188	$55,466	$10,305	$93,398	$12,223	$14,234	$55,846	$1,575	$15,360	$8,272	$2,064	$3,411	$129	$140
	Total Production Expense		$31,039,472	$11,480,766	$3,914,003	$739,515	$6,672,431	$885,474	$1,020,673	$4,062,929	$113,296	$1,126,073	$589,942	$150,298	$263,794	$9,982	$10,295
	Purchased Power																

Louisville Gas & Electric
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(Labor)

Acct. No.	Account Description	Allocator	Total System	Residential Rate RS	Gen. Service GSS	Rate PS Primary	Rate PS Secondary	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Secondary	Rate RTS Transmissio	Sp. Contract Ft. Knox	Sp. Contract Water Co.	St. Lighting RLS & LS	St. Lighting LE	Traffic SL TLE
555	PURCHASED POWER		$0														
556	SYSTEM CONTROL AND LOAD DISPATCH	51	$1,033,082	$388,491	$131,240	$24,383	$220,992	$28,922	$33,681	$132,139	$3,727	$36,344	$19,573	$4,884	$8,071	$305	$331
557	OTHER EXPENSES	51	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Purchased Power Labor		$1,033,082	$388,491	$131,240	$24,383	$220,992	$28,922	$33,681	$132,139	$3,727	$36,344	$19,573	$4,884	$8,071	$305	$331
	Transmission Labor Expenses																
560	OPERATION SUPERVISION AND ENG	51	$447,371	$168,234	$56,833	$10,559	$95,700	$12,524	$14,585	$57,222	$1,614	$15,739	$8,476	$2,115	$3,495	$132	$143
561	LOAD DISPATCHING	51	$716,320	$269,372	$90,999	$16,906	$153,232	$20,054	$23,354	$91,623	$2,584	$25,200	$13,571	$3,386	$5,596	$212	$229
562	STATION EXPENSES	51	$514,340	$193,418	$65,340	$12,139	$110,025	$14,399	$16,769	$65,788	$1,856	$18,095	$9,745	$2,432	$4,018	$152	$165
563	OVERHEAD LINE EXPENSES	51	$8,700	$3,272	$1,105	$205	$1,861	$244	$284	$1,113	$31	$306	$165	$41	$68	$3	$3
566	MISC. TRANSMISSION EXPENSES	51	$141,829	$53,335	$18,018	$3,347	$30,339	$3,971	$4,624	$18,141	$512	$4,990	$2,687	$670	$1,108	$42	$45
569	MAINTENANCE OF STRUCURES	51	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
570	MAINT OF STATION EQUIPMENT	51	$233,328	$87,743	$29,641	$5,507	$49,912	$6,532	$7,607	$29,844	$842	$8,209	$4,421	$1,103	$1,823	$69	$75
571	MAINT OF OVERHEAD LINES	51	($130,389)	($49,033)	($16,564)	($3,077)	($27,892)	($3,650)	($4,251)	($16,678)	($470)	($4,587)	($2,470)	($616)	($1,019)	($39)	($42)
573	MISC PLANT	51	$1,753	$659	$223	$41	$375	$49	$57	$224	$6	$62	$33	$8	$14	$1	$1
	Total Transmission Labor Expenses		$1,933,252	$727,000	$245,595	$45,628	$413,552	$54,122	$63,028	$247,278	$6,975	$68,012	$36,628	$9,139	$15,103	$571	$619
	Distribution Operation Labor Expense																
580	OPERATION SUPERVISION AND ENGI	64	$1,053,694	$766,624	$122,252	$6,699	$77,417	$6,569	$8,316	$28,917	$1,829	$263	$4,316	$1,117	$27,356	$299	$1,720
581	LOAD DISPATCHING	28	$293,653	$142,155	$38,425	$6,144	$53,020	$7,068	$7,578	$29,479	$941	$0	$4,737	$1,099	$2,866	$97	$45
582	STATION EXPENSES	28	$230,749	$111,704	$30,194	$4,828	$41,663	$5,554	$5,955	$23,164	$739	$0	$3,722	$863	$2,252	$76	$35
583	OVERHEAD LINE EXPENSES	55	($159,667)	($97,358)	($21,946)	($1,880)	($20,107)	($2,156)	($2,865)	($8,989)	($365)	$-0	($1,444)	($335)	($2,159)	($37)	($27)
584	UNDERGROUND LINE EXPENSES	58	$73,041	$40,674	$9,208	$1,231	$10,763	$1,414	$1,527	$5,894	$190	$0	$947	$220	$941	$20	$12
585	STREET LIGHTING EXPENSE	15	$4,830	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,830	$0	$0
586	METER EXPENSES	26	$2,521,656	$2,120,884	$279,112	$4,362	$93,392	$782	$3,127	$8,952	$3,329	$983	$202	$479	$0	$656	$5,396
586	METER EXPENSES - LOAD MANAGEMENT		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0			$0	
587	CUSTOMER INSTALLATIONS EXPENSE	7	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
588	MISCELLANEOUS DISTRIBUTION EXP	53	$1,050,099	$602,624	$130,762	$10,837	$116,214	$12,367	$16,361	$51,669	$2,135	$18	$8,279	$1,928	$95,489	$327	$1,090
589	RENTS		$0														
	Total Distribution Operation Labor Expense		$5,068,055	$3,687,307	$588,009	$32,221	$372,361	$31,597	$39,999	$139,086	$8,798	$1,264	$20,758	$5,371	$131,575	$1,437	$8,271
	Distribution Maintenance Labor Expense																
590	MAINTENANCE SUPERVISION AND EN	65	($165)	($168)	($34)	$0	($12)	$0	($2)	$2	($0)	$0	$0	$0	$48	($0)	($0)
591	MAINTENANCE OF STRUCTURES	28	$8,520	$4,124	$1,115	$178	$1,538	$205	$220	$855	$27	$0	$137	$32	$83	$3	$1
592	MAINTENANCE OF STATION EQUIPME	28	$229,427	$111,064	$30,021	$4,800	$41,424	$5,522	$5,921	$23,031	$735	$0	$3,701	$858	$2,239	$76	$35
593	MAINTENANCE OF OVERHEAD LINES	55	$193,562	$118,025	$26,605	$2,279	$24,375	$2,614	$3,473	$10,898	$442	$0	$1,751	$406	$2,617	$45	$32
594	MAINTENANCE OF UNDERGROUND LIN	58	$254,651	$141,806	$32,104	$4,292	$37,523	$4,928	$5,322	$20,550	$662	$0	$3,301	$766	$3,282	$70	$43
595	MAINTENANCE OF LINE TRANSFORME	70	$55,665	$41,221	$8,888	$0	$4,004	$0	$579	$0	$81	$0	$0	$0	$876	$8	$9
596	MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	15	$31,774	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$31,774	$0	$0
597	MAINTENANCE OF METERS		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
598	MAINTENANCE OF MISC DISTR PLANT	53	$36,714	$21,069	$4,572	$379	$4,063	$432	$572	$1,806	$75	$1	$289	$67	$3,339	$11	$38
	Total Distribution Maintenance Labor Expense		$810,148	$437,141	$103,271	$11,929	$112,915	$13,702	$16,086	$57,143	$2,021	$1	$9,180	$2,130	$44,258	$213	$159
	Total Distribution Operation and Maintenance Labor Expenses		$5,878,203	$4,124,449	$691,279	$44,150	$485,277	$45,299	$56,084	$196,229	$10,819	$1,264	$29,939	$7,501	$175,832	$1,650	$8,431
	Transmission and Distribution Labor Expenses		$7,811,455	$4,851,449	$936,874	$89,778	$898,829	$99,421	$119,113	$443,507	$17,794	$69,276	$66,566	$16,640	$190,935	$2,221	$9,050
	Production, Transmission and Distribution Labor Expenses		$39,884,009	$16,720,705	$4,982,118	$853,676	$7,792,253	$1,013,817	$1,173,466	$4,638,575	$134,818	$1,231,694	$676,081	$171,821	$462,800	$12,509	$19,675
	Customer Accounts Expense																
901	SUPERVISION/CUSTOMER ACCTS	6	$576,055	$455,968	$60,398	$1,174	$39,956	$548	$2,191	$1,174	$444	$130	$26	$52	$13,851	$16	$128
902	METER READING EXPENSES	6	$217,099	$171,842	$22,762	$442	$15,058	$206	$826	$442	$167	$49	$10	$20	$5,220	$6	$48
903	RECORDS AND COLLECTION	6	$2,175,355	$1,721,871	$228,080	$4,433	$150,884	$2,069	$8,276	$4,433	$1,675	$493	$99	$197	$52,304	$59	$483
904	UNCOLLECTIBLE ACCOUNTS		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
905	MISC CUST ACCOUNTS	6	$155,402	$123,006	$16,293	$317	$10,779	$148	$591	$317	$120	$35	$7	$14	$3,737	$4	$34
	Total Customer Accounts Labor Expense		$3,123,911	$2,472,686	$327,533	$6,367	$216,676	$2,971	$11,884	$6,367	$2,405	$707	$141	$283	$75,112	$85	$693
	Customer Service Expense																
907	SUPERVISION	6	$75,060	$59,413	$7,870	$153	$5,206	$71	$286	$153	$58	$17	$3	$7	$1,805	$2	$17
908	CUSTOMER ASSISTANCE EXPENSES	6	$354,392	$280,514	$37,157	$722	$24,581	$337	$1,348	$722	$273	$80	$16	$32	$8,521	$10	$79
908	CUSTOMER ASSISTANCE EXP-LOAD MGMT		$0														
909	INFORMATIONAL AND INSTRUCTIONA	6	$2,004	$1,586	$210	$4	$139	$2	$8	$4	$2	$0	$0	$0	$48	$0	$0

Louisville Gas & Electric
Electric Cost of Service Study
(Labor)

Acct. No.	Account Description	Allocator	Total System	Residential Rate RS	Gen. Service GSS	Rate PS Primary	Rate PS Secondary	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Secndary	Rate RTS Transmissio	Sp. Contract Ft. Knox	Sp. Contract Water Co.	St. Lighting RLS & LS	St. Lighting LE	Traffic SL TLE
909	INFORM AND INSTRUC -LOAD MGMT		$0														
910	MISCELLANEOUS CUSTOMER SERVICE	6	$303,019	$239,850	$31,771	$618	$21,018	$288	$1,153	$618	$233	$69	$14	$27	$7,286	$8	$67
911	DEMONSTRATION AND SELLING EXP		$0														
912	DEMONSTRATION AND SELLING EXP		$0														
913	WATER HEATER - HEAT PUMP PROGRAM		$0														
915	MDSE-JOBBING-CONTRACT		$0														
916	MISC SALES EXPENSE		$0														
	Total Customer Service Labor Expense		$734,475	$581,363	$77,008	$1,497	$50,944	$699	$2,794	$1,497	$565	$166	$33	$67	$17,660	$20	$163
	Sub-Total Labor Exp		$43,742,395	$19,774,754	$5,386,658	$861,540	$8,059,873	$1,017,486	$1,188,144	$4,646,439	$137,789	$1,232,567	$676,256	$172,171	$555,572	$12,613	$20,532
	Administrative and General Expense																
920	ADMIN. & GEN. SALARIES-	66	$10,964,829	$4,956,903	$1,350,264	$215,961	$2,020,354	$255,051	$297,830	$1,164,715	$34,539	$308,966	$169,516	$43,158	$139,264	$3,162	$5,147
921	OFFICE SUPPLIES AND EXPENSES		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0				
922	ADMIN. EXPENSES TRANSFERRED - CREDIT	66	($1,341,699)	($606,546)	($165,224)	($26,426)	($247,218)	($31,209)	($36,444)	($142,519)	($4,226)	($37,806)	($20,743)	($5,281)	($17,041)	($387)	($630)
923	OUTSIDE SERVICES EMPLOYED		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0				
924	PROPERTY INSURANCE		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0				
925	INJURIES AND DAMAGES - INSURAN	66	$42,291	$19,119	$5,208	$833	$7,792	$984	$1,149	$4,492	$133	$1,192	$654	$166	$537	$12	$20
926	EMPLOYEE BENEFITS		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
928	REGULATORY COMMISSION FEES		$0														
929	DUPLICATE CHARGES-CR		$0														
930	MISCELLANEOUS GENERAL EXPENSES	66	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
931	RENTS AND LEASES		$0														
935	MAINTENANCE OF GENERAL PLANT	59	$2,758,776	$1,175,465	$348,714	$55,845	$518,107	$65,917	$78,066	$297,956	$8,855	$72,520	$44,550	$11,025	$79,548	$826	$1,384
	Total Administrative and General Expense		$12,424,197	$5,544,940	$1,538,962	$246,213	$2,299,036	$290,743	$340,601	$1,324,644	$39,301	$344,871	$193,977	$49,068	$202,308	$3,614	$5,921
	Total Operation and Maintenance Expenses		$56,166,592	$25,319,695	$6,925,620	$1,107,752	$10,358,909	$1,308,229	$1,528,745	$5,971,082	$177,089	$1,577,438	$870,233	$221,239	$757,880	$16,227	$26,453
	Operation and Maintenance Expenses Less Purchase Power		$56,166,592	$25,319,695	$6,925,620	$1,107,752	$10,358,909	$1,308,229	$1,528,745	$5,971,082	$177,089	$1,577,438	$870,233	$221,239	$757,880	$16,227	$26,453

Louisville Gas & Electric
(Revenues)

Acct. No.	Account Description	Allocator	Total System	Residential Rate RS	Gen. Service GSS	Rate PS Primary	Rate PS Secondary	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Secndary	Rate RTS Transmission	Sp. Contract Ft. Knox	Sp. Contract Water Co.	St. Lighting RLS & LS	St. Lighting LE	Traffic SL TLE
REVENUE																	
	Sales to Ultiate Consumers	74	$783,347,083	$307,974,525	$112,545,511	$15,994,645	$158,911,598	$18,287,716	$21,999,815	$77,266,680	$2,503,294	$19,755,000	$10,433,529	$2,592,630	$14,660,356	$177,965	$243,818
	Intercompany Sales	1	$110,077,528	$39,710,695	$13,727,658	$2,658,919	$23,833,831	$3,226,743	$3,665,379	$14,894,693	$408,662	$4,172,194	$2,101,931	$551,667	$1,047,170	$39,624	$38,362
	Off-System Sales	81	$59,391,514	$21,946,554	$7,485,938	$1,415,761	$12,770,723	$1,696,088	$1,953,928	$7,784,229	$216,927	$2,158,380	$1,129,011	$287,972	$507,079	$19,187	$19,737
	Brokered Purchases	1	($3,239)	($1,168)	($404)	($78)	($701)	($95)	($108)	($438)	($12)	($123)	($62)	($16)	($31)	($1)	($1)
	Settled Swap Revenue	1	$13,437,949	$4,847,768	$1,675,833	$324,593	$2,909,566	$393,911	$447,459	$1,818,301	$49,888	$509,329	$256,598	$67,346	$127,836	$4,837	$4,683
	Settled Swap Expense	1	($3,269,501)	($1,179,479)	($407,736)	($78,975)	($707,908)	($95,840)	($108,868)	($442,399)	($12,138)	($123,922)	($62,431)	($16,385)	($31,103)	($1,177)	($1,139)
	Forfeited Discounts	79	$5,040,755	$3,952,450	$746,971	$112,640	$228,694	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Misc Service Revenues	80	$963,922	$814,597	$149,325	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Rent From Electric Property	69	$2,613,870	$1,108,362	$330,139	$53,269	$493,618	$62,933	$74,408	$284,744	$8,434	$69,889	$42,479	$10,536	$72,977	$786	$1,294
	Other Electric Revenue	69	$4,020,871	$1,704,974	$507,848	$81,943	$759,324	$96,809	$114,460	$438,017	$12,974	$107,510	$65,345	$16,208	$112,260	$1,209	$1,991
	Unbilled Revenue	74	$2,871,000	$1,158,313	$423,291	$60,157	$597,677	$68,781	$82,743	$290,605	$9,415	$74,300	$39,241	$9,751	$55,139	$669	$917
	TOTAL REVENUE		$958,491,752	$382,037,690	$137,184,376	$20,622,875	$199,796,423	$23,737,046	$28,229,215	$102,334,431	$3,197,444	$26,722,557	$14,005,641	$3,519,708	$16,551,683	$243,100	$309,661

Louisville Gas & Electric
Electric Cost of Service Study
(Allocator Amounts)

Alloc. No	Allocator Description	Total System	Residential Rate RS	Gen. Service GSS	Rate PS Primary	Rate PS Secondary	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Secondary	Rate RTS Transmission	Sp. Contract Ft. Knox	Sp. Contract Water Co.	St. Lighting RLS & LS	St. Lighting LE	Traffic SL TLE
1	Energy (Loss Adjusted)	12,111,327,512	4,389,186,346	1,510,391,531	292,648,715	2,622,327,559	355,023,742	403,284,930	1,638,794,983	44,963,246	459,047,442	231,265,844	60,697,382	116,215,369	4,359,817	4,220,806
2	Energy	11,433,525,892	4,099,843,468	1,417,281,935	280,316,205	2,460,671,554	340,177,714	378,424,027	1,570,265,493	42,191,442	448,438,560	221,595,000	58,159,200	108,112,602	4,090,864	3,960,610
3	Customers (Monthly Bills)	5,898,204	4,194,552	505,104	1,080	36,756	252	1,008	540	204	60	12	24	1,146,684	1,296	10,632
4	Average Customers (Bills/12)	491,517	349,546	42,092	90	3,063	21	84	45	17	5	1	2	95,557	108	888
5	Average Customers (Lighting = Lights)	491,517	349,546	42,092	90	3,063	21	84	45	17	5	1	2	95,557	108	888
6	Weighted Average Customers (Lighting =8 Lights per Cust)	441,605	349,546	46,301	900	30,630	420	1,680	900	340	100	20	40	10,618	12	98
7	Street Lighting	96,551	0	0	0	0	0	0	0	0	0	0	0	95,557	108	886
8	Average Customers	491,517	349,546	42,092	90	3,063	21	84	45	17	5	1	2	95,557	108	886
9	Average Customers (Lighting = 9 Lights per Cust)	405,694	349,546	42,092	90	3,063	21	84	45	17	5	1	2	10,618	12	98
10	Average Secondary Customers	405,530	349,546	42,092	0	3,063	0	84	0	17	0	0	0	10,618	12	98
11	Average Primary Customers	405,689	349,546	42,092	90	3,063	21	84	45	17	0	1	2	10,618	12	98
12	Year End Customers	489,035	347,573	41,583	90	3,063	21	84	45	17	5	1	2	95,557	108	886
13	Year End Customers (Lighting = Lights)	489,035	347,573	41,583	90	3,063	21	84	45	17	5	1	2	95,557	108	888
14	Weighted Year End Customers (Lighting =9 Lights per Cust)	438,452	347,573	45,741	900	30,630	420	1,680	450	170	100	20	40	10,618	12	98
15	Street Lighting	68,350,905	0	0	0	0	0	0	0	0	0	0	0	68,350,905	0	0
16	Year End Customers	489,035	347,573	41,583	90	3,063	21	84	45	17	5	1	2	95,557	108	886
17	Year End Customers (Lighting = 9 Lights per Cust)	403,212	347,573	41,583	90	3,063	21	84	45	17	5	1	2	10,618	12	98
18	Year End Secondary Customers	403,048	347,573	41,583	0	3,063	0	84	0	17	0	0	0	10,618	12	98
19	Year End Primary Customers	403,207	347,573	41,583	90	3,063	21	84	45	17	0	1	2	10,618	12	98
20	Maximum Class Non-Coincident Peak Demands	2,645,808	1,243,554	336,140	53,744	463,813	61,828	66,295	257,876	8,229	78,969	41,438	9,611	25,069	850	392
21	Total Transmission Plant	241,924,058	90,975,613	30,733,362	5,709,826	51,751,294	8,772,781	7,887,248	30,943,995	872,824	8,510,926	4,583,519	1,143,688	1,889,983	71,515	77,483
22	Net Utility Plant	2,131,822,334	907,049,382	269,481,972	43,239,795	401,032,255	51,042,025	60,434,818	230,752,757	6,852,496	56,268,879	34,497,041	8,538,093	60,831,401	638,532	1,064,887
23	Total Utility Plant	3,884,036,397	1,649,026,436	491,023,147	79,018,755	732,509,782	93,266,690	110,414,163	421,830,824	12,513,093	103,146,598	63,050,151	15,607,603	109,518,819	1,163,080	1,927,257
24	Taxable Income	138,062,867	56,358,476	35,113,033	2,390,520	33,568,497	1,886,663	3,036,683	2,018,674358,040		(452,015)	(407,848)	(185,251)	4,454,214	(25,012)	(19,780)
25	Revenue and Expense Adjust before IT	(68,240,104)	(33,761,361)	(6,557,757)	(1,288,742)	(12,013,850)	(1,511,688)	(1,880,262)	(6,232,089)	(193,902)	(1,459,156)	(830,769)	(228,927)	(269,079)	(19,024)	(16,511)
26	Meter Cost - Wghted Cost of Meters	100.0000%	84.1068%	11.0686%	0.1730%	3.7036%	0.0310%	0.1240%	0.3550%	0.1320%	0.0390%	0.0080%	0	0	0	0
27	Customer Services - Weighted cost of Services	100.0000%	88.3841%	10.5717%	0.0000%	0.7787%	0.0000%	0.0214%	0.0000%	0.0114%	0.0000%	0.0000%	0	0	0.0275%	0
28	Maximum Class Demands (Primary)	2,568,839	1,243,554	336,140	53,744	463,813	61,828	66,295	257,876	8,229	0	41,438	9,611	25,069	850	392
29	Sum of the Individual Customer Demands (Secondary)	3,744,771	2,384,385	778,126	0	474,570	0	71,433	0	9,946	0	0	0	25,069	850	392
30	Summer Peak Period Demand Allocator	2,474,288	1,178,425	322,201	48,733	488,532	54,730	69,106	229,132	7,821	48,605	42,032	6,553	0	0	418
31	Winter Peak Period Demand Allocator	1,910,903	778,786	281,780	43,621	417,092	41,489	59,841	182,646	5,892	52,833	38,051	8,454	0	0	418
32	Weighted Avg Summer Winter Peak	4,385,191	1,957,211	603,981	92,354	885,624	96,219	128,947	411,778	13,713	99,438	80,083	15,007	0	0	838
33	Production Residual Winter Demand Allocator	1,910,903	778,786	281,780	43,621	417,092	41,489	59,841	182,646	5,892	52,833	38,051	8,454	0	0	418
34	Production Winter Demand Allocator	46,777,080	18,878,017	7,192,626	1,113,459	10,646,658	1,059,024	1,527,478	4,662,183150,407		1,348,609	971,282	216,787	0	0	10,670
35	Production Residual Summer Demand Allocator.	2,474,288	1,178,425	322,201	48,733	488,532	54,730	69,106	229,132	7,821	48,605	42,032	6,553	0	0	418
36	Production Summer Demand Allocator	24,853,572	11,741,715	3,210,385	485,5724,668,406		545,323	688,563	2,283,049	77,928	464,371	418,802	65,293	0	0	4,165
37	Production Residual Summer Demand Allocator	2,474,288	1,178,425	322,201	48,733	488,532	54,730	69,106	229,132	7,821	48,605	42,032	6,553	0	0	418
38	Production Summer Demand Total	24,853,572	11,741,715	3,210,385	485,5724,668,408		545,323	688,563	2,283,049	77,928	464,371	418,802	65,293	0	0	4,165
39	Distribution O&M-- (Lines, Transformers & Services Plant)	656,049,333	413,926,226	90,148,918	6,852,257	76,675,861	7,862,905	10,904,833	32,784,742	1,395,475	0	5,266,656	1,221,961	8,697,824	149,170	162,508
40	Temperature Normalization Revenues	5,151,223	4,284,806	476,872	24,653	258,591	27,262	40,404	0	0	0	39,835	0	0	0	0
41	Customer Specific Assignment	0		0	0	0	0	0	0	0	0	0			0	
42	Year-End Customers	489,035	347,573	41,583	90	3,063	21	84	45	17	5	1	2	95,557	108	886
43	Merger Surcredit Revenue	(2,324,405)	(1,012,997)	(325,785)	(48,219)	(464,706)	(43,500)	(65,543)	(216,357)	(8,586)	(60,600)	(27,098)	(9,175)	(41,853)	(954)	(1,122)
44	Interruptible Credit Allocator	1,578,237,008	679,620,958	223,590,783	34,387,787	329,162,880	34,482,053	47,629,124	149,272,703	4,907,566	38,966,178	29,876,914	6,041,233	0	0	318,838
45	Operation and Maintenance Less Fuel	585,007,135	222,516,181	69,883,675	12,713,364	115,663,606	15,298,489	17,518,962	70,387,859	1,975,643	19,452,660	10,019,548	2,607,309	6,565,979	187,624	216,206
46	Full Year Base Rate Change	(2,561,101)	(1,172,720)	601,474	(143,236)	(691,684)	(103,302)	(132,729)	(632,528)	(10,706)	(411,843)	(28,118)	(16,342)	(15,020)	(1,288)	(1,061)
47	VDT Revenue	(3)	0	(3)	0	0	0	0	0	0	0	0	0	0	0	0
48	DSM Revenue	12,170,475	9,169,340	1,112,292	111,2751,288,021		228,895	262,652	0	0	0	0	0	0	0	0
49	ECR Revenue	8,389,626	3,343,631	1,238,262	175,6161,759,675		202,859	243,405	862,080	27,981	229,786	118,384	27,425	157,871	1,850	2,611
50	ECR Revenue for Roll-In	6,824,455	2,294,004	2,469,204	113,6601,102,981		108,687	125,043	384,132	12,393	128,738	85,621	0	(436)	(450)	0
51	Gross Production Plant	2,288,143,689	852,183,991	287,884,611	53,484,910	484,763,145	63,441,793	73,881,191	289,857,851	8,175,888	79,723,280	42,934,600	10,713,118	17,703,793	669,891	725,798
52	Gross Transmission Plant	241,924,058	90,975,613	30,733,362	5,709,826	51,751,294	8,772,781	7,887,248	30,943,995	872,824	8,510,926	4,583,519	1,143,688	1,889,983	71,515	77,483
53	Gross Distribution Plant	849,053,125	487,249,063	105,727,371	8,762,304	93,964,035	9,999,185	13,228,575	41,776,902	1,726,299	14,175	6,693,776	1,559,194	77,206,970	264,292	880,986
54	Total Prod.,Trans., Distrib Plant	3,357,120,852	1,430,408,668	424,345,344	67,957,040	630,478,474	80,213,759	94,997,013	362,578,548	10,775,011	88,248,391	54,211,894	13,416,000	96,800,746	1,005,698	1,684,267
55	Dist. Overhead Lines Gross Plant	328,045,484	198,807,354	44,814,411	3,838,556	41,058,923	4,402,793	5,850,585	18,358,654	744,453	0	2,948,732	684,201	4,407,920	78,281	54,621
56	Gross Intangible Plant	44,812,680	19,093,875	5,664,393	907,1288,415,971		1,070,737	1,268,072	4,839,896143,831		1,177,988	723,850	179,064	1,292,149	13,425	22,483
57	Gross Total Plant in Service	3,589,541,649	1,529,325,637	453,725,137	72,669,464	674,197,027	85,776,425	101,583,616	387,725,744	11,521,690	94,378,166	57,971,440	14,346,475	103,454,849	1,075,315	1,600,462
58	Dist. Underground Lines Gross Plant	178,787,538	89,560,211	22,540,069	3,013,700	26,344,642	3,460,112	3,736,843	14,428,087	464,722	0	2,317,923	537,760	2,304,354	48,812	30,301
59	Gross General Plant	18,821,680	7,167,416	2,126,267	340,5153,159,168		401,931	476,008	1,816,789	63,991	442,190	271,642	67,224	485,044	5,039	8,439
60	Labor Accts 501-507	19,054,593	7,121,594	2,413,963	451,3094,083,540		537,224	823,218	2,458,472	69,048	678,154	381,438	90,895	153,740	5,817	6,184
61	Labor Accts 511-514	8,234,284	2,974,856	1,027,547	198,7431,782,140		241,002	273,990	1,112,098	30,540	311,330	157,192	41,187	77,853	2,946	2,862
62	Labor Accts 538-540	144,930	54,501	16,412	3,421	31,003	4,057	4,725	18,638	623	5,099	2,746	685	1,132	43	48
63	Labor Accts 542-545	182,801	67,046	22,964	4,376	39,393	5,284	6,037	24,202	671	6,733	3,480	896	1,617	61	62
64	Labor Accts 581-588	4,014,381	2,920,683	465,756	25,522	294,944	25,028	31,683	110,169	6,969	1,001	16,443	4,254	104,219	1,139	6,552
65	Labor Accts 591-598	(1,883,187)	(1,713,463)	(345,690)	3,562	(125,014)	4,223	(17,957)	17,718	(2,571)	5	2,852	661	492,835	(212)	(138)
66	Labor Accts 500-916	43,742,395	19,774,754	5,366,658	881,5408,059,873		1,017,488	1,188,144	4,646,439137,789		1,232,567	676,256	172,171	555,572	12,613	20,532
67	O&M less Purchased Power	565,007,135	222,516,181	69,883,675	12,713,364	115,663,606	15,298,489	17,518,962	70,387,859	1,975,843	19,452,690	10,019,548	2,607,309	6,565,979	187,624	216,206
68	Dist. Lines Gross Plant	504,833,022	208,367,566	67,354,480	6,852,257	67,403,565	7,862,905	9,587,428	32,784,742	1,209,175	0	5,266,655	1,221,961	6,712,274	125,093	84,922
69	Rate Base	1,904,728,109	807,682,668	240,572,450	38,817,435	359,699,329	45,859,507	54,220,821	207,482,762	8,145,724	50,928,344	30,854,691	7,677,754	53,178,529	572,888	943,010
70	Gross Transformer Plant	126,200,230	93,453,428	20,149,813	0	8,077,496	0	1,312,051	0	183,448	0	0	0	1,985,550	17,197	21,249
71	Dpreciation Expense	109,158,113	45,650,753	13,606,137	2,253,931	20,644,484	2,682,256	3,145,617	12,051,785	355,604	2,988,666	1,799,603	445,865	2,870,390	32,648	52,373
72	Total Labor	56,168,592	25,319,695	6,925,620	1,107,752	10,358,909	1,308,229	1,528,745	5,971,082177,089		1,577,438	870,233	221,239	757,880	16,227	26,453
73	Distribution O&M	8,437,683	5,672,472	817,488	84,435	577,668	61,950	52,657	275,010	14,772	2,860	40,606	10,672	627,438	2,618	17,038
74	Rev	766,665,594	309,313,388	113,034,782	16,064,179	159,602,437	18,367,218	22,095,455	77,602,583	2,614,177	19,840,881	10,478,887	2,603,901	14,724,089	178,739	244,878
75	Distribution Poles, Lines, Transform & Services	656,049,333	413,926,226	90,148,918	6,852,257	76,675,861	7,862,905	10,904,833	32,784,742	1,395,475	0	5,266,655	1,221,961	8,697,824	149,170	162,508
76	Late Payment Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
77	Temperature Normalization Expenses	83,463,000	63,818,000	8,278,000	834,0008,748,000		821,000	1,365,000	0	0	0	1,521,000	0	0	0	0
78	O&M Expenses	642,626,776	250,673,608	79,587,312	14,582,818	132,443,125	17,560,327	20,096,448	80,815,067	2,262,737	22,368,863	11,500,176	2,993,408	7,287,013	214,908	242,968
79	Forfeited Discounts	5,040,755	3,952,450	748,971	112,840	228,694	0	0	0	0	0	0	0	0	0	0
80	Misc Revenue	963,922	814,697	149,325	0	0	0	0	0	0	0	0	0	0	0	0

Louisville Gas & Electric
Electric Cost of Service Study
(Allocator Amounts)

Alloc. No	Allocator Description	Total System	Residential Rate RS	Gen. Service GSS	Rate PS Primary	Rate PS Secondary	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Secndary	Rate RTS Transmission	Sp. Contract Ft. Knox	Sp. Contract Water Co.	St. Lighting RLS & LS	St. Lighting LE	Traffic SL TLE
81	Off-System Sales Allocator	59,391,514	21,946,654	7,485,938	1,415,761	12,770,723	1,696,088	1,953,928	7,784,229216,927		2,158,380	1,129,011	287,972	507,079	19,187	19,737
82	Rate Switching	30,674	0	0	1,929	22,942	2,498	3,305	0	0	0	0	0	0	0	0
83	BIP															
84	Primary Dist Lines	424,405,054	242,460,821	52,819,849	6,852,257	59,690,544	7,862,905	8,445,923	32,784,742	1,049,984	0	5,268,655	1,221,961	5,764,871	110,842	73,621
85	Secondary Dist Lines	80,427,968	55,908,745	14,534,631	0	7,713,020	0	1,141,505	0	159,212	0	0	0	947,402	14,151	11,301
86	Dist Transformers	126,200,230	93,453,426	20,149,813	0	9,077,496	0	1,312,051	0	183,448	0	0	0	1,985,550	17,197	21,249
87																
88																
89																
MEMO	Off-System Sales Allocator															
	Off-System Sales	59,391,514	22,334,198	7,544,933	1,401,742	12,704,762	1,662,694	1,938,292	7,596,643214,275		2,069,403	1,125,238	280,771	463,984	17,557	19,022
	Less: Adjustment to Reallocate Expenses															
	Costs allocated on Energy to be reallocated on RBPPT	(25,339,000)	(9,141,096)	(3,160,001)	(612,063)	(5,488,365)	(742,771)	(843,742)	(3,428,644)	(94,071)	(960,407)	(483,848)	(126,989)	(241,051)	(9,121)	(8,631)
	Costs allocated on Energy reallocated on RBPPT	25,339,000	9,528,738	3,218,996	598,0445,420,404		709,378	826,106	3,241,058	91,419	891,430	480,075	119,789	197,956	7,490	8,116
	Net Adjustment	0	387,642	58,995	(14,018)	(65,961)	(33,394)	(17,636)	(187,586)	(2,652)	(68,977)	(3,773)	(7,200)	(43,095)	(1,631)	(715)
	Off-System Sales Allocator	59,391,514	21,946,554	7,485,938	1,415,761	12,770,723	1,696,088	1,953,928	7,784,229216,927		2,158,380	1,129,011	287,972	507,079	19,187	19,737

Louisville Gas & Electric
Electric Cost of Service Study
(Allocator Percentages)

Alloc. No	Allocator Description	Total System	Residential Rate RS	Gen. Service GSS	Rate PS Primary	Rate PS Secondary	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Secndary	Rate RTS Transmission	Sp. Contract Ft. Knox	Sp. Contract Water Co.	St. Lighting RLS & LS	St. Lighting LE	Traffic SL TLE
1	Energy (Loss Adjusted)	100.0000%	36.0752%	12.4709%	2.4155%	21.6519%	2.9313%	3.3298%	13.6311%	0.3712%	3.7902%	1.9095%	0.5012%	0.9513%	0.0360%	0.0349%
2	Energy	100.0000%	35.8581%	12.3958%	2.4517%	21.5215%	2.9753%	3.3098%	13.7339%	0.3690%	3.9221%	1.9381%	0.5087%	0.9456%	0.0358%	0.0346%
3	Customers (Monthly Bills)	100.0000%	71.1157%	8.5637%	0.0183%	0.6232%	0.0043%	0.0171%	0.0092%	0.0035%	0.0010%	0.0002%	0.0004%	19.4412%	0.0220%	0.1803%
4	Average Customers (Bills/12)	100.0000%	71.1157%	8.5637%	0.0183%	0.6232%	0.0043%	0.0171%	0.0092%	0.0035%	0.0010%	0.0002%	0.0004%	19.4412%	0.0220%	0.1803%
5	Average Customers (Lighting = Lights)	100.0000%	71.1157%	8.5637%	0.0183%	0.6232%	0.0043%	0.0171%	0.0092%	0.0035%	0.0010%	0.0002%	0.0004%	19.4412%	0.0220%	0.1803%
6	Weighted Average Customers (Lighting =9 Lights per Cust)	100.0000%	79.1535%	10.4847%	0.2038%	6.9361%	0.0951%	0.3804%	0.2038%	0.0770%	0.0226%	0.0045%	0.0091%	2.4044%	0.0027%	0.0222%
7	Street Lighting	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	98.9705%	0.1119%	0.9176%
8	Average Customers	100.0000%	71.1157%	8.5637%	0.0183%	0.6232%	0.0043%	0.0171%	0.0092%	0.0035%	0.0010%	0.0002%	0.0004%	19.4412%	0.0220%	0.1803%
9	Average Customers (Lighting = 9 Lights per Cust)	100.0000%	86.1600%	10.3753%	0.0222%	0.7550%	0.0052%	0.0207%	0.0111%	0.0042%	0.0012%	0.0002%	0.0005%	2.6172%	0.0030%	0.0242%
10	Average Secondary Customers	100.0000%	86.1949%	10.3795%	0.0000%	0.7553%	0.0000%	0.0207%	0.0000%	0.0042%	0.0000%	0.0000%	0.0000%	2.6183%	0.0030%	0.0242%
11	Average Primary Customers	100.0000%	86.1611%	10.3754%	0.0222%	0.7550%	0.0052%	0.0207%	0.0111%	0.0042%	0.0000%	0.0002%	0.0005%	2.6173%	0.0030%	0.0242%
12	Year End Customers	100.0000%	71.0732%	8.5031%	0.0184%	0.6263%	0.0043%	0.0172%	0.0092%	0.0035%	0.0010%	0.0002%	0.0004%	19.5399%	0.0221%	0.1812%
13	Year End Customers (Lighting = Lights)	100.0000%	71.0732%	8.5031%	0.0184%	0.6263%	0.0043%	0.0172%	0.0092%	0.0035%	0.0010%	0.0002%	0.0004%	19.5399%	0.0221%	0.1812%
14	Weighted Year End Customers (Lighting =9 Lights per Cust)	100.0000%	79.2726%	10.4324%	0.2053%	6.9859%	0.0958%	0.3832%	0.1026%	0.0388%	0.0228%	0.0046%	0.0091%	2.4217%	0.0027%	0.0224%
15	Street Lighting	100.0000%	0.0000%	-0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%
16	Year End Customers	100.0000%	71.0732%	8.5031%	0.0184%	0.6263%	0.0043%	0.0172%	0.0092%	0.0035%	0.0010%	0.0002%	0.0004%	19.5399%	0.0221%	0.1812%
17	Year End Customers (Lighting = 9 Lights per Cust)	100.0000%	86.2011%	10.3129%	0.0223%	0.7597%	0.0052%	0.0208%	0.0112%	0.0042%	0.0012%	0.0002%	0.0005%	2.6334%	0.0030%	0.0243%
18	Year End Secondary Customers	100.0000%	86.2361%	10.3171%	0.0000%	0.7600%	0.0000%	0.0208%	0.0000%	0.0042%	0.0000%	0.0000%	0.0000%	2.6344%	0.0030%	0.0243%
19	Year End Primary Customers	100.0000%	86.2021%	10.3131%	0.0223%	0.7597%	0.0052%	0.0208%	0.0112%	0.0042%	0.0000%	0.0002%	0.0005%	2.6334%	0.0030%	0.0243%
20	Maximum Class Non-Coincident Peak Demands	100.0000%	47.0009%	12.7046%	2.0313%	17.5301%	2.3368%	2.5057%	9.7466%	0.3110%	2.9091%	1.5662%	0.3633%	0.9475%	0.0321%	0.0148%
21	Total Transmission Plant	100.0000%	37.6050%	12.7037%	2.3602%	21.3915%	2.7995%	3.2602%	12.7908%	0.3608%	3.5180%	1.8946%	0.4727%	0.7812%	0.0296%	0.0320%
22.	Net Utility Plant	100.0000%	42.5481%	12.6409%	2.0283%	18.8117%	2.3943%	2.8349%	10.8242%	0.3214%	2.6394%	1.6182%	0.4005%	2.8582%	0.0300%	0.0500%
23	Total Utility Plant	100.0000%	42.4565%	12.6421%	2.0344%	18.8595%	2.4018%	2.8428%	10.8606%	0.3222%	2.8557%	1.6233%	0.4018%	2.8197%	0.0299%	0.0496%
24	Taxable Income	100.0000%	40.8209%	25.4326%	1.7315%	24.3139%	1.3520%	2.1995%	1.4607%	0.2593%	-0.3274%	-0.2954%	-0.1414%	3.2262%	-0.0181%	-0.0143%
25	Revenue and Expense Adjust before IT	100.0000%	50.9682%	9.9000%	1.9425%	18.1368%	2.2821%	2.8084%	9.4083%	0.2927%	2.2026%	1.2542%	0.3456%	0.4062%	0.0287%	0.0234%
26	Meter Cost - Wighted Cost of Meters	100.0000%	84.1068%	11.0886%	0.1730%	3.7036%	0.0310%	0.1240%	-0.3550%	0.1320%	0.0390%	0.0080%	0.0190%	0.0000%	0.0260%	0.2140%
27	Customer Services - Weighted cost of Services	100.0000%	88.3641%	10.5717%	0.0000%	0.7787%	0.0000%	0.0214%	0.0000%	0.0114%	0.0000%	0.0000%	0.0000%	0.0000%	0.0275%	0.2262%
28	Maximum Class Demands (Primary)	100.0000%	48.4092%	13.0853%	2.0922%	18.0554%	2.4068%	2.5807%	10.0388%	0.3203%	0.0000%	1.6131%	0.3741%	0.9759%	0.0331%	0.0153%
29	Sum of the Individual Customer Demands (Secondary)	100.0000%	63.6724%	20.7790%	0.0000%	12.6729%	0.0000%	1.9076%	0.0000%	0.2656%	0.0000%	0.0000%	0.0000%	0.6694%	0.0227%	0.0105%
30	Summer Peak Period Demand Allocator	100.0000%	47.6268%	13.0220%	1.9696%	18.9360%	2.2118%	2.7930%	9.2605%	0.3161%	1.8836%	1.6988%	0.2648%	0.0000%	0.0000%	0.0169%
31	Winter Peak Period Demand Allocator	100.0000%	40.7549%	14.7459%	2.2827%	21.8270%	2.1712%	3.1316%	9.5581%	0.3083%	2.7648%	1.9913%	0.4424%	0.0000%	0.0000%	0.0219%
32	Weighted Avg Summer Winter Peak	100.0000%	44.6323%	13.7732%	2.1060%	20.1958%	2.1942%	2.9405%	9.3902%	0.3127%	2.2676%	1.8262%	0.3422%	0.0000%	0.0000%	0.0191%
33	Production Residual Winter Demand Allocator	100.0000%	40.7549%	14.7459%	2.2827%	21.8270%	2.1712%	3.1316%	9.5581%	0.3083%	2.7648%	1.9913%	0.4424%	0.0000%	0.0000%	0.0219%
34	Production Winter Demand Allocator	100.0000%	40.7548%	14.7459%	2.2828%	21.8270%	2.1712%	3.1315%	9.5581%	0.3084%	2.7648%	1.9913%	0.4424%	0.0000%	0.0000%	0.0219%
35	Production Residual Summer Demand Allocator	100.0000%	47.6268%	13.0220%	1.9696%	18.9360%	2.2119%	2.7930%	9.2605%	0.3161%	1.8836%	1.6988%	0.2648%	0.0000%	0.0000%	0.0169%
36	Production Summer Demand Allocator	100.0000%	47.6268%	13.0220%	1.9696%	18.9360%	2.2119%	2.7930%	9.2605%	0.3161%	1.8836%	1.6987%	0.2648%	0.0000%	0.0000%	0.0169%
37	Production Residual Summer Demand Allocator	100.0000%	47.6268%	13.0220%	1.9696%	18.9360%	2.2119%	2.7930%	9.2605%	0.3161%	1.8836%	1.6988%	0.2648%	0.0000%	0.0000%	0.0169%
38	Production Summer Demand Total	100.0000%	47.6268%	13.0220%	1.9696%	18.9360%	2.2119%	2.7930%	9.2605%	0.3161%	1.8836%	1.6987%	0.2648%	0.0000%	0.0000%	0.0169%
39	Distribution O&M-- (Lines, Transformers & Services Plant)	100.0000%	63.0938%	13.7412%	1.0445%	11.6875%	1.1985%	1.6622%	4.9973%	0.2127%	0.0000%	0.8028%	0.1863%	1.3258%	0.0227%	0.0248%
40	Temperature Normalization Revenues	100.0000%	83.1765%	9.2380%	0.4786%	5.0200%	0.5292%	0.7844%	0.0000%	0.0000%	0.0000%	0.7733%	0.0000%	0.0000%	0.0000%	0.0000%
41	Customer Specific Assignment															
42	Year-End Customers	100.0000%	71.0732%	8.5031%	0.0184%	0.6263%	0.0043%	0.0172%	0.0092%	0.0035%	0.0010%	0.0002%	0.0004%	19.5399%	0.0221%	0.1812%
43	Merger Surcredit Revenue	100.0000%	43.5809%	14.0163%	2.0745%	19.9925%	1.8714%	2.8198%	9.3081%	0.2833%	2.6026%	1.1658%	0.3947%	1.8006%	0.0410%	0.0483%
44	Interruptible Credit Allocator	100.0000%	43.0620%	14.1671%	2.1776%	20.8564%	2.1848%	3.0179%	9.4582%	0.3110%	2.4690%	1.8831%	0.3828%	0.0000%	0.0000%	0.0202%
45	Operation and Maintenance Less Fuel	100.0000%	39.3829%	12.3886%	2.2501%	20.4712%	2.7077%	3.1007%	12.4579%	0.3497%	3.4429%	1.7733%	0.4615%	1.1621%	0.0332%	0.0383%
46	Full Year Base Rate Change	100.0000%	45.7897%	-31.2941%	5.5928%	27.0073%	4.0335%	5.1825%	24.8975%	0.4180%	16.0807%	1.0978%	0.7162%	0.5865%	0.0503%	0.0414%
47	VDT Revenue	100.0000%	-0.0000%	100.0000%	-0.0000%	-0.0000%	-0.0000%	-0.0000%	-0.0000%	-0.0000%	-0.0000%	-0.0000%	-0.0000%	-0.0000%	-0.0000%	-0.0000%
48	DSM Revenue	100.0000%	75.3409%	9.1393%	0.9143%	10.5887%	1.8807%	2.1581%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
49	ECR Revenue 0 0	100.0000%	39.8544%	14.7594%	2.0956%	20.9768%	2.4180%	2.9013%	10.2755%	0.3335%	2.7390%	1.3870%	0.3269%	1.8794%	0.0221%	0.0311%
50	ECR Revenue for Roll-In 0 0	100.0000%	33.6277%	38.1817%	1.6655%	16.1622%	1.5923%	1.8323%	5.6288%	0.1816%	1.8864%	1.2546%	0.0000%	-0.0064%	-0.0066%	0.0000%
51	Gross Production Plant 0 0	100.0000%	37.6060%	12.7037%	2.3602%	21.3915%	2.7995%	3.2602%	12.7908%	0.3608%	3.5180%	1.8946%	0.4727%	0.7812%	0.0296%	0.0320%
52	Gross Transmission Plant 0 0	100.0000%	37.6050%	12.7037%	2.3602%	21.3915%	2.7995%	3.2602%	12.7908%	0.3608%	3.5180%	1.8946%	0.4727%	0.7812%	0.0296%	0.0320%
53	Gross Distribution Plant 0 0	100.0000%	57.3873%	12.4524%	1.0320%	11.0669%	1.1777%	1.5580%	4.9204%	0.2033%	0.0017%	0.7884%	0.1836%	9.0933%	0.0311%	0.1038%
54	Total Prod.,Trans., Distrib Plant 0 0	100.0000%	42.6082%	12.6402%	2.0243%	18.7803%	2.3894%	2.8297%	10.8003%	0.3210%	2.6287%	1.6148%	0.3996%	2.8834%	0.0300%	0.0502%
55	Dist. Overhead Lines Gross Plant 0 0	100.0000%	60.9753%	13.7448%	1.1773%	12.5930%	1.3504%	1.7944%	5.6301%	0.2283%	0.0000%	0.9044%	0.2098%	1.3519%	0.0234%	0.0168%
56	Gross Intangible Plant 0 0	100.0000%	42.6082%	12.6402%	2.0243%	18.7803%	2.3894%	2.8297%	10.8003%	0.3210%	2.6287%	1.6148%	0.3996%	2.8834%	0.0300%	0.0502%
57	Gross Total Plant in Service 0 0	100.0000%	42.6050%	12.6402%	2.0245%	18.7820%	2.3896%	2.8300%	10.8015%	0.3210%	2.6293%	1.6150%	0.3997%	2.8821%	0.0300%	0.0502%
58	Dist. Underground Lines Gross Plant 0 0	100.0000%	55.6863%	12.6072%	1.6856%	14.7352%	1.9353%	2.0901%	8.0700%	0.2599%	0.0000%	1.2965%	0.3008%	1.2889%	0.0273%	0.0169%
59	Gross General Plant 0 0	100.0000%	42.6082%	12.6402%	2.0243%	18.7803%	2.3894%	2.8297%	10.8003%	0.3210%	2.6287%	1.6148%	0.3996%	2.8834%	0.0300%	0.0502%
60	Labor Accts 501-507 0 0	100.0000%	37.3747%	12.6687%	2.3685%	21.4307%	2.8194%	3.2707%	12.9023%	0.3624%	3.5690%	1.8969%	0.4770%	0.8068%	0.0305%	0.0325%
61	Labor Accts 511-514 0 0	100.0000%	36.1277%	12.4789%	2.4136%	21.6429%	2.9268%	3.3274%	13.5057%	0.3709%	3.7809%	1.9090%	0.5002%	0.9465%	0.0358%	0.0348%
62	Labor Accts 536-540 0 0	100.0000%	37.6050%	12.7037%	2.3602%	21.3915%	2.7995%	3.2602%	12.7908%	0.3608%	3.5180%	1.8946%	0.4727%	0.7812%	0.0296%	0.0320%
63	Labor Accts 542-545 0 0	100.0000%	36.6773%	12.5825%	2.3937%	21.5494%	2.8795%	3.3024%	13.2397%	0.3671%	3.6831%	1.9036%	0.4900%	0.8844%	0.0335%	0.0337%

Louisville Gas & Electric
Electric Cost of Service Study
(Allocator Percentages)

Alloc. No	Allocator Description	Total System	Residential Rate RS	Gen. Service GSS	Rate PS Primary	Rate PS Secondary	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Seondary	Rate RTS Transmission	Sp. Contract Ft. Knox	Sp. Contract Water Co.	St. Lighting RLS & LS	St. Lighting LE	Traffic SL TLE
64	Labor Accts 581-588 0 0	100.0000%	72.7559%	11.6023%	0.6358%	7.3472%	0.6235%	0.7892%	2.7444%	0.1736%	0.0249%	0.4096%	0.1060%	2.5962%	0.0284%	0.1632%
65	Labor Accts 591-598 0 0	100.0000%	101.7987%	20.5378%	-0.2117%	7.4272%	-0.2509%	1.0689%	-1.0527%	0.1527%	-0.0003%	-0.1895%	-0.0392%	-29.2798%	0.0126%	0.0082%
66	Labor Accts 500-916 0 0	100.0000%	45.2073%	12.3145%	1.9696%	18.4258%	2.3261%	2.7162%	10.6223%	0.3150%	2.8176%	1.5460%	0.3938%	1.2701%	0.0288%	0.0469%
67	O&M less Purchased Power 0 0	100.0000%	39.3829%	12.3686%	2.2501%	20.4712%	2.7077%	3.1007%	12.4579%	0.3497%	3.4429%	1.7733%	0.4615%	1.1621%	0.0332%	0.0383%
68	Dist. Lines Gross Plant 0 0	100.0000%	59.1022%	13.3419%	1.3573%	13.3517%	1.5575%	1.8991%	6.4942%	0.2395%	0.0000%	1.0432%	0.2421%	1.3296%	0.0248%	0.0168%
69	Rate Base 0 0	100.0000%	42.4031%	12.8303%	2.0380%	18.8846%	2.4077%	2.8486%	10.8936%	0.3227%	2.6738%	1.6252%	0.4031%	2.7919%	0.0301%	0.0495%
70	Gross Transformer Plant 0 0	100.0000%	74.0517%	15.9665%	0.0000%	7.1929%	0.0000%	1.0397%	0.0000%	0.1454%	0.0000%	0.0000%	0.0000%	1.5733%	0.0136%	0.0168%
71	Dpreciation Expense 0 0	100.0000%	42.0040%	12.6478%	2.0648%	19.0967%	2.4389%	2.8817%	11.0407%	0.3258%	2.7361%	1.6486%	0.4085%	2.6296%	0.0299%	0.0480%
72	Total Labor 0 0	100.0000%	45.0796%	12.3305%	1.9723%	18.4432%	2.3292%	2.7218%	10.6310%	0.3153%	2.8085%	1.5494%	0.3939%	1.3493%	0.0289%	0.0471%
73	Distribution O&M 0 0	100.0000%	69.5982%	9.6885%	0.7637%	6.8463%	0.7342%	0.6241%	3.2693%	0.1751%	0.0339%	0.4812%	0.1265%	7.4381%	0.0310%	0.2019%
74	Rev 0 0	100.0000%	40.3453%	14.7437%	2.0953%	20.8177%	2.3957%	2.8820%	10.1221%	0.3279%	2.5879%	1.3668%	0.3396%	1.9205%	0.0233%	0.0319%
75	Distribution Poles, Lines, Transform & Services 0 0	100.0000%	63.0938%	13.7412%	1.0445%	11.6875%	1.1985%	1.6622%	4.9973%	0.2127%	0.0000%	0.8026%	0.1863%	1.3258%	0.0227%	0.0248%
76	Late Payment Revenue 0 0															
77	Temperature Normalization Expenses 0 0	100.0000%	76.4419%	7.5201%	0.9990%	10.4788%	1.1032%	1.6351%	0.0000%	0.0000%	0.0000%	1.8219%	0.0000%	0.0000%	0.0000%	0.0000%
78	O&M Expenses 0 0	100.0000%	39.0077%	12.3847%	2.2692%	20.6096%	2.7326%	3.1272%	12.5757%	0.3521%	3.4805%	1.7896%	0.4658%	1.1339%	0.0334%	0.0378%
79	Forfeited Discounts 0 0	100.0000%	78.4099%	14.8186%	2.2346%	4.5369%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
80	Misc Revenue 0 0	100.0000%	84.5086%	15.4914%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
81	Off-System Sales Allocator 0 0	100.0000%	36.9523%	12.6044%	2.3838%	21.5026%	2.8558%	3.2899%	13.1066%	0.3652%	3.6342%	1.9010%	0.4849%	0.8538%	0.0323%	0.0332%
82	Rate Switching 0 0	100.0000%	0.0000%	0.0000%	6.2887%	74.7930%	8.1437%	10.7746%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
83	BIP 0 0															
84	Primary Dist Lines 0 0	100.0000%	57.1296%	12.4456%	1.6146%	14.0645%	1.8527%	1.9901%	7.7249%	0.2474%	0.0000%	1.2410%	0.2879%	1.3583%	0.0281%	0.0173%
85	Secondary Dist Lines 0 0	100.0000%	69.5116%	18.0716%	0.0000%	9.5900%	0.0000%	1.4193%	0.0000%	0.1980%	0.0000%	0.0000%	0.0000%	1.1780%	0.0176%	0.0141%
86	Dist Transformers 0 0	100.0000%	74.0517%	15.9685%	0.0000%	7.1929%	0.0000%	1.0397%	0.0000%	0.1454%	0.0000%	0.0000%	0.0000%	1.5733%	0.0138%	0.0168%

Louisville Gas & Electric
Natural Gas Cost of Service Study
(Summary)

Account Description	Allocator	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
Revenues								
Operating Revenues		$418,890,260	$273,733,052	$126,407,695	$10,424,199	$2,836,844	$4,119,691	$1,368,778
Total Revenue Adjustments		($299,715,634)	($191,700,564)	($96,621,128)	($8,518,361)	($2,614,927)	($234,483)	($26,172)
Total Adjusted Revenues		**$119,174,626**	**$82,032,489**	**$29,786,568**	**$1,905,838**	**$221,917**	**$3,885,208**	**$1,342,605**
Expenses								
Operation and Maintenance Expenses		$29,143,381	$19,217,822	$7,242,224	$578,282	$65,813	$1,456,298	$582,942
Customer Accounting Expenses		$13,152,228	$11,849,305	$1,148,514	$88,643	$6,127	$57,189$2,451	
Administrative & General Expenses		$17,863,027	$12,588,135	$3,913,146	$308,900	$34,272	$737,758	$280,815
Depreciation and Amortization Expenses		$20,081,022	$14,840,512	$3,783,447	$264,491	$40,492	$845,951	$306,129
Other Expenses (ITC amortization, Reg Credits, Accretion)		($167,322)	($117,875)	($35,297)	($2,635)	($374)	($8,163)	($2,979)
Other Taxes		$5,819,250	$4,128,282	$1,234,060	$97,949	$11,705	$250,813	$96,440
Total Operating Expenses		**$85,891,586**	**$62,506,182**	**$17,286,094**	**$1,335,629**	**$158,036**	**$3,339,847**	**$1,265,799**
Pro-Forma Adjustments to Expenses								
Eliminate DSM Expenses	47	($1,898,813)	($1,806,959)	($85,362)	$0	($736)	($5,756)	$0
Year-End Customer Adjustment	44	$541,722	$79,790	$432,103	$29,829	$0	$0	$0
Depreciation Expenses	42	$385,987	$285,257	$72,723	$5,084	$778	$16,260$5,884	
Labor Adjustment	41	$209,494	$148,619	$44,426	$3,526	$421	$9,029	$3,472
Pensions/Post Retirement Benefits Adjmt.	42	$78,706	$58,166	$14,829	$1,037	$159	$3,316	$1,200
Property Insurance Adjmt.	43	$88,922	$61,635	$20,048	$1,534	$183	$4,043	$1,479
Liability Insurance Adjmt.	43	$128,741	$89,235	$29,026	$2,221	$265	$5,854	$2,141
Eliminate Advertising Expenses	30	($149,398)	($103,672)	($35,786)	($2,396)	($284)	($5,327)	($1,933)
Rate Case Expenses	38	$107,664	$70,996	$26,755	$2,136	$243	$5,380	$2,154
Retired Mainframe Adjmt.	43	($352,000)	($243,983)	($79,362)	($6,072)	($724)	($16,005)	($5,855)
2009 Winter Storm Adjmt	45	$33,538	$20,494	$8,245	$691	$117	$2,918	$1,073
Interest Rate Swap Amortization	43	$53,039	$36,763	$11,958	$915	$109	$2,412	$882
Normalize 925 Injuries/Damages Adjmt. (See Func Assign)	43	$38,531	$26,707	$8,687	$665	$79	$1,752	$641
Adjustment to correct Edison Electric Invoice	43	($62,735)	($43,484)	($14,144)	($1,082)	($129)	($2,852)	($1,043)
Property Tax Adjmt.	43	($29,440)	($20,406)	($6,638)	($508)	($61)	($1,339)	($490)
Federal & State Income Tax Adjmt.	46	$3,014,150	$1,936,024	$964,531	$85,054	$26,221	$2,154	$166
Federal & State Income Tax Interest Adjmt.	40	($97,159)	($68,047)	($20,673)	($1,554)	($221)	($4,882)	($1,782)
Prior Income tax true-ups & adjustments	43	$232,125	$160,894	$52,335	$4,004	$477	$10,554$3,861	
Tax Basis depreciation reduction Adjmt.	43	$13,472	$9,338	$3,037	$232	$28	$613	$224
Total Expense Adjustments		$2,336,546	$697,365	$1,446,740	$125,317	$26,925	$28,124	$12,074
Net Income Before Income Taxes		$30,946,494	$18,828,941	$11,053,734	$444,893	$36,956	$517,237	$64,732
Income Taxes	23	$6,084,288	$3,418,876	$2,617,820	$82,503	$3,929	($1,529)	($37,311)
Net Operating Income (Pro-Forma)		$24,862,206	$15,410,066	$8,435,914	$362,390	$33,027	$518,766	$102,043
Unadjusted Net Cost Rate Base		$491,799,638	$340,882,709	$110,881,594	$8,483,064	$1,011,024	$22,361,054	$8,180,194
Depreciation Adjustment	42	($385,987)	($285,257)	($72,723)	($5,084)	($778)	($16,260)	($5,884)
Cash Woking Capital Adjustment	38	($94,673)	($62,430)	($23,527)	($1,879)	($214)	($4,731)	($1,894)
Net Cost Rate Base		$491,318,978	$340,535,023	$110,785,344	$8,476,102	$1,010,032	$22,340,062	$8,172,416
Rate of Return -- Pro-Forma		5.06%	4.53%	7.61%	4.28%	3.27%	2.32%	1.25%

Louisville Gas & Electric
Natural Gas Cost of Service Study
(Rate Base)

Acct. No.	Account Description	Allocator	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
Plant-in-Service									
	Underground Storage Plant								
350-357	Underground Storage Plant	2	$62,838,253	$40,973,701	$20,197,085	$1,667,466	$0	$0	$0
358	Asset Retire Obligations Gas Plant	2	$520,992	$339,713	$167,454	$13,825	$0	$0	$0
	Sub-total		$63,359,245	$41,313,414	$20,364,539	$1,681,291	$0	$0	$0
	Transmission Plant								
365-371	Transmission								
	Demand	3	$13,658,204	$8,905,836	$4,389,936	$362,432	$0	$0	$0
	Customer	-	$0	$0	$0	$0	$0	$0	$0
	Sub-total		$13,658,204	$8,905,836	$4,389,936	$362,432	$0	$0	$0
	Distribution Plant								
374	Land and Land Rights	9	$133,743	$76,600	$35,733	$2,878	$712	$9,979	$7,841
375	Structures and Improvements	9	$701,947	$402,031	$187,546	$15,103	$3,737	$52,376	$41,154
376	Mains								
	L/M Pressure								
	Demand	49	$211,603,955	$120,221,575	$57,990,023	$5,078,514	$785,095	$20,508,128	$7,020,620
	Customer	13	$36,809,325	$33,655,155	$3,124,581	$26,006	$231	$3,352	$0
	H Pressure								
	Demand	48	$33,075,872	$17,384,411	$8,484,997	$744,004	$201,888	$4,193,580	$2,066,992
	Customer	12	$2,476,779	$2,264,090	$210,216	$1,788	$117	$544	$23
378	Meas. & Reg. Station Equip.- Gen.	9	$9,160,306	$5,246,449	$2,447,449	$197,088	$48,762	$683,502	$537,056
379	Meas. & Reg. Station Equip.- City Gate	9	$4,003,923	$2,293,196	$1,069,767	$86,146	$21,314	$298,755	$234,745
380	Services	14	$138,086,721	$127,087,686	$10,777,475	$100,389	$33,831	$81,554	$5,785
381	Meters	15	$34,911,864	$26,447,911	$6,758,765	$396,597	$113,515	$1,130,352	$64,724
382	Meter Installations	15	$0	$0	$0	$0	$0	$0	$0
383	House Regulators	15	$13,852,262	$10,493,951	$2,681,730	$157,361	$45,040	$448,499	$25,681
384	House Regulators Installations	15	$0	$0	$0	$0	$0	$0	$0
385	Indust. Meas. & Reg. Station Equip.	15	$155,769	$118,005	$30,156	$1,770	$506	$5,043	$289
387	Other Equipment	15	$51,112	$38,721	$9,895	$581	$166	$1,655	$95
388	Asset Retire Obligations Gas Plant - City Gate	9	$364	$208	$97	$8	$2	$27	$21
388	Asset Retire Obligations Gas Plant - Mains								
	L/M Pressure								
	Demand	49	$22,657	$12,872	$6,209	$544	$84	$2,196	$752
	Customer	13	$3,941	$3,603	$335	$3	$0	$0	$0
	H Pressure								
	Demand	48	$3,542	$1,862	$909	$80	$22	$449	$221
	Customer	12	$265	$242	$22	$0	$0	$0	$0
	Sub-total		$485,054,347	$345,748,568	$93,815,905	$6,808,859	$1,255,022	$27,419,993	$10,006,000
	Other Plant-In-Service								

Louisville Gas & Electric
Natural Gas Cost of Service Study
(Rate Base)

Acct. No.	Account Description	Allocator	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
117	Gas Stored Underground/Non-Current	7	$2,139,990	$1,417,390	$667,855	$54,744	$0	$0	$0
301-303	Intangible Plant	34	$1,187	$836	$250	$19	$3	$58	$21
389-399	General Plant	34	$9,196,988	$6,479,086	$1,940,126	$144,852	$20,535	$448,664	$163,725
	Common Utility Plant	34	$58,087,778	$40,921,624	$12,253,755	$914,878	$129,701	$2,833,742	$1,034,078
	Sub-total		$69,425,943	$48,818,936	$14,861,987	$1,114,492	$150,239	$3,282,464	$1,197,824
TOTAL PLANT-IN-SERVICE			**$631,497,739**	**$444,786,754**	**$133,432,368**	**$9,967,075**	**$1,405,262**	**$30,702,456**	**$11,203,824**
Construction Work In Progress									
	Underground Storage	7	$4,142,848	$2,743,953	$1,292,914	$105,980	$0	$0	$0
	Transmission	8	$1,250,818	$828,461	$390,360	$31,998	$0	$0	$0
	Distribution Mains								
	L/M Pressure								
	Demand	49	$20,992,014	$11,926,493	$5,752,857	$503,810	$77,885	$2,034,494	$696,475
	Customer	13	$3,651,642	$3,338,735	$309,972	$2,580	$23	$333	$0
	H Pressure								
	Demand	48	$3,281,267	$1,724,607	$841,748	$73,808	$20,028	$416,021	$205,054
	Customer	12	$245,707	$224,607	$20,854	$177	$12	$54	$2
	Other Distribution	35	$18,893,204	$13,467,147	$3,654,195	$265,210	$48,884	$1,068,028	$389,741
	General	34	$648,045	$456,534	$136,707	$10,207	$1,447	$31,614	$11,536
	Common	34	$42,241,284	$29,758,101	$8,910,899	$665,297	$94,318	$2,060,690	$751,979
	Sub-total		$95,346,829	$64,468,638	$21,310,505	$1,659,067	$242,597	$5,611,233	$2,054,788
TOTAL	**GAS PLANT AT ORIGINAL COST**		**$726,844,568**	**$509,255,392**	**$154,742,873**	**$11,626,142**	**$1,647,859**	**$36,313,689**	**$13,258,612**
LESS									
Depreciation	**Reserve**								
	Underground Storage	7	$32,445,945	$21,490,087	$10,125,841	$830,017	$0	$0	$0
	Transmission	8	$12,204,475	$8,083,452	$3,808,814	$312,209	$0	$0	$0
	Distribution	35	$174,352,614	$124,279,201	$33,722,094	$2,447,442	$451,117	$9,856,107	$3,596,653
	General and Intangible	34	$6,203,552	$4,370,273	$1,308,654	$97,705	$13,852	$302,633	$110,436
	Common	34	$26,723,610	$18,826,224	$5,637,409	$420,895	$59,670	$1,303,679	$475,734
	Sub-total		$251,930,196	$177,049,236	$54,602,813	$4,108,268	$524,639	$11,462,418	$4,182,822
Other	**Rate Base Items**								
	Customer Advances for Construction	36	$7,485,292	$5,331,504	$1,429,252	$105,538	$18,111	$439,611	$161,276
	Accum. Deferred Income Taxes	34	$48,874,215	$34,430,862	$10,310,132	$769,765	$109,129	$2,384,269	$870,059
	FAS 109 Deferred Income Taxes	34	$4,053,496	$2,855,603	$855,095	$63,842	$9,051	$197,745	$72,160
	Asset Retirement Obligation - Net Assets	37	$131,229	$92,224	$28,442	$2,140	$273	$5,971	$2,179
	Asset Retirement Obligation - Liabilities	37	$0	$0	$0	$0	$0	$0	$0
	Asset Retirement Obligation - Regulatory Assets	37	$0	$0	$0	$0	$0	$0	$0

Louisville Gas & Electric
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(Rate Base)

Acct. No.	Account Description	Allocator	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
	Asset Retirement Obligation - Regulatory Liabilities	37	($2,353,476)	($1,653,955)	($510,087)	($38,379)	($4,901)	($107,079)	($39,075)
	Accum Depr. Reclassification	34	$0	$0	$0	$0	$0	$0	$0
			$58,190,756						
PLUS									
	Materials and Supplies	34	$60,055	$42,307	$12,669	$946	$134	$2,930	$1,069
	Prepayments	34	$659,791	$464,809	$139,184	$10,392	$1,473	$32,187	$11,746
	Gas Stored Underground	7	$66,447,790	$44,010,701	$20,737,254	$1,699,836	$0	$0	$0
	Cash Working Capital	38	$7,908,386	$5,214,973	$1,965,259	$156,923	$17,859	$395,183	$158,188
	Sub-total		$75,076,022	$49,732,791	$22,854,366	$1,868,097	$19,466	$430,300	$171,003
ADJUSTMENTS									
	Unamortized Debt	-	$ -						
	Regulatory	-	$ -						
	Customer Advances for Construction	-	$ -						
	Depreciation Adjustment	-	$ -						
NET COST RATE BASE			**$491,799,638**	**$340,882,709**	**$110,881,594**	**$8,483,064**	**$1,011,024**	**$22,361,054**	**$8,180,194**

Louisville Gas & Electric
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(Expenses)

Acct. No.	Account Description	Allocator	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
O & M Expenses									
807-813	**Procurement Expenses**								
	Demand	6	$69,689	$39,913	$18,619	$1,499	$371	$5,200	$4,086
	Commodity	1	$523,911	$250,663	$128,821	$12,297	$3,607	$93,758	$34,765
	Sub-total		$593,600	$290,577	$147,440	$13,797	$3,978	$98,958	$38,851
	Storage Operating Expenses								
814	Operations Supervision and Engineer								
	Demand	7	$115,402	$76,435	$36,015	$2,952	$0	$0	$0
	Commodity	2	$351,353	$229,100	$112,930	$9,323	$0	$0	$0
815	Maps and Records	-	$0	$0	$0	$0	$0	$0	$0
816	Well Expenses	7	($27,306)	($18,086)	($8,522)	($699)	$-0	$-0	$-0
817	Lines Expenses	7	$530,675	$351,485	$165,615	$13,575	$0	$0	$0
818	*Compressor Station Exp - Payroll*	2	$1,549,437	$1,010,311	$498,011	$41,116	$0	$0	$0
819	Compressor Station Fuel and Power	2	$1,064,778	$694,289	$342,234	$28,255	$0	$0	$0
820	Measurement and Regulator Station	-	$0	$0	$0	$0	$0	$0	$0
821	Purification of Natural Gas	2	$1,698,551	$1,107,541	$545,938	$45,072	$0	$0	$0
823	Gas losses	-	$0	$0	$0	$0	$0	$0	$0
824	Other Expenses	2	$14,187	$9,251	$4,560	$376	$0	$0	$0
825	Storage Well Royalities	7	$42,906	$28,418	$13,390	$1,098	$0	$0	$0
826	Rents	7	$43,171	$28,594	$13,473	$1,104	$0	$0	$0
	Sub-total		$5,383,154	$3,517,336	$1,723,644	$142,174	$0	$0	$0
	Storage Maintenance Expenses								
830	Maintenance Super and Eng.								
	Demand	7	$116,564	$77,204	$36,378	$2,982	$0	$0	$0
	Commodity	2	$208,386	$135,878	$66,978	$5,530	$0	$0	$0
831	Maintenance of Structures	-	$0	$0	$0	$0	$0	$0	$0
832	Maintenance of Resevoirs	7	$580,151	$384,254	$181,056	$14,841	$0	$0	$0
833	Maintenance of Lines	7	$172,608	$114,324	$53,868	$4,416	$0	$0	$0
834	*Main of Compressor Station Equipment*	2	$927,003	$604,453	$297,952	$24,599	$0	$0	$0
835	Main of Meas and Reg Sta. Equip	7	$52,410	$34,713	$16,356	$1,341	$0	$0	$0
836	Main of Purification Equip	2	$464,091	$302,611	$149,165	$12,315	$0	$0	$0
837	Main of Other Equipment	7	$52,201	$34,575	$16,291	$1,335	$0	$0	$0
	Sub-total		$2,573,414	$1,688,012	$818,044	$67,358	$0	$0	$0
	Transmission Expense								
850-867	Transmission Expense	8	$1,040,622	$689,240	$324,761	$26,621	$0	$0	$0
	Sub-total		$1,040,622	$689,240	$324,761	$26,621	$0	$0	$0

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Acct. No.	Account Description	Allocator	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
	Distribution Expense								
870	Operation Supr and Engr	-	$0	$0	$0	$0	$0	$0	$0
871	Dist Load Dispatching	4	$374,650	$179,250	$92,120	$8,794	$2,579	$67,047	$24,860
872	Compr. Station Labor and Exp.	-	$0	$0	$0	$0	$0	$0	$0
873	Compr. Station Fuel and Power	-	$0	$0	$0	$0	$0	$0	$0
874.01	Other Mains/Serv. Expenses	36	$3,368,434	$2,399,214	$643,173	$47,493	$8,150	$197,828	$72,575
874.02	Leak Survey-Mains	-	$0	$0	$0	$0	$0	$0	$0
874.03	Leak Survey - Service	-	$0	$0	$0	$0	$0	$0	$0
874.04	Locate Main per Request	-	$0	$0	$0	$0	$0	$0	$0
874.05	Check Stop Box Access	-	$0	$0	$0	$0	$0	$0	$0
874.06	Patrolling Mains	-	$0	$0	$0	$0	$0	$0	$0
874.07	Check/Grease Valves	-	$0	$0	$0	$0	$0	$0	$0
874.08	Opr. Odor Equipment	-	$0	$0	$0	$0	$0	$0	$0
874.09	Locate and Inspect Valve Boxes	-	$0	$0	$0	$0	$0	$0	$0
874.1	Cut Grass - Right of Way	-	$0	$0	$0	$0	$0	$0	$0
875	Meas and Reg Station Exp.- General	9	$644,897	$369,357	$172,303	$13,875	$3,433	$48,119	$37,809
876	Meas and Reg Station Exp.- Industrial	15	$266,889	$202,185	$51,668	$3,032	$868	$8,641	$495
877	Meas and Reg Station Exp. - City Gate	9	$186,285	$106,692	$49,772	$4,008	$992	$13,900	$10,922
878	Meter and House Reg. Expense	15	$93,528	$70,853	$18,107	$1,062	$304	$3,028	$173
879	Customer Installation Expense	15	$406,005	$307,574	$78,601	$4,612	$1,320	$13,145	$753
880	Other Expenses	35	$3,029,079	$2,159,139	$585,864	$42,520	$7,837	$171,233	$62,486
881	Rents	35	$9,718	$6,927	$1,880	$136	$25	$549	$200
	Sub-total		$8,379,485	$5,801,192	$1,693,487	$125,533	$25,508	$523,491	$210,274
	Distribution Maintenance Expenses								
885	Maintenance Supr and Engr	-	$0	$0	$0	$0	$0	$0	$0
886	Maintenance Structures	9	$592,928	$339,592	$158,418	$12,757	$3,156	$44,242	$34,763
887	Maintenance Mains								
	L/M Pressure								
	Demand	49	$6,302,964	$3,580,993	$1,727,326	$151,272	$23,385	$610,868	$209,120
	Customer	13	$1,096,425	$1,002,473	$93,071	$775	$7	$100	$0
	H Pressure								
	Demand	48	$985,218	$517,823	$252,739	$22,161	$6,014	$124,913	$61,569
	Customer	12	$73,775	$67,440	$6,262	$53	$3	$16	$1
888	Maintenance Comp. Station Equip.	-	$0	$0	$0	$0	$0	$0	$0
889	Maintenance Meas and Reg. General	9	$71,202	$40,780	$19,024	$1,532	$379	$5,313	$4,174
890	Maintenance Meas and Reg - Industrial	15	$208,249	$157,762	$40,316	$2,366	$677	$6,743	$386
891	Maintenance Meas and Reg.-City Gate	9	$280,673	$160,752	$74,990	$6,039	$1,494	$20,943	$16,455
892	Maintenance Services	14	$1,207,872	$1,111,661	$94,273	$878	$296	$713	$51

Louisville Gas & Electric
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893	Maintenance Meters and House Reg.	-	$0	$0	$0	$0	$0	$0	$0
894	Maintenance Other Equipment	35	$353,800	$252,190	$68,430	$4,966	$915	$20,000	$7,298
	Sub-total		$11,173,106	$7,231,465	$2,534,848	$202,799	$36,327	$833,849	$333,817
Total O&M Expense			**$29,143,381**	**$19,217,822**	**$7,242,224**	**$578,282**	**$65,813**	**$1,456,298**	**$582,942**
Customer Accounts Expense									
901	Supervision	17	$655,292	$590,376	$57,223	$4,416	$305	$2,849	$122
902	Meter Reading	17	$1,729,593	$1,558,251	$151,036	$11,657	$806	$7,521	$322
903	Customer Records and Collection	17	$4,346,793	$3,916,179	$379,582	$29,296	$2,025	$18,901	$810
904	Uncollectible Accounts	17	$1,517,462	$1,367,135	$132,512	$10,227	$707	$6,598	$283
905	Misc. Cust Accounts Expense	17	$270,177	$243,412	$23,593	$1,821	$126	$1,175	$50
	Sub-total		$8,519,317	$7,675,352	$743,946	$57,418	$3,969	$37,044	$1,588
Customer Service & Information Expenses									
907-910	Customer Service	18	$4,610,603	$4,153,854	$402,619	$31,074	$2,148	$20,048	$859
	Sub-total		$4,610,603	$4,153,854	$402,619	$31,074	$2,148	$20,048	$859
Sales Expenses									
911-916	Sales Expenses	18	$22,308	$20,098	$1,948	$150	$10	$97	$4
	Sub-total		$22,308	$20,098	$1,948	$150	$10	$97	$4
Total Customer Accounting Expenses			**$13,152,228**	**$11,849,305**	**$1,148,514**	**$88,643**	**$6,127**	**$57,189**	**$2,451**
Administrative & General Expenses									
920	Admin and General Salaries	39	$3,325,921	$2,345,155	$735,282	$58,817	$6,089	$130,297	$50,280
921	Office Supplies and Expense	39	$1,061,002	$748,128	$234,562	$18,763	$1,942	$41,566	$16,040
922	Admin. Expenses Transferred	39	($410,957)	($289,772)	($90,853)	($7,268)	($752)	($16,100)	($6,213)
923	Outside Services Employed	39	$1,214,328	$856,240	$268,459	$21,475	$2,223	$47,573	$18,358
924	Property Insurance	40	$147,521	$103,319	$31,388	$2,359	$336	$7,412	$2,706
925	Injuries and Damages	39	$467,992	$329,988	$103,462	$8,276	$857	$18,334	$7,075
926	Employee Pensions and Benefits	39	$9,307,982	$6,563,193	$2,057,774	$164,607	$17,041	$364,651	$140,715
927	Franchise Requirement	40	$524,749	$367,519	$111,652	$8,390	$1,195	$26,365	$9,627
928	Regulatory Commission Fee	40	$55,329	$38,751	$11,773	$885	$126	$2,780	$1,015
929	Duplicate Charges -Credit	39	($1,086,388)	($766,028)	($240,175)	($19,212)	($1,989)	($42,561)	($16,424)
930.1	General Advertising Expense	40	$127,090	$89,010	$27,041	$2,032	$290	$6,385	$2,332
930.2	Misc. General Expense	39	$215,931	$152,256	$47,737	$3,819	$395	$8,459	$3,264
931	Rents	40	$350,181	$245,256	$74,509	$5,599	$798	$17,594	$6,424
935	Maintenance of General Plant	34	$2,562,346	$1,805,119	$540,533	$40,357	$5,721	$125,001	$45,615

Louisville Gas & Electric
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	Sub-total		$17,863,027	$12,588,135	$3,913,146	$308,900	$34,272	$737,758	$280,815
Total	**Administrative & General**		**$17,863,027**	**$12,588,135**	**$3,913,146**	**$308,900**	**$34,272**	**$737,758**	**$280,815**
Depreciation	**Expense**								
	Underground Storage Plant								
350-357	Underground Storage Plant	7	$1,086,254	$719,464	$339,002	$27,788	$0	$0	$0
358	Asset Retire Obligations Gas Plant	7	$13,193	$8,738	$4,117	$337	$0	$0	$0
	Sub-total		$1,099,447	$728,202	$343,119	$28,126	$0	$0	$0
	Transmission Plant								
365-371	Transmission	8	$91,870	$60,849	$28,671	$2,350	$0	$0	$0
	Sub-total		$91,870	$60,849	$28,671	$2,350	$0	$0	$0
	Distribution Plant								
374	Land and Land Rights	9	$568	$325	$152	$12	$3	$42	$33
375	Structures and Improvements	9	$41,312	$23,661	$11,038	$889	$220	$3,083	$2,422
376	Mains								
	L/M Pressure								
	Demand	49	$4,237,842	$2,407,706	$1,161,380	$101,709	$15,723	$410,721	$140,604
	Customer	13	$737,189	$674,020	$62,577	$521	$5	$67	$0
	H Pressure								
	Demand	48	$662,418	$348,162	$169,931	$14,900	$4,043	$83,986	$41,396
	Customer	12	$49,603	$45,343	$4,210	$36	$2	$11	$0
378	Meas. & Reg. Station Equip.- Gen.	9	$238,761	$136,747	$63,792	$5,137	$1,271	$17,815	$13,998
379	Meas. & Reg. Station Equip.- City Gate	9	$100,315	$57,454	$26,802	$2,158	$534	$7,485	$5,881
380	Services	14	$5,770,372	$5,310,744	$450,369	$4,195	$1,414	$3,408	$242
381	Meters	15	$1,202,032	$910,614	$232,707	$13,655	$3,908	$38,919	$2,228
382	Meter Installations	15	$0	$0	$0	$0	$0	$0	$0
383	House Regulators	15	$296,890	$224,913	$57,476	$3,373	$965	$9,613	$550
384	House Regulators Installations	15	$0	$0	$0	$0	$0	$0	$0
385	Indust. Meas. & Reg. Station Equip.	15	$3,086	$2,338	$597	$35	$10	$100	$6
387	Other Equipment	15	$1,636	$1,239	$317	$19	$5	$53	$3
388	Asset Retire Obligations Gas Plant - City Gate	9	$5	$3	$1	$0	$0	$0	$0
388	Asset Retire Obligations Gas Plant - Mains								
	L/M Pressure								
	Demand	49	$235	$134	$64	$6	$1	$23	$8
	Customer	13	$41	$37	$3	$0	$0	$0	$0
	H Pressure								
	Demand	48	$37	$19	$9	$1	$0	$5	$2

Louisville Gas & Electric
Natural Gas Cost of Service Study
(Expenses)

Acct. No.	Account Description	Allocator	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
	Customer	12	$3	$3	$0	$0	$0	$0	$0
	Sub-total		$13,342,345	$10,143,462	$2,241,428	$146,645	$28,105	$575,330	$207,375
	Other Plant-In-Service								
117	Gas Stored Underground/Non-Current	-	$0						
301-303	Intangible Plant	34	$0						
389-399	General Plant	34	$352,364	$248,233	$74,332	$5,550	$787	$17,190	$6,273
	Common Utility Plant	34	$5,194,996	$3,659,766	$1,095,897	$81,821	$11,600	$253,432	$92,481
	Sub-total		$5,547,360	$3,907,999	$1,170,229	$87,370	$12,386	$270,621	$98,754
TOTAL DEPRECIATION EXPENSE			**$20,081,022**	**$14,840,512**	**$3,783,447**	**$264,491**	**$40,492**	**$845,951**	**$306,129**
Regulatory Credits and Accretion									
	Regulatory Credits	34	($477,534)	($336,413)	($100,737)	($7,521)	($1,066)	($23,296)	($8,501)
	Accretion	34	$464,021	$326,893	$97,886	$7,308	$1,036	$22,637	$8,260
	Amortization of Income Tax Credits	34	($153,809)	($108,355)	($32,446)	($2,422)	($343)	($7,503)	($2,738)
	Sub-total		($167,322)	($117,875)	($35,297)	($2,635)	($374)	($8,163)	($2,979)
Taxes Other Than Income									
	Property Taxes	40	$0	$0	$0	$0	$0	$0	$0
	Unemployment Insurance	41	$5,819,250	$4,128,282	$1,234,060	$97,949	$11,705	$250,813	$96,440
	Federal Old Age & Survivor Insurance	41	$0	$0	$0	$0	$0	$0	$0
	Public Service Commission Fee	40	$0	$0	$0	$0	$0	$0	$0
	Miscellaneous	40	$0	$0	$0	$0	$0	$0	$0
	Sub-total		$5,819,250	$4,128,282	$1,234,060	$97,949	$11,705	$250,813	$96,440
	Interest Expense	40	$10,397,327	$7,281,979	$2,212,270	$166,246	$23,685	$522,401	$190,746
Total Expenses			$85,891,586	$62,506,182	$17,286,094	$1,335,629	$158,036	$3,339,847	$1,265,799

Louisville Gas & Electric
Natural Gas Cost of Service Study
(Labor)

Acct. No	Account Description	Allocator	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
Labor Expenses									
807-813	**Procurement Expenses**								
	Demand	6	$56,002	$32,074	$14,963	$1,205	$298	$4,179	$3,283
	Commodity	1	$421,015	$201,433	$103,520	$9,882	$2,898	$75,344	$27,937
	Sub-total		$477,017	$233,508	$118,483	$11,087$3,197		$79,523	$31,220
Storage Expenses									
Operation									
814	Operations Supervision and Engineer								
	Demand	7	$82,102	$54,379	$25,623	$2,100	$0	$0	$0
	Commodity	2	$249,967	$162,991	$80,343	$6,633	$0	$0	$0
815	Maps and Records	-	$0	$0	$0	$0	$0	$0	$0
816	Well Expenses	7	$17,775	$11,773	$5,547	$455	$0	$0	$0
817	Lines Expenses	7	$254,059	$168,272	$79,288	$6,499	$0	$0	$0
818	Compressor Station Exp - Payroll	2	$337,393	$219,997	$108,443	$8,953	$0	$0	$0
819	Compressor Station Fuel and Power	-	$0	$0	$0	$0	$0	$0	$0
820	Measurement and Regulator Station	-	$0	$0	$0	$0	$0	$0	$0
821	Purification of Natural Gas	2	$490,234	$319,657	$157,568	$13,009	$0	$0	$0
823	Gas losses	-	$0	$0	$0	$0	$0	$0	$0
824	Other Expenses	-	$0	$0	$0	$0	$0	$0	$0
825	Storage Well Royalities	-	$0	$0	$0	$0	$0	$0	$0
826	Rents	-	$0	$0	$0	$0	$0	$0	$0
Total	**Storage Operation Labor**		$1,431,530	$937,070	$456,811	$37,649	$0	$0	$0
Storage Expense									
Maintenance									
830	Maintenance Super and Eng.								
	Demand	7	$83,326	$55,190	$26,005	$2,132	$0	$0	$0
	Commodity	2	$148,966	$97,133	$47,880	$3,953	$0	$0	$0
831	Maintenance of Structures	-	$0	$0	$0	$0	$0	$0	$0
832	Maintenance of Resevoirs	7	$177,940	$117,856	$55,532	$4,552	$0	$0	$0
833	Maintenance of Lines	7	$61,424	$40,683	$19,169	$1,571	$0	$0	$0
834	Main of Compressor Station Equipment	2	$435,341	$283,864	$139,925	$11,552	$0	$0	$0
835	Main of Meas and Reg Sta. Equip	7	$36,483	$24,164	$11,386	$933	$0	$0	$0
836	Main of Purification Equip	2	$113,675	$74,122	$36,537	$3,016	$0	$0	$0

Louisville Gas & Electric
Natural Gas Cost of Service Study
(Labor)

Acct. No		Account Description	Allocator	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
	837	Main of Other Equipment	7	$31,252	$20,699	$9,753	$799	$0	$0	$0
Total		**Maintenance Labor**		$1,088,407	$713,712	$346,186	$28,509	$0	$0	$0
Total		**Storage Labor**		$2,519,937	$1,650,781	$802,997	$66,158	$0	$0	$0
Transmission										
850-867		Transmission Expenses	8	$448,209	$296,865	$139,879	$11,466	$0	$0	$0
Distribution		**Expenses**								
Operation										
	870	Operation Supr and Engr	-	$0	$0	$0	$0	$0	$0	$0
	871	Dist Load Dispatching	4	$294,287	$140,801	$72,360	$6,908	$2,026	$52,665	$19,528
	872	Compr. Station Labor and Exp.	-	$0	$0	$0	$0	$0	$0	$0
	873	Compr. Station Fuel and Power	-	$0	$0	$0	$0	$0	$0	$0
	874.01	Other Mains/Serv. Expenses	36	$553,484	$394,227	$105,683	$7,804	$1,339	$32,506	$11,925
	874.02	Leak Survey-Mains	-	$0	$0	$0	$0	$0	$0	$0
	874.03	Leak Survey - Service	-	$0	$0	$0	$0	$0	$0	$0
	874.04	Locate Main per Request	-	$0	$0	$0	$0	$0	$0	$0
	874.05	Check Stop Box Access	-	$0	$0	$0	$0	$0	$0	$0
	874.06	Patrolling Mains	-	$0	$0	$0	$0	$0	$0	$0
	874.07	Check/Grease Valves	-	$0	$0	$0	$0	$0	$0	$0
	874.08	Opr. Odor Equipment	-	$0	$0	$0	$0	$0	$0	$0
	874.09	Locate and Inspect Valve Boxes	-	$0	$0	$0	$0	$0	$0	$0
	874.1	Cut Grass - Right of Way	-	$0	$0	$0	$0	$0	$0	$0
	875	Meas and Reg Station Exp.- General	9	$366,738	$210,045	$97,985	$7,891	$1,952	$27,364	$21,501
	876	Meas and Reg Station Exp.- Industrial	15	$177,634	$134,569	$34,389	$2,018	$578	$5,751	$329
	877	Meas and Reg Station Exp. - City Gate	9	$21,164	$12,121	$5,655	$455	$113	$1,579	$1,241
	878	Meter and House Reg. Expense	15	$7,634	$5,783	$1,478	$87	$25	$247	$14
	879	Customer Installation Expense	15	$224,982	$170,438	$43,555	$2,556	$732	$7,284	$417
	880	Other Expenses	35	$1,277,222	$910,409	$247,032	$17,929	$3,305	$72,201	$26,347
	881	Rents	-	$0	$0	$0	$0	$0	$0	$0
Total		**Operations Distribution Labor**		$2,923,145	$1,978,392	$608,137	$45,646	$10,069	$199,598	$81,303
Total		**Operations Transmission and Distribution Labor**		$3,371,354	$2,275,256	$748,015	$57,112	$10,069	$199,598	$81,303

Louisville Gas & Electric
Natural Gas Cost of Service Study
(Labor)

Acct. No	Account Description	Allocator	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
Maintenance	**Expense – Distribution**								
885	Maintenance Supr and Engr	-	$0	$0	$0	$0	$0	$0	$0
886	Maintenance Structures	9	$25,478	$14,592	$6,807	$548	$136	$1,901	$1,494
887	Maintenance Mains								
	L/M Pressure								
	Demand	49	$2,218,586	$1,260,477	$608,003	$53,246$8,231		$215,020	$73,608
	Customer	13	$385,932	$352,862	$32,760	$273	$2	$35	$0
	H Pressure								
	Demand	48	$346,788	$182,269	$88,962	$7,801	$2,117	$43,968	$21,672
	Customer	12	$25,968	$23,738	$2,204	$19	$1	$6	$0
888	Maintenance Comp. Station Equip.	-	$0	$0	$0	$0	$0	$0	$0
889	Maintenance Meas and Reg. General	9	$36,857	$21,109	$9,847	$793	$196	$2,750	$2,161
890	Maintenance Meas and Reg - Industrial	15	$150,451	$113,976	$29,127	$1,709	$489	$4,871	$279
891	Maintenance Meas and Reg.-City Gate	9	$143,956	$82,449	$38,462	$3,097	$766	$10,741	$8,440
892	Maintenance Services	14	$574,417	$528,663	$44,832	$418	$141	$339	$24
893	Maintenance Meters and House Reg.	-	$0	$0	$0	$0	$0	$0	$0
894	Maintenance Other Equipment	35	$154,778	$110,326	$29,936	$2,173	$400	$8,750	$3,193
Total	**Maintenance Labor**		$4,063,211	$2,690,461	$890,941	$70,076	$12,480	$288,381	$110,871
Total	**Transmission & Distribution Labor**		$7,434,565	$4,965,718	$1,638,956	$127,188	$22,549	$487,980	$192,174
Customer	**Accounts Expense**								
901	Supervision	17	$471,318	$424,627	$41,158	$3,177	$220	$2,049	$88
902	Meter Reading	17	$177,627	$160,030	$15,511	$1,197	$83	$772	$33
903	Customer Records and Collections	17	$1,779,757	$1,603,446	$155,417	$11,995	$829	$7,739	$332
904	Uncollectible Accounts	-	$0	$0	$0	$0	$0	$0	$0
905	Misc. Cust Account Expenses	17	$126,229	$113,724	$11,023	$851	$59	$549	$24
Total	**Customer Accounts Labor**		$2,554,931	$2,301,827	$223,108	$17,220$1,190		$11,109	$476
Customer	**Service Expenses**								
907-910	Customer Service	18	$395,379	$356,211	$34,526	$2,665	$184	$1,719	$74
Sales	**Expenses**								

Louisville Gas & Electric
Natural Gas Cost of Service Study
(Labor)

Acct. No	Account Description	Allocator	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
911-916	Sales Expenses	-	$0	$0	$0	$0	$0	$0	$0
Administrative & General									
920	Admin and General Salaries	39	$2,577,542	$1,817,462	$569,833	$45,583$4,719		$100,978	$38,967
921	Office Supplies and Expense	-	$0	$0	$0	$0	$0	$0	$0
922	Admin. Expenses Transferred	39	($272,690)	($192,278)	($60,285)	($4,822)	($499)	($10,683)	($4,122)
923	Outside Services Employed	-	$0	$0	$0	$0	$0	$0	$0
924	Property Insurance	-	$0	$0	$0	$0	$0	$0	$0
925	Injuries and Damages	39	$6,261	$4,415	$1,384	$111	$11	$245	$95
926	Employee Pensions and Benefits	-	$0	$0	$0	$0	$0	$0	$0
927	Franchise Requirement	-	$0	$0	$0	$0	$0	$0	$0
928	Regulatory Commission Fee	-	$0	$0	$0	$0	$0	$0	$0
929	Duplicate Charges -Credit	-	$0	$0	$0	$0	$0	$0	$0
930.1	General Advertising Expense	-	$0	$0	$0	$0	$0	$0	$0
930.2	Misc. General Expense	-	$0	$0	$0	$0	$0	$0	$0
931	Rents	-	$0	$0	$0	$0	$0	$0	$0
935	Maintenance of General Plant	34	$968,557	$682,328	$204,319	$15,255$2,163		$47,250	$17,242
Total	**Administrative and General Labor**		**$3,279,670**	**$2,311,927**	**$715,252**	**$56,126$6,394**		**$137,790**	**$52,181**
Total	**Labor Expense**		**$16,661,499**	**$11,819,972**	**$3,533,323**	**$280,444**	**$33,514**	**$718,121**	**$276,125**

Louisville Gas & Electric
Natural Gas Cost of Service Study
(Revenues)

Acct. No.	Account Description	Allocator	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
Operating Revenues									
	Sales and Transportation	28	$408,703,213	$266,835,228	$123,545,049	$10,222,598	$2,791,492	$3,961,597	$1,347,249
	Interdepartmental Sales	28	$6,531,020	$4,263,990	$1,974,233	$163,356	$44,608	$63,306	$21,529
	Forfeited Discounts	Dir	$3,212,301	$2,605,350	$555,512	$38,246	$0	$13,193	$0
	Miscellaneous Revenue	31	$443,726	$28,485	$332,902	$0	$744	$81,595	$0
Total	**Operating Revenues**		$418,890,260	$273,733,052	$126,407,695	$10,424,199	$2,836,844	$4,119,691	$1,368,778
Pro-Forma	**Adjustments to Revenues**								
	VDT Amortization and Surcredit	30	($323)	($224)	($77)	($5)	($1)	($12)	($4)
	Adjust Base Rates to reflect full year of FAC Roll-in	32	$9,941,202	$7,856,572	$1,939,946	$78,152	$6,208	$54,562	$5,762
	Elimination of ECR, MSR, DSM, FAC, and GSC accruals	28	$2,228,479	$1,454,935	$673,637	$55,739	$15,221	$21,601	$7,346
	Temperature Normalization	Dir	($248,948)	($190,208)	($16,121)	($18,867)	($1,739)	($13,063)	($8,950)
	Year-End Customer Adjustment	Dir	$1,760,940	$259,367	$1,404,610	$96,963	$0	$0	$0
	Rate Switching	Dir	$22,135	$0	$0	($22,236)	$0	$44,371	$0
	Adjustment to eliminate gas supply cost recoveries	33	($322,476,565)	($206,301,504)	($103,957,947)	($8,992,672)	($2,711,423)	($445,190)	($67,829)
	Adjustment to eliminate unbilled revenues	28	$11,377,000	$7,427,846	$3,439,102	$284,565	$77,706	$110,278	$37,503
	Removal of DSM Revenues	Dir	($2,319,554)	($2,207,347)	($104,277)	$0	($899)	($7,031)	$0
Total	**Revenue Adjustments**		($299,715,634)	($191,700,564)	($96,621,128)	($8,518,361)	($2,614,927)	($234,483)	($26,172)
Total	**Adjusted Revenue**		**$119,174,626**	**$82,032,489**	**$29,786,568**	**$1,905,838**	**$221,917**	**$3,885,208**	**$1,342,605**

Louisville Gas and Electric
Natural Gas Class Cost of Service Study
(Allocation Amounts)

Acct. No.	Account Description	Allocator	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
1	Procurement Expenses	COM01	42,412,266	20,292,002	10,428,447	995,514	291,983	7,590,002	2,814,318
2	Storage	COM02	23,642,092	15,415,833	7,598,896	627,363	0	0	0
3	Transmission	COM03	23,642,092	15,415,833	7,598,896	627,363	0	0	0
4	Distribution	COM04	42,412,266	20,292,002	10,428,447	995,514	291,983	7,590,002	2,814,318
5	Adjusted Deliveries		42,977,597	20,304,230	11,007,576	1,043,051	288,669	7,559,624	2,774,447
6	Procurement Expenses	DEM01	516,420	295,773	137,977	11,111	2,749	38,533	30,277
7	Storage	DEM02	12,289,964	8,140,074	3,835,494	314,396	0	0	0
8	Transmission	DEM03	12,289,964	8,140,074	3,835,494	314,396	0	0	0
9	Distribution Structures	DEM04	516,420	295,773	137,977	11,111	2,749	38,533	30,277
10	High Pressure Distribution Mains	DEM05	516,420	295,773	137,977	11,111	2,749	38,533	30,277
11	Low/Medium Pressure Distribution Mains	DEM05a	449,611	295,773	135,880	11,028	241	6,689	0
12	High Pressure Distrib Mains (yr-end cust.)	CUST01	318,528	291,175	27,035	230	15	70	3
13	Low/Med Pres. Distrib Mains (yr-end cust.)	CUST01a	318,464	291,175	27,033	225	2	29	0
14	Services	CUST02	154,617,164	142,301,428	12,067,653	112,407	37,881	91,317	6,478
15	Meters	CUST03	45,693,971	34,616,028	8,846,128	519,081	148,573	1,479,448	84,713
16	Customer Count (Average)		315,940	290,075	25,560	217	15	70	3
17	Customer Accounts	CUST04	321,971	290,075	28,116	2,170	150	1,400	60
18	Customer Service	CUST05	321,971	290,075	28,116	2,170	150	1,400	60
19	Forfeited Discounts	REVFD	3,212,302	2,605,350	555,513	38,246	0	13,193	0
20	Net Income Before Income Tax	NIBIT	30,946,494	18,828,941	11,053,734	444,893	36,956	517,237	64,732
21	Interest Expense	INT	10,397,327	7,281,979	2,212,270	166,246	23,685	522,401	190,746
22	**Interest Adjustment**		**0**	**0**	**0**	**0**	**0**	**0**	**0**
23	Taxable Income	TXINC	20,549,167	11,546,963	8,841,465	278,647	13,271	(5,164)	(126,014)
24	Total Distribution Expense	DISTRT	19,552,591	13,032,657	4,228,335	328,332	61,835	1,357,340	544,091
25	Meter Cost		1.000000	0.772847	0.180153	0.010163	0.003431	0.031572	0.001834
26	Number of Customers		318,528	291,175	27,035	230	15	70	3
27	Services Cost		1.00	0.92	0.08	0.00	0.00	0.00	0.00
28	Actual Revenue	REV01	421,091,066	274,923,042	127,289,717	10,532,446	2,876,103	4,081,674	1,388,084
29	Actual Net Revenue	REVUC	102,114,452	70,860,600	24,460,062	1,637,375	194,108	3,641,316	1,320,991
30	DSM Allocation	REVADJ4	2,356,128	2,242,152	105,921	0	913	7,142	0
31	Miscellaneous Revenue Allocation	REVMISC	544,576	34,959	408,564	0	913	100,140	0
32	Rev. Adj. Reflective Base Rates for Full Ye	REVADJ1	9,941,202	7,856,572	1,939,946	78,152	6,208	54,562	5,762
33	GSC Revenue	REVGSC	318,976,614	204,062,442	102,829,655	8,895,071	2,681,995	440,358	67,093
34	PTD Plant		562,071,796	395,967,818	118,570,381	8,852,583	1,255,022	27,419,993	10,006,000
35	Dist Plant		485,054,347	345,748,568	93,815,905	6,808,859	1,255,022	27,419,993	10,006,000
36	Mains + Services		422,052,652	300,612,917	80,587,292	5,950,703	1,021,162	24,787,158	9,093,421
37	Depreciation Reserve		251,930,196	177,049,236	54,602,813	4,108,268	524,639	11,462,418	4,182,822
38	O&M Expense		29,143,381	19,217,822	7,242,224	578,282	65,813	1,456,298	582,942
39	Labor Excl. A&G		14,813,359	10,445,114	3,274,883	261,967	27,120	580,331	223,944
40	PTD Plant + CWIP		657,418,625	460,436,456	139,880,886	10,511,650	1,497,619	33,031,226	12,060,788
41	Total Labor		16,661,499	11,819,972	3,533,323	280,444	33,514	718,121	276,125
42	Depreciation Expenses		20,081,022	14,840,512	3,783,447	264,491	40,492	845,951	306,129

Louisville Gas and Electric
Natural Gas Class Cost of Service Study
(Allocation Amounts)

Acct. No.	Account Description	Allocator	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
43	Rate Base	RBT	491,799,638	340,882,709	110,881,594	8,483,064	1,011,024	22,361,054	8,180,194
44	Year-End Customer Adjustment	REVADJ2	1,760,940	259,367	1,404,610	96,963	0	0	0
45	Mains		283,965,931	173,525,231	69,809,816	5,850,314	987,331	24,705,604	9,087,635
46	Pro Forma Adjustments	PROFO	(300,541,676)	(193,041,406)	(96,173,618)	(8,480,781)	(2,614,506)	(214,798)	(16,567)
47	DSM Revenue		2,319,554	2,207,347	104,277	0	899	7,031	0
48	Peak & Avg High Pressure		100.00%	52.56%	25.65%	2.25%	0.61%	12.68%	6.25%
49	Peak & Avg Low Pressure		100.00%	56.81%	27.40%	2.40%	0.37%	9.69%	3.32%

Louisville Gas and Electric
Natural Gas Class Cost of Service Study
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Acct. No.	Account Description	Allocator	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
1	Procurement Expenses	COM01	42,412,266	20,292,002	10,428,447	995,514	291,983	7,590,002	2,814,318
2	Storage	COM02	23,642,092	15,415,833	7,598,896	627,363	0	0	0
3	Transmission	COM03	23,642,092	15,415,833	7,598,896	627,363	0	0	0
4	Distribution	COM04	42,412,266	20,292,002	10,428,447	995,514	291,983	7,590,002	2,814,318
5	Adjusted Deliveries		42,977,597	20,304,230	11,007,576	1,043,051	288,669	7,559,624	2,774,447
6	Procurement Expenses	DEM01	516,420	295,773	137,977	11,111	2,749	38,533	30,277
7	Storage	DEM02	12,289,964	8,140,074	3,835,494	314,396	0	0	0
8	Transmission	DEM03	12,289,964	8,140,074	3,835,494	314,396	0	0	0
9	Distribution Structures	DEM04	516,420	295,773	137,977	11,111	2,749	38,533	30,277
10	High Pressure Distribution Mains	DEM05	516,420	295,773	137,977	11,111	2,749	38,533	30,277
11	Low/Medium Pressure Distribution Mains	DEM05a	449,611	295,773	135,880	11,028	241	6,689	0
12	High Pressure Distrib Mains (yr-end cust.)	CUST01	318,528	291,175	27,035	230	15	70	3
13	Low/Med Pres. Distrib Mains (yr-end cust.)	CUST01a	318,464	291,175	27,033	225	2	29	0
14	Services	CUST02	154,617,164	142,301,428	12,067,653	112,407	37,881	91,317	6,478
15	Meters	CUST03	45,693,971	34,616,028	8,846,128	519,081	148,573	1,479,448	84,713
16	Customer Count (Average)		315,940	290,075	25,560	217	15	70	3
17	Customer Accounts	CUST04	321,971	290,075	28,116	2,170	150	1,400	60
18	Customer Service	CUST05	321,971	290,075	28,116	2,170	150	1,400	60
19	Forfeited Discounts	REVFD	3,212,302	2,605,350	555,513	38,246	0	13,193	0
20	Net Income Before Income Tax	NIBIT	30,946,494	18,828,941	11,053,734	444,893	36,956	517,237	64,732
21	Interest Expense	INT	10,397,327	7,281,979	2,212,270	166,246	23,685	522,401	190,746
22	**Interest Adjustment**		**0**	**0**	**0**	**0**	**0**	**0**	**0**
23	Taxable Income	TXINC	20,549,167	11,546,963	8,841,465	278,647	13,271	(5,164)	(126,014)
24	Total Distribution Expense	DISTRT	19,552,591	13,032,657	4,228,335	328,332	61,835	1,357,340	544,091
25	Meter Cost		1.000000	0.772847	0.180153	0.010163	0.003431	0.031572	0.001834
26	Number of Customers		318,528	291,175	27,035	230	15	70	3
27	Services Cost		1.00	0.92	0.08	0.00	0.00	0.00	0.00
28	Actual Revenue	REV01	421,091,066	274,923,042	127,289,717	10,532,446	2,876,103	4,081,674	1,388,084
29	Actual Net Revenue	REVUC	102,114,452	70,860,600	24,460,062	1,637,375	194,108	3,641,316	1,320,991
30	DSM Allocation	REVADJ4	2,356,128	2,242,152	105,921	0	913	7,142	0
31	Miscellaneous Revenue Allocation	REVMISC	544,576	34,959	408,564	0	913	100,140	0
32	Rev. Adj. Reflective Base Rates for Full Ye:	REVADJ1	9,941,202	7,856,572	1,939,946	78,152	6,208	54,562	5,762
33	GSC Revenue	REVGSC	318,976,614	204,062,442	102,829,655	8,895,071	2,681,995	440,358	67,093
34	PTD Plant		562,071,796	395,967,818	118,570,381	8,852,583	1,255,022	27,419,993	10,006,000
35	Dist Plant		485,054,347	345,748,568	93,815,905	6,808,859	1,255,022	27,419,993	10,006,000
36	Mains + Services		422,052,652	300,612,917	80,587,292	5,950,703	1,021,162	24,787,158	9,093,421
37	Depreciation Reserve		251,930,196	177,049,236	54,602,813	4,108,268	524,639	11,462,418	4,182,822
38	O&M Expense		29,143,381	19,217,822	7,242,224	578,282	65,813	1,456,298	582,942
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40	PTD Plant + CWIP		657,418,625	460,436,456	139,880,886	10,511,650	1,497,619	33,031,226	12,060,788
41	Total Labor		16,661,499	11,819,972	3,533,323	280,444	33,514	718,121	276,125
42	Depreciation Expenses		20,081,022	14,840,512	3,783,447	264,491	40,492	845,951	306,129
43	Rate Base	RBT	491,799,638	340,882,709	110,881,594	8,483,064	1,011,024	22,361,054	8,180,194

Louisville Gas and Electric
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44	Year-End Customer Adjustment	REVADJ2	1,760,940	259,367	1,404,610	96,963	0	0	0
45	Mains		283,965,931	173,525,231	69,809,816	5,850,314	987,331	24,705,604	9,087,635
46	Pro Forma Adjustments	PROFO	(300,541,676)	(193,041,406)	(96,173,618)	(8,480,781)	(2,614,506)	(214,798)	(16,567)
47	DSM Revenue		2,319,554	2,207,347	104,277	0	899	7,031	0
48	Peak & Avg High Pressure		100.00%	52.56%	25.65%	2.25%	0.61%	12.68%	6.25%
49	Peak & Avg Low Pressure		100.00%	56.81%	27.40%	2.40%	0.37%	9.69%	3.32%

Value Line Natural Gas Utilities
Rates of Return on Common Equity
(1999-2009)

Company	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	All Years
AGL Resources	7.9%	11.5%	12.3%	14.5%	14.0%	11.0%	12.9%	13.2%	12.7%	12.6%	14.5%	
Atmos Energy Corp.	6.6%	8.2%	9.6%	10.4%	9.3%	7.6%	8.5%	9.8%	8.7%	8.8%	8.3%	
Laclede Group	9.5%	9.1%	10.5%	7.8%	11.6%	10.1%	10.9%	12.5%	11.6%	11.8%	12.4%	
New Jersey Resources	14.8%	14.6%	14.9%	15.7%	15.6%	15.3%	17.0%	12.6%	10.1%	15.7%	14.6%	
Nicor, Inc.	15.4%	19.2%	18.7%	17.5%	12.3%	13.1%	12.5%	14.7%	14.3%	12.3%	13.1%	
Northwest Natural Gas	9.9%	10.0%	10.2%	8.5%	9.0%	8.9%	9.9%	10.9%	12.5%	10.9%	11.1%	
Piedmont Natural Gas	11.8%	12.1%	11.7%	10.6%	11.8%	11.1%	11.5%	11.0%	11.9%	12.4%	13.2%	
South Jersey Industries	14.6%	14.8%	12.8%	12.5%	11.6%	12.5%	12.4%	16.3%	12.8%	13.1%	13.1%	
Southwest Gas	7.8%	7.2%	6.6%	6.5%	6.1%	8.3%	6.4%	8.9%	8.5%	5.9%	7.9%	
UGI Corp.	17.2%	17.6%	22.5%	23.8%	17.6%	14.1%	18.2%	16.0%	14.5%	15.2%	16.2%	
WGL Holdings	9.9%	11.7%	11.2%	7.2%	14.0%	11.7%	12.0%	10.3%	10.4%	11.6%	11.6%	
AVERAGE	**11.4%**	**12.4%**	**12.8%**	**12.3%**	**12.1%**	**11.2%**	**12.0%**	**12.4%**	**11.6%**	**11.8%**	**12.4%**	**12.0%**
STANDARD DEVIATION												**0.47%**

Source: Value Line Investment Survey, March 12, 2010.

Schedule GAW-7

Comparison of Value Line Electric Rates of Return, 2000-2009

Company	Location	Own Gen?	Pct Elec Rev 1/	Rate of Return on Common Equity										
				2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Average
Allegheny Energy	East	NO	100%	13.4%	16.6%	-26.3%	-22.1%	5.0%	8.8%	15.3%	16.3%	13.9%	12.6%	5.3%
Cen. Vermont Pub. Serv.	East	YES	100%	6.9%	5.8%	9.3%	8.1%	6.8%	0.5%	10.1%	8.2%	7.3%	7.5%	7.1%
CH Energy Group	East	YES	58%	10.6%	10.2%	7.1%	9.1%	8.6%	8.8%	7.9%	8.1%	6.7%	8.1%	8.5%
Consol. Edison	East	NO	64%	10.7%	12.0%	11.3%	9.8%	7.8%	9.7%	9.2%	10.4%	9.5%	8.5%	9.9%
Constellation Energy	East	YES	18%	11.0%	9.2%	9.3%	11.1%	11.7%	12.3%	14.8%	14.7%	2.7%	3.0%	10.0%
Dominion Resources	East	YES	43%	8.0%	9.0%	13.3%	11.8%	12.3%	9.9%	13.1%	14.9%	17.5%	15.5%	12.5%
Duke Energy	East	YES	79%							4.1%	7.2%	6.1%	6.7%	6.0%
Exelon Corp.	East	YES	55%	7.8%	17.2%	20.1%	18.8%	19.5%	23.6%	23.7%	26.9%	24.6%	22.5%	20.5%
FirstEnergy Corp.	East	YES	100%	12.9%	8.9%	10.5%	5.4%	10.6%	10.2%	13.9%	14.6%	16.2%	11.9%	11.5%
FPL Group	East	YES	100%	12.6%	13.0%	10.9%	12.5%	11.8%	10.6%	12.9%	12.2%	14.0%	12.4%	12.3%
Northeast Utilities	East	NO	80%	-1.3%	8.5%	6.3%	6.9%	5.1%	5.1%	4.3%	8.4%	9.6%	9.0%	6.2%
NSTAR	East	NO	84%	13.0%	13.7%	13.8%	13.7%	13.1%	12.8%	13.1%	13.0%	13.3%	13.0%	13.3%
Pepco Holdings	East	YES	51%	9.8%	12.6%	9.2%	7.7%	7.7%	7.7%	7.0%	7.4%	9.5%	5.0%	8.4%
PPL Corp.	East	YES	100%	23.6%	28.2%	21.1%	19.6%	16.3%	16.7%	17.3%	18.2%	18.2%	8.1%	18.7%
Progress Energy	East	YES	100%	6.7%	11.5%	12.1%	10.9%	9.9%	9.0%	6.1%	8.2%	8.9%	9.0%	9.2%
Public Serv. Enterprise	East	NO	66%	19.1%	18.6%	19.7%	15.4%	12.6%	14.2%	13.8%	18.1%	19.0%	18.0%	16.9%
SCANA Corp.	East	YES	51%	10.9%	10.2%	11.6%	12.1%	12.2%	11.8%	10.5%	10.8%	11.4%	10.2%	11.2%
Southern Co.	East	YES	100%	12.3%	14.0%	15.1%	14.8%	14.9%	14.9%	13.8%	14.0%	13.1%	12.5%	13.9%
TECO Energy	East	YES	66%	16.7%	15.4%	9.9%	-0.9%	10.7%	13.3%	14.1%	13.2%	8.1%	10.3%	11.1%
UIL Holdings	East	NO	100%	12.5%	11.9%	9.1%	6.0%	6.7%	5.8%	9.9%	10.1%	10.1%	9.5%	9.2%
Allete	Central	YES	91%					6.1%	11.3%	11.6%	11.8%	10.0%	6.6%	9.6%
Allant Energy	Central	YES	72%	9.6%	9.8%	5.8%	6.7%	8.2%	13.1%	9.1%	11.3%	9.3%	6.8%	9.0%
Amer. Electric Power	Central	NO	100%	3.7%	12.8%	13.7%	12.4%	12.2%	11.3%	12.0%	11.4%	11.3%	10.4%	11.1%
Ameren Corp.	Central	YES	83%	14.3%	14.0%	9.9%	11.6%	9.1%	9.7%	8.1%	9.2%	8.7%	7.8%	10.2%
CenterPoint Energy	Central	NO	21%		6.6%	27.2%	23.8%	18.6%	17.4%	27.8%	22.0%	21.9%	14.1%	19.9%
Cleco Corp.	Central	YES	100%	14.9%	14.6%	13.1%	12.5%	11.9%	10.7%	8.3%	7.8%	9.6%	9.5%	11.3%
CMS Energy Corp.	Central	YES	55%	12.1%	8.8%	-38.0%	-2.9%	6.2%	9.9%	6.4%	7.2%	11.7%	8.5%	3.0%
DPL Inc.	Central	NO	100%	22.9%	27.8%	10.8%	14.6%	20.7%	11.9%	17.5%	24.2%	25.0%	20.7%	19.6%
DTE Energy	Central	YES	59%	11.7%	7.2%	13.8%	9.1%	8.0%	10.0%	7.5%	7.7%	7.4%	8.4%	9.1%
Empire Dist. Elec.	Central	YES	87%	9.8%	3.9%	7.8%	7.8%	5.8%	6.0%	8.5%	6.2%	7.5%	6.9%	7.0%
Entergy Corp.	Central	YES	73%	9.7%	9.3%	10.9%	9.8%	11.0%	11.9%	13.8%	14.4%	15.3%	14.3%	12.0%
Great Plains Energy	Central	YES	100%	13.8%	12.6%	13.6%	16.4%	15.5%	13.3%	9.4%	10.1%	4.6%	4.8%	11.4%
Integrys Energy	Central	YES	17%	11.9%	10.8%	11.7%	9.1%	14.0%	11.8%	9.7%	5.5%	3.9%	6.1%	9.5%
ITC Holdings	Central	NO	100%					1.3%	13.2%	6.2%	13.0%	11.8%	12.9%	9.7%
MGE Energy	Central	YES	62%	13.7%	12.6%	12.8%	11.6%	10.0%	9.3%	11.3%	11.4%	11.0%	10.2%	11.4%
NiSource Inc.	Central	YES	18%	5.5%	6.8%	9.7%	9.4%	9.0%	6.0%	6.3%	6.1%	7.8%	5.0%	7.2%
OGE Energy	Central	YES	100%	13.8%	9.7%	11.4%	11.8%	12.3%	12.1%	14.1%	14.5%	12.2%	12.7%	12.5%
Otter Trail Corp	Central	NO	100%	14.8%	14.9%	14.5%	11.7%	9.1%	11.2%	10.2%	10.2%	5.1%	3.8%	10.6%
Vectren Corp.	Central	NO	25%	9.7%	8.5%	13.1%	10.4%	9.9%	12.0%	9.3%	11.6%	9.5%	10.5%	10.5%
Westar Energy	Central	YES	100%	3.2%	-2.2%	7.3%	10.3%	7.1%	9.5%	10.7%	9.2%	6.2%	6.2%	6.7%
Wisconsin Energy	Central	YES	66%	6.5%	10.6%	12.6%	11.4%	8.8%	11.3%	10.8%	10.9%	10.7%	10.6%	10.4%
Avista	West	YES	56%	11.1%	7.9%	4.5%	6.6%	4.7%	5.9%	8.0%	4.2%	7.4%	8.0%	6.8%
Black Hills	West	YES	41%	19.0%	17.2%	11.9%	8.1%	7.8%	9.5%	9.4%	10.3%	0.7%	6.5%	10.0%
Edison International	West	YES	100%		13.6%	11.9%	13.6%	3.5%	16.7%	14.0%	13.0%	12.8%	10.5%	12.2%
El Paso Electric	West	YES	100%	14.6%	14.6%	6.3%	6.3%	6.3%	6.6%	10.6%	11.2%	11.2%	9.0%	9.7%
Hawiian Electric	West	YES	100%	9.8%	11.6%	11.3%	10.8%	8.9%	9.7%	9.9%	7.2%	6.5%	6.0%	9.2%
IDACORP	West	YES	100%	16.0%	14.4%	7.0%	4.2%	7.2%	6.2%	8.9%	6.8%	7.6%	8.0%	8.6%
MDU Resources	West	NO	5%	12.4%	13.3%	10.1%	12.6%	12.6%	14.5%	14.7%	12.8%	13.7%	10.1%	12.7%
NV Energy Inc.	West	YES	94%	-3.6%	1.8%	-23.1%	-9.4%	4.8%	4.0%	9.0%	6.6%	6.7%	6.0%	0.3%
PG&E Corp	West	YES	77%		22.9%	-24.9%	18.5%	10.3%	12.3%	12.7%	11.8%	12.6%	11.5%	9.7%
Pinnacle West Capital	West	YES	100%	11.9%	12.5%	8.0%	8.1%	8.0%	6.5%	9.2%	8.5%	6.2%	7.5%	8.6%
PNM Resources	West	YES	100%	10.0%	15.4%	6.5%	6.3%	8.0%	8.2%	7.2%	3.5%	0.5%	4.5%	7.0%
Portland General	West	YES	100%					7.2%	5.3%	5.8%	11.0%	6.4%	6.5%	7.0%
Puget Energy Inc.	West	YES	100%	13.0%	7.7%	7.2%	7.0%	8.1%	7.2%	7.9%	7.3%			8.2%
Sempra Energy	West	NO	60%	17.2%	19.4%	20.4%	16.6%	18.9%	14.4%	14.8%	13.5%	14.0%	13.5%	16.3%
UniSource Energy	West	YES	84%	7.1%	14.9%	7.6%	8.4%	7.9%	7.5%	10.6%	8.5%	2.1%	12.5%	8.7%
Xcel Energy Inc.	West	YES	80%	9.7%	12.6%	3.7%	9.8%	10.0%	9.2%	9.7%	9.1%	9.2%	9.5%	9.3%
Average			76%	11.3%	12.2%	8.4%	9.5%	9.9%	10.4%	11.0%	11.2%	10.3%	9.6%	10.3%

Source: Value Line Investment Analyzer, April 12, 2010 except where otherwise noted.
1/ Source: February 2010 AUS Monthly Utility Reports

Competitive Fixed Period Electric Residential Rates in Texas 1/

	Company	Customer Charge		Average Cents/kWh Charge
1	Amigo Energy	$6.95	2a/	10.58
2	Texas Power	$10.00	2b/	10.28
3	Champion Energy Services	$4.95		10.07
4	Gexa Energy	$4.79		10.43
5	Cirro Energy	$9.89		10.43
6	Kinetic Energy	$7.54		10.32
7	Simple Power	**$0.00**		10.30
8	Ambit Energy	$9.99	2b/	10.75
9	StarTex Power	$4.99	2a/	10.47
10	YEP	$7.95	2b/	10.25
11	Brilliant Energy	$2.15		10.70
12	Southwest Power & Light	$7.95	2b/	10.28
13	Dynowatt	$6.95	2b/	10.18
14	APNA Energy	$6.95		10.95
15	Gateway Power Services	$11.69		11.47
16	MX Energy	$9.90		11.77
17	Mega Energy	**$0.00**		9.85
18	Stream Energy	**$0.00**		11.27
19	Texpo Energy	$7.95	2b/	12.97
20	Spark Energy	**$0.00**		10.22
21	TXU Energy	$5.95		12.02
22	Reliant Energy	$5.00		10.70
23	CPL Retail Energy	$4.95		12.90
24	WTU Energy	$4.95		10.40
25	Direct Energy	$5.00		11.33
26	Potentia	$4.88		10.05
27	Tara	$6.95	2a/	10.98
28	Abacus Resources	$5.95	2a/	10.30
29	Bounce	$4.95	2a/	10.40
30	Frontier	$4.95		11.75

Customer Charges:	
No Customer Charge	4
Waivable Customer Charge	11
Traditional Customer Charge	15
Total	30

Avg. Non-Waivable Customer Charge: $6.24

1/ "Fixed Period" means customer enters a contract to not switch provider for at least a predetermined time period, in this case 12 months.
2a/ Customer charge is waived with a minimum usage of 500kWh.
2b/ Customer charge is waived with a minimum usage of 1000 kWh.

Schedule GAW-9

Louisville Gas & Electric
Residential Electric Customer Costs

	Residential Amount
Rate Base:	
Gross Plant	
Services	22,105,235
Meters	30,569,462
Total	52,674,697
Depreciation Reserve	
Services	(17,148,245)
Meters	(20,236,781)
Total	(37,385,026)
Net Rate Base	15,289,671
Operation & Maintenance Expenses	
Meter Operations	5,058,958
Meter Maint.	0
Meter Reading	1,673,264
Records & Collections	4,206,469
Misc. Customer Accts.	300,266
Total	11,238,958
Depreciation Expense	
Services	977,051
Meters	1,158,583
Total	2,135,634
Revenue Requirement:	
Interest	325,220
Equity Return	823,502
Income Tax @ effective rate	487,628
Revenue for Return	1,636,349
Total Customer Revenue Requirement	15,010,940
Number of Bills	4,194,552
Monthly Cost	**$3.58**

	Pct	Cost	Weighted Cost
LT- Debt	46.14%	0.0461	2.13%
Equity	53.86%	10.00%	5.39%
Total	100.00%		7.51%

Schedule GAW-10

Louisville Gas & Electric
Residential Gas Customer Charge

	Residential Amount
Rate Base:	
Gross Plant	
Services	127,087,686
Meters	26,447,911
House Regulators	10,493,951
Total	164,029,548
Depreciation Reserve	
Services	(58,409,592)
Meters	(3,413,716)
House Regulators	(1,231,021)
Total	(63,054,328)
Net Rate Base	100,975,219
Operation & Maintenance Expenses	
Meter & House Regulators Expense	70,853
Customer Installations	307,574
Maint. Services	1,111,661
Maint. Meters & House Regulators	0
Meter Reading	1,558,251
Cust. Records & Collections	3,916,179
Misc. Cust Accounts	243,412
Total	7,207,930
Depreciation Expense	
Services	4,575,157
Meters	1,055,272
House Regulators	232,966
Total	5,863,394
Revenue Requirement	
Interest	2,147,797
Equity Return	5,438,525
Income Tax @ effective rate	3,220,365
Revenue for Return	10,806,688
Total Customer Revenue Requirement	23,878,012
Number of Bills	3,480,900
Monthly Cost	**$6.86**

	Pct	Cost	Weighted Cost
LT- Debt	46.14%	0.0461	2.13%
Equirty	53.86%	10.00%	5.39%
Total	100.00%		7.51%