COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF BASE RATES	)))	CASE NO. 2008-000252
APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY TO FILE DEPRECIATION STUDY	)))	CASE NO. 2007-00564

PREPARED DIRECT TESTIMONY AND SCHEDULES

OF

GLENN A. WATKINS

ON BEHALF OF THE

KENTUCKY OFFICE OF THE ATTORNEY GENERAL

OCTOBER 30, 2008

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, Kentucky, Maine, Maryland, Massachusetts, Michigan, 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 gas class cost of service

studies (CCOSS), proposed distribution of revenues by class, and residential electric and 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.

ELECTRIC WEATHER NORMALIZATION

Q. HAVE YOU EXAMINED LG&E'S PROPOSED ELECTRIC WEATHER NORMALIZATION ADJUSTMENT IN THIS CASE?

A. Yes.

Q. WHAT IS THE NET EFFECT OF THE COMPANY'S PROPOSED WEATHER NORMALIZATION ADJUSTMENT?

A. LG&E witness William Seelye sponsors a weather normalization adjustment that will impact customers' ultimate rates in two respects: the first is the overall revenue requirement effect and the second is a rate design effect. In terms of the overall revenue requirement effect, Mr. Seelye adjusts actual test year revenues and variable expenses downward to correct for what he considers to be unusual (or abnormal) weather occurring during the test year. In other words, the Company does not expect to achieve the same level of kWh sales (and revenue) that was experienced during the test year on a going forward basis. Mr. Seelye's weather normalization adjustment results in reduction to actual test year revenues of $14.374 million and a reduction in variable expenses of $4.751 million. This downward adjustment to actual net revenues has an upward impact on the Company's revenue requirement on a going forward basis; i.e., all other things constant, this adjustment increases the revenue requirement. The second aspect of this weather normalization adjustment is the rate design effect. Because the weather adjustment reduces test year kWh sales, there are fewer units (kWh) to collect the overall revenue requirement such that there is an additional upward pressure on customers resulting from the weather normalization adjustment.

Q. MR. WATKINS, WHAT IS THE BASIS FOR LG&E'S REQUEST TO ADJUST ITS ACTUAL TEST YEAR SALES VOLUMES AND REVENUES?

A. As a result of abnormal weather, the Company claims that actual test year sales volumes (kWh) were greater than can be expected on a going forward basis.

Q. DO YOU AGREE THAT THE COMPANY'S PROPOSED ELECTRIC WEATHER NORMALIZATION ADJUSTMENT SHOULD BE USED FOR RATEMAKING PURPOSES?

A. From a conceptual standpoint, the general consensus of public utility commissions throughout the United States is that it is unreasonable to weather normalize electric utility revenues for ratemaking purposes. In this regard, this Commission would be well advised to continue its current practice of not considering electric weather normalization which is consistent with the vast majority of other states. This would translate to a disallowance of $9.6230 million from the company's request in net revenue ($14.374 million in revenue less $4.751 million in variable expense).

Q. DO CUSTOMERS KWH ENERGY USAGES VARY MATERIALLY WITH CHANGES IN WEATHER CONDITIONS?

A. Yes for some customers, and no for other customers. As a result of variances in electrical appliance and equipment saturations, some customers' electric usage varies significantly with changes in weather (temperature) while other customers' energy usage vary much less. For example, on an extremely hot summer day, residential customers will generally use considerably more electricity than on a mild, spring like day due to air conditioning load. On the other hand, the total electricity used by an industrial customer may not be materially different on the hot verses mild days due to this customer's non-weather sensitive load over shadowing its space cooling requirements (at least in terms of ambient outdoor temperatures).

Q. OVER THE COURSE OF AN ENTIRE YEAR, DO PERIODS OF MILD WEATHER OFFSET PERIODS OF EXTREME WEATHER IN TERMS OF ELECTRICITY USAGE?

A. In general, yes. This is particularly true for electricity sales.

Q. PLEASE EXPLAIN.

A. Although the following is common knowledge, it is important to consider how electricity is used and how weather affects this usage. For purposes of my explanation, I will focus on residential customers. As indicated earlier, there is no doubt that weather, primarily temperature, effects energy usage. In the summer there are periods of days that are very hot and electricity sales are elevated. Similarly there are mild days throughout the summer in which electricity sales are depressed due to reduced air conditioner loads. These hot and mild periods occur virtually every year. The question then arises if a particular cooling season (summer) as a whole is abnormally warm with an attendant abnormally high level of energy sales. In addition to cooling load (air conditions), electricity is also used for space heating by many customers in the winter. Similar to severe and mild weather in the summer, electricity sales on a daily basis are affected in the winter due to electric heating requirements. In addition to weather sensitive appliances, residential customers use a significant amount of electricity for other appliances that do not vary with weather; e.g., refrigerators/freezers, televisions, etc. Because of these factors and situations, annual electricity sales tend to be much more stable than say, natural gas sales, which are predominated by space heating load requirements in the winter. For these reasons, it is rare for commissions to consider weather normalization for electric utilities. In this regard, and as a matter of policy, the Commission would be well guided to continue its practice of not considering weather normalization for Kentucky electric utilities.

Q. WE KNOW THAT RESIDENTIAL KWH SALES VARY DUE TO WEATHER CONDITIONS ON A DAY-TO-DAY BASIS BUT HOW DOES ONE DETERMINE IF WEATHER IS ABNORMAL OVER THE COURSE OF A SEASON?

A. There is no definitive answer to this question. There is no doubt that a summer day in the high 90's is a hot day and warmer than "average". However, the question that must be answered is whether the summer overall was "abnormal". Similarly, one must determine if a winter season is materially different than normal; i.e., extremely severe or

mild. With regard to seasonal variations from year to year, there is significant debate as to what constitutes departure from what is reasonably normal or expected. The National Oceanic and Atmospheric Administration ("NOAA"), National Climatic Data Center defines normal weather as a thirty-year average for the most recent completed three decades. In other words, the current NOAA definition of normal weather is for the period 1971 through 2000. Because of short-term trends in seasonal weather patters, shorter periods are sometimes used to define normal weather as well as using the most recent thirty years to define normal. I am also aware of instances in which much longer periods are used to define normal weather for a season.

Even with these differences in defining "normal" weather, one cannot say that the weather was particularly extreme simply because there is somewhat of a deviation from a historical average. In other words, assume the average maximum temperature for a given summer day is 85 degrees. If the actual temperature is 87 degrees, I do not believe it can be said that this is "abnormal" or "extreme" for that day. In this regard, the determination of "abnormal" or "extreme" is truly subjective.

Q. EVEN THOUGH THE DEFINITION OF ABNORMAL WEATHER IS SUBJECTIVE, ARE THERE METHODS THAT CAN BE USED TO FAIRLY AND REASONABLY DEFINE NORMAL AND ABNORMAL WEATHER?

A. Yes.

Q. PLEASE EXPLAIN.

A. Remembering that we should be concerned about the overall variation in weather over an entire season (hearting or cooling), a banding approach is, in my opinion, a fair and reasonable way to determine if a season's weather falls inside or outside of a band of reasonably normal weather. This banding approach is used by Mr. Seelye in this case. To the extent the Commission authorizes a weather normalization adjustment in this case, I could support the concept of banding, as it eliminates quibbling over minor variances from a pre-determined average or "normal" weather pattern.

Q. PLEASE EXPLAIN THIS BANDING APPROACH IN LAYMAN'S TERMS.

A. The traditional unit to measure summer temperatures over time is cooling degree days ("CDD") and the traditional unit to measure winter temperatures over time is Heating Degree Days ("HDD").[1] Assume that "normal" or average CDD's over the entire cooling season are 1,000. As discussed earlier, if the actual CDD were say 1010, we likely would not consider this an abnormally warm summer. However, if we subjectively determine a relative percentage of time in which we deem weather as abnormal, we can apply a simple statistical technique to determine the bands of normalcy. If we assume the variations in weather from year to year are random (no trend or pattern) we can subjectively define a percentage of time (years) in which weather is considered normal. For example, suppose we decide (subjectively) that weather occurring 75% of the time within a long term average is normal and the remaining 25% of the time the weather is defined as abnormal (12.5% mild and 12.5% severe), we can quantify the bands of normal weather. Consider the following hypothetical example:

Seasonal Cooling Degree Days

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            900          1,000          1,100
←----------------|----------------|----------------|----------------→
Abnormal → |          ←Normal→          | ← Abnormal
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If we know that 75% of the time a season's CDD fall between 900 and 1,100 we would define this range as normal. If a season's actual CDD's are greater than 1,100 we would deem that season as abnormally warm. Similarly, if the actual CDD's in a season are less than 900 we would deem that season abnormally mild. This is the approach proposed by Mr. Seelye. As indicated earlier, I support this approach but it must be emphasized that the range of normalcy is subjective and should be determined by the Commission. It should also be noted that this approach requires the assumption that annual seasonal weather variations are truly random; i.e., no trends or patterns are present.

Q. IN YOUR HYPOTHETICAL EXAMPLE, YOU USED A NORMALCY BAND OF 75%. WHAT BAND IS USED BY MR. SEELYE?

A. Approximately sixty-eight percent.

[1] CDD is traditionally defined as 65 degrees minus the average temperature (High and Low) for a day. HDD is traditionally defined as average temperature minus 65 degrees. CDD and HDD cannot be negative.

Q. HOW DID MR. SEELYE SELECT SIXTY-EIGHT PERCENT AS HIS NORMAL BAND FOR WEATHER?

A. This 68% is a convenient percentage in statistics in that it represents the percentage of time that one can expect weather to vary within plus or minus one standard deviation. There is nothing especially significant about a standard deviation of 1.0, as the exact same statistical techniques can be used at any level selected for normalcy; e.g., 50%, 75%, etc.

Q. WHAT WEATHER PATTERNS WERE ACTUALLY EXPERIENCED IN THE LG&E SERVICE AREA DURING THE TEST YEAR?

A. Overall, the cooling season (summer period) was exceptionally warm during the test year, whereas the heating season (winter period) was somewhat milder than average. The following is a comparison of monthly CDD and HDD to the most recent 30-year average for CDD and HDD:

Month	CDD or HDD Actual Test Year	30-Year Average	Difference
Cooling Season (CDD)			
June	376	306	70
July	396	438	<42>
August	629	407	222
September	350	204	146
Total	1,751	1,355	396
Heating Season (HDD)			
November	480	500	<20>
December	712	833	<121>
January	935	954	<19>
February	787	769	18
March	569	558	11
Total	3,483	3,614	<131>

As can be seen above, August and September 2007 were exceptionally warmer than the 30-year average, while December 2007 was considerably milder than the 30-year average.

Q. WHY ARE APRIL, MAY AND OCTOBER NOT PROVIDED IN THE TABLE ABOVE?

A. These months are considered shoulder months. Days in April and May 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 usually not predictable in April and May. The same is true for October. Generally, the early part of October is warm and air conditioning load is still present. By the middle to end of October, the weather cools to the point that there is some heating load. As such, October is not very consistent as far as what can be considered "normal" weather.

Q. MR. WATKINS, IT IS GENERALLY FAIRLY COOL IN APRIL AND FAIRLY WARM BY THE END OF MAY IN KENTUCKY. WOULD IT BE APPROPRIATE TO CONSIDER EACH APRIL AS PART OF THE HEATING SEASON AND LATE MAY AS PART OF THE COOLING SEASON?

A. In my opinion no. Both of these months experience considerable variation between periods cold enough for space heating, mild enough for open windows, and warm enough for air conditioning load.

Q. FOR PURPOSES OF WEATHER NORMALIZATIONS, HOW DO YOU DEFINE LG&E'S COOLING AND HEATING SEASONS?

A. I define LG&E's cooling season as the months of June through September and the heating season as the months of November through March.

Q. IF THE COMMISSION ACCEPTS A BANDING APPROACH AS PROPOSED BY MR. SEELYE AND SUPPORTED BY YOU, HOW SHOULD THIS APPROACH BE APPLIED TO THE HEATING AND COOLING SEASONS?

A. The banding should be applied separately to the entire heating season and again separately for the entire cooling season. This is a major difference in the manner in which Mr. Seelye applied his weather banding, in that Mr. Seelye applies a weather normalcy band to each individual month. Mr. Seelye's monthly banding results in a bias to the annual normalized sales volumes.

Q. PLEASE EXPLAIN.

A. As discussed earlier, a given heating or cooling season is comprised of days in which it is milder than expected and more severe than expected. The overall objective is to consider the overall effects of weather during a heating or cooling season and Mr. Seelye's monthly banding does not meet this objective. To illustrate, consider the actual experience of July and August during the test year. July's actual CDDs were 396 which compare to a 30-year average July CDD of 438. This is a difference of -42 CDD which indicates that July was somewhat milder than the long-term average. Because this deviation from average (-42) does not fall outside of Mr. Seelye's monthly band, it is not adjusted and this mild weather for July is not considered any further in his analysis.

However, August was adjusted by Mr. Seelye because this individual month's weather fell outside of his monthly band. The actual CDDs for August in the test year were 629. This compares with a long-term average of 407 for August and is a difference of 222 CDDs. This exceptionally hot weather during August 2007 falls outside of Mr. Seelye's normalcy band and August's kWh sales were adjusted downward. However, no adjustment or consideration was given to the somewhat milder weather experienced during July 2007.

Q. HOW HAVE YOU ESTIMATED THE EFFECTS OF WEATHER ON CUSTOMER'S ELECTRICITY USAGE?

A. As discussed earlier, variations in electricity sales during the summer are affected by variations in air conditioning load, while winter kWh sales variations are affected by changes in space heating load. The two uses cannot be measured together and must be examined separately. Therefore, I have conducted separate analyses for the cooling (summer) and heating (winter) seasons.

I conducted linear regression analyses by season for each rate class in order to develop a weather sensitive usage coefficient for each class. In other words, the weather sensitive coefficient measures the incremental level at which a classes kWh usage varies with an incremental change in weather (CDD in summer, HDD in winter). Specifically, I developed a separate regression model for each class and each season (cooling and heating). These regression models were developed based on daily kWh usage and daily

degree days. In other words, the cooling season is comprised of four months (June through September). My model was developed using each daily observation during this season (142 days). Because usage patterns can and do vary significantly between weekdays and weekends/holidays, I have also reflected this reality in my analysis of daily observations. With regard to the Residential class, I have expressed daily kWh usage on a per customer basis in order to prevent any skewness in my regression models. The Commercial and Industrial classes were analyzed on a total class basis.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING WEATHER NORMALIZATION FOR LG&E'S ELECTRIC OPERATIONS DURING THE TEST YEAR?

A. Based on my analyses, I conclude that the overall cooling season (summer) during the test year was exceptionally warm which translated into exceptionally high summer energy sales for LG&E. This weather (and attendant kWh sales) falls beyond what can reasonably be expected on a going-forward basis and warrants a downward adjustment. Although the test year's heating season was somewhat milder than normal, these sales do not warrant adjustment.

Q. IS THERE ANY BIAS IN YOUR CONCLUSION THAT SUMMER KWH SALES SHOULD BE ADJUSTED DOWNWARD DUE TO EXCEPTIONALLY SEVERE WEATHER, BUT WINTER KWH SALES DO NOT WARRANT AN OPPOSITE UPWARD ADJUSTMENT DUE TO A SOMEWHAT MILDER WINTER?

A. As long as a banding approach is used, the answer is no. This is because the summer normalization is made only to the outer limit of the "normalcy" band and not all the way to an average historical experience. Thus, while it is true that the milder winter sales somewhat offset the extreme weather-related summer sales, each season reflects a reasonable level of what can be expected on a going-forward basis.

Q. WHAT ARE THE RESULTS OF YOUR WEATHER NORMALIZATION ANALYSIS FOR LG&E'S ELECTRIC OPERATIONS?

A. My Schedule GAW_2 presents the results of my weather normalization analysis for LG&E's electric operations. Page 1 of this Schedule provides a summary of each class' kWh and revenue adjustment as well as the adjustment required to variable expenses. Pages 2 through 12 present the detailed kWh adjustment for each class. My weather normalization analysis results in a reduction to actual test year revenues of $9.038 million and a reduction to actual test year expenses of $2.985 million.

Q. YOU HAVE ALREADY DISCUSSED YOUR DISAGREEMENT WITH MR. SEELYE REGARDING MONTHLY VERSUS SEASONAL ANALYSIS AND ADJUSTMENTS. DO YOU HAVE ANY OTHER DISAGREEMENTS WITH MR. SEELYE'S PROPOSED WEATHER NORMALIZATION ANALYSES?

A. Yes.

Q. PLEASE EXPLAIN THESE OTHER DISAGREEMENTS.

A. I disagree with Mr. Seelye's decision to use the step-wise multiple regression technique as well as his inclusion of numerous weather-related variables. At the outset I want it to be clear that I understand and appreciate Mr. Seelye's desire to conduct his statistical analysis on an objective basis. However, Mr. Seelye's procedures are not warranted and often produce conflicting model results.

We have already established that weather generally affects electricity sales. On an hourly or daily basis, these weather factors can include ambient temperature, wind velocity, relative humidity, the degree of cloud cover, whether snow cover is present to insulate structures, whether a thunderstorm appears on a hot afternoon and dramatically and suddenly reduces load (and sales), wind direction, and perhaps a few more factors.

Mr. Seelye has attempted to consider many of these short-term factors in his modeling analysis by using a technique known as step-wise regression. This statistical technique selects a combination of possible variables to be considered and selects an equation that maximizes certain statistic parameters. This step-wise technique is simply a mathematical algorithm calculated by a computer. In other words, the variables offered to a computer in the step-wise technique are simply sets of numbers. Obviously, the computer has no ability to determine if the potential variables are consistent with the task

at hand or even if they make sense from a conceptual perspective. There is no doubt that variables selected using the step-wise technique is objective. However, this technique is no substitute for informed human judgment. In their much respected text book, Applied Regression Analysis, Norman Draper and Harry Smith render the following opinion regarding the step-wise procedure used for econometric regression analyses:

> ***Opinion.*** We believe this to be one of the best of the variable selection procedures and recommend its use. It makes economical use of computer facilities, and it avoids working with more *X*'s than are necessary while improving the equation at every stage. However, stepwise regression can easily be abused by the "amateur" statistician. As with all the procedures discussed, sensible judgment is still required in the initial selection of variables and in the critical examination of the model through examination of residuals. It is easy to rely too heavily on the automatic selection performed in the computer. [Third Edition, page 338]

As a result of Mr. Seelye's attempt to be unnecessarily surgically precise, he arrives at nonsensical conclusions and models. As an illustration, remember that Mr. Seelye developed a separate regression equation, by class, for each month. Consider and compare Mr. Seelye's step-wise derived Residential models for July and August.

Variable	July 1/	August 1/
Intercept	-9,073,496	1,166,041
Maximum Temperature	246,777	--
Minimum Temperature	--	145,063
Cloudy	--	-492,074
CDD70	227,194	512,577
Weekend	--	762,045

1/ Per Seelye Exhibit 17.

Mr. Seelye's step-wise procedures result in a finding that in July, kWh sales are a function (related to) of maximum temperature and cooling degree days (CDD70). However, in August, the computer determined that Residential kWh sales are not a function of this set of explanatory variables, but rather, minimum temperature (the opposite concept of what would be expected), cloudiness, and weekdays versus weekend days. Related to the inconsistency of these adjoining summer months is the level in which kWh usage varies with changes in overall average daily temperatures (CDD70).

Notice that the July model has a CDD70 coefficient of 227,194, while the August coefficient of 512,577. What this means is that, all other things constant, kWh sales will vary by 227,194 kWh for each variation in CDD70 during July, but will vary by 512,577 in August.

There are many more inconsistencies and seemingly non-sensical results for other months as well as across classes, that I will not dwell on. In my opinion, and that of the industry, HDD and CDD are the accepted and most appropriate explanatory variables.

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. 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 LG&E'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. I have two material disagreements with Mr. Seelye's CCOSS.

Q. PLEASE OUTLINE YOUR TWO MATERIAL DISAGREEMENTS.

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

A. <u>Generation</u>

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") <u>Electric Utility Cost Allocation Manual</u> 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, <u>Principles of Public Utilities Rates</u>.

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. However, it is my understanding that LG&E is consistently a summer peaking utility. Therefore, this methodology is likely not well suited in this instance.

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.

Average and Excess ("A&E") -- The A&E method also considers both peak demands and energy consumption throughout the year. However, the A&E method is

much different than the P&A method in both concept and application. The A&E method recognizes class load diversity within a system, such that all classes do not call on the utility's resources to the same degree, at the same times. Mechanically, the A&E method weights average and excess demands based on system coincident load factor. Individual class "excess" demands represent the difference between the class non-coincident peak demand and its average annual demand. The classes' "excess" demands are then summed to determine the system excess demand. Under this method, it is important to distinguish between coincident and non-coincident demands. This is because if coincident, instead of non-coincident, demands are used when calculating class excesses, the end result will be exactly the same as that achieved under 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 cheap 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 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 factors.[2] 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

[2] Capacity factor is the ratio of average utilization (output) over a year to peak hour output.

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 before. However, I would be reluctant to say his approach is totally unreasonable.

Whereas Mr. Seelye's Modified BIP method does allocate a portion of generation facilities based on energy and a portion on peak demands, 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 peak demand).

Mr. Seelye's approach ignores the actually supply-side characteristics of EON's generation portfolio because it only considers relative differences in system usages and demands. In fact, given LG&E's 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 LG&E'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. HAVE YOU CONDUCTED A CLASS COST OF SERVICE STUDY USING A TRADITIONAL BIP APPROACH?

A. Yes.

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

A. During the discovery phase of this proceeding, LG&E provided the hourly loads (output) of each EON generation unit during the test year. In other words, for each EON generating unit, I was provided hourly output during the test year. With this data, I examined the timing, frequency, and level of dispatch for each EON generating unit. This examination revealed clear and distinct patterns for individual generating units. Many units are clearly base load in nature, others are clearly peaker facilities, and some units are neither base load or clearly peaker, but intermediate plants. From this examination, I was able to classify each generating unit as base, intermediate, or peak. Base load plants were classified as 100% energy-related, peaker units were classified as 100% demand-related, and intermediate plants were classified as partially energy-related and partially demand-related based on their individual capacity factors. The results of my BIP generation classification is presented in my Schedule GAW_3. It should be noted that EON's hydroelectric facilities were classified as 100% energy-related as these facilities are largely run-of-river or flood control dams. My BIP classification study results in the following aggregate generation classification:

Energy-related:	82.78%
Demand-related:	17.22%

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

A. Individual class rates of return utilizing the traditional BIP classification method, compared to Mr. Seelye's Modified BIP are presented below:

Class	OAG Traditional BIP	Seelye Modified BIP
R	6.58%	5.45%
GS	13.96%	13.17%
LC-Pri.	8.75%	9.89%
LC-Sec.	10.88%	10.42%
LC-TOD-Pri.	5.74%	7.47%
LC-TOD-Sec.	8.02%	9.58%
LP-Pri.	9.87%	11.38%
LP-Sec.	9.46%	9.89%
LP-TOD-Trans.	4.66%	8.39%
LP-TOD-Pri.	4.43%	7.16%
LP-TOD-Sec.	8.76%	10.94%
Sp. Contracts A	0.51%	8.71%
Sp. Contracts B	1.98%	3.67%
Sp. Contracts C	0.49%	6.36%
PSL	3.91%	6.02%
SLE	1.31%	11.75%
OL	7.03%	8.71%
TLE	-0.68%	2.07%
STOD-Pr.	3.33%	4.24%
STOD-Sec.	4.61%	5.68%
TOTAL COMPANY	7.77%	7.77%

B. <u>Distribution</u>

Q. AS WE MOVE DOWNSTREAM FROM GENERATION THROUGH TRANSMISSION, TO THE DISTRIBUTION SYSTEM, HOW HAS THE COMPANY 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 (or do not understand) how a distribution system is designed and connected.

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, 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,[3] the zero-intercept method is very straight-forward. First, various types of equipment are separated by size and type. Next, historical accounting costs are

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

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 form:

$$\text{cost/unit} = a + b\ (\text{size})$$

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 28, 29, and 30. 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 74 of his direct testimony, Mr. Seelye states:

> "Like most electric utilities, the number of feet of conductors on LG&E's system is not uniformly distributed over all sizes of wire. For example, LG&E has over 20 million feet of 1/0 overhead conductor, but only 10,421 feet of 1,000 MCM overhead conductor. 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 at best 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 28. Although not shown in his exhibit, Mr. Seelye's equation for Overhead conductors is:

$$(\text{cost per foot x feet}^{0.5}) = 0 + 2.2913(\text{feet}^{0.5}) + 0.00818(\text{capacity x feet}^{0.5})$$

Notice that the equation's true intercept is forced to zero. However, if capacity is set to zero, the second term [0.00818(capacity x feet$^{0.5}$)] becomes zero. If we then ask what is the cost for a foot of a zero capacity conductor we see that feet$^{0.5}$ = 1 $^{0.5}$ = 1, such that the cost for one foot becomes $2.2913. 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 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:

cost/feet = 1.75 + 0.805(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:

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

Account	Percentage	
	Customer	Demand
Overhead Conductors	60.56%	39.44%
Underground Conductors	62.65%	37.35%
Lines Transformers	48.75%	51.25%

Q. HAVE YOU CONDUCTED AN INDEPENDENT ANALYSIS TO CLASSIFY LG&E'S DISTRIBUTION PLANT?

A. Yes. Although I prefer to use the zero-intercept method when possible, the data is such that this method is not reliable in this instance. This is because the regression equations produce negative intercept values (illogical) and have low R^2 (poor fits). As a result, I conducted a minimum size analysis, which by its very nature tends to overstate the customer percentage of distribution plant. I used the same data relied upon by Mr. Seelye in his Exhibits 28, 29, and 30 and selected a reasonable minimum size for each account (Overhead conductors, underground conductors, and line transformers) based on the data provided. The following are my selected minimum sizes and resulting customer/demand classifications:

Account	Minimum Size	Percentage	
		Customer	Demand
Overhead Conductors	$1.4869	39.3%	60.7%
Underground Conductors	$1.658	20.1%	79.9%
Line Transformers	$606.63	26.5%	73.5%

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:

Class	ROR At Current Rates	
	OAG Recommended	Seelye
R	7.22%	5.45%
GS	13.61%	13.17%
LC-Pri.	8.07%	9.89%
LC-Sec.	9.99%	10.42%
LC-TOD-Pri.	5.17%	7.47%
LC-TOD-Sec.	7.26%	9.58%
LP-Pri.	9.15%	11.38%
LP-Sec.	8.62%	9.89%
LP-TOD-Trans.	4.66%	8.39%
LP-TOD-Pri.	3.95%	7.16%
LP-TOD-Sec.	7.99%	10.94%
Sp. Contracts A	0.17%	8.71%
Sp. Contracts B	1.50%	3.67%
Sp. Contracts C	0.03%	6.36%
PSL	4.29%	6.02%
SLE	0.72%	11.75%
OL	7.51%	8.71%
TLE	-0.57%	2.07%
STOD-Pri.	2.84%	4.24%
STOD-Sec.	3.99%	5.68%
TOTAL COMPANY	7.77%	7.77%

As can be seen above, my CCOSS study which is based on accepted industry practices, produces significantly different results than those obtained by Mr. Seelye.

ELECTRIC CLASS REVENUE DISTRIBUTION

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

A. LG&E witness Seelye presents the Company's proposed distribution of its requested $14.75 million revenue increase to customer classes. In large part, Mr. Seelye proposes that the Residential and lighting classes should be responsible for almost all of the entire rate increase proposed by LG&E. According to Mr. Seelye, this proposed increase is based on his CCOSS results. However, Mr. Seelye apparently ignored his own CCOSS study results for certain classes. For example, even though the LC-TOD

primary class is contributing slightly less than the current system average rate of return (7.47% compared to 7.77%), Mr. Seeyle assigns no revenue increase to this class. Similar situations exist for the LP-TOD Primary and Special Contracts "A" classes.

A summary of LG&E's proposed revenue increase for each customer class is shown below:

	LG&E Proposed Electric Increase		
Class	Amount	Percent	Percent of Avg.
R	$13,673,276	3.81%	230%
GS	228,601	0.18%	11%
LC-Pri.	0	0.00%	0%
LC-Sec.	0	0.00%	0%
LC-TOD-Pri.	0	0.00%	0%
LC-TOD-Sec.	0	0.00%	0%
LP-Pri.	0	0.00%	0%
LP-Sec.	0	0.00%	0%
LP-TOD-Trans.	-8,461	-0.03%	-2%
LP-TOD-Pri.	0	0.00%	0%
LP-TOD-Sec.	0	0.00%	0%
Sp. Contracts A	-145,782	-2.05%	-124%
Sp. Contracts B	0	0.00%	0%
Sp. Contracts C	0	0.00%	0%
PSL	199,009	3.39%	205%
SLE	0	0.00%	0%
OL	462,434	5.12%	309%
TLE	9,376	4.12%	249%
STOD-Pri.	45,334	6.01%	363%
STOD-Sec.	287,867	5.27%	318%
TOTAL COMPANY	$14,751,654	1.66%	100%

Q. MR. WATKINS, IN YOUR OPINION ARE LG&E'S PROPOSED CUSTOMER CLASS REVENUE INCREASES REASONABLE?

A. No.

Q. DO YOU HAVE AN ALTERNATIVE REVENUE INCREASE DISTRIBUTION TO THAT PROPOSED BY MR. SEELYE?

A. Yes, I do. Using the results of my CCOSS as a guide, and also considering principles of gradualism, fairness and equity, I propose an equitable and cost based mechanism to assign class revenue increases at LG&E's requested overall revenue level.

My proposed revenue distribution is presented in my Schedule GAW_5 and results in the following class increases:

Class	OAG Proposed Electric Increase		
	Amount	Percent	Percent of Avg.
R	$6,987,615	1.95%	118%
GS	1,059,478	0.83%	50%
LC-Pri.	165,183	1.66%	100%
LC-Sec.	1,812,934	1.24%	75%
LC-TOD-Pri.	389,305	2.07%	125%
LC-TOD-Sec.	344,591	1.66%	100%
LP-Pri.	89,466	1.24%	75%
LP-Sec.	452,458	1.24%	75%
LP-TOD-Trans.	543,277	2.07%	125%
LP-TOD-Pri.	1,933,032	2.07%	125%
LP-TOD-Sec.	44,764	1.66%	100%
Sp. Contracts A	176,845	2.49%	150%
Sp. Contracts B	270,913	2.49%	150%
Sp. Contracts C	71,528	2.49%	150%
PSL	121,435	2.07%	125%
SLE	4,805	2.49%	150%
OL	149,549	1.66%	100%
TLE	5,649	2.49%	150%
STOD-Pri.	15,622	2.07%	125%
STOD-Sec.	113,204	2.07%	125%
TOTAL COMPANY	$14,751,654	1.66%	100%

My specific electric revenue allocation methodology is as follows, with the actual calculations provided in Schedule GAW_5.

First, I recognize class cost of service and the concept of gradualism. In doing so, I recommend a graduated scale of increases such that no class receives a rate decrease and that all class increases are limited to a range of 50% of the system average percentage increase to 150% of the system average increase. In order to recognize the higher than system average ROR's provided by certain classes, I increased these higher than average ROR classes less than the system average percentage. Similarly, those classes with low rates of return were increased by a higher percentage. Finally, due to its size relative to the system, the Residential class was treated as a residual.

Q. MR. WATKINS, PLEASE PROVIDE YOUR RECOMMENDED SCALE BACK METHOD TO ASSIGN CLASS REVENUE INCREASES SHOULD THE COMMISSION AUTHORIZE AN OVERALL REVENUE REQUIREMENT INCREASE LESS THAN THAT PROPOSED BY LG&E OR AN OVERALL DECREASE AS RECOMMENDED BY THE OAG.

A. I recommend that my customer class revenue increases be reduced proportionally downward.

RESIDENTIAL ELECTRIC RATE DESIGN

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

A. Currently, Residential rates include a fixed monthly customer charge of $5.00 and a flat kWh energy charge.

Q. WITH RESPECT TO THE CURRENT RESIDENTIAL CUSTOMER CHARGE OF $5.00, DOES LG&E PROPOSE AN INCREASE TO THIS FIXED MONTHLY RATE?

A. Yes. LG&E proposes an increase to the monthly Residential customer charge from the current $5.00 level to $8.23.

Q. DOES MR. SEELYE PROVIDE ANY JUSTIFICATION FOR THE LARGE INCREASE IN THE FIXED CUSTOMER CHARGE?

A. As part of his CCOSS, Mr. Seelye functionalizes all costs that include an assignment of overheads to each functional and classification category. Within Mr. Seelye's CCOSS, these fully allocated costs that are classified as "customer" equate to a monthly residential "customer allocated cost" of $16.43.

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

A. No. Mr. Seelye's customer cost analysis includes not only those costs that are directly attributable to customers but also assigns a significant level of corporate

overhead costs. In my opinion, any customer cost analysis used as a basis for establishing fixed monthly customer charges should only include direct customer costs.

Q. HAVE YOU CONDUCTED SUCH A DIRECT CUSTOMER COST ANALYSIS?

A. Yes. The results of my direct customer costs analysis are presented in my Schedule GAW_6 and result in a monthly Residential customer cost of $2.98.

Q. WHAT IS YOUR RECOMMENDATION AS TO RESIDENTIAL CUSTOMER CHARGES IN THIS CASE?

A. Given that my direct customer cost analysis results in a monthly customer cost of $2.98, I recommend maintaining the current monthly customer charge of $5.00 regardless of any increase or decrease in revenue requirement authorized by this Commission.

Q. DOES LG&E'S PROPOSED 65% INCREASE TO THE RESIDENTIAL CUSTOMER CHARGE PROMOTE OR DISCOURAGE CONSERVATION?

A. LG&E's proposed increased reliance on customer charge revenue will discourage conservation from its electric customers as a larger percentage of customers' bills will be collected from a fixed monthly charge that does not vary with usage. As such, the Company proposed 65% increase to the fixed customer charge would send a price signal to customers that is contrary to conservation efforts and encourage additional usage of electricity.

<u>NATURAL GAS OPERATIONS</u>

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.

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 Demand 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 as historical loads, but rather estimate class demand 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 LG&E. The first is the recognition of how and why natural gas consumers are customers of LG&E. That is, 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 centers have obviously changed over the last few decades. Yet, Mr. Seeyle 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.[4]

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. Seeyle's results using his Peak Responsibility method.

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

Class	ROR at Current Rates: OAG Peak & Average	ROR at Current Rates: Seelye Peak Responsibility
RSG	3.53%	2.77%
CGS	6.42%	5.37%
IGS	6.15%	6.52%
AAGS	2.36%	14.65%
FT	0.37%	18.73%
SP	-3.73%	22.04%
Total Company	3.88%	3.88%

The details of my recommended natural gas CCOSS are provided in my Schedule GAW_7.

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 its requested $29.76 million revenue increase to customer classes. In large part, Mr. Seelye proposes that the Residential class should be responsible for almost all of the entire rate increase proposed by LG&E. According to Mr. Seelye, this proposed increase is based on his CCOSS results.

A summary of LG&E's proposed natural gas revenue increase for each customer class is shown below:

Class	LG&E Proposed Natural Gas Increase: Amount	Percent	Percent of Avg.
RGS	$25,482,608	37.00%	125%
CGS	4,012,950	16.75%	57%
IGS	55,838	3.03%	10%
AAGS	23,962	9.77%	33%
FT	175,907	4.10%	14%
SP	11,200	0.70%	2%
TOTAL COMPANY	$29,762,465	29.53%	100%

Q. MR. WATKINS, IN YOUR OPINION ARE LG&E'S PROPOSED NATURAL GAS CUSTOMER CLASS REVENUE INCREASES REASONABLE?

A. No.

Q. DO YOU HAVE AN ALTERNATIVE REVENUE INCREASE DISTRIBUTION TO THAT PROPOSED BY MR. SEELYE?

A. Yes, I do. Using the results of my CCOSS as a guide, and also considering Mr. Seelye's CCOSS results in conjunction with the principles of gradualism, fairness and equity, I propose an equal percentage increase for all classes regardless of the overall increase in revenue requirement authorized by the Commission. My proposed across the board class revenue increases are as follows using LG&E's required overall increase of $29.76 million:

	OAG Proposed Natural Gas Increase	
Class	Amount	Percent
RGS	$20,334,498	29.53%
CGS	7,073,326	29.53%
IGS	544,098	29.53%
AAGS	72,380	29.53%
FT	1,265,374	29.53%
SP	472,789	29.53%
TOTAL COMPANY	$29,762,465	29.53%

RESIDENTIAL NATURAL GAS RATE DESIGN

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

A. Currently, Residential rates include a fixed monthly customer charge of $8.50 and a flat base rate usage charge.

Q. WITH RESPECT TO THE CURRENT RESIDENTIAL CUSTOMER CHARGE OF $8.50, DOES LG&E PROPOSE AN INCREASE TO THIS FIXED MONTHLY RATE?

A. Yes. LG&E proposes an increase to the monthly Residential customer charge from the current $8.50 level to $13.65.

Q. DOES MR. SEELYE PROVIDE ANY JUSTIFICATION FOR THE LARGE INCREASE IN THE FIXED CUSTOMER CHARGE?

A. As part of his CCOSS, Mr. Seelye functionalizes all costs that include an assignment of overheads to each functional and classification category. Within Mr. Seelye's CCOSS, these fully allocated costs that are classified as "customer" equate to a monthly residential "customer allocated cost" of $13.71.

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

A. No. Mr. Seelye's customer cost analysis includes not only those costs that are directly attributable to customers but also assigns a significant level of corporate overhead costs. In my opinion, any customer cost analysis used as a basis for establishing fixed monthly customer charges should only include direct customer costs.

Q. HAVE YOU CONDUCTED SUCH A DIRECT CUSTOMER COST ANALYSIS?

A. Yes. The results of my direct customer costs analysis are presented in my Schedule GAW_8 and result in a monthly Residential customer cost of $6.96.

Q. WHAT IS YOUR RECOMMENDATION AS TO RESIDENTIAL CUSTOMER CHARGES IN THIS CASE?

A. Given the direct customer cost analysis that results in a monthly customer cost of $6.96. I recommend maintaining the current monthly customer charge of $8.50 regardless of any increase in revenue requirement authorized by this Commission.

Q. DOES LG&E'S PROPOSED 61% INCREASE TO THE RESIDENTIAL CUSTOMER CHARGE PROMOTE OR DISCOURAGE CONSERVATION?

A. LG&E's proposed increased reliance on customer charge revenue will discourage conservation from its natural gas customers as a larger percentage of customers' bills will be collected from a fixed monthly charge that does not vary with usage. As such, the

Company's proposed 61% increase to the fixed customer charge would send a price signal to customers that is contrary to conservation efforts and encourage additional usage of natural gas.

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. Public Utility Regulation

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

GLENN A. WATKINS

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

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

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

II. Transportation Regulation

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

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

III. Insurance Studies

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

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

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

GLENN A. WATKINS

IV. Anti-Trust and Commercial Business Damage Litigation

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

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

MEMBERSHIPS AND CERTIFICATIONS

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

LOUISVILLE GAS AND ELECTRIC COMPANY

OAG Adjustment to Reflect Electric Weather Normalization

(12 Months Ended April 30, 2008)

	(1)	(2)	(3)
	OAG Test Year Adjustment to kWh	Energy Rate	OAG Test Year Revenue Adjustment (1) * (2)
Residential Rate R	(110,959,088)	$0.06404	($7,105,820)
General Service Rate GS			
Single Phase	(5,744,499)	0.07621	(437,788)
Three Phase	(10,694,430)	0.07621	(815,023)
Total	(16,438,929)		(1,252,811)
Large Commercial Rate LC			
Secondary	(16,593,235)	0.02702	(448,349)
Primary	(1,270,282)	0.02702	(34,323)
Secondary Small Time of Day	(699,053)	0.03289	(22,992)
Primary Small Time of Day	(108,092)	0.03289	(3,555)
Total	(18,670,661)		(509,219)
Large Commercial Rate LCTOD			
Secondary	(1,735,249)	0.02706	(46,956)
Primary	(2,228,694)	0.02706	(60,308)
Total	(3,963,943)		(107,264)
Industrial Power Rate LP			
Secondary	(2,196,464)	0.02357	(51,771)
Primary	(453,706)	0.02357	(10,694)
Total	(2,650,170)		(62,465)
Industrial Power Rate LPTOD	-		0
Secondary	-	0.02362	0
Primary	-	0.02362	0
Special Contracts	-		0
Fort Knox	-	0.02365	0
DuPont	-	0.02379	0
Louisville Water Company	-	0.02364	0
Lighting			
Street Lighting Rate SLE	-	0.00000	0
Traffic Lighting Rate TLE	-	0.00000	0
Public Street Lighting Rate PSL	-	0.00000	0
Outdoor Lighting Rate OL	-	0.00000	0
Total Company	(152,682,791)		($9,037,579)
Variable Expenses	(152,682,791)	$0.01955	($2,984,949)

LOUISVILLE GAS AND ELECTRIC

OAG kWh Weather Adjustment
(June through September, 2007)

Residential

	Degree Days			Normal Weather Band							
	Actual [1]	30-year Average [2]	30-year Std Dev[3]	Upper Limit	Lower Limit	Adjustment	Boundary Limit less Actual	kWh Per Customer Per Degree Day[4]	Average Customers	kWh Adjustment	Model R-square
Cooling Month (CDD)											
June	376	306									
July	396	438									
August	629	407									
September	350	204									
Seasonal Aggregate	1,751	1,356	202	1,558	1,154	Yes	(193)	1.60079	358,712	(110,959,088)	92.0941%
Heating Month											
November	480	500									
December	712	833									
January	935	954									
February	787	769									
March	569	558									
	3,483	3,615	347	3,962	3,268	No	479				

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and binary variable for Weekdays and Holidays.

LOUISVILLE GAS AND ELECTRIC

OAG kWh Weather Adjustment
(June through September, 2007)

GS Secondary 1 Phase

	Degree Days			Normal Weather Band						
	Actual [1]	30-year Average [2]	30-year Std Dev[3]	Upper Limit	Lower Limit	Adjustment	Boundary Limit less Actual	kWh Per Degree Day[4]	kWh Adjustment	Model R-square
Cooling Season (CDD)										
Cooling Month										
June	376	306								
July	396	438								
August	629	407								
September	350	204								
Seasonal Aggregate	1,751	1,356	202	1,558	1,154	Yes	(193)	29,728.30	(5,744,499)	91.1264%
Heating Season (HDD)										
Heating Month										
November	480	500								
December	712	833								
January	935	954								
February	787	769								
March	569	558								
	3,483	3,615	347	3,962	3,268	No	479			

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and binary variable for Weekdays and Holidays.

LOUISVILLE GAS AND ELECTRIC

OAG kWh Weather Adjustment
(June through September, 2007)

GS Secondary 3 Phase

	Degree Days			Normal Weather Band						
	Actual [1]	30-year Average [2]	30-year Std Dev[3]	Upper Limit	Lower Limit	Adjustment	Boundary Limit less Actual	kWh Per Degree Day[4]	kWh Adjustment	Model R-square
Cooling Season (CDD)										
Cooling Month										
June	376	306								
July	396	438								
August	629	407								
September	350	204								
Seasonal Aggregate	1,751	1,356	202	1,558	1,154	Yes	(193)	55,344.64	(10,694,430)	88.8312%
Heating Season (HDD)										
Heating Month										
November	480	500								
December	712	833								
January	935	954								
February	787	769								
March	569	558								
	3,483	3,615	347	3,962	3,268	No	479			

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and binary variable for Weekdays and Holidays.

LOUISVILLE GAS AND ELECTRIC

OAG kWh Weather Adjustment
(June through September, 2007)

LC Secondary

	Degree Days			Normal Weather Band						
	Actual [1]	30-year Average [2]	30-year Std Dev[3]	Upper Limit	Lower Limit	Adjustment	Boundary Limit less Actual	kWh Per Degree Day[4]	kWh Adjustment	Model R-square
Cooling Season (CDD)										
Cooling Month										
June	376	306								
July	396	438								
August	629	407								
September	350	204								
Seasonal Aggregate	1,751	1,356	202	1,558	1,154	Yes	(193)	85,871.49	(16,593,235)	92.2827%
Heating Season (HDD)										
Heating Month										
November	480	500								
December	712	833								
January	935	954								
February	787	769								
March	569	558								
	3,483	3,615	347	3,962	3,268	No	479			

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and binary variable for Weekdays and Holidays.

LOUISVILLE GAS AND ELECTRIC

OAG kWh Weather Adjustment
(June through September, 2007)

LC Primary

	Degree Days			Normal Weather Band						
	Actual [1]	30-year Average [2]	30-year Std Dev[3]	Upper Limit	Lower Limit	Adjustment	Boundary Limit less Actual	kWh Per Degree Day[4]	kWh Adjustment	Model R-square
Cooling Season (CDD)										
Cooling Month										
June	376	306								
July	396	438								
August	629	407								
September	350	204								
Seasonal Aggregate	1,751	1,356	202	1,558	1,154	Yes	(193)	6,573.82	(1,270,282)	88.6240%
Heating Season (HDD)										
Heating Month										
November	480	500								
December	712	833								
January	935	954								
February	787	769								
March	569	558								
	3,483	3,615	347	3,962	3,268	No	479			

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and binary variable for Weekdays and Holidays.

LOUISVILLE GAS AND ELECTRIC

OAG kWh Weather Adjustment
(June through September, 2007)

LC STOD Secondary

	Degree Days			Normal Weather Band						
	Actual [1/]	30-year Average [2/]	30-year Std Dev[3/]	Upper Limit	Lower Limit	Adjustment	Boundary Limit less Actual	kWh Per Degree Day[4/]	kWh Adjustment	Model R-square
Cooling Season (CDD)										
Cooling Month										
June	376	306								
July	396	438								
August	629	407								
September	350	204								
Seasonal Aggregate	1,751	1,356	202	1,558	1,154	Yes	(193)	3,617.66	(699,053)	89.1158%
Heating Season (HDD)										
Heating Month										
November	480	500								
December	712	833								
January	935	954								
February	787	769								
March	569	558								
	3,483	3,615	347	3,962	3,268	No	479			

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and binary variable for Weekdays and Holidays.

LOUISVILLE GAS AND ELECTRIC

OAG kWh Weather Adjustment
(June through September, 2007)

LC STOD Primary

	Degree Days			Normal Weather Band						
	Actual [1]	30-year Average [2]	30-year Std Dev[3]	Upper Limit	Lower Limit	Adjustment	Boundary Limit less Actual	kWh Per Degree Day[4]	kWh Adjustment	Model R-square
Cooling Season (CDD)										
Cooling Month										
June	376	306								
July	396	438								
August	629	407								
September	350	204								
Seasonal Aggregate	1,751	1,356	202	1,558	1,154	Yes	(193)	559.38	(108,092)	92.0316%
Heating Season (HDD)										
Heating Month										
November	480	500								
December	712	833								
January	935	954								
February	787	769								
March	569	558								
	3,483	3,615	347	3,962	3,268	No	479			

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and binary variable for Weekdays and Holidays.

LOUISVILLE GAS AND ELECTRIC

OAG kWh Weather Adjustment
(June through September, 2007)

LC Secondary

	Degree Days			Normal Weather Band						
	Actual [1/]	30-year Average [2/]	30-year Std Dev[3/]	Upper Limit	Lower Limit	Adjustment	Boundary Limit less Actual	kWh Per Degree Day[4/]	kWh Adjustment	Model R-square
Cooling Season (CDD)										
Cooling Month										
June	376	306								
July	396	438								
August	629	407								
September	350	204								
Seasonal Aggregate	1,751	1,356	202	1,558	1,154	Yes	(193)	8,980.07	(1,735,249)	93.4691%
Heating Season (HDD)										
Heating Month										
November	480	500								
December	712	833								
January	935	954								
February	787	769								
March	569	558								
	3,483	3,615	347	3,962	3,268	No	479			

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and binary variable for Weekdays and Holidays.

LOUISVILLE GAS AND ELECTRIC

OAG kWh Weather Adjustment
(June through September, 2007)

LC Primary

	Degree Days			Normal Weather Band						
	Actual [1/]	30-year Average [2/]	30-year Std Dev[3/]	Upper Limit	Lower Limit	Adjustment	Boundary Limit less Actual	kWh Per Degree Day[4/]	kWh Adjustment	Model R-square
Cooling Season (CDD)										
Cooling Month										
June	376	306								
July	396	438								
August	629	407								
September	350	204								
Seasonal Aggregate	1,751	1,356	202	1,558	1,154	Yes	(193)	11,533.69	(2,228,694)	60.3444%
Heating Season (HDD)										
Heating Month										
November	480	500								
December	712	833								
January	935	954								
February	787	769								
March	569	558								
	3,483	3,615	347	3,962	3,268	No	479			

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and binary variable for Weekdays and Holidays.

LOUISVILLE GAS AND ELECTRIC

OAG kWh Weather Adjustment
(June through September, 2007)

LP Secondary

	Degree Days			Normal Weather Band						
	Actual [1/]	30-year Average [2/]	30-year Std Dev[3/]	Upper Limit	Lower Limit	Adjustment	Boundary Limit less Actual	kWh Per Degree Day[4/]	kWh Adjustment	Model R-square
Cooling Season (CDD)										
Cooling Month										
June	376	306								
July	396	438								
August	629	407								
September	350	204								
Seasonal Aggregate	1,751	1,356	202	1,558	1,154	Yes	(193)	11,366.90	(2,196,464)	94.5151%
Heating Season (HDD)										
Heating Month										
November	480	500								
December	712	833								
January	935	954								
February	787	769								
March	569	558								
	3,483	3,615	347	3,962	3,268	No	479			

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and binary variable for Weekdays and Holidays.

LOUISVILLE GAS AND ELECTRIC

OAG kWh Weather Adjustment
(June through September, 2007)

LP Primary

	Degree Days			Normal Weather Band						
	Actual [1/]	30-year Average [2/]	30-year Std Dev[3/]	Upper Limit	Lower Limit	Adjustment	Boundary Limit less Actual	kWh Per Degree Day[4/]	kWh Adjustment	Model R-square
Cooling Season (CDD)										
Cooling Month										
June	376	306								
July	396	438								
August	629	407								
September	350	204								
Seasonal Aggregate	1,751	1,356	202	1,558	1,154	Yes	(193)	2,347.97	(453,706)	87.8536%
Heating Season (HDD)										
Heating Month										
November	480	500								
December	712	833								
January	935	954								
February	787	769								
March	569	558								
	3,483	3,615	347	3,962	3,268	No	479			

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and binary variable for Weekdays and Holidays.

Schedule GAW_ 3

Eon Generation Unit Classification

Unit	Type	Gross Plant	Percent Energy	Demand	Gross Plant Energy	Gross Plant Demand
Trimble 1	Base	$598.442	100%	0%	$598.442	$0.000
Mill Creek 3	Base	$272.591	100%	0%	$272.591	$0.000
Mill Creek 4	Base	$494.022	100%	0%	$494.022	$0.000
Mill Creek 1	Base	$153.584	100%	0%	$153.584	$0.000
Mill Creek 2	Base	$121.972	100%	0%	$121.972	$0.000
Ghent 1	Base	$341.335	100%	0%	$341.335	$0.000
Cane Run 6	Base	$131.258	100%	0%	$131.258	$0.000
Ghent 4	Base	$365.800	100%	0%	$365.800	$0.000
Ghent 3	Base	$490.572	100%	0%	$490.572	$0.000
Cane Run 5	Base	$89.856	100%	0%	$89.856	$0.000
Cane Run 4	Base	$70.514	100%	0%	$70.514	$0.000
Brown 2	Base	$43.716	100%	0%	$43.716	$0.000
Brown 3	Base	$145.556	100%	0%	$145.556	$0.000
Brown 1	Base	$53.103	100%	0%	$53.103	$0.000
Ghent 2	Base	$148.052	100%	0%	$148.052	$0.000
Green River 4	Intermediate	$42.268	63%	37%	$26.629	$15.639
Tyrone 3	Intermediate	$24.555	69%	31%	$16.943	$7.612
Green River 3	Intermediate	$19.529	68%	32%	$13.280	$6.249
Trimble 5	Peak	$63.319	0%	100%	$0.000	$63.319
Trimble 6	Peak	$55.910	0%	100%	$0.000	$55.910
Trimble 7	Peak	$52.341	0%	100%	$0.000	$52.341
Trimble 8	Peak	$51.951	0%	100%	$0.000	$51.951
Trimble 9	Peak	$52.052	0%	100%	$0.000	$52.052
Trimble 10	Peak	$52.023	0%	100%	$0.000	$52.023
Brown 6	Peak	$58.868	0%	100%	$0.000	$58.868
Brown 7	Peak	$58.872	0%	100%	$0.000	$58.872
Brown 8	Peak	$35.458	0%	100%	$0.000	$35.458
Brown 9	Peak	$45.866	0%	100%	$0.000	$45.866
Brown 10	Peak	$28.591	0%	100%	$0.000	$28.591
Brown 11	Peak	$43.497	0%	100%	$0.000	$43.497
Brown 5	Peak	$45.189	0%	100%	$0.000	$45.189
Paddys Run 13	Peak	$64.098	0%	100%	$0.000	$64.098
Paddys Run 11	Peak	$1.826	0%	100%	$0.000	$1.826
Cane Run 11	Peak	$2.797	0%	100%	$0.000	$2.797
Paddys Run 12	Peak	$3.162	0%	100%	$0.000	$3.162
Zorn 1	Peak	$1.901	0%	100%	$0.000	$1.901
Haefling 1,2 & 3	Peak	$5.345	0%	100%	$0.000	$5.345
Ohio Falls 1- 8	Hydro	$29.739	100%	0%	$29.739	$0.000
Dix Dam 1,2, &3	Hydro	$11.033	100%	0%	$11.033	$0.000
Total		$4,370.563			$3,617.997	$752.566
Percent					82.78%	17.22%

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

Account Description	Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP- Pri	LP-Sec	LP-TOD Trans
Cost of Service Summary -- Pro-Forma										
total Operating Revenue	$932,384,516	$373,638,974	$132,330,260	$10,108,726	$152,499,710	$19,884,331	$21,888,647	$7,079,501	$38,755,862	$28,577,022
Pro-Forma Adjustments:										
Eliminate Unbilled Revenue	-$785,000	-315,918	-114,501	-8,371	-127,979	-18,261	-18,148	-6,010	-32,360	-23,192
Mismatch in Fuel Cos Recovery	-$50,610,168	-18,161,881	-6,065,964	-820,822	-8,524,116	-1,294,637	-1,336,972	-433,653	-2,244,537	-2,133,998
To Reflect a Full Year of the FAC Roll-	$31,805	11,413	3,812	390	5,357	614	840	273	1,411	1,341
Remove ECR Revenue	-$10,158,132	-4,121,348	-1,483,109	-106,483	-1,655,315	-207,917	-236,442	-77,318	-416,461	-292,061
To Reflect a full Year of the ECR Roll-	$1,215,475	493,141	177,462	12,739	198,067	24,878	28,292	9,252	49,832	34,947
Remove Off-System ECR Revenues	-$746,947	-299,898	-93,199	-8,560	-126,518	-17,441	-18,218	-5,799	-32,113	-26,341
Eliminate Brokered Sales	$2,000,584	717,918	239,783	24,541	336,952	51,184	52,850	17,142	88,725	84,355
Eliminate Rate Refund Acct	$9,763,357	3,929,179	1,424,100	104,115	1,591,721	202,499	225,717	74,745	402,469	288,444
Eliminate DSM Revenue	-$4,381,617	-3,773,223	-297,092	-14,001	-186,346	-49,730	-49,326	0	0	0
Year End Revenue Adjustment	-$764,511	$246,004	-$882,592	$352,824	-$337,723	$0	$0	$448,017	-$697,363	$0
Weather Normalized Electric Operating Revenues	-$14,374,348	-5,158,298	-1,722,861	-176,327	-2,421,028	-367,761	-379,728	-123,167	-637,496	-606,100
Adjustment for Merger Surecredit	$19,476,242	6,545,841	3,090,592	223,971	3,453,144	437,142	491,163	161,193	872,420	113,772
VDT Surecredit Revenues	$7,375,580	2,969,727	1,075,671	77,677	1,203,462	152,190	171,163	58,169	304,075	216,031
Sub-Total	-$41,959,678	-$14,917,139	-$4,427,898	-$138,087	-$6,592,320	-$1,085,260	-$1,088,509	$120,864	-$2,341,398	-$2,342,801
Total Pro-Forma Operating Revenue	$890,424,838	$358,721,834	$127,902,362	$9,970,639	$145,907,390	$18,799,071	$20,799,838	$7,200,364	$36,414,465	$26,234,221
Operating Expenses										
Operation and Maintenance Expenses	617,893,122	243,462,157	75,350,602	7,011,919	97,542,964	14,580,293	15,100,551	4,892,000	25,504,421	23,146,669
Depreciation and Amortization Expenses	$108,263,300	$48,673,705	$13,219,132	$1,091,365	$15,719,160	$2,253,340	$2,383,613	$751,645	$4,060,588	$3,145,181
Regulatory Credits	-$1,556,535	-$590,750	-$189,869	-$18,571	-$256,676	-$38,546	-$39,766	-$12,755	-$66,726	-$60,615
Accretion Expense	$1,389,410	$527,579	$169,483	$16,568	$229,016	$34,387	$35,479	$11,379	$59,535	$54,057
Property and Other Taxes	$17,703,456	$7,548,257	$2,161,426	$181,473	$2,602,499	$374,889	$395,519	$124,947	$672,720	$530,400
Amortization of Investment Tax Credit	$3,910,846	$1,667,476	$477,476	$40,089	$574,915	$82,818	$87,374	$27,602	$146,610	$117,170
Other Expenses	-$456,255	-$194,068	-$55,704	-$4,684	-$67,148	-$9,679	-$10,208	-$3,227	-$17,363	-$13,754
State and Federal Income Taxes	$42,796,679	$16,033,092	$10,736,560	$383,625	$8,719,033	$455,937	$842,744	$282,134	$1,963,564	$757,733
Specific Assignment of Interruptible Credit	-$6,266,793	$0	$0	$0	$0	$0	$0	$0	$0	-$2,391,305
Allocation of Interruptible Credits	$6,266,793	$2,822,318	$814,344	$65,325	$1,062,405	$128,637	$136,689	$42,306	$257,629	$167,751
Adjustments to Operating Expenses:										
Eliminate mismatch in fuel cost recovery	-50,792,206	-18,227,007	-6,087,782	-823,055	-8,554,776	-1,299,495	-1,341,781	-435,213	-2,252,610	-2,141,674
Remove ECR expenses	-10,942,070	-4,439,404	-1,597,565	-114,679	-1,783,061	-223,963	-254,690	-83,285	-448,601	-314,600
Reflect full year of ECR roll-in	8,811,442	3,574,968	1,286,489	92,349	1,435,865	180,353	205,097	67,068	361,250	253,342
Eliminate brokered sales expenses	-78,168	-26,051	-9,369	-959	-13,166	-2,000	-2,065	-670	-3,467	-3,296
Eliminate DSM Expenses	-3,860,848	-3,324,763	-261,782	-12,337	-165,961	-43,820	-43,463	0	0	0
Year end Expense adjustment	-427,934	137,701	-370,885	197,492	-169,040	0	0	250,777	-390,348	0
Adjustment to annualize depreciation expense	16,722,648	7,209,349	2,041,864	168,575	2,428,025	346,057	388,179	116,101	627,210	485,613
Depreciation adjustment	0	0	0	0	0	0	0	0	0	0
Labor adjustment	2,761,011	1,249,221	354,993	27,014	387,887	55,855	56,217	18,832	99,918	81,433
Adjustment for pension and post Ret Exp. (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0
Storm damage adjustment	-1,213,974	-858,013	-143,914	-4,525	-86,584	-8,854	-11,176	-3,153	-21,022	-5
Adjustment to eliminate advertising expense (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0
Amortization of rate case expenses	187,842	74,951	22,859	2,106	29,361	4,376	4,537	1,470	7,670	8,913
Amortization of ESM audit expenses	-10,656	-4,286	-1,554	-114	-1,737	-221	-246	-82	-439	-315
Adjustment for FERC assessment fee (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0
Adjustment for injuries and damages (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0
Adjustment for postage rate increase (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0
Adjustment to property tax expense (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0
Adjustment to sales and use tax (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0
Adjustment railcar property tax expense (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0
Adjustment for EKPC settlement charges	-678,288	-243,407	-81,297	-8,320	-114,242	-17,354	-17,918	-5,812	-30,082	-28,600
Adjustment to reflect reallocation of OVEC demand charges	-3,145,310	-1,128,708	-376,987	-38,582	-529,755	-80,470	-83,089	-26,950	-139,492	-132,623

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

Account Description	Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP- Pri	LP-Sec	LP-TOD Trans
Adjustment for MISO schedule 10 expenses	1,380,429	513,597	165,941	16,329	225,378	33,898	34,943	11,214	58,602	53,500
Reflect weather normalized electric sales margins	-4,751,178	-1,704,981	-569,460	-56,282	-800,228	-121,557	-125,512	-40,710	-210,713	-200,335
Adjustment for IT prepaid amortizaton (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0
Adjustment to remove IMEA/IMPA reactive power credits	-330,012	-118,426	-39,554	-4,048	-55,583	-8,443	-8,718	-2,828	-14,636	-13,915
Adjustment to remove reclassified capital lease	1,757,267	707,197	256,318	16,739	288,487	36,447	40,626	13,453	72,439	51,916
Adjustment for new credit facilities bank fees	5,394,978	2,171,162	788,921	57,531	879,544	111,896	124,725	41,302	222,394	159,387
Adjustment to reflect annualized vehicle fuel costs	158,347	63,725	23,097	1,689	26,815	3,284	3,661	1,212	6,527	4,678
Total Expense Adjustments	-39,076,680	-14,375,177	-4,601,569	-283,076	-6,595,767	-1,032,007	-1,048,674	-77,273	-2,055,399	-1,738,382
Total Operating Expenses	750,867,345	303,574,589	98,081,984	6,484,233	119,530,402	16,830,080	17,883,320	6,038,758	30,527,580	23,714,907
Net Operating Income -- Pro-Forma	139,557,494	55,147,245	29,820,378	1,488,406	26,376,987	1,968,991	2,916,518	1,161,608	5,886,884	2,519,314
Net Cost Rate Base	1,826,018,111	776,697,455	222,937,770	18,748,124	268,739,555	38,737,284	40,855,815	12,914,556	69,489,563	55,046,323
Less: ECR Rate Base	13,285,453	5,319,847	1,653,245	151,847	2,244,282	309,375	323,165	102,865	569,652	467,254
Adjustment to Reflect Depreciation Reserve	-16,722,648	-7,209,349	-2,041,864	-156,575	-2,428,025	-348,057	-368,179	-116,101	-627,210	-485,813
Cash Working Capital	-788,376	-314,571	-96,359	-8,840	-123,229	-18,375	-19,041	-6,169	-32,192	-29,012
Adjusted Net Cost Rate Base	1,795,221,634	763,853,688	219,146,303	18,416,861	263,944,019	38,061,477	40,145,230	12,689,421	68,260,510	54,064,243
RoR	7.77%	7.22%	13.61%	8.07%	9.99%	5.17%	7.26%	9.15%	8.62%	4.66%

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

Account Description	LP-TOD Pri	LP-TOD Sec	Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
Cost of Service Summary -- Pro-Forma											
total Operating Revenue	##########	$2,830,994	$7,781,860	$11,613,536	$3,075,165	$6,222,827	$207,198	$8,619,655	$280,300	$802,735	$5,941,047
Pro-Forma Adjustments:											
Eliminate Unbilled Revenue	-81,748	-2,364	-6,533	-9,286	-2,488	-5,762	-173	-8,143	-242	-845	-4,838
Mismatch in Fuel Cos Recovery	-7,069,940	-171,322	-580,778	-833,978	-228,954	-203,634	-14,926	-228,555	-14,638	-55,850	-391,012
To Reflect a Full Year of the FAC Roll-	4,443	108	385	524	144	128	9	144	9	35	246
Remove ECR Revenue	-1,041,665	-30,811	-83,494	-122,024	-32,095	-72,651	-2,182	-103,494	-3,076	-8,170	-62,039
To Reflect a full Year of the ECR Roll-	124,641	3,697	9,991	14,601	3,840	8,693	261	12,384	388	978	7,423
Remove Off-System ECR Revenues	-89,196	-2,249	-5,776	-11,145	-2,501	-1,644	-121	-1,846	-177	-773	-5,431
Eliminate Brokered Sales	279,470	6,772	22,958	32,967	9,050	8,050	590	9,035	579	2,208	15,456
Eliminate Rate Refund Acct	1,016,728	29,399	81,251	115,498	30,945	71,912	2,152	101,261	3,013	8,019	60,171
Eliminate DSM Revenue	0	0	0	0	0	0	0	0	0	-1,260	-8,640
Year End Revenue Adjustment	$0	$0	$0	$0	$0	-$315,830	-$1,476	$395,736	-$43,432	$0	-$148,674
Weather Normalized Electric Operating Revenues	-2,008,011	-48,659	-164,953	-236,867	-65,028	-57,836	-4,239	-64,914	-4,157	-15,862	-111,056
Adjustment for Merger Surecredit	1,173,992	63,668	0	250,635	66,905	155,464	4,654	219,227	6,505	17,039	128,914
VDT Surecredit Revenues	768,918	22,775	61,458	87,255	23,360	54,246	1,626	76,416	2,275	5,936	44,922
Sub-Total	-$6,922,367	-$128,996	-$665,501	-$711,822	-$196,821	-$358,886	-$13,827	$407,269	-$52,973	-$48,346	-$474,558
Total Pro-Forma Operating Revenue	$93,343,802	$2,701,998	$7,116,358	$10,901,714	$2,878,344	$5,863,941	$193,369	$9,026,923	$227,327	$754,388	$5,466,489
Operating Expenses											
Operation and Maintenance Expenses	78,634,424	1,933,859	6,459,989	9,415,402	2,607,114	3,115,202	175,155	3,703,250	223,096	627,407	4,406,645
Depreciation and Amortization Expenses	$11,662,976	$299,208	$962,001	$1,478,521	$421,113	$1,418,789	$25,594	$1,874,262	$32,305	$96,632	$694,167
Regulatory Credits	-$201,840	-$4,976	-$16,818	-$25,133	-$7,080	-$5,753	-$380	-$6,608	-$416	-$1,654	-$11,605
Accretion Expense	$180,059	$4,439	$15,003	$22,422	$6,316	$5,162	$339	$5,984	$372	$1,475	$10,354
Property and Other Taxes	$1,942,882	$49,632	$160,431	$245,822	$69,933	$216,694	$4,197	$285,223	$5,232	$16,078	$115,210
Amortization of Investment Tax Credit	$429,195	$10,964	$35,441	$54,304	$15,449	$47,870	$927	$63,008	$1,156	$3,552	$25,451
Other Expenses	-$60,237	-$1,282	-$4,147	-$6,343	-$1,803	-$5,601	-$109	-$7,372	-$137	-$415	-$2,974
State and Federal Income Taxes	$1,773,538	$120,897	-$87,602	-$97,199	-$73,079	$267,853	-$3,048	$606,964	$1,079	$3,250	$109,302
Specific Assignment of Interruptible Credit	-$3,675,468	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Allocation of Interruptible Credits	$591,298	$15,950	$19,999	$81,236	$12,015	$0	$0	$0	$1,078	$5,933	$41,880
Adjustments to Operating Expenses:											
Eliminate mismatch in fuel cost recovery	-7,095,369	-171,938	-582,867	-836,978	-229,777	-204,366	-14,980	-229,377	-14,590	-56,051	-392,419
Remove ECR expenses	-1,122,054	-33,169	-89,938	-131,441	-34,572	-78,258	-2,350	-111,481	-3,313	-8,801	-66,826
Reflect full year of ECR roll-in	903,569	26,727	72,425	105,847	27,840	63,019	1,892	89,773	2,668	7,087	53,814
Eliminate brokered sales expenses	-10,920	-265	-897	-1,286	-354	-315	-23	-353	-23	-66	-604
Eliminate DSM Expenses	0	0	0	0	0	0	0	0	0	-1,110	-7,613
Year end Expense adjustment	0	0	0	0	0	-176,785	-827	221,513	-24,311	0	-63,221
Adjustment to annualize depreciation expense	1,801,496	46,217	148,593	228,376	65,046	219,160	3,953	289,504	4,990	14,926	107,223
Depreciation adjustment	0	0	0	0	0	0	0	0	0	0	0
Labor adjustment	292,699	7,483	24,048	36,202	10,211	15,876	749	19,615	1,472	2,387	16,898
Adjustment for pension and post Ret Exp. (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0	0
Storm damage adjustment	-41,919	-1,409	-3,154	-6,155	-1,895	-8,059	-184	-10,119	-239	-383	-3,214
Adjustment to eliminate advertising expense (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0	0
Amortization of rate case expenses	23,583	581	1,937	2,828	784	979	53	1,171	70	188	1,323
Amortization of ESM audit expenses	-1,110	-32	-89	-126	-34	-78	-2	-111	-3	-9	-66
Adjustment for FERC assessment fee (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0	0
Adjustment for injuries and damages (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0	0
Adjustment for postage rate increase (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0	0
Adjustment to property tax expense (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0	0
Adjustment to sales and use tax (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0	0
Adjustment railcar property tax expense (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0	0
Adjustment for EKPC settlement charges	-94,753	-2,296	-7,784	-11,177	-3,068	-2,729	-200	-3,063	-196	-749	-5,240
Adjustment to reflect reallocation of OVEC demand charges	-439,381	-10,647	-36,095	-51,829	-14,230	-12,655	-929	-14,205	-910	-3,471	-24,300

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

Account Description	LP-TOD Pri	LP-TOD Sec	Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
Adjustment for MISO schedule 10 expenses	177,570	4,372	14,801	22,098	6,222	4,531	332	5,086	362	1,454	10,196
Reflect weather normalized electric sales margins	-663,711	-16,083	-54,522	-78,292	-21,494	-19,117	-1,401	-21,456	-1,374	-5,243	-36,707
Adjustment for IT prepaid amortizaton (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0	0
Adjustment to remove IMEA/IMPA reactive power credits	-48,101	-1,117	-3,787	-5,438	-1,493	-1,328	-97	-1,490	-95	-364	-2,550
Adjustment to remove reclassified capital lease	182,997	5,291	14,624	20,788	5,570	12,943	387	18,229	542	1,443	10,830
Adjustment for new credit facilities bank fees	561,617	16,245	44,897	63,821	17,099	39,736	1,189	55,965	1,665	4,431	33,249
Adjustment to reflect annualized vehicle fuel costs	16,490	477	1,318	1,873	502	1,166	35	1,643	49	130	976
Total Expense Adjustments	-5,555,097	-129,584	-456,488	-640,891	-173,643	-146,289	-12,402	310,843	-33,337	-44,219	-388,249
Total Operating Expenses	85,531,892	2,299,107	7,087,607	10,526,142	2,876,336	4,913,949	190,274	6,835,535	230,428	708,039	5,000,180
Net Operating Income -- Pro-Forma	7,812,110	402,890	28,551	373,572	2,007	949,993	3,095	2,191,388	-3,101	46,349	466,309
Net Cost Rate Base	201,059,366	5,132,028	16,598,206	25,384,220	7,214,231	22,416,070	436,111	29,502,991	548,040	1,661,445	11,901,156
Less: ECR Rate Base	1,582,242	39,903	102,456	197,705	44,369	29,170	2,138	32,740	3,136	13,714	96,347
Adjustment to Reflect Depreciation Reserve	-1,801,496	-46,217	-148,593	-228,376	-65,046	-219,150	-3,953	-289,504	-4,990	-14,926	-107,223
Cash Working Capital	-98,980	-2,439	-8,129	-11,868	-3,289	-4,108	-223	-4,915	-294	-790	-5,555
Adjusted Net Cost Rate Base	197,576,649	5,043,469	16,339,028	24,946,271	7,101,527	22,163,642	429,797	29,175,832	539,620	1,632,015	11,692,031
RoR	3.95%	7.99%	0.17%	1.50%	0.03%	4.28%	0.72%	7.51%	-0.57%	2.84%	3.99%

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

Acct. No.	Account Description		Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP- Pri	LP-Sec	LP-TOD Trans
RATE BASE												
Plant-in-Service												
	Intangible Plant											
301.00	ORGANIZATION		$2,240	956	274	23	329	47	50	16	85	67
302.00	FRANCHISE AND CONSENTS		100	43	12	1	15	2	2	1	4	3
302.00	SOFTWARE - COMMON		21,651,799	9,238,846	2,643,499	221,691	3,180,203	457,965	483,243	152,641	822,014	647,327
301.00	ORGANIZATION - COMMON		61,999	26,455	7,570	635	9,106	1,311	1,384	437	2,354	1,854
302.00	FRANCHISE AND CONSENTS - COMMON		3,108	1,326	379	32	457	66	69	22	118	93
	Total Intangible Plant		21,719,246	9,267,626	2,651,734	222,381	3,190,109	459,392	484,748	153,116	824,575	649,344
	Production Plant											
	Steam Production Generation	$1,949,427,033										
330	Hydro Baseload Generation	$29,738,482										
340	Other Production Generation	$225,596,172										
	Total Production	2,204,761,687										
	Energy Related		1,825,101,724	654,945,811	218,750,531	22,388,074	307,396,309	46,694,366	48,213,815	15,638,388	80,942,400	76,956,142
	Demand Related		379,659,962	177,409,143	50,179,406	4,074,927	57,860,252	8,242,324	8,415,511	2,535,501	14,030,856	9,748,473
	Total Production Pant		2,204,761,687	832,354,954	268,929,937	26,463,001	365,258,581	54,936,690	56,629,327	18,173,889	94,973,256	86,704,615
	Transmission Plant											
	Transmission Plant		$255,091,069	96,303,522	31,115,211	3,061,771	42,260,208	6,356,179	6,552,017	2,102,720	10,988,412	10,031,729
	Total Transmission Plant		255,091,069	96,303,522	31,115,211	3,061,771	42,260,208	6,356,179	6,552,017	2,102,720	10,988,412	10,031,729
	Distribution Plant											
360-362	Total Accounts 360-362		$94,845,074	46,108,848	12,252,224	1,004,564	13,654,761	1,983,870	1,981,071	697,942	3,499,854	0
364-365	OVERHEAD LINES	288,850,108										
	Primary:	237,801,861										
	Customer		93,377,531	81,002,988	9,442,654	11,299	605,180	3,164	11,751	9,943	73,218	1,130
	Demand		144,224,330	70,114,530	18,631,107	1,527,571	20,763,848	3,016,734	3,012,477	1,061,313	5,321,986	0
	Secondary	51,248,247										
	Customer		20,140,561	17,478,480	2,037,496	0	130,563	0	2,536	0	15,799	0
	Demand		31,107,686	21,514,614	4,833,748	0	3,190,151	0	423,212	0	789,821	0
366-367	UNDERGROUND LINES	157,900,818										
	Primary:	123,978,007										
	Customer		24,919,579	21,617,196	2,519,953	3,015	161,504	844	3,136	2,654	19,540	302
	Demand		99,058,428	48,157,167	12,796,511	1,049,190	14,261,353	2,072,000	2,069,077	728,947	3,655,330	0
	Secondary	33,922,811										
	Customer		6,818,485	5,917,251	689,784	0	44,208	0	858	0	5,349	0
	Demand		27,104,326	18,745,821	4,211,676	0	2,779,599	0	368,747	0	688,176	0
368	TRANSFORMERS - POWER POOL	108,478,013										
	Customer		28,692,435	24,900,009	2,902,636	0	186,030	0	3,612	0	22,507	0
	Demand		79,785,579	55,181,087	12,397,688	0	8,182,161	0	1,085,461	0	2,025,747	0
369	SERVICES		24,560,987	17,979,330	2,843,524	0	3,111,656	0	80,101	0	512,735	0
370	METERS		34,389,048	23,419,433	9,483,513	12,827	715,927	78,755	20,665	35,858	264,116	10,497
371	CUSTOMER INSTALLATION		0	0	0	0	0	0	0	0	0	0
373	STREET LIGHTING		67,121,503	0	0	0	0	0	0	0	0	0
374	ASSET RETIRE OBLIGATIONS DIST PLANT		37,874	24,796	4,558	201	3,220	394	460	140	809	0
	Total Distribution Plant		776,183,225	452,161,550	95,047,071	3,608,668	67,790,181	7,153,761	9,043,153	2,536,807	16,894,987	11,929
	General Plant											
	Total General Plant		16,654,627	7,106,547	2,033,387	170,625	2,446,221	352,268	371,712	117,412	632,296	497,926
	TOTAL COMMON PLANT		111,473,234	47,565,749	13,609,925	1,141,363	16,373,119	2,357,613	2,487,951	785,864	4,232,100	3,332,733

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

Acct. No.	Account Description	Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP- Pri	LP-Sec	LP-TOD Trans
106	COMPLETED CONSTR NOT CLASSIFIED	0	0	0	0	0	0	0	0	0	0
105	PLANT HELD FOR FUTURE USE	649,014	378,080	79,475	3,017	56,683	5,982	7,562	2,121	14,127	10
105	PLANT HELD FOR FUTURE USE	22,013,472	8,310,659	2,685,135	264,220	3,645,909	548,516	565,416	181,457	948,262	865,703
	PROPERTY HELD UNDER CAPITAL LEASE	2,876,958	1,086,127	350,922	34,531	476,617	71,686	73,895	23,715	123,929	113,139
	OTHER	0	0	0	0	0	0	0	0	0	0
	Total General Plant	153,667,305	64,447,161	18,758,844	1,613,657	22,899,550	3,336,265	3,506,535	1,110,570	5,850,714	4,809,511
	Construction Work In Progress										
	CWIP Production	146,057,359	55,140,457	17,815,620	1,753,077	24,196,905	3,639,354	3,751,485	1,203,953	6,291,629	5,743,862
	CWIP Transmission	24,336,419	9,187,632	2,968,480	292,102	4,031,745	606,398	625,081	200,606	1,048,326	957,058
	CWIP Distribution Plant	92,896,770	54,116,536	11,375,621	431,900	8,113,405	856,191	1,082,321	303,615	2,022,061	1,428
	CWIP Common Plant	26,558,015	11,332,334	3,242,506	271,925	3,900,825	561,739	592,743	187,229	1,008,280	794,009
	Total CWIP	289,848,563	129,776,959	35,402,227	2,749,003	40,242,879	5,663,881	6,051,631	1,895,403	10,370,296	7,496,355
	TOTAL PLANT-IN-SERVICE	**3,411,422,531**	**1,454,534,813**	**416,502,796**	**34,969,477**	**501,496,610**	**72,242,287**	**76,215,779**	**24,077,102**	**129,631,943**	**102,207,128**
	TOTAL UTILITY PLANT	**3,701,271,094**	**1,584,311,771**	**451,905,022**	**37,718,480**	**541,739,489**	**77,906,968**	**82,267,410**	**25,972,505**	**140,002,239**	**109,703,482**
	Accumulated Reserve for Depreciation										
	Intangible Plant										
	Intangible Plant	14,293,347	6,098,986	1,745,095	146,348	2,099,398	302,324	319,011	100,765	542,649	427,330
	Sub-total	14,293,347	6,098,986	1,745,095	146,348	2,099,398	302,324	319,011	100,765	542,649	427,330
	Production Plant										
	Production Plant	1,056,980,153	399,037,534	128,927,134	12,686,571	175,106,878	26,337,083	27,148,546	8,712,706	45,530,928	41,566,876
	Sub-total	1,056,980,153	399,037,534	128,927,134	12,686,571	175,106,878	26,337,083	27,148,546	8,712,706	45,530,928	41,566,876
	Transmisson Plant										
	Transmission Plant	137,604,053	51,949,113	16,784,512	1,651,614	22,796,470	3,428,720	3,534,362	1,134,273	5,927,491	5,411,427
	Sub-total	137,604,053	51,949,113	16,784,512	1,651,614	22,796,470	3,428,720	3,534,362	1,134,273	5,927,491	5,411,427
	Distribution Plant										
	Distribution Plant	395,791,787	230,566,472	48,466,456	1,840,134	34,567,607	3,647,850	4,611,290	1,293,570	8,615,101	6,083
	Sub-total	395,791,787	230,566,472	48,466,456	1,840,134	34,567,607	3,647,850	4,611,290	1,293,570	8,615,101	6,083
	General Plant										
	General & Common Plant	61,263,746	26,141,306	7,479,778	627,273	8,998,381	1,295,613	1,367,334	431,897	2,325,888	1,831,612
	Sub-total	61,263,746	26,141,306	7,479,778	627,273	8,998,381	1,295,613	1,367,334	431,897	2,325,888	1,831,612
	TOTAL ACCUMULATED RESERVE FOR DEPRECIATION	**1,665,933,086**	**713,793,412**	**203,402,975**	**16,951,941**	**243,568,734**	**35,011,790**	**36,980,542**	**11,673,211**	**62,942,058**	**49,243,328**
	Rate Base Adjustments and Working Capital										
	Working Capital Assets										
	Cash Working Capital - Operation and Maintenance Expenses	66,891,862	26,690,590	8,175,801	750,074	10,455,691	1,559,040	1,815,546	523,387	2,731,399	2,461,602
	Materials and Supplies	69,130,135	29,475,149	8,440,143	708,632	10,162,484	1,463,940	1,544,460	487,906	2,626,902	2,071,157
	Prepayments	3,275,528	1,396,593	399,911	33,576	481,519	69,365	73,180	23,118	124,468	98,136
WC	Mill Creek Ash Dredging Project	4,033,077	1,522,592	491,942	48,408	668,148	100,493	103,590	33,245	173,731	158,605
	Sub-total	143,330,602	59,084,924	17,507,797	1,540,691	21,767,843	3,192,838	3,336,775	1,067,656	5,656,500	4,789,500
	Customer Advances										
	Customer Advances	12,089,685	7,700,255	1,492,784	70,118	1,134,856	137,816	159,440	48,788	286,017	39
	Sub-total										
	Other Items										
	Total Accumulated Deferred Income Tax	340,560,616	145,205,573	41,579,292	3,490,988	50,064,187	7,211,916	7,608,588	2,403,607	12,941,100	10,203,293

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

Acct. No.	Account Description	Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP- Pri	LP-Sec	LP-TOD Trans
	Sub-total	340,560,816	145,205,573	41,579,292	3,490,888	50,064,187	7,211,916	7,608,588	2,403,607	12,941,100	10,203,293
	TOTAL OTHER RATE BASE	483,891,418	204,290,497	59,087,089	5,031,678	71,832,030	10,404,754	10,945,363	3,471,263	18,597,600	14,992,793
TOTAL RATE BASE		**1,826,018,111**	**776,697,455**	**222,937,770**	**18,746,124**	**268,739,555**	**38,737,284**	**40,855,615**	**12,914,556**	**69,489,553**	**55,046,323**

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

Acct. No.	Account Description		LP-TOD Pri	LP-TOD Sec	Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
RATE BASE													
Plant-in-Service													
	Intangible Plant												
301.00	ORGANIZATION		246	6	20	31	9	28	1	36	1	2	15
302.00	FRANCHISE AND CONSENTS		11	0	1	1	0	1	0	2	0	0	1
302.00	SOFTWARE - COMMON		2,373,141	60,641	195,946	300,303	85,439	266,323	5,132	350,641	6,403	19,640	140,761
301.00	ORGANIZATION - COMMON		6,795	174	561	860	245	763	15	1,004	18	56	403
302.00	FRANCHISE AND CONSENTS - COMMON		341	9	28	43	12	38	1	50	1	3	20
	Total Intangible Plant		2,380,533	60,830	198,557	301,239	85,705	267,153	5,148	351,733	6,423	19,701	141,199
	Production Plant												
	Steam Production Generation	$1,949,427,033											
330	Hydro Baseload Generation	$29,738,482											
340	Other Production Generation	$225,596,172											
	Total Production	2,204,761,687											
	Energy Related		254,955,869	6,178,197	20,943,987	30,074,872	8,256,515	7,343,441	538,275	8,242,149	527,864	2,014,048	14,100,871
	Demand Related		32,820,325	906,578	3,042,459	5,737,836	1,827,883	0	0	0	58,768	343,117	2,426,604
	Total Production Pant		287,776,193	7,084,775	23,986,446	35,812,708	10,084,398	7,343,441	538,275	8,242,149	586,632	2,357,165	16,527,275
	Transmission Plant												
	Transmission Plant		33,295,724	819,709	2,775,233	4,143,533	1,166,765	849,637	62,276	953,617	67,873	272,724	1,912,207
	Total Transmission Plant		33,295,724	819,709	2,775,233	4,143,533	1,166,765	849,637	62,276	953,617	67,873	272,724	1,912,207
	Distribution Plant												
360-362	Total Accounts 360-362		9,397,194	233,482	707,525	1,381,099	425,075	367,237	28,288	434,625	13,666	85,226	568,523
364-365	OVERHEAD LINES	288,850,108											
	Primary:	237,601,861											
	Customer		10,395	2,938	226	226	226	943,700	2,938	1,229,568	18,079	678	7,231
	Demand		14,289,861	355,039	1,075,885	2,100,141	646,382	588,845	43,015	660,904	20,782	129,597	864,514
	Secondary	51,248,247											
	Customer		0	634	0	0	0	203,628	634	265,311	3,901	0	1,560
	Demand		0	62,139	0	0	0	76,513	5,589	85,876	2,700	0	123,322
366-367	UNDERGROUND LINES	157,900,616											
	Primary:	123,978,007											
	Customer		2,774	784	60	60	60	251,845	784	326,134	4,825	181	1,930
	Demand		9,814,650	243,854	738,956	1,442,452	443,958	404,440	29,544	453,933	14,274	89,012	593,779
	Secondary	33,922,811											
	Customer		0	215	0	0	0	68,937	215	89,820	1,321	0	528
	Demand		0	54,142	0	0	0	66,666	4,870	74,824	2,353	0	107,451
368	TRANSFORMERS - POWER POOL	108,478,013											
	Customer		0	903	0	0	0	280,090	903	377,964	5,557	0	2,223
	Demand		0	159,376	0	0	0	196,241	14,336	220,266	6,926	0	316,299
369	SERVICES		0	17,930	0	0	0	0	5,846	0	27,828	0	2,039
370	METERS		96,575	27,293	1,288	2,266	2,577	0	29,544	0	180,283	802	8,819
371	CUSTOMER INSTALLATION		0	0	0	0	0	0	0	0	0	0	0
373	STREET LIGHTING		0	0	0	0	0	28,132,656	0	38,988,847	0	0	0
374	ASSET RETIRE OBLIGATIONS DIST PLANT		1,865	55	140	274	84	236	7	292	6	17	130
	Total Distribution Plant		33,613,115	1,158,784	2,524,061	4,926,518	1,516,363	31,811,034	166,512	43,210,354	302,499	305,512	2,598,349
	General Plant												
	Total General Plant		1,825,427	46,645	150,722	230,994	65,720	204,856	3,948	269,714	4,925	15,107	108,274
	TOTAL COMMON PLANT		12,218,000	312,207	1,008,820	1,546,097	439,878	1,371,151	26,423	1,805,258	32,966	101,117	724,700

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

Acct. No.	Account Description	LP-TOD Pri	LP-TOD Sec	Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
106	COMPLETED CONSTR NOT CLASSIFIED	0	0	0	0	0	0	0	0	0	0	0
105	PLANT HELD FOR FUTURE USE	28,106	969	2,111	4,119	1,270	26,432	139	36,131	253	255	2,173
105	PLANT HELD FOR FUTURE USE	2,873,305	70,738	239,493	357,572	100,688	73,321	5,374	82,294	5,857	23,535	165,017
	PROPERTY HELD UNDER CAPITAL LEASE	375,515	9,245	31,300	46,731	13,159	9,582	702	10,755	765	3,076	21,586
	OTHER	0	0	0	0	0	0	0	0	0	0	0
	Total General Plant	17,320,353	439,803	1,432,446	2,185,515	620,714	1,685,342	36,587	2,204,152	44,767	143,091	1,021,729
	Construction Work In Progress											
	CWIP Production	19,064,115	469,340	1,589,014	2,372,460	868,054	486,476	35,659	546,012	38,862	156,154	1,094,871
	CWIP Transmission	3,176,508	78,203	264,765	395,305	111,313	81,058	5,942	90,976	6,475	26,019	182,430
	CWIP Distribution Plant	4,022,955	138,688	302,092	569,626	181,724	3,783,337	19,929	5,171,591	36,204	36,565	310,981
	CWIP Common Plant	2,910,886	74,382	240,347	368,351	104,799	326,671	6,295	430,095	7,854	24,091	172,657
	Total CWIP	29,174,463	760,613	2,396,218	3,725,742	1,065,890	4,677,542	67,824	6,238,676	89,396	242,828	1,760,939
	TOTAL PLANT-IN-SERVICE	**374,385,918**	**9,563,901**	**30,914,763**	**47,369,511**	**13,475,945**	**41,756,606**	**808,801**	**54,962,005**	**1,008,194**	**3,098,194**	**22,200,759**
	TOTAL UTILITY PLANT	**403,660,381**	**10,324,514**	**33,310,981**	**51,095,253**	**14,541,835**	**46,434,148**	**876,625**	**61,200,681**	**1,097,590**	**3,341,022**	**23,961,698**
	Accumulated Reserve for Depreciation											
	Intangible Plant											
	Intangible Plant	1,566,619	40,032	129,353	198,244	56,402	175,812	3,388	231,474	4,227	12,965	92,923
	Sub-total	1,566,619	40,032	129,353	198,244	56,402	175,812	3,388	231,474	4,227	12,965	92,923
	Production Plant											
	Production Plant	137,962,178	3,396,497	11,499,292	17,166,895	4,834,540	3,520,504	258,053	3,951,351	281,236	1,130,044	7,923,306
	Sub-total	137,962,178	3,396,497	11,499,292	17,166,895	4,834,540	3,520,504	258,053	3,951,351	281,236	1,130,044	7,923,306
	Transmisson Plant											
	Transmission Plant	17,960,749	442,176	1,497,047	2,235,150	629,390	458,320	33,595	514,411	36,613	147,116	1,031,504
	Sub-total	17,960,749	442,176	1,497,047	2,235,150	629,390	458,320	33,595	514,411	36,613	147,116	1,031,504
	Distribution Plant											
	Distribution Plant	17,140,018	590,888	1,287,081	2,512,133	774,244	16,119,116	84,908	22,033,848	154,250	155,787	1,324,951
	Sub-total	17,140,018	590,888	1,287,081	2,512,133	774,244	16,119,116	84,908	22,033,848	154,250	155,787	1,324,951
	General Plant											
	General & Common Plant	6,714,800	171,583	554,430	849,708	241,749	753,561	14,522	992,138	18,118	55,572	398,282
	Sub-total	6,714,800	171,583	554,430	849,708	241,749	753,561	14,522	992,138	18,118	55,572	398,282
	TOTAL ACCUMULATED RESERVE FOR DEPRECIATION	**181,344,364**	**4,641,176**	**14,967,203**	**22,964,130**	**6,536,325**	**21,027,313**	**394,466**	**27,723,222**	**494,444**	**1,501,484**	**10,770,966**
	Rate Base Adjustments and Working Capital											
	Working Capital Assets											
	Cash Working Capital - Operation and Maintenance Expenses	6,398,221	200,980	689,728	1,006,946	279,066	348,567	16,913	417,030	24,916	67,066	471,298
	Materials and Supplies	7,586,674	193,806	626,466	959,911	273,081	846,169	16,390	1,113,767	20,430	62,783	449,583
	Prepayments	359,472	9,183	29,683	45,463	12,939	40,093	777	52,773	968	2,975	21,316
WC	Mill Creek Ash Dredging Project	526,417	12,960	43,677	65,511	18,447	13,433	985	15,077	1,073	4,312	30,233
	Sub-total	16,870,784	422,926	1,389,755	2,077,850	583,533	1,248,262	37,064	1,598,647	47,388	137,138	972,730
	Customer Advances											
	Customer Advances	652,652	19,477	49,120	95,875	29,514	70,483	2,370	86,282	1,846	5,939	46,013
	Sub-total											
	Other Items											
	Total Accumulated Deferred Income Tax	37,374,782	954,760	3,086,207	4,728,678	1,345,298	4,186,644	80,742	5,486,833	100,648	309,291	2,216,292

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

Acct. No.	Account Description	LP-TOD Pri	LP-TOD Sec	Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
	Sub-total	37,374,782	954,760	3,086,207	4,728,878	1,345,298	4,168,544	80,742	5,486,833	100,648	309,291	2,216,292
	TOTAL OTHER RATE BASE	54,245,566	1,377,688	4,475,962	6,806,727	1,928,830	5,416,808	117,806	7,085,480	148,035	446,429	3,189,022
TOTAL RATE BASE		201,059,366	5,132,028	16,598,206	25,384,220	7,214,231	22,416,070	436,111	29,502,991	548,040	1,661,445	11,901,155

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

Acct. No.	Account Description		Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP- Pri	LP-Sec	LP-TOD Trans
O & M Expenses												
	Steam Production O&M											
500	OPERATION SUPERVISION & ENGINEERING		$2,089,969	783,314	254,280	25,166	347,082	52,280	53,905	17,327	90,417	83,058
501	FUEL		$287,348,507	103,116,280	34,440,622	3,524,833	48,397,231	7,351,678	7,590,902	2,462,146	12,743,771	12,116,164
502	STEAM EXPENSES		$27,325,773	10,316,191	3,333,112	327,982	4,526,983	680,884	701,863	225,247	1,177,097	1,074,615
505	ELECTRIC EXPENSES		$754,249	284,749	92,001	9,053	124,954	18,794	19,373	6,217	32,490	29,662
506	MISC. STEAM POWER EXPENSES		$16,989,296	6,413,902	2,072,301	203,917	2,814,568	423,327	436,370	140,043	731,838	668,122
507	RENTS		$51,252	19,349	6,252	615	8,491	1,277	1,316	422	2,208	2,016
509	ALLOWANCES		$3,372	1,273	411	40	559	84	87	28	145	133
510	MAINTENANCE SUPERVISION & ENGINEERING		$2,346,687	843,763	281,453	28,763	395,002	59,980	61,928	20,079	103,962	98,699
511	MAINTENANCE OF STRUCTURES		$2,279,365	860,520	278,030	27,358	377,618	56,796	58,546	18,789	98,187	89,638
512	MAINTENANCE OF BOILER PLANT		$39,886,283	14,313,369	4,780,635	489,275	6,717,925	1,020,472	1,053,678	341,768	1,768,938	1,681,821
513	MAINTENANCE OF ELECTRIC PLANT		$7,544,241	2,707,284	904,227	92,543	1,270,653	193,016	199,297	64,643	334,584	318,106
514	MAINTENANCE OF MISC STEAM PLANT		$1,334,745	478,979	159,978	16,373	224,807	34,149	35,260	11,437	59,195	56,280
	Sub-total		387,953,739	140,138,972	46,603,303	4,745,920	65,205,872	9,892,735	10,212,524	3,308,144	17,142,832	16,218,314
	Hydraulic Production O&M											
535	OPERATION SUPERVISION & ENGINEERING		$53,088	20,042	6,476	637	8,795	1,323	1,364	438	2,287	2,088
536	WATER FOR POWER		$39,005	14,726	4,758	468	6,462	972	1,002	322	1,680	1,534
537	HYDRAULIC EXPENSES		$0									
538	ELECTRIC EXPENSES		$161,489	60,966	19,698	1,938	26,753	4,024	4,148	1,331	6,956	6,351
539	MISC. HYDRAULIC POWER EXPENSES		$129,702	48,966	15,821	1,557	21,487	3,232	3,331	1,069	5,587	5,101
540	RENTS		$238,696	90,114	29,115	2,865	39,544	5,948	6,131	1,968	10,282	9,387
541	MAINTENANCE SUPERVISION & ENGINEERING		$4,568	1,671	551	56	765	116	119	39	200	188
542	MAINTENANCE OF STRUCTURES		$189,915	71,698	23,165	2,279	31,463	4,732	4,878	1,565	8,181	7,469
543	MAINT. OF RESERVES, DAMS, AND WATERWAYS		$87,399	32,995	10,661	1,049	14,479	2,178	2,245	720	3,765	3,437
544	MAINTENANCE OF ELECTRIC PLANT		$282,889	101,516	33,906	3,470	47,646	7,238	7,473	2,424	12,546	11,928
545	MAINTENANCE OF MISC HYDRAULIC PLANT		$0									
	Sub-total		1,186,753	442,694	144,150	14,320	197,395	29,761	30,691	9,875	51,485	47,482
	Other Power Generation Operation Expense											
546	OPERATION SUPERVISION & ENGINEERING		$28,825	10,882	3,516	348	4,775	718	740	238	1,242	1,134
547	FUEL		$30,157,562	10,822,174	3,614,584	389,935	5,079,346	771,567	796,674	258,405	1,337,474	1,271,606
548	GENERATION EXPENSE		$925,321	349,333	112,868	11,106	153,295	23,056	23,767	7,627	39,860	36,389
549	MISC OTHER POWER GENERATION		$37,851	14,290	4,617	454	6,271	943	972	312	1,630	1,489
550	RENTS		$22,836	8,621	2,785	274	3,783	569	587	188	984	898
551	MAINTENANCE SUPERVISION & ENGINEERING		$16,488	6,225	2,011	198	2,732	411	424	136	710	648
552	MAINTENANCE OF STRUCTURES		$91,930	34,708	11,213	1,103	15,230	2,291	2,361	758	3,960	3,615
553	MAINTENANCE OF GENERATING & ELEC PLANT		$1,860,881	702,531	226,984	22,336	308,287	46,368	47,797	15,339	80,160	73,181
554	MAINTENANCE OF MISC OTHER POWER GEN PLT		$110,415	41,684	13,468	1,325	18,292	2,751	2,836	910	4,756	4,342
	Sub-total		33,252,108	11,990,446	3,992,047	407,078	5,592,011	848,675	876,157	283,914	1,470,776	1,393,302
	Other Power Supply Expense											
555	PURCHASED POWER	81,802,192										
	Demand		10,759,242	4,061,694	1,312,379	129,140	1,782,453	288,091	276,351	88,689	463,470	423,119
	Energy		71,042,950	25,494,076	8,514,968	871,466	11,965,547	1,817,600	1,876,746	608,732	3,150,721	2,995,554
555	PURCHASED POWER OPTIONS		$0									
555	BROKERAGE FEES		$0									
555	MISO TRANSMISSION EXPENSES		$0									

Louisville Gas and Electric
Electric Cost of Service Study
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Acct. No.	Account Description	Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP- Pri	LP-Sec	LP-TOD Trans
556	SYSTEM CONTROL AND LOAD DISPATCH	$1,014,056	382,833	123,691	12,171	167,996	25,268	26,046	8,359	43,682	39,879
557	OTHER EXPENSES	-570,439	-215,356	-69,580	-6,847	-94,503	-14,214	-14,652	-4,702	-24,572	-22,433
558	DUPLICATE CHARGES	-2,771,363	-994,516	-332,166	-33,996	-466,772	-70,904	-73,211	-23,746	-122,909	-116,856
	Sub-total	79,474,446	28,728,931	9,549,292	971,935	13,354,721	2,025,641	2,091,280	677,331	3,510,392	3,319,263
	Transmission Expenses										
560	OPERATION SUPERVISION AND ENG	$707,432	267,074	86,290	8,491	117,198	17,627	18,170	5,831	30,474	27,821
561	LOAD DISPATCHING	711,516	288,616	86,789	8,540	117,875	17,729	18,275	5,865	30,650	27,981
562	STATION EXPENSES	1,234,251	465,962	150,550	14,814	204,475	30,754	31,702	10,174	53,167	48,538
563	OVERHEAD LINE EXPENSES	86,952	32,827	10,606	1,044	14,405	2,167	2,233	717	3,746	3,419
565	TRANSMISSION OF ELECTRICITY BY OTHERS	3,214,182	1,213,437	392,058	38,579	532,484	80,089	82,556	26,495	138,455	126,401
566	MISC. TRANSMISSION EXPENSES	3,724,941	1,406,262	454,357	44,709	617,100	92,815	95,675	30,705	160,457	146,487
567	RENTS	22,490	8,491	2,743	270	3,726	560	578	185	969	884
568	MAINTENACE SUPERVISION AND ENG	0	0	0	0	0	0	0	0	0	0
569	STRUCTURES	30,412	11,481	3,710	365	5,038	758	781	251	1,310	1,196
570	MAINT OF STATION EQUIPMENT	996,472	376,194	121,547	11,960	165,083	24,829	25,594	8,214	42,924	39,187
571	MAINT OF OVERHEAD LINES	776,625	293,196	94,730	9,322	128,661	19,351	19,948	6,402	33,454	30,542
572	UNDERGROUND LINES	0	0	0	0	0	0	0	0	0	0
573	MISC PLANT	2,418	913	295	29	401	60	62	20	104	95
575	MARKET FACILITATION, MONITORING AND COMPLIANCE	7,533	2,844	919	90	1,248	188	193	62	325	296
	Sub-total	11,515,224	4,347,297	1,404,591	138,213	1,907,894	286,928	295,769	94,920	496,035	452,849
	Distribution Expense - Operating										
580	OPERATION SUPERVISION AND ENGI	$1,235,544	788,258	221,708	4,651	82,034	9,651	10,349	3,604	21,784	146
581	LOAD DISPATCHING	333,427	162,095	43,073	3,532	48,003	6,974	6,964	2,454	12,304	0
582	STATION EXPENSES	937,276	455,656	121,079	9,927	134,939	19,605	19,577	6,897	34,586	0
583	OVERHEAD LINE EXPENSES	4,516,341	2,972,491	546,386	24,061	386,039	47,218	53,942	16,750	96,954	18
584	UNDERGROUND LINE EXPENSES	440,566	263,494	56,411	2,936	48,121	5,784	6,813	2,041	12,188	1
585	STREET LIGHTING EXPENSE	18,496	0	0	0	0	0	0	0	0	0
586	METER EXPENSES	5,620,801	3,827,846	1,550,056	2,097	117,016	12,545	3,378	5,863	43,169	1,716
586	METER EXPENSES - LOAD MANAGEMENT	0									
587	CUSTOMER INSTALLATIONS EXPENSE	-221,632	-129,111	-27,140	-1,030	-19,357	-2,043	-2,582	-724	-4,824	-3
588	MISCELLANEOUS DISTRIBUTION EXP	2,960,271	1,724,491	362,498	13,763	258,544	27,284	34,490	9,675	64,435	45
588	MISC DISTR EXP – MAPPIN	0									
589	RENTS	14,166	8,252	1,735	66	1,237	131	165	46	308	0
590	MAINTENANCE SUPERVISION AND EN	$9,951	6,264	1,202	54	894	107	125	38	225	0
591	STRUCTURES	$796,271	387,106	102,863	8,434	114,638	16,656	16,632	5,860	29,383	0
592	MAINTENANCE OF STATION EQUIPME	728,659	354,237	94,129	7,718	104,904	15,241	15,220	5,362	26,888	0
593	MAINTENANCE OF OVERHEAD LINES	12,568,540	8,272,155	1,520,538	66,960	1,074,309	131,403	150,116	46,613	269,812	49
594	MAINTENANCE OF UNDERGROUND LIN	1,540,702	921,464	197,274	10,267	168,283	20,228	23,826	7,139	42,624	3
595	MAINTENANCE OF LINE TRANSFORME	223,512	165,002	31,525	0	17,242	0	2,244	0	4,220	0
596	MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	792,957	0	0	0	0	0	0	0	0	0
597	MAINTENANCE OF METERS	0									
598	MISCELLANEOUS DISTRIBUTION EXPENSES	263,243	153,351	32,235	1,224	22,991	2,426	3,067	860	5,730	4
	Sub-total	32,779,090	20,333,051	4,855,573	154,658	2,559,838	313,407	344,326	112,476	659,768	1,978
	Customer Accounts Expense										
901	SUPERVISION/CUSTOMER ACCTS	$658,533	529,663	67,919	739	39,572	414	1,537	650	4,788	148
902	METER READING EXPENSES	2,117,207	1,702,884	218,361	2,375	127,224	1,330	4,941	2,090	15,392	475
903	RECORDS AND COLLECTION	4,762,532	3,830,537	491,191	5,343	286,162	2,992	11,114	4,702	34,624	1,069

Louisville Gas and Electric
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(Expenses)

Acct. No.	Account Description		Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP- Pri	LP-Sec	LP-TOD Trans
904	UNCOLLECTIBLE ACCOUNTS		848,931	682,801	87,556	952	51,013	533	1,981	838	8,172	190
905	MISC CUST ACCOUNTS		258,880	208,203	26,698	290	15,555	163	604	256	1,882	58
	Sub-total		8,646,062	6,954,087	891,724	9,700	519,545	5,432	20,177	8,536	62,858	1,940
	Customer Service & Information Expense											
907	SUPERVISION		$139,749	121,011	14,106	17	904	5	18	15	109	2
908	CUSTOMER ASSISTANCE EXPENSES		4,201,997	3,638,581	424,155	506	27,184	142	528	447	3,289	51
908	CUSTOMER ASSISTANCE EXP-INCENTIVES		0									
909	INFORMATIONAL AND INSTRUCTIONA		332,270	287,718	33,540	40	2,150	11	42	35	260	4
909	INFORM AND INSTRUC -LOAD MGMT		0									
910	MISCELLANEOUS CUSTOMER SERVICE		849,309	562,248	65,542	78	4,201	22	82	69	508	8
911	DEMONSTRATION AND SELLING EXP		0									
912	DEMONSTRATION AND SELLING EXP		0									
913	ADVERTISING EXPENSES		57,093	49,438	5,783	7	369	2	7	6	45	1
915	MDSE-JOBBING-CONTRACT		0									
916	MISC SALES EXPENSE		0									
	Sub-total		5,380,416	4,658,996	543,107	650	34,808	182	676	572	4,211	65
	General Expenses											
920	ADMIN. & GEN. SALARIES-		$13,327,243	6,047,292	1,716,948	130,018	1,887,484	268,831	280,097	90,686	480,966	392,126
921	OFFICE SUPPLIES AND EXPENSES		6,596,133	2,993,023	849,780	84,351	924,285	133,054	138,630	44,884	238,048	194,077
922	ADMINISTRATIVE EXPENSES TRANSFERRED		-1,911,957	-867,559	-246,317	-16,853	-267,914	-38,567	-40,183	-13,010	-69,001	-56,255
923	OUTSIDE SERVICES EMPLOYED		4,480,744	2,033,156	577,254	43,713	627,866	90,383	94,171	30,490	161,705	131,836
924	PROPERTY INSURANCE		3,126,943	1,333,241	361,770	32,053	459,677	66,218	69,860	22,069	118,822	93,684
925	INJURIES AND DAMAGES - INSURAN		2,160,289	980,240	278,310	21,075	302,711	43,576	45,403	14,700	77,963	63,562
926	EMPLOYEE BENEFITS		22,164,705	10,086,403	2,858,055	216,430	3,108,638	447,499	466,254	150,957	800,623	652,738
927	FRANCHISE REQUIREMENTS		26,016	11,092	3,176	267	3,824	551	581	184	989	779
928	REGULATORY COMMISSION FEES		653,611	278,682	79,800	6,700	96,084	13,841	14,603	4,613	24,837	19,582
929	DUPLICATE CHARGES-CR		-32,795	-14,881	-4,225	-320	-4,595	-662	-689	-223	-1,184	-965
930	MISCELLANEOUS GENERAL EXPENSES		921,538	418,152	118,722	8,990	129,131	18,589	19,368	6,271	33,257	27,114
931	RENTS AND LEASES		1,249,895	524,199	152,580	13,125	187,073	27,136	28,521	9,033	48,402	39,119
935	MAINTENANCE OF GENERAL PLANT		4,922,918	2,064,643	600,962	51,695	738,818	106,881	112,338	35,578	190,636	154,079
	Sub-total		57,705,282	25,867,683	7,366,816	569,445	8,171,082	1,177,332	1,228,952	396,232	2,106,066	1,711,477
	TOTAL O & M EXPENSES		**617,693,122**	**243,462,157**	**75,350,602**	**7,011,919**	**97,542,964**	**14,580,293**	**15,100,551**	**4,892,000**	**25,504,421**	**23,146,669**
	Depreciation Expense											
	Steam Production		$57,680,730	21,775,978	7,035,715	692,322	9,555,801	1,437,246	1,481,530	475,463	2,484,680	2,268,356
	Hydraulic Production		$702,679	265,280	85,711	8,434	116,411	17,509	18,048	5,792	30,269	27,634
	Other Production		$7,423,757	2,802,682	905,527	89,105	1,229,873	184,980	190,679	61,194	319,789	291,947
	Transmission - Kentucky System Property		$6,076,139	2,293,901	741,148	72,930	1,006,617	151,401	156,066	50,086	261,738	238,951
	Transmission - Virginia Property		$0	0	0	0	0	0	0	0	0	0
	Distribution		$25,989,528	15,140,066	3,182,533	120,832	2,269,870	239,535	302,799	84,942	565,708	399
	General & Common Plant		$5,173,681	2,169,811	631,574	54,329	774,350	112,326	118,058	37,391	200,349	161,927
	Intangible Plant		$5,216,787	2,226,008	636,925	53,414	766,238	110,342	116,433	36,777	198,056	155,967
	TOTAL DEPRECIATION EXPENSES		**$108,263,300**	**$46,673,705**	**$13,219,132**	**$1,091,365**	**$15,719,160**	**$2,253,340**	**$2,383,613**	**$751,645**	**$4,060,589**	**$3,145,181**
	Other Expenses											
	Regulatory Credits	-$1,558,535										
	Production		-$1,539,331	-561,138	-187,763	-18,476	-255,017	-38,358	-39,538	-12,689	-66,309	-60,536

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Acct. No.	Account Description		Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP- Pri	LP-Sec	LP-TOD Trans
	Transmission		-$1,999	-755	-244	-24	-331	-50	-51	-16	-86	-79
	Distribution		-$15,205	-8,858	-1,862	-71	-1,328	-140	-177	-50	-331	0
	Accretion Expense	$1,389,410										
	Production		$1,372,760	518,253	167,445	16,477	227,421	34,205	35,259	11,316	59,134	53,985
	Transmission		$1,820	687	222	22	302	45	47	15	78	72
	Distribution		$14,830	8,839	1,816	69	1,295	137	173	48	323	0
	Property Taxes & Other		$17,703,456	7,548,257	2,161,426	181,473	2,602,499	374,899	395,519	124,947	672,720	530,400
	Amortization of Investment Tax Credit		$3,910,848	1,667,476	477,478	40,089	574,915	82,818	87,374	27,602	148,610	117,170
	Gain on Disposition of Allowances		-$456,255	-194,068	-55,704	-4,684	-67,148	-9,679	-10,208	-3,227	-17,363	-13,754
	Interest		$45,715,737	19,445,205	5,581,415	469,323	6,728,097	969,817	1,022,851	323,326	1,739,723	1,378,126
	Other Deductions		$0									
	Total Other Expenses		$66,706,661	$28,403,699	$8,144,230	$684,198	$9,810,705	$1,413,697	$1,491,248	$471,272	$2,536,500	$2,005,385
TOTAL EXPENSES			$792,863,083	$318,539,561	$98,713,964	$8,787,462	$123,072,829	$18,247,330	$18,975,412	$8,114,917	$32,101,510	$28,297,236
Assignment of Innteruptible Credit			-$6,266,793									-2,391,305
Allocation of Innteruptible Credit			$6,266,793	2,822,318	814,344	65,325	1,062,405	128,637	136,689	42,308	257,629	167,751
Calculation of Taxable Income and Allocation of Income Taxes:												
	Total Operating Revenue		$932,384,516	$373,638,974	$132,330,260	$10,108,726	$152,499,710	$19,884,331	$21,868,647	$7,079,501	$38,755,862	$28,577,022
	Operating Expenses		$748,703,881	$302,507,423	$92,136,762	$8,402,055	$117,663,612	$17,444,696	$18,129,016	$5,846,652	$30,686,141	$24,756,170
	Interest Expense		$45,715,737	$19,445,205	$5,581,415	$469,323	$6,728,097	$969,817	$1,022,851	$323,326	$1,739,723	$1,378,126
	Taxable Income		**$137,984,899**	**$51,686,345**	**$34,612,084**	**$1,237,348**	**$28,107,800**	**$1,469,818**	**$2,716,780**	**$909,523**	**$6,329,998**	**$2,442,726**
	Income Taxes											
	State & Federal Income Taxes		$42,796,679	16,033,092	10,736,660	383,825	8,719,033	455,937	842,744	282,134	1,963,564	757,733

Louisville Gas and Electric
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Acct. No.	Account Description		LP-TOD Pri	LP-TOD Sec	Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
O & M Expenses													
	Steam Production O&M												
500	OPERATION SUPERVISION & ENGINEERING		275,594	6,768	22,920	34,020	9,544	7,173	526	8,051	563	2,245	15,737
501	FUEL		40,140,879	972,711	3,297,473	4,735,062	1,299,926	1,156,169	84,747	1,297,664	83,108	317,097	2,220,044
502	STEAM EXPENSES		3,566,693	87,809	297,288	443,862	124,986	91,014	6,671	102,153	7,271	29,215	204,839
505	ELECTRIC EXPENSES		98,448	2,424	8,206	12,252	3,450	2,512	184	2,820	201	808	5,654
506	MISC. STEAM POWER EXPENSES		2,217,525	54,593	184,833	275,963	77,708	56,587	4,148	63,512	4,520	18,184	127,355
507	RENTS		8,690	165	558	833	234	171	13	192	14	55	384
509	ALLOWANCES		440	11	37	55	15	11	1	13	1	4	25
510	MAINTENANCE SUPERVISION & ENGINEERING		327,011	7,929	26,877	38,649	10,621	9,381	688	10,529	677	2,587	18,110
511	MAINTENANCE OF STRUCTURES		297,514	7,325	24,798	37,025	10,426	7,592	556	8,521	606	2,437	17,087
512	MAINTENANCE OF BOILER PLANT		5,571,877	135,020	457,716	657,265	180,440	160,486	11,764	180,126	11,536	44,016	308,160
513	MAINTENANCE OF ELECTRIC PLANT		1,053,886	25,538	86,574	124,317	34,129	30,355	2,225	34,070	2,182	8,325	58,287
514	MAINTENANCE OF MISC STEAM PLANT		186,456	4,518	15,317	21,995	6,038	5,370	394	6,028	386	1,473	10,312
	Sub-total		53,743,012	1,304,810	4,422,595	6,381,296	1,757,517	1,528,821	111,916	1,713,677	111,065	426,422	2,985,994
	Hydraulic Production O&M												
535	OPERATION SUPERVISION & ENGINEERING		6,929	171	576	862	243	177	13	198	14	57	398
536	WATER FOR POWER		5,091	125	424	634	178	130	10	146	10	42	292
537	HYDRAULIC EXPENSES												
538	ELECTRIC EXPENSES		21,078	519	1,757	2,623	739	538	39	604	43	173	1,211
539	MISC. HYDRAULIC POWER EXPENSES		16,929	417	1,411	2,107	593	432	32	485	35	139	972
540	RENTS		31,156	767	2,597	3,877	1,092	795	58	892	64	255	1,789
541	MAINTENANCE SUPERVISION & ENGINEERING		623	15	51	76	21	17	1	19	1	5	35
542	MAINTENANCE OF STRUCTURES		24,789	610	2,068	3,085	869	633	46	710	51	203	1,424
543	MAINT. OF RESERVES, DAMS, AND WATERWAYS		11,408	281	951	1,420	400	291	21	327	23	93	655
544	MAINTENANCE OF ELECTRIC PLANT		39,518	958	3,246	4,662	1,280	1,138	83	1,278	82	312	2,186
545	MAINTENANCE OF MISC HYDRAULIC PLANT												
	Sub-total		157,521	3,863	13,081	19,344	5,414	4,151	304	4,659	322	1,279	8,962
	Other Power Generation Operation Expense												
546	OPERATION SUPERVISION & ENGINEERING		3,782	93	314	468	132	96	7	108	8	31	216
547	FUEL		4,212,832	102,087	346,074	496,950	138,429	121,341	8,894	136,191	8,722	33,280	232,996
548	GENERATION EXPENSE		120,777	2,973	10,067	15,030	4,232	3,082	226	3,459	246	989	8,938
549	MISC OTHER POWER GENERATION		4,940	122	412	615	173	128	9	141	10	40	284
550	RENTS		2,981	73	248	371	104	76	6	85	6	24	171
551	MAINTENANCE SUPERVISION & ENGINEERING		2,152	53	179	268	75	55	4	82	4	18	124
552	MAINTENANCE OF STRUCTURES		11,999	295	1,000	1,493	420	306	22	344	24	98	689
553	MAINTENANCE OF GENERATING & ELEC PLANT		242,891	5,980	20,245	30,227	8,512	6,198	454	6,957	495	1,990	13,949
554	MAINTENANCE OF MISC OTHER POWER GEN PLT		14,412	355	1,201	1,794	505	368	27	413	29	118	828
	Sub-total		4,616,747	112,031	379,740	547,216	150,583	131,648	9,650	147,760	9,546	36,568	256,194
	Other Power Supply Expense												
555	PURCHASED POWER	81,802,192											
	Demand		1,404,349	34,574	117,054	174,766	49,212	35,836	2,627	40,222	2,863	11,503	80,653
	Energy		9,924,278	240,489	815,255	1,170,679	321,389	285,847	20,953	320,830	20,547	78,398	548,875
555	PURCHASED POWER OPTIONS												
555	BROKERAGE FEES												
555	MISO TRANSMISSION EXPENSES												

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Acct. No.	Account Description	LP-TOD Pri	LP-TOD Sec	Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
556	SYSTEM CONTROL AND LOAD DISPATCH	132,360	3,259	11,032	16,472	4,636	3,378	248	3,791	270	1,084	7,602
557	OTHER EXPENSES	-74,457	-1,833	-6,206	-9,266	-2,609	-1,900	-139	-2,132	-152	-610	-4,276
558	DUPLICATE CHARGES	-387,143	-9,381	-31,803	-45,668	-12,537	-11,151	-817	-12,515	-802	-3,058	-21,411
	Sub-total	10,999,367	267,107	905,332	1,306,983	360,092	312,010	22,870	350,194	22,727	87,317	611,442
	Transmission Expenses											
560	OPERATION SUPERVISION AND ENG	92,337	2,273	7,696	11,491	3,236	2,356	173	2,645	188	756	5,303
561	LOAD DISPATCHING	92,871	2,286	7,741	11,557	3,254	2,370	174	2,660	189	761	5,334
562	STATION EXPENSES	161,100	3,966	13,428	20,048	5,645	4,111	301	4,614	328	1,320	9,252
563	OVERHEAD LINE EXPENSES	11,349	279	946	1,412	398	290	21	325	23	93	652
565	TRANSMISSION OF ELECTRICITY BY OTHERS	419,531	10,328	34,968	52,209	14,701	10,706	785	12,018	855	3,436	24,094
566	MISC. TRANSMISSION EXPENSES	486,197	11,970	40,525	60,508	17,038	12,407	909	13,925	991	3,982	27,923
567	RENTS	2,935	72	245	365	103	75	5	84	6	24	169
568	MAINTENACE SUPERVISION AND ENG	0	0	0	0	0	0	0	0	0	0	0
569	STRUCTURES	3,970	98	331	494	139	101	7	114	8	33	228
570	MAINT OF STATION EQUIPMENT	130,084	3,202	10,841	18,186	4,558	3,319	243	3,725	265	1,065	7,470
571	MAINT OF OVERHEAD LINES	101,369	2,498	8,449	12,615	3,552	2,587	190	2,903	207	830	5,822
572	UNDERGROUND LINES	0	0	0	0	0	0	0	0	0	0	0
573	MISC PLANT	316	8	26	39	11	8	1	9	1	3	18
575	MARKET FACILITATION, MONITORING AND COMPLIANCE	983	24	82	122	34	25	2	28	2	8	56
	Sub-total	1,503,023	37,003	125,279	187,046	52,670	38,354	2,811	43,048	3,064	12,311	86,320
	Distribution Expense - Operating											
580	OPERATION SUPERVISION AND ENGI	43,006	1,602	3,155	6,155	1,920	13,199	554	17,592	2,585	390	3,020
581	LOAD DISPATCHING	33,036	821	2,487	4,855	1,494	1,361	99	1,528	48	300	1,999
582	STATION EXPENSES	92,665	2,307	6,992	13,648	4,201	3,827	280	4,295	135	842	5,618
583	OVERHEAD LINE EXPENSES	223,590	6,579	16,826	32,840	10,110	28,342	816	35,050	711	2,037	15,583
584	UNDERGROUND LINE EXPENSES	27,392	834	2,062	4,025	1,239	2,209	99	2,641	64	249	1,963
585	STREET LIGHTING EXPENSE	0	0	0	0	0	7,752	0	10,744	0	0	0
586	METER EXPENSES	15,765	4,461	211	370	421	0	4,829	0	29,467	131	1,441
586	METER EXPENSES - LOAD MANAGEMENT											
587	CUSTOMER INSTALLATIONS EXPENSE	-9,598	-331	-721	-1,407	-434	-9,026	-48	-12,338	-86	-87	-742
588	MISCELLANEOUS DISTRIBUTION EXP	128,198	4,419	9,627	18,789	5,791	120,561	635	164,799	1,154	1,165	9,910
588	MISC DISTR EXP – MAPPIN											
589	RENTS	613	21	46	90	28	577	3	789	6	6	47
590	MAINTENANCE SUPERVISION AND EN	505	15	38	74	23	148	2	195	2	5	36
591	STRUCTURES	78,894	1,960	5,940	11,595	3,569	3,251	237	3,649	115	716	4,773
592	MAINTENANCE OF STATION EQUIPME	72,195	1,794	5,436	10,610	3,288	2,975	217	3,339	105	655	4,388
593	MAINTENANCE OF OVERHEAD LINES	622,229	18,308	48,824	91,392	28,135	78,874	2,270	97,540	1,978	5,669	43,366
594	MAINTENANCE OF UNDERGROUND LIN	95,793	2,917	7,211	14,075	4,332	7,727	346	9,237	222	870	6,868
595	MAINTENANCE OF LINE TRANSFORME	0	330	0	0	0	1,002	31	1,233	26	0	658
596	MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	0	0	0	0	0	332,352	0	460,604	0	0	0
597	MAINTENANCE OF METERS											
598	MISCELLANEOUS DISTRIBUTION EXPENSES	11,400	393	856	1,671	515	10,721	56	14,655	103	104	681
	Sub-total	1,435,901	46,432	106,989	208,784	64,611	605,652	10,428	815,552	36,632	13,050	99,788
	Customer Accounts Expense											
901	SUPERVISION/CUSTOMER ACCTS	1,359	384	30	30	30	4,813	19	6,271	118	4	47
902	METER READING EXPENSES	4,371	1,235	95	95	95	15,473	62	20,162	380	14	152
903	RECORDS AND COLLECTION	9,832	2,778	214	214	214	34,806	139	45,353	855	32	342

Louisville Gas and Electric
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Acct. No.	Account Description		LP-TOD Pri	LP-TOD Sec	Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
904	UNCOLLECTIBLE ACCOUNTS		1,752	495	38	38	38	6,204	25	8,084	152	6	61
905	MISC CUST ACCOUNTS		534	151	12	12	12	1,892	8	2,465	46	2	19
	Sub-total		17,848	5,044	388	388	388	63,187	252	82,336	1,552	58	621
	Customer Service & Information Expense												
907	SUPERVISION		18	4	0	0	0	1,410	40	1,837	243	1	11
908	CUSTOMER ASSISTANCE EXPENSES		467	132	10	10	10	42,390	1,198	55,231	7,309	30	325
908	CUSTOMER ASSISTANCE EXP-INCENTIVES												
909	INFORMATIONAL AND INSTRUCTIONA		37	10	1	1	1	3,352	95	4,367	578	2	26
909	INFORM AND INSTRUC -LOAD MGMT												
910	MISCELLANEOUS CUSTOMER SERVICE		72	20	2	2	2	6,550	185	8,535	1,129	5	50
911	DEMONSTRATION AND SELLING EXP												
912	DEMONSTRATION AND SELLING EXP												
913	ADVERTISING EXPENSES		6	2	0	0	0	576	16	750	98	0	4
915	MDSE-JOBBING-CONTRACT												
916	MISC SALES EXPENSE												
	Sub-total		598	169	13	13	13	54,278	1,534	70,720	9,358	39	416
	General Expenses												
920	ADMIN. & GEN. SALARIES-		1,409,316	36,040	115,757	174,161	49,107	73,890	3,635	90,676	7,235	11,488	81,287
921	OFFICE SUPPLIES AND EXPENSES		697,522	17,638	57,292	86,199	24,305	36,571	1,799	44,978	3,581	5,686	40,232
922	ADMINISTRATIVE EXPENSES TRANSFERRED		-202,184	-5,170	-16,607	-24,986	-7,045	-10,600	-521	-13,037	-1,038	-1,648	-11,662
923	OUTSIDE SERVICES EMPLOYED		473,826	12,117	38,919	58,565	16,510	24,843	1,222	30,553	2,432	3,862	27,330
924	PROPERTY INSURANCE		343,166	8,766	28,337	43,419	12,352	38,275	741	50,379	924	2,840	20,349
925	INJURIES AND DAMAGES - INSURAN		228,444	5,842	18,784	28,231	7,960	11,977	589	14,731	1,173	1,862	13,176
926	EMPLOYEE BENEFITS		2,345,969	59,993	192,690	289,911	81,744	122,999	6,051	151,274	12,043	19,123	135,312
927	FRANCHISE REQUIREMENTS		2,855	73	236	361	103	316	8	419	8	24	169
928	REGULATORY COMMISSION FEES		71,730	1,832	5,923	9,076	2,562	8,000	155	10,530	193	594	4,254
929	DUPLICATE CHARGES-CR		-3,466	-89	-285	-429	-121	-182	-9	-224	-18	-28	-200
930	MISCELLANEOUS GENERAL EXPENSES		97,450	2,492	8,004	12,043	3,398	5,109	251	6,284	500	794	5,621
931	RENTS AND LEASES		140,880	3,577	11,651	17,776	5,049	13,708	298	17,928	364	1,164	8,311
935	MAINTENANCE OF GENERAL PLANT		554,878	14,090	45,890	70,016	19,885	53,992	1,172	70,613	1,434	4,584	32,732
	Sub-total		6,160,387	157,401	506,571	764,333	215,827	378,900	15,389	475,304	28,831	50,343	356,911
	TOTAL O & M EXPENSES		**78,634,424**	**1,933,859**	**6,459,989**	**9,415,402**	**2,607,114**	**3,115,202**	**175,155**	**3,703,250**	**223,096**	**627,407**	**4,406,645**
	Depreciation Expense												
	Steam Production		7,528,769	185,351	627,531	938,928	263,827	192,118	14,082	215,630	15,347	81,868	432,385
	Hydraulic Production		91,717	2,258	7,645	11,414	3,214	2,340	172	2,627	187	751	5,267
	Other Production		968,985	23,855	80,766	120,587	33,956	24,726	1,812	27,753	1,975	7,937	55,650
	Transmission - Kentucky System Property		793,087	19,525	66,105	98,697	27,792	20,238	1,483	22,715	1,617	6,496	45,548
	Transmission - Virginia Property		0	0	0	0	0	0	0	0	0	0	0
	Distribution		1,125,493	38,800	84,516	164,958	50,840	1,058,456	5,575	1,446,845	10,129	10,230	87,002
	General & Common Plant		583,143	14,807	48,228	73,582	20,898	56,742	1,232	74,210	1,507	4,818	34,400
	Intangible Plant		571,785	14,611	47,211	72,355	20,586	64,168	1,237	84,483	1,543	4,732	33,915
	TOTAL DEPRECIATION EXPENSES		**$11,662,978**	**$299,208**	**$962,001**	**$1,478,521**	**$421,113**	**$1,418,789**	**$25,594**	**$1,674,262**	**$32,305**	**$96,632**	**$694,167**
	Other Expenses												
	Regulatory Credits	-$1,556,535											
	Production		-200,921	-4,946	-16,747	-25,004	-7,041	-5,127	-376	-5,755	-410	-1,648	-11,539

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

Acct. No.	Account Description		LP-TOD Pri	LP-TOD Sec	Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
	Transmission		-261	-6	-22	-32	-9	-7	0	-7	-1	-2	-15
	Distribution		-658	-23	-49	-97	-30	-619	-3	-846	-6	-6	-51
	Accretion Expense	$1,389,410											
	Production		179,179	4,411	14,935	22,298	6,279	4,572	335	5,132	365	1,468	10,290
	Transmission		238	6	20	30	8	6	0	7	0	2	14
	Distribution		642	22	48	94	29	604	3	826	6	6	50
	Property Taxes & Other		1,942,862	49,632	160,431	245,822	69,933	216,694	4,197	285,223	5,232	16,078	115,210
	Amortization of Investment Tax Credit		429,195	10,964	35,441	54,304	15,449	47,870	927	63,008	1,156	3,552	25,451
	Gain on Disposition of Allowances		-50,237	-1,282	-4,147	-6,343	-1,803	-5,601	-109	-7,372	-137	-415	-2,974
	Interest		5,033,672	128,484	415,549	635,513	180,614	561,203	10,918	738,630	13,721	41,596	297,954
	Other Deductions												
	Total Other Expenses		$7,333,712	$187,261	$605,458	$926,586	$263,429	$819,596	$15,893	$1,078,845	$19,927	$60,632	$434,390
TOTAL EXPENSES			$97,631,114	$2,420,328	$8,027,447	$11,820,509	$3,291,657	$5,353,587	$216,642	$8,656,357	$275,328	$784,670	$5,535,202
Assignment of Innteruptible Credit			-3,875,488										
Allocation of Innteruptible Credit			591,298	15,950	19,999	81,236	12,015	0	0	0	1,078	5,933	41,880
Calculation of Taxable Income and Allocation of Income Taxes:													
	Total Operating Revenue		$100,266,170	$2,830,994	$7,781,860	$11,613,536	$3,075,165	$6,222,827	$207,196	$8,619,655	$260,300	$802,735	$5,941,047
	Operating Expenses		$89,515,092	$2,312,770	$7,648,716	$11,291,365	$3,130,138	$4,798,137	$206,103	$5,924,336	$263,102	$750,662	$5,290,733
	Interest Expense		$5,033,672	$128,484	$415,549	$635,513	$180,614	$561,203	$10,918	$738,630	$13,721	$41,596	$297,954
	Taxable Income		**$5,717,405**	**$389,740**	**-$282,405**	**-$313,342**	**-$235,586**	**$863,487**	**-$9,825**	**$1,956,689**	**$3,478**	**$10,477**	**$352,360**
	Income Taxes												
	State & Federal Income Taxes		1,773,538	120,897	-87,602	-97,199	-73,079	267,853	-3,048	606,964	1,079	3,250	109,302

Louisville Gas and Electric
Electric Cost of Service Study
(Salaries and Wages)

Acct. No.	Account Description	Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP- Pri	LP-Sec	LP-TOD Trans
	Labor O & M Expenses										
	Labor Expenses										
	Steam Power Generation Operation Expenses										
500	OPERATION SUPERVISION & ENGINEERING	$1,077,777	403,947	131,130	12,978	178,987	26,960	27,798	8,935	46,627	42,832
501	FUEL	$2,704,814	970,634	324,190	33,179	455,563	69,201	71,453	23,176	119,957	114,050
502	STEAM EXPENSES	$11,190,363	4,224,653	1,364,965	134,314	1,653,875	278,834	287,425	92,242	482,041	440,073
505	ELECTRIC EXPENSES	$528,289	198,688	64,195	6,317	87,189	13,114	13,518	4,338	22,671	20,697
506	MISC. STEAM POWER EXPENSES	$4,082,740	1,541,341	498,000	49,004	676,376	101,731	104,885	33,654	175,870	160,558
507	RENTS	$0	0	0	0	0	0	0	0	0	0
	Total Steam Power Operation Expenses	$19,581,983	$7,339,284	$2,382,480	$235,792	$3,251,991	$489,840	$505,059	$162,348	$847,166	$778,210
	Steam Power Generation Maintenance Expenses										
510	MAINTENANCE SUPERVISION & ENGINEERING	$1,482,893	533,182	177,853	18,176	249,606	37,902	39,133	12,688	65,695	62,369
511	MAINTENANCE OF STRUCTURES	$291,815	110,188	35,595	3,503	48,344	7,271	7,495	2,405	12,570	11,478
512	MAINTENANCE OF BOILER PLANT	$5,621,258	2,088,983	697,716	71,408	980,456	148,934	153,780	49,879	258,170	245,458
513	MAINTENANCE OF ELECTRIC PLANT	$1,610,447	577,916	193,023	19,755	271,243	41,203	42,543	13,799	71,423	67,905
514	MAINTENANCE OF MISC STEAM PLANT	$52,464	18,827	6,288	644	8,836	1,342	1,388	450	2,327	2,212
	Total Steam Power Generation Maintenance Expense	$9,258,874	$3,329,076	$1,110,474	$113,485	$1,558,485	$236,652	$244,338	$79,222	$410,184	$389,418
	Total Steam Power Generation Expense	$28,840,857	$10,668,339	$3,492,954	$349,276	$4,810,476	$726,492	$749,397	$241,568	$1,257,350	$1,167,627
	Hydraulic Power Generation Operation Expenses										
535	OPERATION SUPERVISION & ENGINEERING	$41,501	15,668	5,082	498	6,875	1,034	1,086	342	1,788	1,632
536	WATER FOR POWER	$0	0	0	0	0	0	0	0	0	0
537	HYDRAULIC EXPENSES	$0	0	0	0	0	0	0	0	0	0
538	ELECTRIC EXPENSES	$133,065	50,235	16,231	1,597	22,044	3,316	3,418	1,097	5,732	5,233
539	MISC. HYDRAULIC POWER EXPENSES	$10,772	4,067	1,314	129	1,785	268	277	89	464	424
540	RENTS	$0	0	0	0	0	0	0	0	0	0
	Total Hydraulic Power Operation Expenses	$185,338	$69,970	$22,607	$2,225	$30,704	$4,618	$4,760	$1,528	$7,984	$7,289
	Hydraulic Power Generation Maintenance Expenses										
541	MAINTENANCE SUPERVISION & ENGINEERING	$3,574	1,307	431	43	598	91	93	30	157	147
542	MAINTENANCE OF STRUCTURES	$28,335	10,697	3,456	340	4,694	706	728	234	1,221	1,114
543	MAINT. OF RESERVES, DAMS, AND WATERWAYS	$45,458	17,162	5,545	546	7,531	1,133	1,168	375	1,958	1,788
544	MAINTENANCE OF ELECTRIC PLANT	$126,489	45,384	15,158	1,551	21,301	3,236	3,341	1,084	5,609	5,333
545	MAINTENANCE OF MISC HYDRAULIC PLANT	$0	0	0	0	0	0	0	0	0	0
	Total Hydraulic Power Generation Maint. Expense	$203,836	$74,550	$24,590	$2,481	$34,124	$5,165	$5,330	$1,722	$8,944	$8,382
	Total Hydraulic Power Generation Expense	$389,175	$144,520	$47,197	$4,705	$64,829	$9,783	$10,090	$3,250	$16,928	$15,670
	Other Power Generation Operation Expense										
546	OPERATION SUPERVISION & ENGINEERING	$20,122	7,596	2,454	242	3,334	501	517	166	867	791
547	FUEL	$0	0	0	0	0	0	0	0	0	0
548	GENERATION EXPENSE	$183,989	69,453	22,440	2,208	30,478	4,584	4,725	1,516	7,925	7,235
549	MISC OTHER POWER GENERATION	$0	0	0	0	0	0	0	0	0	0

Louisville Gas and Electric
Electric Cost of Service Study
(Salaries and Wages)

Acct. No.	Account Description	Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP- Pri	LP-Sec	LP-TOD Trans
550	RENTS	$0	0	0	0	0	0	0	0	0	0
	Total Other Power Generation Expenses	$204,091	$77,050	$24,894	$2,450	$33,811	$5,085	$5,242	$1,682	$8,791	$8,026
Other Power Generation Maintenance Expense											
551	MAINTENANCE SUPERVISION & ENGINEERING	$15,085	5,695	1,840	181	2,499	376	387	124	650	593
552	MAINTENANCE OF STRUCTURES	$45,406	17,142	5,538	545	7,522	1,131	1,166	374	1,956	1,786
553	MAINTENANCE OF GENERATING & ELEC PLANT	$268,788	101,474	32,786	3,226	44,529	6,697	6,904	2,216	11,576	10,570
554	MAINTENANCE OF MISC OTHER POWER GEN PLT	$33,195	12,532	4,049	398	5,499	827	853	274	1,430	1,305
	Total Other Power Generation Maintenance Expense	$362,474	$136,843	$44,213	$4,351	$80,050	$9,032	$9,310	$2,988	$15,614	$14,255
	Total Other Power Generation Expense	$566,564	$213,893	$69,108	$6,800	$93,861	$14,117	$14,552	$4,670	$24,406	$22,281
	Total Production Expense	$29,796,596	$11,026,752	$3,609,259	$360,782	$4,969,165	$750,392	$774,039	$249,488	$1,298,684	$1,205,578
Purchased Power											
555	PURCHASED POWER	$0									
556	SYSTEM CONTROL AND LOAD DISPATCH	710,294	268,154	88,639	8,525	117,672	17,899	18,244	5,855	30,597	27,933
557	OTHER EXPENSES	265	100	32	3	44	7	7	2	11	10
	Total Purchased Power Labor	$710,558	$268,254	$86,672	$8,529	$117,716	$17,705	$18,251	$5,857	$30,608	$27,943
Transmission Labor Expenses											
560	OPERATION SUPERVISION AND ENG	$474,326	179,071	57,857	5,693	78,581	11,819	12,183	3,910	20,432	18,653
561	LOAD DISPATCHING	536,971	202,721	65,498	6,445	88,958	13,380	13,792	4,426	23,131	21,117
562	STATION EXPENSES	559,972	211,404	68,304	6,721	92,769	13,953	14,383	4,616	24,122	22,022
563	OVERHEAD LINE EXPENSES	7,204	2,720	879	86	1,193	179	185	59	310	283
566	MISC. TRANSMISSION EXPENSES	142,661	53,858	17,401	1,712	23,634	3,555	3,664	1,176	6,145	5,610
569	MAINTENACE OF STRUCTURES	3,759	1,419	458	45	623	94	97	31	162	148
570	MAINT OF STATION EQUIPMENT	223,429	84,350	27,253	2,682	37,015	5,567	5,739	1,842	9,625	8,787
571	MAINT OF OVERHEAD LINES	5,995	2,263	731	72	993	149	154	49	258	236
573	MAINT OF MISC. TRANSMISSION PLANT	745	281	91	9	123	19	19	8	32	29
	Total Transmission Labor Expenses	$1,955,063	$738,087	$238,473	$23,466	$323,890	$48,715	$50,216	$16,116	$84,217	$76,865
Distribution Operation Labor Expense											
580	OPERATION SUPERVISION AND ENGI	$772,745	492,999	138,663	2,909	51,306	6,161	6,472	2,254	13,612	91
581	LOAD DISPATCHING	251,408	122,222	32,477	2,663	36,195	5,258	5,251	1,850	9,277	0
582	STATION EXPENSES	194,829	94,619	25,143	2,061	28,021	4,071	4,065	1,432	7,182	0
583	OVERHEAD LINE EXPENSES	2,089,509	1,375,239	252,788	11,132	178,603	21,848	24,957	7,749	44,858	6
584	UNDERGROUND LINE EXPENSES	93,338	55,824	11,951	622	10,195	1,225	1,443	432	2,582	0
585	STREET LIGHTING EXPENSE	7,108	0	0	0	0	0	0	0	0	0
586	METER EXPENSES	2,224,315	1,514,790	613,402	830	46,307	4,965	1,337	2,320	17,083	679
588	METER EXPENSES - LOAD MANAGEMENT	0									
587	CUSTOMER INSTALLATIONS EXPENSE	0									
588	MISCELLANEOUS DISTRIBUTION EXP	1,116,394	650,350	136,707	5,190	97,504	10,289	13,007	3,649	24,300	17
589	RENTS	0									
	Total Distribution Operation Labor Expense	$8,749,448	$4,308,043	$1,211,132	$25,407	$448,130	$53,816	$56,533	$19,687	$118,893	$796

Louisville Gas and Electric
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Acct. No.	Account Description	Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP- Pri	LP-Sec	LP-TOD Trans
Distribution Maintenance Labor Expense											
590	MAINTENANCE SUPERVISION AND EN	$2,889	1,819	349	16	260	31	36	11	65	0
591	MAINTENANCE OF STRUCTURES	10,923	5,310	1,411	116	1,573	228	228	80	403	0
592	MAINTENANCE OF STATION EQUIPME	153,675	74,709	19,852	1,628	22,124	3,214	3,210	1,131	5,671	0
593	MAINTENANCE OF OVERHEAD LINES	1,868,160	1,229,555	226,009	9,953	159,683	19,531	22,313	6,928	40,104	7
594	MAINTENANCE OF UNDERGROUND LIN	276,603	165,431	35,417	1,843	30,212	3,631	4,277	1,282	7,652	1
595	MAINTENANCE OF LINE TRANSFORME	116,235	65,807	16,394	0	8,967	0	1,167	0	2,195	0
596	MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	50,878	0	0	0	0	0	0	0	0	0
597	MAINTENANCE OF METERS	0									
598	MAINTENANCE OF MISC DISTR PLANT	42,413	24,708	5,194	197	3,704	391	494	139	923	1
	Total Distribution Maintenance Labor Expense	$2,521,775	$1,567,338	$304,628	$13,752	$226,522	$27,027	$31,726	$9,571	$57,014	$8
	Total Distribution Operation and Maintenance Labor Expenses	9,271,223	5,893,381	1,515,758	39,159	674,652	80,843	88,259	29,258	175,907	804
	Transmission and Distribution Labor Expenses	11,226,266	8,631,468	1,754,230	62,625	998,542	129,558	138,474	45,373	260,124	77,689
	Production, Transmission and Distribution Labor Expenses	$41,733,441	$17,926,474	$5,450,161	$431,936	$6,085,424	$897,656	$930,764	$300,718	$1,589,416	$1,311,211
Customer Accounts Expense											
901	SUPERVISION/CUSTOMER ACCTS	$463,272	372,613	47,780	520	27,838	291	1,081	457	3,388	104
902	METER READING EXPENSES	215,848	173,608	22,262	242	12,970	136	504	213	1,569	48
903	RECORDS AND COLLECTION	1,902,071	1,529,849	196,173	2,134	114,296	1,195	4,439	1,878	13,828	427
904	UNCOLLECTIBLE ACCOUNTS	0									
905	MISC CUST ACCOUNTS	96,698	77,773	9,973	108	5,811	61	226	95	703	22
	Total Customer Accounts Labor Expense	$2,677,887	$2,153,843	$276,188	$3,004	$160,915	$1,682	$6,249	$2,644	$19,468	$601
Customer Service Expense											
907	SUPERVISION	$75,987	65,798	7,670	9	492	3	10	8	59	1
908	CUSTOMER ASSISTANCE EXPENSES	80,721	69,898	8,148	10	522	3	10	9	63	1
908	CUSTOMER ASSISTANCE EXP-LOAD MGMT	0									
909	INFORMATIONAL AND INSTRUCTIONA	1,150	995	118	0	7	0	0	0	1	0
909	INFORM AND INSTRUC -LOAD MGMT	0									
910	MISCELLANEOUS CUSTOMER SERVICE	15,640	13,543	1,579	2	101	1	2	2	12	0
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	$173,497	$150,234	$17,513	$21	$1,122	$8	$22	$18	$136	$2
	Sub-Total Labor Exp	44,584,824	20,230,551	5,743,862	434,961	6,247,461	899,344	937,035	303,381	1,609,020	1,311,814

Louisville Gas and Electric
Electric Cost of Service Study
(Salaries and Wages)

Acct. No.	Account Description	Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP- Pri	LP-Sec	LP-TOD Trans
Administrative and General Expense											
920	ADMIN. & GEN. SALARIES-	$10,137,273	4,599,830	1,305,985	96,897	1,420,488	204,484	213,054	68,980	365,844	298,268
921	OFFICE SUPPLIES AND EXPENSES	$0									
922	ADMIN. EXPENSES TRANSFERRED - CREDIT	-1,068,560	-484,863	-137,663	-10,425	-149,732	-21,554	-22,458	-7,271	-38,563	-31,440
923	OUTSIDE SERVICES EMPLOYED	0									
924	PROPERTY INSURANCE	0									
925	INJURIES AND DAMAGES - INSURAN	45,353	20,579	5,843	442	6,355	915	953	309	1,637	1,334
926	EMPLOYEE BENEFITS	0									
928	REGULATORY COMMISSION FEES	0									
929	DUPLICATE CHARGES-CR	0									
930	MISCELLANEOUS GENERAL EXPENSES	0									
931	RENTS AND LEASES	0									
935	MAINTENANCE OF GENERAL PLANT	2,117,540	888,084	258,497	22,236	316,935	45,974	48,320	15,304	82,001	66,275
	Total Administrative and General Expense	$11,231,606	$5,023,630	$1,432,662	$111,151	$1,594,046	$229,818	$239,870	$77,321	$410,918	$334,437
	Total Operation and Maintenance Expenses	$55,816,431	$25,254,181	$7,176,525	$546,112	$7,841,507	$1,129,162	$1,176,905	$380,702	$2,019,939	$1,646,251
	Operation and Maintenance Expenses Less Purchase Power	$55,816,431	$25,254,181	$7,176,525	$546,112	$7,841,507	$1,129,162	$1,176,905	$380,702	$2,019,939	$1,646,251

Louisville Gas and Electric
Electric Cost of Service Study
(Salaries and Wages)

Acct. No.	Account Description	LP-TOD Pri	LP-TOD Sec	Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
	Labor O & M Expenses											
	Labor Expenses											
	Steam Power Generation Operation Expenses											
500	OPERATION SUPERVISION & ENGINEERING	142,121	3,490	11,819	17,544	4,922	3,699	271	4,152	290	1,158	8,115
501	FUEL	377,846	9,156	31,039	44,571	12,236	10,883	798	12,215	782	2,985	20,897
502	STEAM EXPENSES	1,460,620	35,959	121,744	181,769	51,184	37,272	2,732	41,833	2,977	11,964	83,885
505	ELECTRIC EXPENSES	68,694	1,691	5,726	8,549	2,407	1,753	128	1,967	140	563	3,945
506	MISC. STEAM POWER EXPENSES	532,899	13,119	44,418	66,317	18,674	13,566	997	15,263	1,086	4,365	30,605
507	RENTS	0	0	0	0	0	0	0	0	0	0	0
	Total Steam Power Operation Expenses	$2,582,181	$63,416	$214,746	$318,750	$89,423	$67,205	$4,926	$75,430	$5,277	$21,034	$147,448
	Steam Power Generation Maintenance Expenses											
510	MAINTENANCE SUPERVISION & ENGINEERING	206,641	5,010	16,984	24,423	6,711	5,928	435	6,653	428	1,634	11,444
511	MAINTENANCE OF STRUCTURES	38,089	938	3,175	4,740	1,335	972	71	1,091	78	312	2,187
512	MAINTENANCE OF BOILER PLANT	813,195	19,706	66,802	95,925	26,335	23,422	1,717	26,289	1,684	6,424	44,975
513	MAINTENANCE OF ELECTRIC PLANT	224,970	5,452	18,481	26,538	7,285	6,480	475	7,273	466	1,777	12,442
514	MAINTENANCE OF MISC STEAM PLANT	7,329	178	602	865	237	211	15	237	15	58	405
	Total Steam Power Generation Maintenance Expense	$1,290,224	$31,283	$106,043	$152,490	$41,903	$37,013	$2,713	$41,543	$2,670	$10,205	$71,454
	Total Steam Power Generation Expense	$3,872,405	$94,699	$320,789	$471,240	$131,326	$104,218	$7,639	$116,973	$7,946	$31,240	$218,902
	Hydraulic Power Generation Operation Expenses											
535	OPERATION SUPERVISION & ENGINEERING	5,417	133	452	674	190	138	10	155	11	44	311
536	WATER FOR POWER	0	0	0	0	0	0	0	0	0	0	0
537	HYDRAULIC EXPENSES	0	0	0	0	0	0	0	0	0	0	0
538	ELECTRIC EXPENSES	17,368	428	1,448	2,161	609	443	32	497	35	142	997
539	MISC. HYDRAULIC POWER EXPENSES	1,406	35	117	175	49	36	3	40	3	12	81
540	RENTS	0	0	0	0	0	0	0	0	0	0	0
	Total Hydraulic Power Operation Expenses	$24,191	$596	$2,016	$3,011	$848	$617	$45	$893	$49	$198	$1,389
	Hydraulic Power Generation Maintenance Expenses											
541	MAINTENANCE SUPERVISION & ENGINEERING	487	12	40	59	16	13	1	15	1	4	27
542	MAINTENANCE OF STRUCTURES	3,696	91	308	460	130	94	7	108	8	30	212
543	MAINT. OF RESERVES, DAMS, AND WATERWAYS	5,933	146	495	738	208	151	11	170	12	49	341
544	MAINTENANCE OF ELECTRIC PLANT	17,667	428	1,451	2,084	572	509	37	571	37	140	977
545	MAINTENANCE OF MISC HYDRAULIC PLANT	0	0	0	0	0	0	0	0	0	0	0
	Total Hydraulic Power Generation Maint. Expense	$27,786	$877	$2,294	$3,341	$926	$768	$56	$862	$57	$222	$1,558
	Total Hydraulic Power Generation Expense	$51,977	$1,273	$4,311	$6,352	$1,774	$1,385	$102	$1,555	$107	$421	$2,947
	Other Power Generation Operation Expense											
546	OPERATION SUPERVISION & ENGINEERING	2,626	65	219	327	92	67	5	75	5	22	151
547	FUEL	0	0	0	0	0	0	0	0	0	0	0
548	GENERATION EXPENSE	24,013	591	2,001	2,988	841	613	45	688	49	197	1,379
549	MISC OTHER POWER GENERATION	0	0	0	0	0	0	0	0	0	0	0

Louisville Gas and Electric
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(Salaries and Wages)

Acct. No.	Account Description	LP-TOD Pri	LP-TOD Sec	Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
550	RENTS	0	0	0	0	0	0	0	0	0	0	0
	Total Other Power Generation Expenses	$26,639	$656	$2,220	$3,315	$933	$680	$50	$763	$54	$216	$1,530
Other Power Generation Maintenance Expense												
551	MAINTENANCE SUPERVISION & ENGINEERING	1,969	46	164	245	69	50	4	56	4	16	113
552	MAINTENANCE OF STRUCTURES	5,927	146	494	738	208	151	11	170	12	49	340
553	MAINTENANCE OF GENERATING & ELEC PLANT	35,083	864	2,924	4,366	1,229	895	66	1,005	72	287	2,015
554	MAINTENANCE OF MISC OTHER POWER GEN PLT	4,333	107	361	539	152	111	8	124	9	35	249
	Total Other Power Generation Maintenance Expense	$47,312	$1,165	$3,943	$5,888	$1,658	$1,207	$88	$1,355	$96	$388	$2,717
	Total Other Power Generation Expense	$73,951	$1,821	$6,164	$9,203	$2,591	$1,887	$138	$2,118	$151	$606	$4,247
	Total Production Expense	$3,998,333	$97,792	$331,264	$486,795	$135,691	$107,491	$7,879	$120,646	$8,204	$32,268	$226,096
Purchased Power												
555	PURCHASED POWER											
556	SYSTEM CONTROL AND LOAD DISPATCH	92,711	2,282	7,726	11,538	3,249	2,366	173	2,655	189	759	5,324
557	OTHER EXPENSES	35	1	3	4	1	1	0	1	0	0	2
	Total Purchased Power Labor	$92,746	$2,283	$7,730	$11,542	$3,250	$2,367	$173	$2,656	$189	$760	$5,326
Transmission Labor Expenses												
560	OPERATION SUPERVISION AND ENG	61,912	1,524	5,160	7,705	2,170	1,580	116	1,773	126	507	3,556
561	LOAD DISPATCHING	70,088	1,726	5,842	8,722	2,456	1,789	131	2,007	143	574	4,025
562	STATION EXPENSES	73,090	1,799	6,092	9,096	2,561	1,865	137	2,093	149	599	4,198
563	OVERHEAD LINE EXPENSES	940	23	78	117	33	24	2	27	2	8	54
566	MISC. TRANSMISSION EXPENSES	18,621	458	1,552	2,317	653	475	35	533	38	153	1,069
569	MAINTENACE OF STRUCTURES	491	12	41	61	17	13	1	14	1	4	28
570	MAINT OF STATION EQUIPMENT	29,163	718	2,431	3,629	1,022	744	55	835	59	239	1,675
571	MAINT OF OVERHEAD LINES	782	19	65	97	27	20	1	22	2	6	45
573	MAINT OF MISC. TRANSMISSION PLANT	97	2	8	12	3	2	0	3	0	1	6
	Total Transmission Labor Expenses	$255,184	$6,282	$21,270	$31,757	$8,942	$6,512	$477	$7,309	$520	$2,090	$14,655
Distribution Operation Labor Expense												
580	OPERATION SUPERVISION AND ENGI	26,897	1,002	1,973	3,850	1,201	8,255	347	11,003	1,616	244	1,889
581	LOAD DISPATCHING	24,909	619	1,876	3,661	1,127	1,026	75	1,152	36	226	1,507
582	STATION EXPENSES	19,264	479	1,452	2,834	872	795	58	892	28	175	1,167
583	OVERHEAD LINE EXPENSES	103,445	3,044	7,784	15,194	4,677	13,113	377	16,216	329	942	7,209
584	UNDERGROUND LINE EXPENSES	5,803	177	437	853	262	468	21	560	13	53	416
585	STREET LIGHTING EXPENSE	0	0	0	0	0	2,979	0	4,129	0	0	0
586	METER EXPENSES	6,247	1,765	83	147	167	0	1,911	0	11,661	52	570
586	METER EXPENSES - LOAD MANAGEMENT											
587	CUSTOMER INSTALLATIONS EXPENSE											
588	MISCELLANEOUS DISTRIBUTION EXP	48,346	1,867	3,630	7,086	2,184	45,467	239	62,150	435	439	3,737
589	RENTS											
	Total Distribution Operation Labor Expense	$234,931	$8,753	$17,236	$33,624	$10,491	$72,103	$3,029	$96,101	$14,119	$2,131	$16,495

Louisville Gas and Electric
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(Salaries and Wages)

Acct. No.	Account Description	LP-TOD Pri	LP-TOD Sec	Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
Distribution Maintenance Labor Expense												
590	MAINTENANCE SUPERVISION AND EN	147	4	11	22	7	43	1	57	0	1	10
591	MAINTENANCE OF STRUCTURES	1,082	27	81	159	49	45	3	50	2	10	65
592	MAINTENANCE OF STATION EQUIPME	15,226	378	1,146	2,238	689	627	46	704	22	138	921
593	MAINTENANCE OF OVERHEAD LINES	92,487	2,721	6,960	13,584	4,182	11,724	337	14,498	294	843	6,446
594	MAINTENANCE OF UNDERGROUND LIN	17,198	524	1,295	2,527	778	1,387	62	1,658	40	156	1,233
595	MAINTENANCE OF LINE TRANSFORME	0	172	0	0	0	521	16	641	13	0	341
596	MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	0	0	0	0	0	21,325	0	29,554	0	0	0
597	MAINTENANCE OF METERS											
598	MAINTENANCE OF MISC DISTR PLANT	1,837	83	138	269	83	1,727	9	2,361	17	17	142
	Total Distribution Maintenance Labor Expense	$127,976	$3,890	$9,631	$16,799	$5,787	$37,399	$475	$49,523	$388	$1,165	$9,159
	Total Distribution Operation and Maintenance Labor Expenses	362,907	12,642	26,867	52,422	16,278	109,502	3,503	145,624	14,507	3,296	25,654
	Transmission and Distribution Labor Expenses	818,092	18,925	48,137	84,179	25,220	116,013	3,980	152,933	15,027	5,386	40,310
	Production, Transmission and Distribution Labor Expenses	$4,709,170	$119,000	$387,131	$582,516	$164,161	$225,871	$12,033	$276,235	$23,420	$38,412	$271,732
Customer Accounts Expense												
901	SUPERVISION/CUSTOMER ACCTS	958	270	21	21	21	3,386	14	4,412	83	3	33
902	METER READING EXPENSES	446	126	10	10	10	1,577	8	2,055	39	1	15
903	RECORDS AND COLLECTION	3,927	1,110	85	85	85	13,901	55	18,113	341	13	137
904	UNCOLLECTIBLE ACCOUNTS											
905	MISC CUST ACCOUNTS	200	56	4	4	4	707	3	921	17	1	7
	Total Customer Accounts Labor Expense	$5,528	$1,562	$120	$120	$120	$19,571	$78	$25,501	$481	$18	$192
Customer Service Expense												
907	SUPERVISION	8	2	0	0	0	767	22	999	132	1	6
908	CUSTOMER ASSISTANCE EXPENSES	9	3	0	0	0	814	23	1,061	140	1	6
908	CUSTOMER ASSISTANCE EXP-LOAD MGMT											
909	INFORMATIONAL AND INSTRUCTIONA	0	0	0	0	0	12	0	15	2	0	0
909	INFORM AND INSTRUC -LOAD MGMT											
910	MISCELLANEOUS CUSTOMER SERVICE	2	0	0	0	0	158	4	206	27	0	1
911	DEMONSTRATION AND SELLING EXP											
912	DEMONSTRATION AND SELLING EXP											
913	WATER HEATER - HEAT PUMP PROGRAM											
915	MDSE-JOBBING-CONTRACT											
916	MISC SALES EXPENSE											
	Total Customer Service Labor Expense	$19	$5	$0	$0	$0	$1,750	$49	$2,280	$302	$1	$13
	Sub-Total Labor Exp	4,714,717	120,568	387,252	582,636	164,282	247,192	12,161	304,017	24,202	38,431	271,937

Louisville Gas and Electric
Electric Cost of Service Study
(Salaries and Wages)

Acct. No.	Account Description	LP-TOD Pri	LP-TOD Sec	Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
Administrative and General Expense												
920	ADMIN. & GEN. SALARIES-	1,071,988	27,414	88,050	132,474	37,353	56,204	2,765	69,124	5,503	8,738	61,831
921	OFFICE SUPPLIES AND EXPENSES											
922	ADMIN. EXPENSES TRANSFERRED - CREDIT	-112,897	-2,890	-9,281	-13,964	-3,937	-5,924	-291	-7,286	-580	-921	-6,517
923	OUTSIDE SERVICES EMPLOYED											
924	PROPERTY INSURANCE											
925	INJURIES AND DAMAGES - INSURAN	4,796	123	394	593	167	251	12	309	25	39	277
926	EMPLOYEE BENEFITS											
928	REGULATORY COMMISSION FEES											
929	DUPLICATE CHARGES-CR											
930	MISCELLANEOUS GENERAL EXPENSES											
931	RENTS AND LEASES											
935	MAINTENANCE OF GENERAL PLANT	238,675	6,061	19,739	30,116	8,553	23,224	504	30,373	617	1,972	14,079
	Total Administrative and General Expense	$1,202,461	$30,707	$98,901	$149,219	$42,136	$73,755	$2,990	$92,521	$5,564	$9,828	$69,669
	Total Operation and Maintenance Expenses	$5,917,179	$151,275	$486,153	$731,856	$206,418	$320,947	$15,151	$396,537	$29,767	$48,259	$341,606
	Operation and Maintenance Expenses Less Purchase Power	$5,917,179	$151,275	$486,153	$731,856	$206,418	$320,947	$15,151	$396,537	$29,767	$48,259	$341,606

Louisville Gas and Electric
Electric Cost of Service Study
(Revenue)

Acct. No.	Account Description	Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP- Pri	LP-Sec	LP-TOD Trans
REVENUE											
	Sales to Ultimate Consumers	$780,783,699	314,219,675	113,888,416	8,326,142	127,291,267	16,194,022	18,050,768	5,977,441	32,185,784	23,067,091
	Rate Refunds	-$9,763,357	-3,929,179	-1,424,100	-104,115	-1,591,720	-202,499	-225,717	-74,745	-402,469	-288,444
	Intercompany Sales	$88,772,853	31,856,530	10,640,015	1,088,955	14,951,741	2,271,212	2,345,117	780,650	3,937,034	3,743,143
	Off-System Sales	$67,472,720	27,017,862	8,396,321	771,186	11,398,017	1,571,223	1,641,257	522,420	2,893,085	2,373,039
	Brokered Sales	-$2,000,584	-717,919	-239,783	-24,541	-336,952	-51,184	-52,850	-17,142	-88,725	-84,355
	Forfeited Discounts	$2,744,200	2,266,501	308,711	3,272	49,789	6,368	7,074	8,518	46,034	33,040
	Misc Service Revenues	$863,121	741,297	121,824	0	0	0	0	0	0	0
	Rent From Electric Property	$3,037,655	1,429,853	376,091	28,061	437,807	56,466	60,210	18,833	109,167	74,995
	Other Electric Revenue	$1,071,355	438,437	150,265	11,396	171,783	22,443	24,639	8,111	43,613	32,757
	Unbilled Revenue	$785,000	315,916	114,501	8,371	127,979	16,281	18,148	6,010	32,360	23,192
	Merger Surcredit Amortization	-$1,382,146							-130,596		-397,436
	TOTAL REVENUE	$932,364,516	373,638,974	$132,330,260	$10,108,728	$152,499,710	$19,884,331	$21,888,647	$7,079,501	$38,755,862	$28,577,022

Louisville Gas and Electric
Electric Cost of Service Study
(Revenue)

Acct. No.	Account Description	LP-TOD Pri	LP-TOD Sec	Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
REVENUE												
	Sales to Ultimate Consumers	81,308,569	2351093	6,497,749	9236472	2474679	5750822	172123	8099498	240932	641268	4811908
	Rate Refunds	-1,016,728	-29399	-81,251	-115498	-30945	-71912	-2152	-101281	-3013	-8019	-60171
	Intercompany Sales	12,401,040	300,507	1,018,714	1,462,840	401,596	357,185	26,182	400,898	25,675	97,963	685,856
	Off-System Sales	8,035,718	202,656	520,343	1,004,081	225,336	148,146	10,859	166,276	15,927	69,651	489,318
	Brokered Sales	-279,470	-6,772	-22,958	-32,967	-9,050	-8,050	-590	-9,035	-579	-2,208	-15,456
	Forfeited Discounts	14,892	0	0	0	0	0	0	0	0	0	0
	Misc Service Revenues	0	0	0	0	0	0	0	0	0	0	0
	Rent From Electric Property	278,302	7,357	15,912	36,167	7,589	33,754	368	45,363	797	2,525	18,038
	Other Electric Revenue	114,060	3,188	8,969	13,153	3,472	7,100	233	9,792	318	909	6,716
	Unbilled Revenue	81,748	2,364	6,533	9,286	2,488	5,762	173	8,143	242	645	4,838
	Merger Surcredit Amortization	-671,962		-182,152								
	TOTAL REVENUE	$100,266,170	$2,830,994	$7,761,860	$11,613,536	$3,075,165	$6,222,827	$207,196	$8,619,655	$280,300	$802,735	$5,941,047

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

Acct. No.	Account Description	Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP- Pri	LP-Sec	LP-TOD Trans
1	Energy loss adjusted	$13,418,256,759	$4,815,200,674	$1,608,266,956	$164,598,454	$2,259,996,003	$343,299,768	$354,470,845	$114,974,363	$595,093,351	$565,788,147
2	Energy @ meter	$12,671,329,647	$4,518,362,613	$1,509,123,731	$157,715,440	$2,120,676,289	$328,944,000	$332,619,135	$110,166,480	$558,408,226	$552,708,000
3	Monthly Bills	$5,890,668	$4,301,388	$501,420	$600	$32,138	$168	$824	$528	$3,888	$60
4	Average Customers (Bills/12)	$490,889	$358,449	$41,785	$50	$2,678	$14	$52	$44	$324	$5
5	Average Customers (Lighting = Lights)	$490,889	$358,449	$41,785	$50	$2,678	$14	$52	$44	$324	$5
6 Cust05	Weighted Average Customers (Lighting = 9 Lights)	$446,662	$358,449	$45,964	$500	$26,780	$280	$1,040	$440	$3,240	$100
7 Cust04	Street Lighting	$57,069,712									
8 Cust01	Average Customers	$490,889	$358,449	$41,785	$50	$2,678	$14	$52	$44	$324	$5
9 Cust06	Average Customers (Lighting = 9 Lights Per Customer)	$413,953	$358,449	$41,785	$50	$2,678	$14	$52	$44	$324	$5
10 Cust07	Average Secondary Customers	$413,043	$358,449	$41,785	$0	$2,678	$0	$52	$0	$324	$0
11 Cust08	Average Primary Customers	$413,203	$358,449	$41,785	$50	$2,678	$14	$52	$44	$324	$0
12	Year End Customers	$490,889	$358,449	$41,785	$50	$2,678	$14	$52	$44	$324	$5
13	Year End Customers (Lighting = Lights)	$490,889	$358,449	$41,785	$50	$2,678	$14	$52	$44	$324	$5
14 YECust05	Weighted Year End Customers (Lighting =9 Lights Per Customer)	$446,327	$358,449	$45,964	$500	$26,780	$280	$1,040	$440	$3,240	$100
15 YECust04	Street Lighting (Plant-In-Service balance)	$67,121,503			$0						
16 YECust01	Year End Customers	$490,889	$358,449	$41,785	$50	$2,678	$14	$52	$44	$324	$5
17 YECust06	Year End Customers (Lighting = 9 Lights per Customer)	$413,208	$358,449	$41,785	$50	$2,678	$14	$52	$44	$324	$5
18 YECust07	Year End Secondary Customers	$413,043	$358,449	$41,785	$0	$2,678	$0	$52		$324	
19 YECust08	Year End Primary Customers	$413,208	$358,449	$41,785	$50	$2,678	$14	$52	$44	$324	$5
20 NCP	Maximum Class Non-Coincident Peak Demands	$2,961,081	$1,400,160	$372,056	$30,505	$414,648	$60,243	$60,158	$21,194	$106,278	$80,977
21 C01	Primary Distribution Plant – Average Number of Customers	1.00000000	0.66748863	0.10112460	0.00012101	0.00648107	0.00003388	0.00012585	0.00010649	0.00078412	0.00000000
22 C02	Customer Services – Weighted cost of Services	1.00000000	0.73202800	0.11577400	0.00000000	0.12669100	0.00000000	0.00244700	0.00000000	0.02087600	0.00000000
23 C03	Meter Costs – Weighted Cost of Meters	1.00000000	0.68101428	0.27577133	0.00037300	0.02081846	0.00223196	0.00060092	0.00104301	0.00768024	0.00030524
24 C04	Lighting Systems -- Lighting Customers	1.00000000	0.00000000	0.00000000	0.00000000	0.00000000	0.00000000	0.00000000	0.00000000	0.00000000	0.00000000
25 C05	Meter Reading and Billing – Weighted Cost	1.00000000	0.80430708	0.10313537	0.00112163	0.06009040	0.00062828	0.00233361	0.00098730	0.00727009	0.00022439
26 C06	Marketing/Economic Development	1.00000000	0.86591715	0.10094141	0.00012079	0.00646933	0.00003382	0.00012562	0.00010629	0.00078270	0.00001208
27 R01	Rev	780783899	314219675	113886418	5326142	127291267	16194022	18050768	5977441	32185764	23067091
28 NCPP	Maximum Class Demands (Primary)	$2,880,104	$1,400,160	$372,056	$30,505	$414,648	$60,243	$60,158	$21,164	$106,278	$0
29 SICD	Sum of the Individual Customer Demands (Secondary)	$4,780,839	$3,306,511	$742,883		$490,284		$65,042		$121,385	
30 SCP	Summer Peak Period Demand Allocator	$2,681,053	$1,252,814	$354,353	$28,776	$408,593	$58,205	$59,428	$17,905	$99,082	$68,841
31 WCP	Winter Peak Period Demand Allocator	$2,259,111	$992,115	$280,238	$23,087	$408,593	$44,604	$48,745	$15,359	$99,082	$62,104
32 BDEM	Base Demand Allocator	$1,527,581	$548,179	$163,091	$18,738	$257,288	$39,082	$40,354	$13,089	$67,747	$64,411
33 PPWDRA	Production Residual Winter Demand Allocator	$2,259,111	$992,115	$280,238	$23,087	$408,593	$44,604	$48,745	$15,359	$99,082	$62,104
34 PPWDA	Production Winter Demand Allocator	$36,437,515	$16,001,960	$4,681,289	$372,373	$6,590,253	$719,424	$788,215	$247,727	$1,598,107	$1,001,684
35 PPSDRA	Production Residual Summer Demand Allocator	$2,681,053	$1,252,814	$354,353	$28,776	$408,593	$58,205	$59,428	$17,905	$99,082	$68,841
36 PPSDA	Production Summer Demand Allocator	$24,112,391	$11,267,342	$3,186,919	$258,801	$3,874,733	$523,474	$534,473	$161,031	$891,107	$619,130
37 PPBDRA	Production Residual Base Demand Allocator	$1,527,579	$548,179	$163,091	$18,738	$257,286	$39,082	$40,354	$13,089	$67,747	$64,411
38 PPBDA	Production Base Demand Allocator	$30,612,253	$10,985,342	$3,669,081	$376,513	$5,155,928	$783,200	$808,686	$262,301	$1,357,639	$1,290,778
39 SDALL	Distribution O&M	$706,478,040	$489,324,850	$83,751,469	$2,633,143	$50,387,823	$5,152,496	$5,503,894	$1,834,633	$12,233,612	$2,808
40 OREV	Total Other Revenue allocator	$7,476,653	$3,059,718	$1,048,651	$79,528	$1,198,818	$156,619	$171,949	$56,607	$304,361	$228,601
41 FDIS	Forfeited Discounts	$2,744,186	$2,266,489	$308,710	$3,272	$49,789	$6,368	$7,074	$8,618	$46,034	$33,040
42 MISCR	Misc Revenue Allocator	$863,121	$741,297	$121,824	$0	$0	$0	$0	$0	$0	$0
43 OSSALL	Off-System Sales Allocator	$164,244,989	$61,763,773	$19,194,281	$1,762,957	$28,056,263	$3,591,869	$3,751,970	$1,194,271	$6,613,692	$5,424,851
44 INTCRE	Interruptible Credit Allocator (Winter & Summer Peak Prod Plant)	$1,548,745,217	$697,494,096	$201,252,982	$16,144,167	$262,557,773	$31,790,844	$33,780,555	$10,455,219	$63,669,102	$41,457,181
45 OMLF	O&M less fuel	$167,758,283	$88,640,199	$21,639,929	$1,328,428	$21,155,384	$2,658,755	$2,822,608	$900,072	$5,201,947	$3,378,813
46	Base Rate Revenue at Current Rates	$741,330,322	$299,728,700	$109,984,799	$7,840,189	$121,065,621	$15,241,445	$17,124,072	$5,884,983	$30,757,406	$20,696,994
47 VDTREV	VDT Revenue	-$7,375,617	-$2,969,742	-$1,075,876	-$77,877	-$1,203,468	-$152,191	-$171,164	-$58,189	-$304,077	-$216,032
48 MSCREV	Merger Surcredit Revenue	-$18,092,533	-$7,936,893	-$2,871,018	-$208,059	-$3,207,812	-$406,085	-$456,288	-$149,741	-$810,436	-$105,689
49 ECRREV	ECR Revenue	$10,161,263	$4,122,618	$1,483,566	$106,499	$1,655,825	$207,981	$238,515	$77,342	$416,589	$292,151
50 DSMREV	DSM revenue	$4,404,262	$3,792,723	$298,827	$14,073	$189,320	$49,987	$49,580	$0	$0	$0
51	Gross Production Plant	2,204,761,687	632,354,954	268,929,937	26,463,001	365,256,561	54,936,690	56,629,327	18,173,889	94,973,256	85,704,615
52	Gross Transmission Plant	255,091,069	96,303,522	31,116,211	3,061,771	42,260,208	6,356,179	6,552,017	2,102,720	10,988,412	10,031,729
53	Gross Distribution Plant	776,183,225	452,161,550	95,047,071	3,608,668	67,790,181	7,153,761	9,043,153	2,536,807	16,894,987	11,929
54	Gross Prod,, Trans, Dist. Plant	3,236,035,980	1,360,820,026	395,092,219	33,133,439	475,306,950	68,446,630	72,224,496	22,813,416	122,856,654	96,748,273
55	Dist. Overhead Lines Gross Plant	288,850,108	180,110,612	34,945,005	1,538,870	24,689,792	3,019,897	3,449,975	1,071,256	6,200,824	1,130
56	Gross Intangible Plant	21,719,246	9,267,826	2,851,734	222,381	3,190,109	459,392	484,748	153,116	824,575	649,344
57	Gross Total Plant in Service	3,411,422,531	1,464,534,813	416,502,796	34,989,477	501,496,610	72,242,287	76,215,779	24,077,102	129,631,943	102,207,128
58	Dist. Underground Lines Gross Plant	157,900,816	94,437,435	20,217,923	1,052,206	17,248,665	2,072,845	2,441,818	731,601	4,368,395	302
59	Gross General Plant	153,667,305	64,447,181	18,758,844	1,613,657	22,999,550	3,336,265	3,506,535	1,110,570	5,950,714	4,809,511
60	Labor Accts 501-507	$16,504,206	$6,935,316	$2,251,350	$222,814	$3,073,004	$462,879	$477,261	$153,411	$800,539	$735,376
61	Labor Accts 511-514	$7,775,981	$2,795,894	$932,822	$95,309	$1,308,879	$198,750	$205,205	$66,534	$344,490	$327,049
62	Labor Accts 536-540	$143,837	$54,302	$17,645	$1,726	$23,829	$3,584	$3,894	$1,186	$6,196	$5,657
63	Labor Accts 542-545	$200,262	$73,243	$24,159	$2,437	$33,526	$5,074	$5,236	$1,692	$8,788	$8,235
64	Labor Accts 561-568	5,976,702	3,613,043	1,072,489	22,498	396,824	47,655	50,060	17,433	105,281	704
65	Labor Accts 591-598	2,518,886	1,585,519	304,277	13,737	226,263	26,996	31,690	9,560	56,948	8

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

	Acct. No.	Account Description	Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP- Pri	LP-Sec	LP-TOD Trans
66		Labor Accts 500-916	44,584,824	20,230,551	5,743,862	434,961	6,247,461	899,344	937,035	303,381	1,809,020	1,311,814
67		O&M less Purchased Power	536,090,930	213,906,187	65,523,255	6,011,313	83,794,964	12,494,602	12,947,454	4,194,680	21,890,230	19,727,996
68		Dist. Lines Gross Plant	446,750,926	284,548,047	55,162,928	2,591,076	41,936,427	5,092,742	5,691,794	1,802,857	10,569,218	1,431
69		Rate Base	1,626,018,111	776,697,455	222,937,770	18,746,124	268,739,555	38,737,284	40,855,615	12,914,555	69,489,563	55,046,323
70		Gross Transformer Plant	108,478,013	80,081,096	15,300,324	0	8,368,191	0	1,089,073	0	2,048,254	0
71		Dpreciation Expense	108,263,300	46,673,705	13,219,132	1,091,365	15,719,160	2,253,340	2,383,613	751,845	4,060,589	3,145,181
72		Total Labor	55,816,431	25,254,181	7,176,525	546,112	7,841,507	1,129,162	1,176,905	380,702	2,019,939	1,646,251
73		Distribution O&M	32,779,090	20,333,051	4,855,573	154,658	2,559,838	313,407	344,326	112,476	659,768	1,978
74		Sales Revenue	760,783,699	314,219,675	113,888,416	8,328,142	127,291,267	16,194,022	16,050,768	5,977,441	32,185,764	23,067,091
75		Distribution Poles, Lines, Transform & Services	579,769,926	382,808,473	73,306,776	2,591,076	53,416,273	5,092,742	7,040,987	1,802,857	13,130,208	1,431

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

Acct. No.	Account Description	LP-TOD Pri	LP-TOD Sec	Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
1	Energy loss adjusted	$1,874,450,757	$45,422,475	$153,981,442	$221,112,251	$60,702,392	$53,989,416	$3,957,427	$60,596,772	$3,880,889	$14,807,401	$103,668,978
2	Energy @ meter	$1,796,066,850	$42,622,361	$147,542,400	$211,866,000	$58,184,000	$50,651,184	$3,713,467	$56,861,223	$3,641,648	$14,188,200	$97,279,200
3	Monthly Bills	$550	$156	$12	$12	$12	$450,984	$1,416	$587,652	$8,640	$36	$384
4	Average Customers (Bills/12)	$46	$13	$1	$1	$1	$37,582	$118	$48,971	$720	$3	$32
5	Average Customers (Lighting = Lights)	$46	$13	$1	$1	$1	$37,582	$118	$48,971	$720	$3	$32
6 Cust05	Weighted Average Customers (Lighting = 9 Lights)	$920	$260	$20	$20	$20	$3,257	$13	$4,244	$80	$3	$32
7 Cust04	Street Lighting						$23,919,846		$33,150,066			
8 Cust01	Average Customers	$46	$13	$1	$1	$1	$37,582	$118	$48,971	$720	$3	$32
9 Custo6	Average Customers (Lighting = 9 Lights Per Customer)	$46	$13	$1	$1	$1	$4,176	$118	$5,441	$720	$3	$32
10 Cust07	Average Secondary Customers	$0	$13	$0	$0	$0	$4,176	$13	$5,441	$80	$0	$32
11 Cust08	Average Primary Customers	$46	$13	$1	$1	$1	$4,176	$13	$5,441	$80	$3	$32
12	Year End Customers	$46	$13	$1	$1	$1	$37,582	$118	$48,971	$720	$3	$32
13	Year End Customers (Lighting = Lights)	$46	$13	$1	$1	$1	$37,582	$118	$48,971	$720	$3	$32
14 YECust05	Weighted Year End Customers (Lighting =9 Lights Per Customer)	$920	$260	$20	$20	$20	$3,257	$13	$4,244	$80	$80	$640
15 YECust04	Street Lighting (Plant-In-Service balance)						$28,132,656	$0	$38,988,847			
16 YECust01	Year End Customers	$46	$13	$1	$1	$1	$37,582	$118	$48,971	$720	$3	$32
17 YECust06	Year End Customers (Lighting = 9 Lights per Customer)	$46	$13	$1	$1	$1	$4,176	$13	$5,441	$80	$3	$32
18 YECust07	Year End Secondary Customers		$13				$4,176	$13	$5,441	$80	$0	$32
19 YECust08	Year End Primary Customers	$46	$13	$1	$1	$1	$4,176	$13	$5,441	$80	$3	$32
20 NCP	Maximum Class Non-Coincident Peak Demands	$285,359	$7,090	$21,485	$41,939	$12,908	$11,759	$859	$13,198	$415	$2,588	$17,264
21 C01	Primary Distribution Plant – Average Number of Customers	0.00011133	0.00003146	0.00000242	0.00000242	0.00000242	0.01010587	0.00003173	0.01316840	0.00019361	0.00000726	0.00007744
22 C02	Customer Services – Weighted cost of Services	0.00000000	0.00073000	0.00000000	0.00000000	0.00000000	0.00000000	0.00023800	0.00000000	0.00113300	0.00000000	0.00008300
23 C03	Meter Costs – Weighted Cost of Meters	0.00280831	0.00079365	0.00003745	0.00006589	0.00007493	0.00000000	0.00085911	0.00000000	0.00524245	0.00002332	0.00025645
24 C04	Lighting Systems – Lighting Customers	0.00000000	0.00000000	0.00000000	0.00000000	0.00000000	0.41913031	0.00000000	0.58086969	0.00000000	0.00000000	0.00000000
25 C05	Meter Reading and Billing – Weighted Cost	0.00206435	0.00058340	0.00004488	0.00004488	0.00004488	0.00730847	0.00002942	0.00952326	0.00017951	0.00000673	0.00007180
26 C06	Marketing/Economic Development	0.00011112	0.00003140	0.00000242	0.00000242	0.00000242	0.01008756	0.00028506	0.01314454	0.00173933	0.00000725	0.00007730
27 R01	Rev	8130856 9	2351093	6497749	9236472	2474679	5750822	172123	8099498	240932	641268	4811908
28 NCPP	Maximum Class Demands (Primary)	$285,350	$7,090	$21,485	$41,939	$12,908	$11,759	$859	$13,198	$415	$2,588	$17,264
29 SICD	Sum of the Individual Customer Demands (Secondary)		$9,550				$11,759	$859	$13,198	$415	$0	$18,953
30 SCP	Summer Peak Period Demand Allocator	$231,768	$6,402	$21,485	$40,519	$12,908	$0	$0	$0	$415	$2,423	$17,136
31 WCP	Winter Peak Period Demand Allocator	$224,978	$5,985	$0	$26,070	$0	$0	$0	$0	$415	$2,203	$15,533
32 BDEM	Base Demand Allocator	$213,394	$5,171	$17,530	$25,172	$6,911	$6,146	$451	$6,899	$442	$1,686	$11,802
33 PPWDRA	Production Residual Winter Demand Allocator	$224,978	$5,985	$0	$26,070	$0	$0	$0	$0	$415	$2,203	$15,533
34 PPWDA	Production Winter Demand Allocator	$3,628,701	$96,533	$0	$420,487	$0	$0	$0	$0	$6,694	$35,532	$250,534
35 PPSDRA	Production Residual Summer Demand Allocator	$231,768	$6,402	$21,485	$40,519	$12,908	$0	$0	$0	$415	$2,423	$17,136
36 PPSDA	Production Summer Demand Allocator	$2,084,435	$57,577	$193,228	$364,413	$116,090	$0	$0	$0	$3,732	$21,792	$154,115
37 PPBDRA	Production Residual Base Demand Allocator	$213,394	$5,171	$17,530	$25,172	$6,911	$6,146	$451	$6,899	$442	$1,686	$11,802
38 PPBDA	Production Base Demand Allocator	$4,276,350	$103,626	$351,291	$504,443	$138,466	$123,171	$9,028	$138,245	$8,854	$33,781	$236,509
39 SDALL	Distribution O&M	$24,394,934	$820,093	$1,835,339	$3,582,071	$1,102,880	$4,690,221	$106,983	$5,858,964	$138,874	$222,695	$1,870,258
40 OREV	Total Other Revenue allocator	$795,990	$22,245	$82,594	$91,792	$24,227	$49,552	$1,627	$68,337	$2,222	$6,344	$48,868
41 FDIS	Forfeited Discounts	$14,892	$0									
42 MISCR	Misc Revenue Allocator	$0	$0									
43 OSSALL	Off-System Sales Allocator	$18,369,931	$463,279	$1,189,522	$2,295,365	$515,126	$338,666	$24,824	$380,113	$36,410	$159,225	$1,118,699
44 INTCRE	Interruptible Credit Allocator (Winter & Summer Peak Prod Plant)	$146,130,576	$3,941,627	$4,942,367	$20,076,164	$2,969,343	$0	$0	$0	$266,875	$1,466,234	$10,350,103
45 OMLF	O&M less fuel	$12,968,220	$352,188	$732,888	$1,692,192	$356,986	$1,150,297	$25,353	$1,513,507	$87,622	$118,148	$839,729
46	Base Rate Revenue at Current Rates	$75,025,769	$2,233,997	$5,830,992	$8,594,227	$2,293,972	$5,677,317	$161,029	$8,049,296	$226,796	$596,933	$4,517,786
47 VDTREV	VDT Revenue	-$768,922	-$22,775	-$61,488	-$87,255	-$23,360	-$54,246	-$1,626	-$78,416	-$2,275	-$5,936	-$44,922
48 MSCREV	Merger Surcredit Revenue	-$1,090,585	-$59,145	$0	-$232,628	-$62,152	-$144,419	-$4,323	-$203,652	-$6,043	-$15,828	-$119,755
49 ECRREV	ECR Revenue	$1,041,988	$30,821	$83,520	$122,061	$32,105	$72,873	$2,182	$103,526	$3,077	$8,173	$62,058
50 DSMREV	DSM revenue	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,266	$8,684
51	Gross Production Plant	287,776,193	7,084,775	23,986,446	35,812,708	10,084,398	7,343,441	538,275	6,242,149	588,832	2,357,165	16,527,275
52	Gross Transmission Plant	33,295,724	819,709	2,775,233	4,143,533	1,166,765	849,837	62,278	953,617	67,873	272,724	1,912,207
53	Gross Distribution Plant	33,613,115	1,158,784	2,524,081	4,928,518	1,518,363	31,611,034	166,512	43,210,354	302,499	305,512	2,598,349
54	Gross Prod., Trans, Dist. Plant	354,685,032	9,063,268	29,285,760	44,882,758	12,769,526	39,804,111	767,065	52,406,120	957,004	2,935,402	21,037,831
55	Dist. Overhead Lines Gross Plant	14,300,056	420,750	1,076,111	2,100,367	646,808	1,812,686	52,178	2,241,659	45,461	130,275	996,628
56	Gross Intangible Plant	2,380,533	80,630	196,557	301,239	85,705	267,153	5,148	351,733	6,423	19,701	141,199
57	Gross Total Plant in Service	374,385,918	9,563,901	30,914,763	47,369,511	13,475,945	41,756,606	808,801	54,962,005	1,008,194	3,088,184	22,200,759
58	Dist. Underground Lines Gross Plant	9,817,425	298,995	739,016	1,442,512	444,019	791,887	35,413	946,710	22,772	89,193	703,688
59	Gross General Plant	17,320,353	439,803	1,432,446	2,185,515	620,714	1,685,342	36,587	2,204,152	44,767	143,091	1,021,729
60	Labor Accts 501-507	$2,440,060	$59,926	$202,927	$301,208	$64,501	$63,506	$4,655	$71,278	$4,986	$19,676	$139,332
61	Labor Accts 511-514	$1,083,583	$26,273	$89,059	$128,068	$35,192	$31,085	$2,279	$34,889	$2,242	$8,571	$60,010
62	Labor Accts 536-540	$18,774	$462	$1,565	$2,338	$658	$479	$35	$538	$38	$154	$1,078
63	Labor Accts 542-545	$27,299	$665	$2,254	$3,283	$910	$755	$55	$847	$56	$218	$1,530
64	Labor Accts 581-588	208,034	7,750	15,262	29,774	9,290	63,848	2,682	85,098	12,503	1,887	14,607
65	Labor Accts 591-598	127,829	3,885	9,620	18,777	5,780	37,356	474	49,467	388	1,163	9,148

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

Acct. No.	Account Description	LP-TOD Pri	LP-TOD Sec	Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
66	Labor Accts 500-916	4,714,717	120,568	387,252	582,636	164,282	247,192	12,161	304,017	24,202	38,431	271,937
67	O&M less Purchased Power	67,305,797	1,658,796	5,527,680	8,069,957	2,236,514	2,793,519	151,576	3,342,199	199,686	537,506	3,777,116
68	Dist. Lines Gross Plant	24,117,481	719,745	1,815,127	3,542,879	1,090,627	2,604,573	87,569	3,188,369	68,233	219,468	1,700,316
69	Rate Base	201,059,366	5,132,028	16,598,206	25,384,220	7,214,231	22,416,070	438,111	29,502,991	548,040	1,661,445	11,901,156
70	Gross Transformer Plant	0	160,279	0	0	0	486,331	15,239	598,221	12,483	0	318,522
71	Depreciation Expense	11,662,978	299,208	962,001	1,478,521	421,113	1,418,789	25,594	1,874,262	32,305	96,632	684,167
72	Total Labor	5,917,179	151,275	486,153	731,856	208,418	320,947	15,151	396,537	29,767	48,259	341,806
73	Distribution O&M	1,435,901	46,432	106,989	208,764	64,611	605,852	10,428	815,552	38,632	13,050	99,786
74	Sales Revenue	81,308,569	2,351,093	6,497,749	9,236,472	2,474,679	5,750,822	172,123	8,099,498	240,932	641,268	4,811,908
75	Distribution Poles, Lines, Transform & Services	24,117,481	897,954	1,815,127	3,542,879	1,090,627	3,090,904	108,673	3,788,589	108,544	219,468	2,020,877

Louisville Gas and Electric
Electric Cost of Service Study
(Allocator Percents)

Acct. No.	Account Description	Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP- Pri	LP-Sec	LP-TOD Trans
1	Energy loss adjusted	100.0000%	35.8854%	11.9857%	1.2267%	16.8427%	2.5585%	2.8417%	0.8569%	4.4350%	4.2165%
2	Energy @ meter	100.0000%	35.6582%	11.9098%	1.2447%	16.7360%	2.5950%	2.8250%	0.8694%	4.4069%	4.3619%
3	Monthly Bills	100.0000%	73.0204%	8.5121%	0.0102%	0.5455%	0.0029%	0.0106%	0.0090%	0.0660%	0.0010%
4	Average Customers (Bills/12)	100.0000%	73.0204%	8.5121%	0.0102%	0.5455%	0.0029%	0.0106%	0.0090%	0.0660%	0.0010%
5	Average Customers (Lighting = Lights)	100.0000%	73.0204%	8.5121%	0.0102%	0.5455%	0.0029%	0.0106%	0.0090%	0.0660%	0.0010%
6 Cust05	Weighted Average Customers (Lighting = 9 Lights)	100.0000%	80.4307%	10.3135%	0.1122%	6.0090%	0.0628%	0.2334%	0.0987%	0.7270%	0.0224%
7 Cust04	Street Lighting	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
8 Cust01	Average Customers	100.0000%	73.0204%	8.5121%	0.0102%	0.5455%	0.0029%	0.0106%	0.0090%	0.0660%	0.0010%
9 Cust06	Average Customers (Lighting = 9 Lights Per Customer)	100.0000%	86.5917%	10.0941%	0.0121%	0.6469%	0.0034%	0.0126%	0.0106%	0.0783%	0.0012%
10 Cust07	Average Secondary Customers	100.0000%	86.7825%	10.1164%	0.0000%	0.6484%	0.0000%	0.0126%	0.0000%	0.0784%	0.0000%
11 Cust08	Average Primary Customers	100.0000%	86.7489%	10.1125%	0.0121%	0.6481%	0.0034%	0.0126%	0.0106%	0.0784%	0.0000%
12	Year End Customers	100.0000%	73.0204%	8.5121%	0.0102%	0.5455%	0.0029%	0.0106%	0.0090%	0.0660%	0.0010%
13	Year End Customers (Lighting = Lights)	100.0000%	73.0204%	8.5121%	0.0102%	0.5455%	0.0029%	0.0106%	0.0090%	0.0660%	0.0010%
14 YECust05	Weighted Year End Customers (Lighting =9 Lights Per Customer)	100.0000%	80.3108%	10.2983%	0.1120%	6.0001%	0.0627%	0.2330%	0.0986%	0.7259%	0.0224%
15 YECust04	Street Lighting (Plant-In-Service balance)	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
16 YECust01	Year End Customers	100.0000%	73.0204%	8.5121%	0.0102%	0.5455%	0.0029%	0.0106%	0.0090%	0.0660%	0.0010%
17 YECust06	Year End Customers (Lighting = 9 Lights per Customer)	100.0000%	86.7478%	10.1123%	0.0121%	0.6481%	0.0034%	0.0126%	0.0106%	0.0784%	0.0012%
18 YECust07	Year End Secondary Customers	100.0000%	86.7825%	10.1164%	0.0000%	0.6484%	0.0000%	0.0126%	0.0000%	0.0784%	0.0000%
19 YECust08	Year End Primary Customers	100.0000%	86.7478%	10.1123%	0.0121%	0.6481%	0.0034%	0.0126%	0.0106%	0.0784%	0.0012%
20 NCP	Maximum Class Non-Coincident Peak Demands	100.0000%	47.2854%	12.5649%	1.0302%	14.0032%	2.0345%	2.0316%	0.7158%	3.5892%	2.7347%
21 C01	Primary Distribution Plant – Average Number of Customers	100.0000%	86.7489%	10.1125%	0.0121%	0.6481%	0.0034%	0.0126%	0.0106%	0.0784%	0.0000%
22 C02	Customer Services -- Weighted cost of Services	100.0000%	73.2028%	11.5774%	0.0000%	12.6691%	0.0000%	0.2447%	0.0000%	2.0876%	0.0000%
23 C03	Meter Costs – Weighted Cost of Meters	100.0000%	68.1014%	27.5771%	0.0373%	2.0816%	0.2232%	0.0801%	0.1043%	0.7680%	0.0305%
24 C04	Lighting Systems – Lighting Customers	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
25 C05	Meter Reading and Billing – Weighted Cost	100.0000%	80.4307%	10.3135%	0.1122%	6.0090%	0.0628%	0.2334%	0.0987%	0.7270%	0.0224%
26 C06	Marketing/Economic Development	100.0000%	86.5917%	10.0941%	0.0121%	0.6469%	0.0034%	0.0126%	0.0106%	0.0783%	0.0012%
27 R01	Rev	100.0000%	40.2441%	14.5862%	1.0684%	16.3030%	2.0741%	2.3119%	0.7656%	4.1222%	2.9544%
28 NCPP	Maximum Class Demands (Primary)	100.0000%	48.6149%	12.9181%	1.0592%	14.3969%	2.0917%	2.0887%	0.7359%	3.6901%	0.0000%
29 SICD	Sum of the Individual Customer Demands (Secondary)	100.0000%	69.1617%	15.5388%	0.0000%	10.2552%	0.0000%	1.3605%	0.0000%	2.5390%	0.0000%
30 SCP	Summer Peak Period Demand Allocator	100.0000%	48.7284%	13.2169%	1.0733%	15.2400%	2.1710%	2.2166%	0.6678%	3.6956%	2.5677%
31 WCP	Winter Peak Period Demand Allocator	100.0000%	43.9162%	12.8474%	1.0220%	18.0865%	1.9744%	2.1577%	0.6799%	4.3859%	2.7490%
32 BDEM	Base Demand Allocator	100.0000%	35.8854%	11.9857%	1.2266%	16.8427%	2.5584%	2.8417%	0.8568%	4.4349%	4.2165%
33 PPWDRA	Production Residual Winter Demand Allocator	100.0000%	43.9162%	12.8474%	1.0220%	18.0885%	1.9744%	2.1577%	0.6799%	4.3859%	2.7490%
34 PPWDA	Production Winter Demand Allocator	100.0000%	43.9162%	12.8474%	1.0220%	18.0865%	1.9744%	2.1577%	0.6799%	4.3859%	2.7490%
35 PPSDRA	Production Residual Summer Demand Allocator	100.0000%	46.7284%	13.2169%	1.0733%	15.2400%	2.1710%	2.2166%	0.6678%	3.6956%	2.5677%
36 PPSDA	Production Summer Demand Allocator	100.0000%	46.7284%	13.2169%	1.0733%	15.2400%	2.1710%	2.2166%	0.6678%	3.6956%	2.5677%
37 PPBDRA	Production Residual Base Demand Allocator	100.0000%	35.8854%	11.9857%	1.2267%	16.8427%	2.5585%	2.8417%	0.8569%	4.4350%	4.2165%
38 PPBDA	Production Base Demand Allocator	100.0000%	35.8854%	11.9857%	1.2267%	16.8427%	2.5585%	2.8417%	0.8569%	4.4350%	4.2165%
39 SDALL	Distribution O&M	100.0000%	70.6780%	11.8548%	0.3727%	7.1323%	0.7293%	0.9208%	0.2597%	1.7316%	0.0004%
40 OREV	Total Other Revenue allocator	100.0000%	40.9236%	14.0257%	1.0637%	16.0342%	2.0948%	2.2998%	0.7571%	4.0708%	3.0575%
41 FDIS	Forfeited Discounts	100.0000%	82.5924%	11.2496%	0.1192%	1.8144%	0.2320%	0.2578%	0.3104%	1.6775%	1.2040%
42 MISCR	Misc Revenue Allocator	100.0000%	85.8856%	14.1144%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
43 OSSALL	Off-System Sales Allocator	100.0000%	40.0426%	12.4440%	1.1430%	16.8928%	2.3287%	2.4325%	0.7743%	4.2878%	3.5170%
44 INTCRE	Interruptible Credit Allocator (Winter & Summer Peak Prod Plant)	100.0000%	45.0361%	12.9946%	1.0424%	16.9529%	2.0527%	2.1812%	0.5751%	4.1110%	2.8768%
45 OMLF	O&M less fuel	100.0000%	52.9570%	12.8964%	0.7919%	12.6106%	1.5849%	1.6825%	0.5365%	3.1008%	2.0129%
46	Base Rate Revenue at Current Rates	100.0000%	40.4309%	14.8361%	1.0576%	16.3309%	2.0560%	2.3099%	0.7669%	4.1489%	2.7919%
47 VDTREV	VDT Revenue	100.0000%	40.2643%	14.5842%	1.0559%	16.3168%	2.0634%	2.3207%	0.7618%	4.1227%	2.9290%
48 MSCREV	Merger Surcredit Revenue	100.0000%	43.8783%	15.8685%	1.1500%	17.7300%	2.2445%	2.5219%	0.8276%	4.4794%	0.5842%
49 ECRREV	ECR Revenue	100.0000%	40.5719%	14.6002%	1.0481%	16.2555%	2.0468%	2.3276%	0.7611%	4.0998%	2.8751%
50 DSMREV	DSM revenue	100.0000%	86.1148%	6.7604%	0.3195%	4.2986%	1.1350%	1.1257%	0.0000%	0.0000%	0.0000%
51	Gross Production Plant	100.0000%	37.7526%	12.1977%	1.2003%	16.5667%	2.4917%	2.5685%	0.8243%	4.3076%	3.9326%
52	Gross Transmission Plant	100.0000%	37.7526%	12.1977%	1.2003%	16.5667%	2.4917%	2.5685%	0.8243%	4.3076%	3.9326%
53	Gross Distribution Plant	100.0000%	58.2545%	12.2454%	0.4649%	8.7338%	0.9217%	1.1651%	0.3268%	2.1767%	0.0015%
54	Gross Prod., Trans. Dist. Plant	100.0000%	42.6701%	12.2091%	1.0239%	14.6879%	2.1151%	2.2319%	0.7050%	3.7965%	2.9897%
55	Dist. Overhead Lines Gross Plant	100.0000%	65.8164%	12.0980%	0.5326%	8.5476%	1.0455%	1.1944%	0.3709%	2.1467%	0.0004%
56	Gross Intangible Plant	100.0000%	42.6701%	12.2091%	1.0239%	14.6878%	2.1151%	2.2319%	0.7050%	3.7965%	2.9897%
57	Gross Total Plant in Service	100.0000%	42.5372%	12.2091%	1.0251%	14.7005%	2.1177%	2.2341%	0.7058%	3.7998%	2.9960%
58	Dist. Underground Lines Gross Plant	100.0000%	59.8061%	12.8042%	0.6664%	10.9225%	1.3128%	1.5464%	0.4633%	2.7665%	0.0002%
59	Gross General Plant	100.0000%	41.9394%	12.2074%	1.0501%	14.9871%	2.1711%	2.2819%	0.7227%	3.8725%	3.1298%
60	Labor Accts 501-507	100.0000%	37.4797%	12.1667%	1.2041%	16.8071%	2.5015%	2.5792%	0.8291%	4.3263%	3.9741%
61	Labor Accts 511-514	100.0000%	36.9555%	11.9936%	1.2257%	16.8323%	2.5556%	2.6390%	0.8556%	4.4302%	4.2059%
62	Labor Accts 536-540	100.0000%	37.7526%	12.1977%	1.2003%	16.5667%	2.4917%	2.5685%	0.8243%	4.3076%	3.9326%
63	Labor Accts 542-545	100.0000%	36.5735%	12.0638%	1.2169%	16.7410%	2.5339%	2.6147%	0.8449%	4.3880%	4.1119%
64	Labor Accts 581-588	100.0000%	63.7984%	17.9442%	0.3764%	6.6355%	0.7973%	0.8376%	0.2917%	1.7615%	0.0118%

Louisville Gas and Electric
Electric Cost of Service Study
(Allocator Percents)

	Acct. No.	Account Description	Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP- Pri	LP-Sec	LP-TOD Trans
65		Labor Accts 591-598	100.0000%	62.9452%	12.0798%	0.5453%	8.9826%	1.0718%	1.2581%	0.3795%	2.2609%	0.0003%
66		Labor Accts 500-916	100.0000%	45.3754%	12.8830%	0.9756%	14.0125%	2.0172%	2.1017%	0.6805%	3.6089%	2.9423%
67		O&M less Purchased Power	100.0000%	39.9011%	12.2224%	1.1213%	15.6307%	2.3307%	2.4152%	0.7824%	4.0833%	3.6800%
68		Dist. Lines Gross Plant	100.0000%	63.6928%	12.3476%	0.5800%	9.3870%	1.1400%	1.3188%	0.4035%	2.3658%	0.0003%
69		Rate Base	100.0000%	42.6350%	12.2090%	1.0266%	14.7172%	2.1214%	2.2374%	0.7073%	3.8055%	3.0146%
70		Gross Transformer Plant	100.0000%	73.8224%	14.1045%	0.0000%	7.7142%	0.0000%	1.0040%	0.0000%	1.8882%	0.0000%
71		Dpreciation Expense	100.0000%	43.1113%	12.2102%	1.0081%	14.5194%	2.0814%	2.2017%	0.6943%	3.7507%	2.9051%
72		Total Labor	100.0000%	45.2451%	12.8574%	0.9794%	14.0487%	2.0230%	2.1085%	0.6821%	3.6189%	2.9494%
73		Distribution O&M	100.0000%	62.0306%	14.8130%	0.4716%	7.8094%	0.9561%	1.0504%	0.3431%	2.0128%	0.0060%
74		Sales Revenue	100.0000%	40.2441%	14.5862%	1.0864%	16.3030%	2.0741%	2.3119%	0.7658%	4.1222%	2.9544%
75		Distribution Poles, Lines, Transform & Services	100.0000%	65.9909%	12.6437%	0.4469%	9.2130%	0.8784%	1.2144%	0.3109%	2.2646%	0.0002%

Louisville Gas and Electric
Electric Cost of Service Study
(Allocator Percents)

Acct. No.	Account Description	LP-TOD Pri	LP-TOD Sec	Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
1	Energy loss adjusted	13.9694%	0.3385%	1.1476%	1.6478%	0.4524%	0.4024%	0.0295%	0.4516%	0.0289%	0.1104%	0.7726%
2	Energy @ meter	14.1743%	0.3364%	1.1644%	1.6720%	0.4590%	0.3998%	0.0293%	0.4487%	0.0287%	0.1120%	0.7677%
3	Monthly Bills	0.0093%	0.0026%	0.0002%	0.0002%	0.0002%	7.6559%	0.0240%	9.9760%	0.1467%	0.0006%	0.0065%
4	Average Customers (Bills/12)	0.0094%	0.0026%	0.0002%	0.0002%	0.0002%	7.6559%	0.0240%	9.9760%	0.1467%	0.0006%	0.0065%
5	Average Customers (Lighting = Lights)	0.0094%	0.0026%	0.0002%	0.0002%	0.0002%	7.6559%	0.0240%	9.9760%	0.1467%	0.0006%	0.0065%
6 Cust05	Weighted Average Customers (Lighting = 9 Lights)	0.2064%	0.0583%	0.0045%	0.0045%	0.0045%	0.7308%	0.0028%	0.9523%	0.0180%	0.0007%	0.0072%
7 Cust04	Street Lighting	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	41.9130%	0.0000%	58.0870%	0.0000%	0.0000%	0.0000%
8 Cust01	Average Customers	0.0094%	0.0026%	0.0002%	0.0002%	0.0002%	7.6559%	0.0240%	9.9760%	0.1467%	0.0006%	0.0065%
9 Cust06	Average Customers (Lighting = 9 Lights Per Customer)	0.0111%	0.0031%	0.0002%	0.0002%	0.0002%	1.0088%	0.0285%	1.3144%	0.1739%	0.0007%	0.0077%
10 Cust07	Average Secondary Customers	0.0000%	0.0031%	0.0000%	0.0000%	0.0000%	1.0110%	0.0031%	1.3173%	0.0194%	0.0000%	0.0077%
11 Cust08	Average Primary Customers	0.0111%	0.0031%	0.0002%	0.0002%	0.0002%	1.0106%	0.0031%	1.3168%	0.0194%	0.0007%	0.0077%
12	Year End Customers	0.0094%	0.0026%	0.0002%	0.0002%	0.0002%	7.6559%	0.0240%	9.9760%	0.1467%	0.0006%	0.0065%
13	Year End Customers (Lighting = Lights)	0.0094%	0.0026%	0.0002%	0.0002%	0.0002%	7.6559%	0.0240%	9.9760%	0.1467%	0.0006%	0.0065%
14 YECust05	Weighted Year End Customers (Lighting =9 Lights Per Customer)	0.2061%	0.0583%	0.0045%	0.0045%	0.0045%	0.7297%	0.0028%	0.9509%	0.0179%	0.0134%	0.1434%
15 YECust04	Street Lighting (Plant-In-Service balance)	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	41.9130%	0.0000%	58.0870%	0.0000%	0.0000%	0.0000%
16 YECust01	Year End Customers	0.0094%	0.0026%	0.0002%	0.0002%	0.0002%	7.6559%	0.0240%	9.9760%	0.1467%	0.0006%	0.0065%
17 YECust06	Year End Customers (Lighting = 9 Lights per Customer)	0.0111%	0.0031%	0.0002%	0.0002%	0.0002%	1.0106%	0.0031%	1.3168%	0.0194%	0.0007%	0.0077%
18 YECust07	Year End Secondary Customers	0.0000%	0.0031%	0.0000%	0.0000%	0.0000%	1.0110%	0.0031%	1.3173%	0.0194%	0.0000%	0.0077%
19 YECust08	Year End Primary Customers	0.0111%	0.0031%	0.0002%	0.0002%	0.0002%	1.0106%	0.0031%	1.3168%	0.0194%	0.0007%	0.0077%
20 NCP	Maximum Class Non-Coincident Peak Demands	9.6370%	0.2394%	0.7258%	1.4163%	0.4359%	0.3971%	0.0290%	0.4457%	0.0140%	0.0874%	0.5830%
21 C01	Primary Distribution Plant – Average Number of Customers	0.0111%	0.0031%	0.0002%	0.0002%	0.0002%	1.0106%	0.0032%	1.3168%	0.0194%	0.0007%	0.0077%
22 C02	Customer Services – Weighted cost of Services	0.0000%	0.0730%	0.0000%	0.0000%	0.0000%	0.0000%	0.0238%	0.0000%	0.1133%	0.0000%	0.0083%
23 C03	Meter Costs – Weighted Cost of Meters	0.2808%	0.0794%	0.0037%	0.0066%	0.0075%	0.0000%	0.0859%	0.0000%	0.5242%	0.0023%	0.0256%
24 C04	Lighting Systems – Lighting Customers	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	41.9130%	0.0000%	58.0870%	0.0000%	0.0000%	0.0000%
25 C05	Meter Reading and Billing – Weighted Cost	0.2064%	0.0583%	0.0045%	0.0045%	0.0045%	0.7308%	0.0029%	0.9523%	0.0180%	0.0007%	0.0072%
26 C06	Marketing/Economic Development	0.0111%	0.0031%	0.0002%	0.0002%	0.0002%	1.0088%	0.0285%	1.3145%	0.1739%	0.0007%	0.0077%
27 R01	Rev	10.4137%	0.3011%	0.8322%	1.1830%	0.3169%	0.7365%	0.0220%	1.0374%	0.0309%	0.0821%	0.6163%
28 NCPP	Maximum Class Demands (Primary)	9.8078%	0.2462%	0.7460%	1.4562%	0.4482%	0.4063%	0.0298%	0.4582%	0.0144%	0.0899%	0.5994%
29 SICD	Sum of the Individual Customer Demands (Secondary)	0.0000%	0.1998%	0.0000%	0.0000%	0.0000%	0.2460%	0.0180%	0.2761%	0.0087%	0.0000%	0.3964%
30 SCP	Summer Peak Period Demand Allocator	8.6447%	0.2386%	0.8014%	1.5113%	0.4815%	0.0000%	0.0000%	0.0000%	0.0155%	0.0904%	0.6392%
31 WCP	Winter Peak Period Demand Allocator	9.9587%	0.2849%	0.0000%	1.1540%	0.0000%	0.0000%	0.0000%	0.0000%	0.0184%	0.0975%	0.6876%
32 SDEM	Base Demand Allocator	13.9694%	0.3385%	1.1476%	1.6478%	0.4524%	0.4023%	0.0295%	0.4516%	0.0289%	0.1104%	0.7726%
33 PPWDRA	Production Residual Winter Demand Allocator	9.9587%	0.2648%	0.0000%	1.1540%	0.0000%	0.0000%	0.0000%	0.0000%	0.0184%	0.0975%	0.6876%
34 PPWDA	Production Winter Demand Allocator	9.9587%	0.2649%	0.0000%	1.1540%	0.0000%	0.0000%	0.0000%	0.0000%	0.0184%	0.0975%	0.6876%
35 PPSDRA	Production Residual Summer Demand Allocator	8.6447%	0.2388%	0.8014%	1.5113%	0.4815%	0.0000%	0.0000%	0.0000%	0.0155%	0.0904%	0.6392%
36 PPSDA	Production Summer Demand Allocator	8.6447%	0.2388%	0.8014%	1.5113%	0.4815%	0.0000%	0.0000%	0.0000%	0.0155%	0.0904%	0.6392%
37 PPBDRA	Production Residual Base Demand Allocator	13.9694%	0.3385%	1.1476%	1.6478%	0.4524%	0.4024%	0.0295%	0.4516%	0.0289%	0.1104%	0.7726%
38 PPBDA	Production Base Demand Allocator	13.9694%	0.3385%	1.1476%	1.6478%	0.4524%	0.4024%	0.0295%	0.4516%	0.0289%	0.1104%	0.7726%
39 SDALL	Distribution O&M	3.4530%	0.1161%	0.2598%	0.5070%	0.1561%	0.6639%	0.0161%	0.8336%	0.0197%	0.0315%	0.2647%
40 OREV	Total Other Revenue allocator	10.6463%	0.2975%	0.8372%	1.2277%	0.3240%	0.6626%	0.0218%	0.9140%	0.0297%	0.0849%	0.6289%
41 FDIS	Forfeited Discounts	0.5427%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
42 MISCR	Misc Revenue Allocator	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0006%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
43 OSSALL	Off-System Sales Allocator	11.9096%	0.3004%	0.7712%	1.4881%	0.3340%	0.2196%	0.0161%	0.2464%	0.0236%	0.1032%	0.7252%
44 INTCRE	Interruptible Credit Allocator (Winter & Summer Peak Prod Plant)	9.4354%	0.2545%	0.3191%	1.2963%	0.1917%	0.0000%	0.0000%	0.0000%	0.0172%	0.0947%	0.6683%
45 OMUF	O&M less fuel	7.7291%	0.2099%	0.4369%	1.0087%	0.2126%	0.6857%	0.0151%	0.9022%	0.0522%	0.0704%	0.5006%
46	Base Rate Revenue at Current Rates	10.1204%	0.3013%	0.7866%	1.1593%	0.3094%	0.7858%	0.0217%	1.0858%	0.0306%	0.0805%	0.6094%
47 VDTREV	VDT Revenue	10.4252%	0.3088%	0.8334%	1.1830%	0.3167%	0.7355%	0.0220%	1.0361%	0.0309%	0.0805%	0.6091%
48 MSCREV	Merger Surcredit Revenue	6.0278%	0.3269%	0.0000%	1.2869%	0.3435%	0.7982%	0.0239%	1.1258%	0.0334%	0.0875%	0.6619%
49 ECRREV	ECR Revenue	10.2546%	0.3033%	0.8219%	1.2012%	0.3160%	0.7152%	0.0215%	1.0188%	0.0303%	0.0804%	0.6107%
50 DSMREV	DSM revenue	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0288%	0.1972%
51	Gross Production Plant	13.0525%	0.3213%	1.0879%	1.6243%	0.4574%	0.3331%	0.0244%	0.3738%	0.0266%	0.1069%	0.7496%
52	Gross Transmission Plant	13.0525%	0.3213%	1.0879%	1.6243%	0.4574%	0.3331%	0.0244%	0.3738%	0.0266%	0.1069%	0.7496%
53	Gross Distribution Plant	4.3306%	0.1493%	0.3252%	0.6347%	0.1956%	4.0726%	0.0215%	5.5670%	0.0380%	0.0394%	0.3348%
54	Gross Prod,, Trans, Dist, Plant	10.9805%	0.2801%	0.9050%	1.3870%	0.3946%	1.2300%	0.0237%	1.6195%	0.0296%	0.0907%	0.6501%
55	Dist. Overhead Lines Gross Plant	4.9507%	0.1457%	0.3725%	0.7271%	0.2239%	0.6276%	0.0181%	0.7761%	0.0157%	0.0451%	0.3450%
56	Gross Intangible Plant	10.9805%	0.2801%	0.9050%	1.3870%	0.3946%	1.2300%	0.0237%	1.6195%	0.0296%	0.0907%	0.6501%
57	Gross Total Plant in Service	10.9745%	0.2803%	0.9062%	1.3886%	0.3950%	1.2240%	0.0237%	1.6111%	0.0296%	0.0908%	0.6508%
58	Dist. Underground Lines Gross Plant	6.2175%	0.1894%	0.4680%	0.9136%	0.2812%	0.5015%	0.0224%	0.5996%	0.0144%	0.0565%	0.4457%
59	Gross General Plant	11.2713%	0.2862%	0.9322%	1.4222%	0.4039%	1.0967%	0.0238%	1.4344%	0.0291%	0.0931%	0.6649%
60	Labor Accts 501-507	13.1865%	0.3236%	1.0967%	1.6278%	0.4567%	0.3432%	0.0252%	0.3852%	0.0269%	0.1074%	0.7530%
61	Labor Accts 511-514	13.9350%	0.3379%	1.1453%	1.6470%	0.4526%	0.3998%	0.0293%	0.4487%	0.0288%	0.1102%	0.7717%
62	Labor Accts 535-540	13.0525%	0.3213%	1.0879%	1.6243%	0.4574%	0.3331%	0.0244%	0.3738%	0.0266%	0.1069%	0.7496%
63	Labor Accts 542-545	13.6315%	0.3322%	1.1256%	1.6392%	0.4542%	0.3768%	0.0276%	0.4229%	0.0281%	0.1091%	0.7641%
64	Labor Accts 581-588	3.4808%	0.1297%	0.2554%	0.4982%	0.1554%	1.0683%	0.0449%	1.4238%	0.0292%	0.0316%	0.2444%

Louisville Gas and Electric
Electric Cost of Service Study
(Allocator Percents)

Acct. No.	Account Description	LP-TOD Pri	LP-TOD Sec	Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
65	Labor Accts 591-598	5.0748%	0.1542%	0.3819%	0.7455%	0.2295%	1.4830%	0.0188%	1.9638%	0.0154%	0.0462%	0.3632%
66	Labor Accts 500-916	10.5747%	0.2704%	0.8686%	1.3068%	0.3685%	0.5644%	0.0273%	0.6819%	0.0543%	0.0862%	0.6099%
67	O&M less Purchased Power	12.5549%	0.3094%	1.0311%	1.5053%	0.4172%	0.5211%	0.0283%	0.6234%	0.0372%	0.1003%	0.7046%
68	Dist. Lines Gross Plant	5.3984%	0.1611%	0.4063%	0.7930%	0.2441%	0.5830%	0.0196%	0.7137%	0.0153%	0.0491%	0.3806%
69	Rate Base	11.0108%	0.2811%	0.9090%	1.3901%	0.3851%	1.2276%	0.0239%	1.6157%	0.0300%	0.0910%	0.6518%
70	Gross Transformer Plant	0.0000%	0.1476%	0.0000%	0.0000%	0.0000%	0.4483%	0.0140%	0.5515%	0.0115%	0.0000%	0.2936%
71	Dpreciation Expense	10.7728%	0.2764%	0.8886%	1.3657%	0.3690%	1.3105%	0.0236%	1.7312%	0.0298%	0.0893%	0.6412%
72	Total Labor	10.6011%	0.2710%	0.8710%	1.3112%	0.3698%	0.5750%	0.0271%	0.7104%	0.0533%	0.0865%	0.6120%
73	Distribution O&M	4.3605%	0.1417%	0.3284%	0.6369%	0.1971%	1.8483%	0.0318%	2.4880%	0.1118%	0.0398%	0.3044%
74	Sales Revenue	10.4137%	0.3011%	0.8322%	1.1830%	0.3169%	0.7365%	0.0220%	1.0374%	0.0309%	0.0821%	0.6163%
75	Distribution Poles, Lines, Transform & Services	4.1597%	0.1549%	0.3131%	0.6111%	0.1881%	0.5331%	0.0187%	0.6531%	0.0187%	0.0379%	0.3486%

Schedule GAW_5

LG&E
OAG Proposed Revenue Distribution

Class	Total Revenue @ Current rates 1/	LG&E Proposed: ROR @ Current Rates	LG&E Proposed: Indexed ROR	LG&E Proposed: Increase Amount 1/	LG&E Proposed: Increase Percent	LG&E Proposed: Percent Of System Average	OAG Proposed: ROR @ Current Rates	OAG Proposed: Indexed ROR	OAG Proposed: Increase Amount	OAG Proposed: Increase Percent	OAG Proposed: Percent Of System Average
R	$358,721,834	5.45%	70%	$13,673,276	3.81%	230%	7.22%	93%	$6,987,615	1.95%	118%
GS	$127,902,362	13.17%	169%	$228,601	0.18%	11%	13.61%	175%	$1,059,478	0.83%	50%
LC Pri	$9,970,639	9.89%	127%	$0	0.00%	0%	8.07%	104%	$165,183	1.66%	100%
LC Sec	$145,907,390	10.42%	134%	$0	0.00%	0%	9.99%	129%	$1,812,934	1.24%	75%
LC-TOD Pri	$18,799,071	7.47%	96%	$0	0.00%	0%	5.17%	67%	$389,305	2.07%	125%
LC-TOD Sec	$20,799,838	9.58%	123%	$0	0.00%	0%	7.26%	93%	$344,591	1.66%	100%
LP- Pri	$7,200,364	11.38%	146%	$0	0.00%	0%	9.15%	118%	$89,466	1.24%	75%
LP-Sec	$36,414,465	9.89%	127%	$0	0.00%	0%	8.62%	111%	$452,458	1.24%	75%
LP-TOD Trans	$26,234,221	8.39%	108%	($8,461)	-0.03%	-2%	4.66%	60%	$543,277	2.07%	125%
LP-TOD Pri	$93,343,802	7.16%	92%	$0	0.00%	0%	3.95%	51%	$1,933,032	2.07%	125%
LP-TOD Sec	$2,701,998	10.94%	141%	$0	0.00%	0%	7.99%	103%	$44,764	1.66%	100%
Special Contracts-A	$7,116,358	8.71%	112%	($145,782)	-2.05%	-124%	0.17%	2%	$176,845	2.49%	150%
Special Contracts-B	$10,901,714	3.67%	47%	$0	0.00%	0%	1.50%	19%	$270,913	2.49%	150%
Special Contracts-C	$2,878,344	6.36%	82%	$0	0.00%	0%	0.03%	0%	$71,528	2.49%	150%
PSL	$5,863,941	6.02%	77%	$199,009	3.39%	205%	4.29%	55%	$121,435	2.07%	125%
SLE	$193,369	11.75%	151%	$0	0.00%	0%	0.72%	9%	$4,805	2.49%	150%
OL	$9,026,923	8.71%	112%	$462,434	5.12%	309%	7.51%	97%	$149,549	1.66%	100%
TLE	$227,327	2.07%	27%	$9,376	4.12%	249%	-0.57%	-7%	$5,649	2.49%	150%
STOD-Pri	$754,388	4.24%	55%	$45,334	6.01%	363%	2.84%	37%	$15,622	2.07%	125%
STOD-Sec	$5,466,489	5.68%	73%	$287,867	5.27%	318%	3.99%	51%	$113,204	2.07%	125%
Total Company	$890,424,838	7.77%	100%	$14,751,654	1.66%	100%	7.77%	100%	$14,751,654	1.66%	100%

1/ Per Seelye Exhibit 27.

Louisville Gas and Electric
Electric Customer Cost Analysis

		Residential
Gross Plant		
	369 Services	$17,979,330
	370 Meters	$23,419,433
	Total Gross Plant	$41,398,763
Depreciation Reserve		
	Services (OVHD & UNGD)	9,168,030
	Meters	11,942,050
	Total Depreciation Reserve	$21,110,080
Total Net Plant		$20,288,882
Operation & Maintenance Expenses		
	Dist Oper - Meter	$3,827,846
	Dist Oper - Cust Installations	-$129,111
	Meter Reading	$1,702,884
	Records & Collections	$3,830,537
	Dist Maint - Meters	$0
	Total O & M Expenses	$9,232,156
Depreciation Expense		
	Services	$602,015
	Meters	$784,171
	Total Depreciation Expense	$1,386,186
Revenue Requirement		
	Interest	$497,073
	Equity return	$1,064,750
	Income Tax	$642,949
	Revenue For Return	2,204,771
	O & M Expenses	$9,232,156
	Depreciation Expense	$1,386,186
	Total Customer Revenue Rec	$12,823,113
	Number of Bills	4,301,388
	Monthly Cost	$2.98

	PCT	Cost	WGHT Cost
Debt	47.52%	5.16%	2.45%
Common	52.48%	10.00%	5.25%
Total	100.00%		7.70%

Louisville Gas and Electric
Gas CCOSS
(Summary)

Account Description	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
Operating Revenues							
Sales and Transportation	$ 93,106,470	$ 64,534,283	$ 21,745,208	$ 1,649,829	$ 200,259	$ 3,701,009	$ 1,275,882
Forfeited Discounts	$ 1,838,323	$ 1,540,850	$ 276,629	$ 20,844	$ -	$ -	$ -
Miscellaneous Revenue	$ 595,857	$ 81,937	$ 413,779	$ -	$ -	$ 100,140	$ -
Total Operating Revenues	$ 95,540,650	$ 66,157,070	$ 22,435,616	$ 1,670,673	$ 200,259	$ 3,801,149	$ 1,275,882
Pro-Forma Adjustments to Revenues							
VDT Amortization and Surcredit	$ 1,903,311	$ 1,234,925	$ 582,431	$ 57,181	$ 16,785	$ 5,272	$ 6,716
Temperature Normalization	$ 1,645,733	$ 1,218,161	$ 312,553	$ 41,506	$ 4,958	$ 44,251	$ 24,304
Year-End Customer Adjustment	$ 526,355	$ 319,390	$ 143,149	$ -	$ -	$ 63,816	$ -
Rate Switching	$ (29,168)	$ -	$ (42,032)	$ 12,864	$ -	$ -	$ -
Adjustment for special contract to electric generation	$ 4,221,720	$ 2,438,338	$ 1,024,067	$ 78,972	$ 26,112	$ 358,648	$ 295,583
Adjustment to eliminate unbilled revenues	$ (1,203,000)	$ (804,000)	$ (404,000)	$ 5,000	$ -	$ -	$ -
Eliminate VDT from rate refund acct.	$ (352,260)	$ (228,557)	$ (107,795)	$ (10,583)	$ (3,107)	$ (976)	$ (1,243)
Removal of DSM Revenues	$ (1,453,819)	$ (1,466,446)	$ 11,951	$ -	$ 131	$ 545	$ -
Total Revenue Adjustments	$ 5,258,872	$ 2,711,811	$ 1,520,324	$ 184,941	$ 44,879	$ 471,557	$ 325,360
Total Adjusted Revenue	$ 100,799,522	$ 68,868,881	$ 23,955,941	$ 1,855,614	$ 245,138	$ 4,272,706	$ 1,601,242
Expenses							
Operation and Maintenance Expenses	$ 52,256,676	$ 37,683,234	$ 10,481,642	$ 847,177	$ 105,796	$ 2,082,786	$ 1,056,040
Depreciation and Amortization Expenses	$ 19,232,812	$ 14,196,984	$ 3,558,330	$ 247,583	$ 44,789	$ 801,980	$ 383,147
Other Expenses (ITC amortization, Reg Credits, Accretion)	$ (171,937)	$ (121,408)	$ (35,085)	$ (2,592)	$ (454)	$ (8,385)	$ (4,012)
Other Taxes	$ 5,674,634	$ 3,978,512	$ 1,176,565	$ 89,565	$ 14,854	$ 279,591	$ 135,547
Total Operating Expenses	$ 76,992,185	$ 55,737,321	$ 15,181,452	$ 1,181,732	$ 164,984	$ 3,155,972	$ 1,570,723
Pro-Forma Adjustments to Expenses							
Eliminate DSM Expenses	(1,921,602)	$ (1,938,292)	$ 15,797	$ -	$ 173	$ 720	$ -
Year-End Customer Adjustment	190,929	115855	51926	0	0	23148	0
Depreciation Expenses	3,488,855	$ 2,575,350	$ 645,485	$ 44,912	$ 8,125	$ 145,480	$ 69,503
Labor Adjustment	733,940	$ 511,914	$ 155,493	$ 12,764	$ 1,742	$ 34,533	$ 17,493
Pensions/Post Retirement Benefits Adjmt. *(see Funct Assig)*							
Eliminate Advertising Expenses *(see Func Assign)*							
Rate Case Expenses	123,722	$ 89,218	$ 24,816	$ 2,006	$ 250	$ 4,931	$ 2,500
Eliminate Amort. One-Utility Costs *(see Func Assign))*							
Normalize 925 Injuries/Damages Adjmt. *(See Func Assign)*							
Adjustment for new credit facilities bank fees	617,418	$ 430,385	$ 132,860	$ 10,041	$ 1,545	$ 28,785	$ 13,803
Adjustment to annualize vehicle fuel costs	55,636	$ 40,120	$ 11,159	$ 902	$ 113	$ 2,217	$ 1,124
Total Expense Adjustments	$ 3,288,898	$ 1,824,550	$ 1,037,537	$ 70,624	$ 11,948	$ 239,816	$ 104,424
Net Income Before Income Taxes	$ 20,518,440	$ 11,307,010	$ 7,736,952	$ 603,257	$ 68,206	$ 876,918	$ (73,904)
Income Taxes	$ 3,486,533	$ 513,074	$ 1,675,527	$ 163,729	$ 42,295	$ 800,300	$ 291,608

Louisville Gas and Electric
Gas CCOSS
(Summary)

Account Description	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
Net Operating Income (Pro-Forma)	$ 17,031,907	$ 10,793,936	$ 6,061,425	$ 439,529	$ 25,911	$ 76,618	$ (365,512)
Unadjusted Net Cost Rate Base	$441,457,053	$307,727,146	$ 94,995,404	$ 7,179,082	$ 1,104,796	$ 20,581,634	$ 9,868,990
Depreciation Adjustment	$ (3,488,855)	$ (2,575,350)	$ (645,485)	$ (44,912)	$ (8,125)	$ (145,480)	$ (69,503)
Cash Woking Capital Adjustment	$ 517,847	$ 373,429	$ 103,870	$ 8,395	$ 1,048	$ 20,640	$ 10,465
Net Cost Rate Base	$438,486,045	$305,525,225	$ 94,453,789	$ 7,142,566	$ 1,097,719	$ 20,456,794	$ 9,809,952
Rate of Return – Pro-Forma	3.88%	3.53%	6.42%	6.15%	2.36%	0.37%	-3.73%

Louisville Gas and Electric
Gas CCOSS
(Rate Base)

Acct. No.	Account Description	Alloc	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		$ 61,770,449	$ 41,045,197	$ 19,155,076	$ 1,570,176	$ -	$ -	$ -
358	Asset Retire Obligations Gas Plant		$ 541,132	$ 359,571	$ 167,806	$ 13,755	$ -	$ -	$ -
	Sub-total		$ 62,311,581	$ 41,404,768	$ 19,322,882	$ 1,583,931	$ -	$ -	$ -
	Transmission Plant								
365-371	Transmission	$ 12,901,908							
	Demand		$ 12,901,908	$ 8,573,053	$ 4,000,894	$ 327,960	$ -	$ -	$ -
	Customer		$ -						
	Sub-total		$ 12,901,908	$ 8,573,053	$ 4,000,894	$ 327,960	$ -	$ -	$ -
	Distribution Plant								
374	Land and Land Rights		$ 133,743	$ 73,806	$ 34,090	$ 2,683	$ 889	$ 12,211	$ 10,065
375	Structures and Improvements		$ 729,373	$ 402,502	$ 185,913	$ 14,631	$ 4,846	$ 66,591	$ 54,891
376	Mains	$279,586,446							
	L/M Pressure								
	Demand		$208,340,477	$116,618,842	$ 55,471,558	$ 4,879,308	$ 966,334	$ 21,138,257	$ 9,266,178
	Customer		$ 36,241,631	$ 33,389,038	$ 2,827,574	$ 22,795	$ 445	$ 1,779	$ -
	H Pressure								
	Demand		$ 32,565,757	$ 17,971,308	$ 8,300,806	$ 653,242	$ 216,387	$ 2,973,210	$ 2,450,803
	Customer		$ 2,436,581	$ 2,246,136	$ 190,231	$ 1,556	$ 120	$ 516	$ 22
378	Meas. & Reg. Station Equip.- Gen.		$ 8,254,321	$ 4,555,120	$ 2,103,974	$ 165,575	$ 54,847	$ 753,608	$ 621,196
379	Meas. & Reg. Station Equip.- City Gate		$ 3,864,491	$ 2,132,607	$ 985,034	$ 77,519	$ 25,678	$ 352,823	$ 290,830
380	Services		$137,878,756	$126,896,285	$ 10,761,244	$ 100,238	$ 33,780	$ 81,431	$ 5,777
381	Meters		$ 22,084,789	$ 17,068,163	$ 3,978,641	$ 224,448	$ 75,773	$ 697,261	$ 40,504
382	Meter Installations		$ 9,381,447	$ 7,250,423	$ 1,690,096	$ 95,344	$ 32,188	$ 296,191	$ 17,206
383	House Regulators		$ 4,941,391	$ 3,818,939	$ 890,206	$ 50,219	$ 16,954	$ 156,010	$ 9,063
384	House Regulators Installations		$ 5,298,054	$ 4,094,585	$ 954,460	$ 53,844	$ 18,178	$ 167,270	$ 9,717
385	Indust. Meas. & Reg. Station Equip.		$ 159,362	$ 123,162	$ 28,710	$ 1,620	$ 547	$ 5,031	$ 292
387	Other Equipment		$ 51,112	$ 39,502	$ 9,208	$ 519	$ 175	$ 1,614	$ 94
388	Asset Retire Obligations Gas Plant - City Gate		$ 1,063	$ 587	$ 271	$ 21	$ 7	$ 97	$ 80
388	Asset Retire Obligations Gas Plant - Mains	$ 29,707							
	L/M Pressure								
	Demand		$ 22,137	$ 12,391	$ 5,894	$ 518	$ 103	$ 2,246	$ 985
	Customer		$ 3,851	$ 3,548	$ 300	$ 2	$ 0	$ 0	$ -
	H Pressure								
	Demand		$ 3,460	$ 1,909	$ 882	$ 69	$ 23	$ 316	$ 260
	Customer		$ 259	$ 239	$ 20	$ 0	$ 0	$ 0	$ 0
	Sub-total		$472,394,055	$336,699,093	$ 88,419,113	$ 6,344,151	$ 1,447,273	$ 26,706,462	$ 12,777,962

Louisville Gas and Electric
Gas CCOSS
(Rate Base)

Acct. No.	Account Description	Alloc	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
	Other Plant-In-Service								
117	Gas Stored Underground/Non-Current		$ 2,139,990	$ 1,421,979	$ 663,613	$ 54,398	$ -	$ -	$ -
301-303	Intangible Plant		$ 1,187	$ 839	$ 242	$ 18	$ 3	$ 58	$ 28
389-399	General Plant		$ 9,038,473	$ 6,382,251	$ 1,844,359	$ 136,269	$ 23,888	$ 440,800	$ 210,905
	Common Utility Plant		$ 46,796,536	$ 33,043,993	$ 9,549,138	$ 705,531	$ 123,679	$ 2,282,236	$ 1,091,958
	Sub-total		$ 57,976,186	$ 40,849,062	$ 12,057,353	$ 896,216	$ 147,570	$ 2,723,095	$ 1,302,891
TOTAL PLANT-IN-SERVICE			$605,583,729	$427,525,977	$123,800,242	$ 9,152,259	$ 1,594,842	$ 29,429,557	$ 14,080,853
Construction Work In Progress									
	Underground Storage		$ 5,807,802	$ 3,859,165	$ 1,801,005	$ 147,632	$ -	$ -	$ -
	Transmission		$ 937,105	$ 622,687	$ 290,597	$ 23,821	$ -	$ -	$ -
	Distribution Mains	$ 25,956,033							
	L/M Pressure								
	Demand		$ 19,341,754	$ 10,826,571	$ 5,149,826	$ 452,981	$ 89,712	$ 1,962,417	$ 860,246
	Customer		$ 3,364,573	$ 3,099,746	$ 262,504	$ 2,116	$ 41	$ 165	$ -
	H Pressure								
	Demand		$ 3,023,315	$ 1,668,407	$ 770,624	$ 60,645	$ 20,089	$ 276,025	$ 227,526
	Customer		$ 226,391	$ 208,525	$ 17,660	$ 144	$ 11	$ 48	$ 2
	Other Distribution		$ 29,497,248	$ 21,024,178	$ 5,521,070	$ 396,142	$ 90,371	$ 1,667,606	$ 797,882
	General		$ 502,110	$ 354,550	$ 102,459	$ 7,570	$ 1,327	$ 24,488	$ 11,716
	Common		$ 9,331,195	$ 6,588,948	$ 1,904,091	$ 140,682	$ 24,661	$ 455,076	$ 217,736
	Sub-total		$ 72,031,493	$ 48,252,777	$ 15,819,837	$ 1,231,734	$ 226,212	$ 4,385,825	$ 2,115,108
TOTAL GAS PLANT AT ORIGINAL COST			$677,615,222	$475,778,754	$139,620,079	$ 10,383,993	$ 1,821,055	$ 33,815,381	$ 16,195,961
LESS									
Depreciation Reserve									
	Underground Storage		$ 33,664,748	$ 22,369,535	$ 10,439,471	$ 855,742	$ -	$ -	$ -
	Transmission		$ 12,066,636	$ 8,018,032	$ 3,741,876	$ 306,728	$ -	$ -	$ -
	Distribution		$159,528,317	$113,703,886	$ 29,859,293	$ 2,142,431	$ 488,747	$ 9,018,820	$ 4,315,141
	General and Intangible		$ 5,750,062	$ 4,060,237	$ 1,173,338	$ 86,691	$ 15,197	$ 280,427	$ 134,173
	Common		$ 21,838,804	$ 15,420,827	$ 4,456,350	$ 329,254	$ 57,718	$ 1,065,064	$ 509,590
	Sub-total		$232,848,567	$163,572,517	$ 49,670,327	$ 3,720,847	$ 561,661	$ 10,364,311	$ 4,958,904
Other Rate Base Items									
	Customer Advances for Construction		$ 8,042,634	$ 5,724,167	$ 1,494,059	$ 108,987	$ 23,447	$ 466,130	$ 225,844
	Accum. Deferred Income Taxes		$ 51,050,223	$ 36,047,609	$ 10,417,131	$ 769,662	$ 134,921	$ 2,489,686	$ 1,191,214
	FAS 109 Deferred Income Taxes		$ 4,502,012	$ 3,178,963	$ 918,665	$ 67,875	$ 11,898	$ 219,560	$ 105,051
	Asset Retirement Obligation - Net Assets		$ 149,250	$ 104,846	$ 31,837	$ 2,385	$ 360	$ 6,643	$ 3,179
	Asset Retirement Obligation - Liabilities		$ (7,928,279)	$ (5,569,493)	$ (1,691,229)	$ (126,691)	$ (19,124)	$ (352,895)	$ (168,846)

Louisville Gas and Electric
Gas CCOSS
(Rate Base)

Acct. No.	Account Description	Alloc	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
	Asset Retirement Obligation - Regulatory Assets		$ 5,354,546	$ 3,761,486	$ 1,142,210	$ 85,564	$ 12,916	$ 238,336	$ 114,034
	Asset Retirement Obligation - Regulatory Liabilities		$ (128,566)	$ (90,316)	$ (27,425)	$ (2,054)	$ (310)	$ (5,723)	$ (2,738)
	Accum Depr. Reclassification		$ 2,424,396	$ 1,711,916	$ 494,714	$ 36,552	$ 6,407	$ 118,236	$ 56,571
PLUS									
	Materials and Supplies		$ 51,524	$ 36,382	$ 10,514	$ 777	$ 136	$ 2,513	$ 1,202
	Prepayments		$ 817,525	$ 577,271	$ 166,821	$ 12,325	$ 2,161	$ 39,870	$ 19,076
	Gas Stored Underground		$ 52,559,620	$ 34,924,790	$ 16,298,789	$ 1,336,041	$ -	$ -	$ -
	Cash Working Capital		$ 6,727,945	$ 4,851,643	$ 1,349,491	$ 109,072	$ 13,621	$ 268,155	$ 135,963
ADJUSTMENTS									
	Unamortized Debt		$ -						
	Regulatory		$ -						
	Customer Advances for Construction		$ -						
	Depreciation Adjustment		$ -						
NET COST RATE BASE			**$441,457,053**	**$307,727,146**	**$ 94,995,404**	**$ 7,179,082**	**$ 1,104,796**	**$ 20,581,634**	**$ 9,868,990**

Louisville Gas and Electric
Gas CCOSS
(Expenses)

Acct. No.	Account Description		Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
O & M Expenses									
	Labor Expenses								
807-813	Procurement Expenses	$ 588,875							
	Demand		$ 69,134	$ 36,151	$ 17,622	$ 1,387	$ 459	$ 6,312	$ 5,203
	Commodity		$ 519,741	$ 238,453	$ 122,254	$ 13,455	$ 4,180	$ 94,397	$ 47,003
	Sub-total		$ 588,875	$ 276,604	$ 139,875	$ 14,841	$ 4,640	$ 100,708	$ 52,206
	Storage Operating Expenses								
814	Operations Supervision and Engineer	$ 509,600							
	Demand		$ 141,741	$ 94,184	$ 43,954	$ 3,603	$ -	$ -	$ -
	Commodity		$ 364,859	$ 235,156	$ 114,444	$ 10,480	$ (335)	$ 3,172	$ 1,943
815	Maps and Records		$ -						
816	Well Expenses		$ 465,962	$ 309,622	$ 144,495	$ 11,845	$ -	$ -	$ -
817	Lines Expenses		$ 568,150	$ 377,524	$ 176,164	$ 14,442	$ -	$ -	$ -
818	Compressor Station Exp - Payroll		$ 1,183,131	$ 792,542	$ 371,107	$ 33,982	$ (1,085)	$ 10,284	$ 6,300
819	Compressor Station Fuel and Power		$ 785,284	$ 506,112	$ 246,310	$ 22,555	$ (720)	$ 6,826	$ 4,181
820	Measurement and Regulator Station		$ -						
821	Purification of Natural Gas		$ 1,668,277	$ 1,073,935	$ 522,653	$ 47,860	$ (1,528)	$ 14,484	$ 8,873
823	Gas losses		$ -						
824	Other Expenses		$ (1,031)	$ (685)	$ (323)	$ (30)	$ 1	$ (9)	$ (5)
825	Storage Well Royalities		$ 44,077	$ 29,288	$ 13,668	$ 1,120	$ -	$ -	$ -
826	Rents		$ 40,158	$ 26,684	$ 12,453	$ 1,021	$ -	$ -	$ -
	Sub-total		$ 5,258,587	$ 3,414,382	$ 1,644,945	$ 146,878	$ (3,886)	$ 34,757	$ 21,292
	Storage Maintenance Expenses								
830	Maintenance Super and Eng.	$ 317,059							
	Demand		$ 124,335	$ 82,618	$ 38,555	$ 3,161	$ -	$ -	$ -
	Commodity		$ 192,724	$ 124,213	$ 60,451	$ 5,536	$ (177)	$ 1,675	$ 1,026
831	Maintenance of Structures		$ -						
832	Maintenance of Reservoirs		$ 483,560	$ 321,316	$ 149,953	$ 12,292	$ -	$ -	$ -
833	Maintenance of Lines		$ 114,378	$ 76,001	$ 35,468	$ 2,907	$ -	$ -	$ -
834	Main of Compressor Station Equipment		$ 895,788	$ 577,345	$ 280,977	$ 25,728	$ (821)	$ 7,787	$ 4,770
835	Main of Meas and Reg Sta. Equip		$ 63,792	$ 42,388	$ 19,782	$ 1,622	$ -	$ -	$ -
836	Main of Purification Equip		$ 296,274	$ 190,952	$ 92,931	$ 8,510	$ (272)	$ 2,575	$ 1,578
837	Main of Other Equipment		$ 92,217	$ 61,276	$ 28,597	$ 2,344	$ -	$ -	$ -
	Sub-total		$ 2,263,065	$ 1,476,109	$ 706,715	$ 62,100	$ (1,270)	$ 12,037	$ 7,374
	Transmission Expense								
850-887	Transmission Expense		$ 1,234,372	$ 820,215	$ 382,780	$ 31,377	$ -	$ -	$ -
	Sub-total		$ 1,234,372	$ 820,215	$ 382,780	$ 31,377	$ -	$ -	$ -
	Distribution Expense								
870	Operation Supr and Engr		$ -						
871	Dist Load Dispatching		$ 354,548	$ 162,664	$ 83,397	$ 9,178	$ 2,852	$ 64,394	$ 32,064
872	Compr. Station Labor and Exp.		$ -						
873	Compr. Station Fuel and Power		$ -						
874.01	Other Mains/Serv. Expenses		$ 3,417,868	$ 2,432,592	$ 634,928	$ 46,316	$ 9,964	$ 198,081	$ 95,977
874.02	Leak Survey-Mains		$ -						
874.03	Leak Survey - Service		$ -						
874.04	Locate Main per Request		$ -						
874.05	Check Stop Box Access		$ -						
874.06	Patrolling Mains		$ -						
874.07	Check/Grease Valves		$ -						
874.08	Opr. Odor Equipment		$ -						
874.09	Locate and Inspect Valve Boxes		$ -						

Louisville Gas and Electric
Gas CCOSS
(Expenses)

Acct. No.	Account Description		Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
874.1	Cut Grass - Right of Way		$ -						
875	Meas and Reg Station Exp.- General		$ 629,659	$ 347,476	$ 180,496	$ 12,630	$ 4,184	$ 57,487	$ 47,386
876	Meas and Reg Station Exp.- Industrial		$ 316,886	$ 244,904	$ 57,068	$ 3,221	$ 1,067	$ 10,005	$ 581
877	Meas and Reg Station Exp. - City Gate		$ 161,553	$ 89,158	$ 41,181	$ 3,241	$ 1,074	$ 14,750	$ 12,159
878	Meter and House Reg. Expense		$ 18,921	$ 14,623	$ 3,409	$ 192	$ 65	$ 597	$ 35
879	Customer Installation Expense		$ 221,770	$ 171,394	$ 39,952	$ 2,254	$ 761	$ 7,002	$ 407
880	Other Expenses		$ 3,196,557	$ 2,278,355	$ 598,309	$ 42,929	$ 9,793	$ 180,716	$ 86,465
881	Rents		$ 9,659	$ 6,885	$ 1,808	$ 130	$ 30	$ 646	$ 261
	Sub-total		$ 8,327,441	$ 5,748,049	$ 1,620,568	$ 120,091	$ 29,809	$ 533,588	$ 275,335
	Distribution Maintenance Expenses								
885	Maintenance Supr and Engr		$ -						
886	Maintenance Structures		$ 536,206	$ 295,904	$ 136,676	$ 10,756	$ 3,563	$ 48,955	$ 40,353
887	Maintenance Mains	$ 6,328,362							
	L/M Pressure								
	Demand		$ 4,714,254	$ 2,838,810	$ 1,255,191	$ 110,407	$ 21,866	$ 478,309	$ 209,672
	Customer		$ 820,063	$ 755,519	$ 63,981	$ 518	$ 10	$ 40	$ -
	H Pressure								
	Demand		$ 736,886	$ 406,848	$ 187,828	$ 14,761	$ 4,896	$ 67,277	$ 55,456
	Customer		$ 55,179	$ 50,624	$ 4,304	$ 35	$ 3	$ 12	$ 1
888	Maintenance Comp. Station Equip.		$ -						
889	Maintenance Meas and Reg. General		$ 64,371	$ 35,523	$ 16,408	$ 1,291	$ 428	$ 5,877	$ 4,844
890	Maintenance Meas and Reg - Industrial		$ 98,086	$ 75,805	$ 17,670	$ 997	$ 337	$ 3,097	$ 180
891	Maintenance Meas and Reg.-City Gate		$ 264,762	$ 146,108	$ 67,486	$ 5,311	$ 1,759	$ 24,172	$ 19,925
892	Maintenance Services		$ 2,195,216	$ 2,020,361	$ 171,334	$ 1,596	$ 538	$ 1,296	$ 92
893	Maintenance Meters and House Reg.		$ -						
894	Maintenance Other Equipment		$ 255,307	$ 181,870	$ 47,766	$ 3,429	$ 762	$ 14,434	$ 6,996
	Sub-total		$ 9,740,330	$ 6,807,488	$ 1,968,664	$ 149,119	$ 34,181	$ 643,469	$ 337,429
Total O&M Expense			$ 52,256,676	$ 37,683,234	$ 10,481,642	$ 847,177	$ 105,796	$ 2,082,766	$ 1,056,040
Customer Accounts Expense									
901	Supervision		$ 538,800	$ 486,802	$ 45,924	$ 3,628	$ 323	$ 2,235	$ 89
902	Meter Reading		$ 1,732,260	$ 1,564,441	$ 147,648	$ 11,665	$ 1,038	$ 7,188	$ 285
903	Customer Records and Collection		$ 3,896,904	$ 3,518,377	$ 332,145	$ 26,241	$ 2,335	$ 16,168	$ 640
904	Uncollectible Accounts		$ 645,241	$ 582,731	$ 54,996	$ 4,345	$ 387	$ 2,677	$ 106
905	Misc. Cust Accounts Expense		$ 167,812	$ 151,555	$ 14,303	$ 1,130	$ 101	$ 699	$ 28
	Sub-total		$ 6,981,017	$ 6,304,706	$ 595,014	$ 47,009	$ 4,182	$ 28,960	$ 1,147
Customer Service & Information Expenses									
907-910	Customer Service		$ 2,677,108	$ 2,423,021	$ 224,525	$ 16,800	$ 1,292	$ 10,985	$ 485
	Sub-total		$ 2,677,108	$ 2,423,021	$ 224,525	$ 16,800	$ 1,292	$ 10,985	$ 485
Sales Expenses									
911-916	Sales Expenses		$ 29,965	$ 27,121	$ 2,513	$ 188	$ 14	$ 123	$ 5
	Sub-total		$ 29,965	$ 27,121	$ 2,513	$ 188	$ 14	$ 123	$ 5
Total - Customer Accounts - Services			$ 9,688,090	$ 8,754,847	$ 822,052	$ 63,997	$ 5,489	$ 40,067	$ 1,637
Administrative & General Expenses									
	Labor-Related								
920	Admin and General Salaries		$ 3,438,447	$ 2,396,771	$ 729,833	$ 60,202	$ 8,114	$ 161,487	$ 82,040
921	Office Supplies and Expense		$ 1,771,717	$ 1,234,976	$ 376,059	$ 31,020	$ 4,181	$ 83,209	$ 42,273
922	Admin. Expenses Transferred		$ (327,510)	$ (228,291)	$ (69,516)	$ (5,734)	$ (773)	$ (15,382)	$ (7,814)
923	Outside Services Employed		$ 1,997,349	$ 1,392,253	$ 423,951	$ 34,970	$ 4,713	$ 93,806	$ 47,658
924	Property Insurance		$ 208,312	$ 146,264	$ 42,922	$ 3,192	$ 560	$ 10,398	$ 4,979
925	Injuries and Damages		$ 579,206	$ 403,736	$ 122,940	$ 10,141	$ 1,367	$ 27,203	$ 13,820
926	Employee Pensions and Benefits		$ 5,706,590	$ 3,977,781	$ 1,211,262	$ 99,913	$ 13,466	$ 268,011	$ 136,157
927	Franchise Requirement		$ 518,035	$ 363,746	$ 109,743	$ 7,939	$ 1,392	$ 25,853	$ 12,362
928	Regulatory Commission Fee		$ 78,843	$ 55,359	$ 16,245	$ 1,208	$ 212	$ 3,935	$ 1,884
929	Duplicate Charges -Credit		$ (899,875)	$ (627,258)	$ (191,004)	$ (15,765)	$ (2,123)	$ (42,263)	$ (21,471)
930.1	General Advertising Expense		$ (29,965)	$ (21,039)	$ (6,174)	$ (456)	$ (81)	$ (1,495)	$ (716)
930.2	Misc. General Expense		$ 69,085	$ 48,142	$ 14,660	$ 1,209	$ 163	$ 3,244	$ 1,648
931	Rents		$ 345,372	$ 242,498	$ 71,163	$ 5,293	$ 928	$ 17,235	$ 8,255

Louisville Gas and Electric
Gas CCOSS
(Expenses)

Acct. No.	Account Description		Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
935	Maintenance of General Plant		$ 1,700,308	$ 1,200,622	$ 346,956	$ 25,635	$ 4,494	$ 82,923	$ 39,675
	Sub-total		$ 15,155,916	$ 10,585,559	$ 3,196,042	$ 258,774	$ 38,612	$ 718,160	$ 360,768
Depreciation Expense									
	Underground Storage Plant								
350-357	Underground Storage Plant		$ 1,362,711	$ 905,494	$ 422,576	$ 34,639	$ -	$ -	$ -
358	Asset Retire Obligations Gas Plant		$ 9,054	$ 6,016	$ 2,808	$ 230	$ -	$ -	$ -
	Sub-total		$ 1,371,765	$ 911,510	$ 425,386	$ 34,870	$ -	$ -	$ -
	Transmission Plant								
365-371	Transmission		$ 216,808	$ 144,064	$ 67,232	$ 5,511	$ -	$ -	$ -
	Sub-total		$ 216,808	$ 144,064	$ 67,232	$ 5,511	$ -	$ -	$ -
	Distribution Plant								
374	Land and Land Rights		$ 2,184	$ 1,205	$ 557	$ 44	$ 15	$ 199	$ 184
375	Structures and Improvements		$ 24,923	$ 13,754	$ 6,363	$ 500	$ 186	$ 2,275	$ 1,876
376	Mains	$ 6,050,220							
	L/M Pressure								
	Demand		$ 4,508,465	$ 2,523,819	$ 1,200,398	$ 105,588	$ 20,911	$ 457,430	$ 200,519
	Customer		$ 784,285	$ 722,535	$ 61,168	$ 493	$ 10	$ 38	$ -
	H Pressure								
	Demand		$ 704,719	$ 368,897	$ 179,628	$ 14,136	$ 4,663	$ 64,340	$ 53,035
	Customer		$ 52,771	$ 48,606	$ 4,117	$ 34	$ 3	$ 11	$ 0
378	Meas. & Reg. Station Equip.- Gen.		$ 258,001	$ 142,377	$ 65,763	$ 5,175	$ 1,714	$ 23,555	$ 19,418
379	Meas. & Reg. Station Equip.- City Gate		$ 122,383	$ 67,526	$ 31,190	$ 2,455	$ 813	$ 11,172	$ 9,209
380	Services		$ 5,852,940	$ 5,386,735	$ 456,814	$ 4,255	$ 1,434	$ 3,457	$ 245
381	Meters		$ 673,531	$ 520,536	$ 121,339	$ 6,845	$ 2,311	$ 21,285	$ 1,235
382	Meter Installations		$ 290,691	$ 224,680	$ 52,369	$ 2,954	$ 997	$ 9,178	$ 533
383	House Regulators		$ 116,500	$ 90,037	$ 20,988	$ 1,184	$ 400	$ 3,678	$ 214
384	House Regulators Installations		$ 111,104	$ 85,866	$ 20,016	$ 1,129	$ 381	$ 3,508	$ 204
385	Indust. Meas. & Reg. Station Equip.		$ 5,769	$ 4,459	$ 1,039	$ 59	$ 20	$ 182	$ 11
387	Other Equipment		$ 1,206	$ 932	$ 217	$ 12	$ 4	$ 38	$ 2
388	Asset Retire Obligations Gas Plant - City Gate		$ 2	$ 1	$ 1	$ 0	$ 0	$ 0	$ 0
388	Asset Retire Obligations Gas Plant - Mains	$ 63							
	L/M Pressure								
	Demand		$ 47	$ 26	$ 13	$ 1	$ 0	$ 5	$ 2
	Customer		$ 8	$ 7	$ 1	$ 0	$ 0	$ 0	$ -
	H Pressure								
	Demand		$ 7	$ 4	$ 2	$ 0	$ 0	$ 1	$ 1
	Customer		$ 1	$ 1	$ 0	$ 0	$ 0	$ 0	$ 0
	Sub-total		$ 13,509,497	$ 10,221,784	$ 2,221,991	$ 144,864	$ 33,661	$ 600,332	$ 288,666
	Other Plant-In-Service								
117	Gas Stored Underground/Non-Current		$ -						
301-303	Intangible Plant		$ 1,851,569	$ 1,307,431	$ 377,825	$ 27,915	$ 4,894	$ 90,300	$ 43,205
389-399	General Plant		$ 414,205	$ 292,479	$ 84,521	$ 6,245	$ 1,095	$ 20,201	$ 9,665
	Common Utility Plant		$ 1,868,968	$ 1,319,717	$ 381,375	$ 28,178	$ 4,939	$ 91,148	$ 43,611
	Sub-total		$ 4,134,742	$ 2,919,626	$ 843,721	$ 62,338	$ 10,928	$ 201,649	$ 96,481
TOTAL DEPRECIATION EXPENSE			$ 19,232,812	$ 14,198,984	$ 3,558,330	$ 247,583	$ 44,789	$ 801,980	$ 383,147
Regulatory Credits and Accretion									
	Regulatory Credits		$ (436,274)	$ (308,082)	$ (89,025)	$ (6,578)	$ (1,153)	$ (21,277)	$ (10,180)
	Accretion		$ 427,171	$ 301,634	$ 87,167	$ 6,440	$ 1,129	$ 20,833	$ 9,968
	Amortization of Income Tax Credits		$ (162,834)	$ (114,960)	$ (33,227)	$ (2,455)	$ (430)	$ (7,941)	$ (3,800)
	Sub-total		$ (171,937)	$ (121,408)	$ (35,085)	$ (2,592)	$ (454)	$ (8,385)	$ (4,012)
Taxes Other Than Income									
	Property Taxes		$ 3,776,543	$ 2,653,055	$ 778,555	$ 57,904	$ 10,155	$ 188,563	$ 90,313
	Unemployment Insurance		$ 32,504	$ 22,671	$ 6,886	$ 565	$ 77	$ 1,529	$ 775
	Federal Old Age & Survivor Insurance		$ 1,227,755	$ 856,344	$ 260,114	$ 21,352	$ 2,914	$ 57,769	$ 29,263
	Public Service Commission Fee		$ 681,570	$ 476,556	$ 140,435	$ 10,445	$ 1,832	$ 34,013	$ 16,290
	Miscellaneous		$ (45,738)	$ (32,114)	$ (9,424)	$ (701)	$ (123)	$ (2,282)	$ (1,093)
	Sub-total		$ 5,674,634	$ 3,978,512	$ 1,176,565	$ 89,565	$ 14,854	$ 279,591	$ 135,547
	Interest Expense		$ 10,397,327	$ 7,300,349	$ 2,142,330	$ 159,332	$ 27,942	$ 518,863	$ 248,511

Louisville Gas and Electric
Gas CCOSS
(Revenue)

Acct. No.	Account Description	Alloc	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
Operating Revenues									
	Sales and Transportation	REVUC	$ 93,106,470	$ 64,534,283	$ 21,745,208	$ 1,649,829	$ 200,259	$ 3,701,009	$ 1,275,882
	Forfeited Discounts	REVFD	$ 1,838,323	$ 1,540,850	$ 276,629	$ 20,844	$ -	$ -	$ -
	Miscellaneous Revenue	REVMISC	$ 595,857	$ 81,937	$ 413,779	$ -	$ -	$ 100,140	$ -
	Total Operating Revenues		$ 95,540,650	$ 66,157,070	$ 22,435,616	$ 1,670,673	$ 200,259	$ 3,801,149	$ 1,275,882
Pro-Forma Adjustments to Revenues									
	VDT Amortization and Surcredit	REVVDT	$ 1,903,311	$ 1,234,925	$ 582,431	$ 57,181	$ 16,785	$ 5,272	$ 6,716
	Temperature Normalization	REVADJ1	$ 1,645,733	$ 1,218,161	$ 312,553	$ 41,506	$ 4,958	$ 44,251	$ 24,304
	Year-End Customer Adjustment	REVADJ2	$ 526,355	$ 319,390	$ 143,149	$ -	$ -	$ 63,816	$ -
	Rate Switching	REVADJ3	$ (29,168)	$ -	$ (42,032)	$ 12,864	$ -	$ -	$ -
	Adjustment for special contract to electric generatio	RBTHP	$ 4,221,720	$ 2,438,338	$ 1,024,067	$ 78,972	$ 26,112	$ 358,648	$ 295,583
	Adjustment to eliminate unbilled revenues	REVUB	$ (1,203,000)	$ (804,000)	$ (404,000)	$ 5,000	$ -	$ -	$ -
	Eliminate VDT from rate refund acct.	REVVDT	$ (352,260)	$ (228,557)	$ (107,795)	$ (10,583)	$ (3,107)	$ (976)	$ (1,243)
	Removal of DSM Revenues	REVADJ4	$ (1,453,819)	$ (1,466,446)	$ 11,951	$ -	$ 131	$ 545	$ -
	Total Revenue Adjustments		$ 5,258,872	$ 2,711,811	$ 1,520,324	$ 184,941	$ 44,879	$ 471,557	$ 325,360
	Total Adjusted Revenue		$100,799,522	$ 68,868,881	$ 23,955,941	$ 1,855,614	$ 245,138	$ 4,272,706	$ 1,601,242

Louisville Gas and Electric
Gas CCOSS
(Allocation Amount)

Acct. No.	Account Description	Alloc	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
1	Procurement Expenses		$ 44,604,231	$ 20,464,024	$ 10,491,813	$ 1,154,680	$ 358,749	$ 8,101,129	$ 4,033,837
2	Storage		$ 24,047,389	$ 15,498,824	$ 7,542,835	$ 690,700	$ (22,051)	$ 209,030	$ 128,050
3	Transmission		$ 24,047,389	$ 15,498,824	$ 7,542,835	$ 690,700	$ (22,051)	$ 209,030	$ 128,050
4	Distribution		$ 44,604,231	$ 20,464,024	$ 10,491,813	$ 1,154,680	$ 358,749	$ 8,101,129	$ 4,033,837
5	Adjusted Deliveries		$ 47,757,220	$ 22,405,080	$ 11,210,089	$ 1,182,410	$ 368,186	$ 8,343,343	$ 4,248,113
6	Procurement Expenses		$ 590,403	$ 325,812	$ 150,490	$ 11,843	$ 3,923	$ 53,903	$ 44,432
7	Storage		$ 12,340,000	$ 8,199,677	$ 3,626,646	$ 313,677	$ -	$ -	$ -
8	Transmission		$ 12,340,000	$ 8,199,677	$ 3,826,646	$ 313,677	$ -	$ -	$ -
9	Distribution Structures		$ 590,403	$ 325,812	$ 150,490	$ 11,843	$ 3,923	$ 53,903	$ 44,432
10	High Pressure Distribution Mains		$ 590,403	$ 325,812	$ 150,490	$ 11,843	$ 3,923	$ 53,903	$ 44,432
11	Low/Medium Pressure Distribution Mains		$ 500,974	$ 325,812	$ 149,179	$ 11,062	$ 785	$ 14,136	$ -
12	High Pressure Distrib Mains (yr-end cust.)		$ 326,002	$ 300,275	$ 25,431	$ 208	$ 16	$ 69	$ 3
13	Low/Med Pres. Distrib Mains (yr-end cust.)		$ 325,929	$ 300,275	$ 25,429	$ 205	$ 4	$ 16	$ -
14	Services		$151,937,410	$139,835,124	$ 11,858,502	$ 110,458	$ 37,225	$ 89,734	$ 6,366
15	Meters		$ 46,190,089	$ 35,697,872	$ 8,321,283	$ 469,430	$ 158,478	$ 1,458,313	$ 84,713
16	Customer Count (Average)		$ 325,556	$ 299,990	$ 25,271	$ 208	$ 16	$ 68	$ 3
17	Customer Accounts		$ 6,981,017	$ 6,304,706	$ 595,014	$ 47,009	$ 4,182	$ 28,960	$ 1,147
18	Customer Service		$ 331,448	$ 299,990	$ 27,798	$ 2,080	$ 160	$ 1,360	$ 60
19	Forfeited Discounts		$ 1,838,323	$ 1,540,850	$ 276,629	$ 20,844	$ -	$ -	$ -
20	Net Income Before Income Tax		$ 20,518,438	$ 9,354,252	$ 7,048,147	$ 618,538	$ 134,681	$ 2,474,619	$ 888,201
21	Interest Expense		$ 10,397,327	$ 7,669,742	$ 2,270,850	$ 153,873	$ 15,421	$ 220,256	$ 67,185
22	Interest Adjustment		$ 330,392	$ 243,719	$ 72,160	$ 4,890	$ 490	$ 6,999	$ 2,135
23	Taxable Income		$ 9,790,719	$ 1,440,791	$ 4,705,137	$ 459,775	$ 118,770	$ 2,247,364	$ 818,881
24	Total Distribution Expense		$ 26,974,573	$ 19,453,189	$ 5,778,232	$ 391,076	$ 60,005	$ 906,068	$ 386,004
25	Meter Cost		$ 46,190,089	$ 35,697,872	$ 8,321,283	$ 469,430	$ 158,478	$ 1,456,313	$ 84,713
26	Number of Customers		$ 326,002	$ 300,275	$ 25,431	$ 208	$ 16	$ 69	$ 3
27	Services Cost		$151,937,410	$139,835,124	$ 11,858,502	$ 110,458	$ 37,225	$ 89,734	$ 6,366
28	Actual Revenue		$ 93,106,470	$ 64,534,283	$ 21,745,208	$ 1,649,829	$ 200,259	$ 3,701,009	$ 1,275,882
29	DSM Allocation		$ 1,008,572	$ 1,017,332	$ (8,291)	$ -	$ (91)	$ (378)	$ -
30	Miscellaneous Revenue Allocation		$ 595,857	$ 81,937	$ 413,779	$ -	$ -	$ 100,140	$ -
31	VDT Revenue		$ (1,876,111)	$ (1,217,277)	$ (574,108)	$ (56,364)	$ (16,545)	$ (5,197)	$ (6,620)
32	High Pressure System		$ 26,909,794	$ 15,542,281	$ 6,527,535	$ 503,380	$ 166,441	$ 2,286,070	$ 1,884,087
33	PTD Plant		$547,607,544	$386,676,915	$111,742,889	$ 8,256,043	$ 1,447,273	$ 26,706,462	$ 12,777,962
34	Dist Plant		$472,394,055	$336,699,093	$ 88,419,113	$ 6,344,151	$ 1,447,273	$ 26,706,462	$ 12,777,962
35	Mains + Services		$417,465,202	$297,121,610	$ 77,551,413	$ 5,657,139	$ 1,217,066	$ 24,195,193	$ 11,722,781
36	Depreciation Reserve		$232,848,567	$163,572,517	$ 49,670,327	$ 3,720,847	$ 561,661	$ 10,364,311	$ 4,958,904
37	O&M Expense		$ 52,256,676	$ 37,683,234	$ 10,481,642	$ 847,177	$ 105,796	$ 2,082,786	$ 1,056,040
38	Labor Excl. A&G		$ 12,166,046	$ 8,480,347	$ 2,582,324	$ 213,008	$ 28,708	$ 571,380	$ 290,278

Louisville Gas and Electric
Gas CCOSS
(Allocation Amount)

Acct. No.	Account Description	Alloc	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
39	PTD Plant + CWIP		$677,615,222	$475,778,754	$139,620,079	$ 10,383,993	$ 1,821,055	$ 33,815,381	$ 16,195,961
40	Total Labor		$ 15,313,282	$ 10,680,829	$ 3,244,289	$ 266,315	$ 36,344	$ 720,523	$ 364,961
41	Depreciation Expenses		$ 19,232,812	$ 14,196,984	$ 3,558,330	$ 247,583	$ 44,789	$ 801,980	$ 383,147
42	Rate Base		$441,457,053	$307,727,146	$ 94,995,404	$ 7,179,082	$ 1,104,796	$ 20,581,634	$ 9,868,990
43	Peak & Avg.		100.0000%	55.9751%	26.6254%	2.3420%	0.4638%	10.1460%	4.4476%

Louisville Gas and Electric
Gas CCOSS
(Allocation Percent)

Acct. No.	Account Description	Alloc	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
1	Procurement Expenses		100.0000%	45.8791%	23.5220%	2.5887%	0.8043%	18.1622%	9.0436%
2	Storage		100.0000%	64.4512%	31.3665%	2.8722%	-0.0917%	0.8692%	0.5325%
3	Transmission		100.0000%	64.4512%	31.3665%	2.8722%	-0.0917%	0.8692%	0.5325%
4	Distribution		100.0000%	45.8791%	23.5220%	2.5887%	0.8043%	18.1622%	9.0436%
5	Adjusted Deliveries		100.0000%	46.9145%	23.4731%	2.4759%	0.7710%	17.4703%	8.8952%
6	Procurement Expenses		100.0000%	55.1847%	25.4894%	2.0059%	0.6645%	9.1299%	7.5257%
7	Storage		100.0000%	66.4479%	31.0101%	2.5420%	0.0000%	0.0000%	0.0000%
8	Transmission		100.0000%	66.4479%	31.0101%	2.5420%	0.0000%	0.0000%	0.0000%
9	Distribution Structures		100.0000%	55.1847%	25.4894%	2.0059%	0.6645%	9.1299%	7.5257%
10	High Pressure Distribution Mains		100.0000%	55.1847%	25.4894%	2.0059%	0.6645%	9.1299%	7.5257%
11	Low/Medium Pressure Distribution Mains		100.0000%	65.0357%	29.7778%	2.2081%	0.1567%	2.8217%	0.0000%
12	High Pressure Distrib Mains (yr-end cust.)		100.0000%	92.1083%	7.8009%	0.0638%	0.0049%	0.0212%	0.0009%
13	Low/Med Pres. Distrib Mains (yr-end cust.)		100.0000%	92.1290%	7.8020%	0.0629%	0.0012%	0.0049%	0.0000%
14	Services		100.0000%	92.0347%	7.8049%	0.0727%	0.0245%	0.0591%	0.0042%
15	Meters		100.0000%	77.2847%	18.0153%	1.0163%	0.3431%	3.1572%	0.1834%
16	Customer Count (Average)		100.0000%	92.1470%	7.7624%	0.0639%	0.0049%	0.0209%	0.0009%
17	Customer Accounts		100.0000%	90.3121%	8.5233%	0.6734%	0.0599%	0.4148%	0.0164%
18	Customer Service		100.0000%	90.5089%	8.3869%	0.6275%	0.0483%	0.4103%	0.0181%
19	Forfeited Discounts		100.0000%	83.8182%	15.0479%	1.1339%	0.0000%	0.0000%	0.0000%
20	Net Income Before Income Tax		100.0000%	45.5895%	34.3503%	3.0145%	0.6564%	12.0605%	4.3288%
21	Interest Expense		100.0000%	73.7665%	21.8407%	1.4799%	0.1483%	2.1184%	0.6462%
22	Interest Adjustment		100.0000%	73.7665%	21.8407%	1.4799%	0.1483%	2.1184%	0.6462%
23	Taxable Income		100.0000%	14.7159%	48.0571%	4.6960%	1.2131%	22.9540%	8.3638%
24	Total Distribution Expense		100.0000%	72.1168%	21.4210%	1.4498%	0.2225%	3.3590%	1.4310%
25	Meter Cost		100.0000%	77.2847%	18.0153%	1.0163%	0.3431%	3.1572%	0.1834%
26	Number of Customers		100.0000%	92.1083%	7.8009%	0.0638%	0.0049%	0.0212%	0.0009%
27	Services Cost		100.0000%	92.0347%	7.8049%	0.0727%	0.0245%	0.0591%	0.0042%
28	Actual Revenue		100.0000%	69.3124%	23.3552%	1.7720%	0.2151%	3.9750%	1.3703%
29	DSM Allocation		100.0000%	100.8686%	-0.8221%	0.0000%	-0.0090%	-0.0375%	0.0000%
30	Miscellaneous Revenue Allocation		100.0000%	13.7512%	69.4427%	0.0000%	0.0000%	16.8061%	0.0000%
31	VDT Revenue		100.0000%	64.8830%	30.6010%	3.0043%	0.8819%	0.2770%	0.3529%
32	High Pressure System		100.0000%	57.7570%	24.2571%	1.8706%	0.6185%	8.4953%	7.0015%
33	PTD Plant		100.0000%	70.6121%	20.4057%	1.5077%	0.2643%	4.8769%	2.3334%
34	Dist Plant		100.0000%	71.2750%	18.7172%	1.3430%	0.3064%	5.6534%	2.7049%
35	Mains + Services		100.0000%	71.1728%	18.5767%	1.3551%	0.2915%	5.7957%	2.8081%
36	Depreciation Reserve		100.0000%	70.2485%	21.3316%	1.5980%	0.2412%	4.4511%	2.1297%
37	O&M Expense		100.0000%	72.1118%	20.0580%	1.6212%	0.2025%	3.9857%	2.0209%
38	Labor Excl. A&G		100.0000%	69.7050%	21.2257%	1.7508%	0.2360%	4.6965%	2.3860%

Louisville Gas and Electric
Gas CCOSS
(Allocation Percent)

Acct. No.	Account Description	Alloc	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
39	PTD Plant + CWIP		100.0000%	70.2137%	20.6046%	1.5324%	0.2687%	4.9904%	2.3901%
40	Total Labor		100.0000%	69.7488%	21.1861%	1.7391%	0.2373%	4.7052%	2.3834%
41	Depreciation Expenses		100.0000%	73.8165%	18.5013%	1.2873%	0.2329%	4.1699%	1.9922%
42	Rate Base		100.0000%	69.7072%	21.5186%	1.6262%	0.2503%	4.6622%	2.2355%
43	Peak & Avg.		100.0000%	55.9751%	26.6254%	2.3420%	0.4638%	10.1460%	4.4476%

Louisville Gas and Electric
Gas CCOSS
(Salaries and Wages)

Acct. No.	Account Description	Alloc	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	$ 481,886							
	Demand		$ 56,573	$ 31,220	$ 14,420	$ 1,135	$ 376	$ 5,165	$ 4,258
	Commodity		$ 425,313	$ 195,130	$ 100,042	$ 11,010	$ 3,421	$ 77,246	$ 38,464
	Sub-total		$ 481,886	$ 226,349	$ 114,462	$ 12,145	$ 3,797	$ 82,411	$ 42,721
Storage Expenses									
Operation									
814	Operations Supervision and Engineer	$ 303,331							
	Demand		$ 84,868	$ 56,393	$ 26,318	$ 2,157	$ -	$ -	$ -
	Commodity		$ 218,463	$ 140,802	$ 68,524	$ 6,275	$ (200)	$ 1,899	$ 1,163
815	Maps and Records		$ -						
816	Well Expenses		$ 15,841	$ 10,526	$ 4,912	$ 403	$ -	$ -	$ -
817	Lines Expenses		$ 315,936	$ 209,933	$ 97,972	$ 8,031	$ -	$ -	$ -
818	Compressor Station Exp - Payroll		$ 369,233	$ 237,975	$ 115,816	$ 10,605	$ (339)	$ 3,210	$ 1,966
819	Compressor Station Fuel and Power		$ -						
820	Measurement and Regulator Station		$ -						
821	Purification of Natural Gas		$ 484,806	$ 312,463	$ 152,067	$ 13,925	$ (445)	$ 4,214	$ 2,582
823	Gas losses		$ -						
824	Other Expenses		$ -						
825	Storage Well Royalities		$ -						
826	Rents		$ -						
Total Storage Operation Labor			$ 1,489,148	$ 968,093	$ 465,609	$ 41,396	$ (983)	$ 9,323	$ 5,711
Storage Expense									
Maintenance									
830	Maintenance Super and Eng.	$ 223,206							
	Demand		$ 87,531	$ 58,163	$ 27,143	$ 2,225	$ -	$ -	$ -
	Commodity		$ 135,675	$ 87,444	$ 42,557	$ 3,897	$ (124)	$ 1,179	$ 722
831	Maintenance of Structures		$ -						
832	Maintenance of Resevoirs		$ 167,523	$ 111,316	$ 51,949	$ 4,258	$ -	$ -	$ -
834	Main of Compressor Station Equipment		$ 384,777	$ 247,993	$ 120,691	$ 11,052	$ (353)	$ 3,345	$ 2,049
835	Main of Meas and Reg Sta. Equip		$ 43,610	$ 28,978	$ 13,523	$ 1,109	$ -	$ -	$ -
836	Main of Purification Equip		$ 122,286	$ 78,815	$ 38,357	$ 3,512	$ (112)	$ 1,063	$ 651
837	Main of Other Equipment		$ 58,500	$ 38,872	$ 18,141	$ 1,487	$ -	$ -	$ -
Total Maintenance Labor			$ 1,057,401	$ 692,181	$ 324,095	$ 28,407	$ (437)	$ 8,391	$ 4,764
Total Storage Labor			$ 2,546,548	$ 1,660,274	$ 789,704	$ 69,803	$ (1,421)	$ 17,714	$ 10,475

Louisville Gas and Electric
Gas CCOSS
(Salaries and Wages)

Acct. No.	Account Description	Alloc	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
Transmission									
850-867	Transmission Expenses		$ 483,796	$ 321,473	$ 150,026	$ 12,298	$ -	$ -	$ -
Distribution Expenses									
Operation									
870	Operation Supr and Engr		$ -						
871	Dist Load Dispatching		$ 278,731	$ 127,879	$ 65,563	$ 7,216	$ 2,242	$ 50,624	$ 25,207
872	Compr. Station Labor and Exp.		$ -						
873	Compr. Station Fuel and Power		$ -						
874.01	Other Mains/Serv. Expenses		$ 445,647	$ 317,180	$ 82,787	$ 6,039	$ 1,299	$ 25,829	$ 12,514
874.02	Leak Survey-Mains		$ -						
874.03	Leak Survey - Service		$ -						
874.04	Locate Main per Request		$ -						
874.05	Check Stop Box Access		$ -						
874.06	Patrolling Mains		-						
874.07	Check/Grease Valves		$ -						
874.08	Opr. Odor Equipment		$ -						
874.09	Locate and Inspect Valve Boxes		$ -						
874.1	Cut Grass - Right of Way		$ -						
875	Meas and Reg Station Exp.- General		$ 372,198	$ 205,396	$ 94,871	$ 7,466	$ 2,473	$ 33,981	$ 28,011
876	Meas and Reg Station Exp.- Industrial		$ 213,534	$ 165,029	$ 38,469	$ 2,170	$ 733	$ 6,742	$ 392
877	Meas and Reg Station Exp. - City Gate		$ 27,338	$ 15,086	$ 6,968	$ 548	$ 182	$ 2,496	$ 2,057
878	Meter and House Reg. Expense		$ 5,262	$ 4,066	$ 948	$ 53	$ 18	$ 166	$ 10
879	Customer Installation Expense		$ 132,415	$ 102,337	$ 23,855	$ 1,346	$ 454	$ 4,181	$ 243
880	Other Expenses		$ 1,173,513	$ 836,422	$ 219,649	$ 15,760	$ 3,595	$ 66,344	$ 31,743
881	Rents		$ -						
Total Operations Distribution Labor			$ 2,648,638	$ 1,773,396	$ 533,110	$ 40,598	$ 10,996	$ 190,362	$ 100,176
Total Operations Transmission and Distribution Labor			$ 3,132,434	$ 2,094,868	$ 683,136	$ 52,896	$ 10,996	$ 190,362	$ 100,176
Maintenance Expense -- Distribution									
885	Maintenance Supr and Engr		$ -						
886	Maintenance Structures		$ 24,283	$ 13,400	$ 6,189	$ 487	$ 161	$ 2,217	$ 1,827
887	Maintenance Mains	$ 2,849,128							
	L/M Pressure								
	Demand		$ 2,123,095	$ 1,188,405	$ 565,283	$ 49,723	$ 9,847	$ 215,410	$ 94,427
	Customer		$ 369,321	$ 340,252	$ 28,814	$ 232	$ 5	$ 18	$ -
	H Pressure								
	Demand		$ 331,862	$ 183,137	$ 84,590	$ 6,657	$ 2,205	$ 30,299	$ 24,975
	Customer		$ 24,850	$ 22,889	$ 1,939	$ 16	$ 1	$ 5	$ 0

Louisville Gas and Electric
Gas CCOSS
(Salaries and Wages)

Acct. No.	Account Description	Alloc	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
888	Maintenance Comp. Station Equip.		$ -						
889	Maintenance Meas and Reg. General		$ 33,209	$ 18,326	$ 8,465	$ 666	$ 221	$ 3,032	$ 2,499
890	Maintenance Meas and Reg - Industrial		$ 64,587	$ 49,916	$ 11,636	$ 656	$ 222	$ 2,039	$ 118
891	Maintenance Meas and Reg.-City Gate		$ 125,858	$ 69,454	$ 32,080	$ 2,525	$ 836	$ 11,491	$ 9,472
892	Maintenance Services		$ 521,123	$ 479,614	$ 40,673	$ 379	$ 128	$ 308	$ 22
893	Maintenance Meters and House Reg.		$ -						
894	Maintenance Other Equipment		$ 117,919	$ 84,047	$ 22,071	$ 1,584	$ 361	$ 6,666	$ 3,190
Total Maintenance Labor			$ 3,736,107	$ 2,449,441	$ 801,740	$ 62,924	$ 13,987	$ 271,484	$ 136,531
Total Transmission & Distribution Labor			$ 6,868,542	$ 4,544,309	$ 1,484,876	$ 115,821	$ 24,983	$ 461,846	$ 236,707
Customer Accounts Expense									
901	Supervision		$ 379,040	$ 342,320	$ 32,307	$ 2,552	$ 227	$ 1,572	$ 62
902	Meter Reading		$ 176,603	$ 159,494	$ 15,052	$ 1,189	$ 106	$ 733	$ 29
903	Customer Records and Collections		$ 1,556,484	$ 1,405,694	$ 132,664	$ 10,481	$ 933	$ 6,457	$ 256
904	Uncollectible Accounts		$ -						
905	Misc. Cust Account Expenses		$ 70,905	$ 64,036	$ 6,043	$ 477	$ 42	$ 294	$ 12
Total Customer Accounts Labor			$ 2,183,033	$ 1,971,544	$ 186,067	$ 14,700	$ 1,308	$ 9,056	$ 359
Customer Service Expenses									
907-910	Customer Service		$ 86,037	$ 77,871	$ 7,216	$ 540	$ 42	$ 353	$ 16
Sales Expenses									
911-916	Sales Expenses		$ -						
Administrative & General									
920	Admin and General Salaries		$ 2,616,333	$ 1,823,716	$ 555,334	$ 45,808	$ 6,174	$ 122,877	$ 62,425
921	Office Supplies and Expense		$ -						
922	Admin. Expenses Transferred		$ (214,389)	$ (149,440)	$ (45,506)	$ (3,754)	$ (506)	$ (10,069)	$ (5,115)
923	Outside Services Employed		$ -						
924	Property Insurance		$ -						
925	Injuries and Damages		$ 6,657	$ 4,640	$ 1,413	$ 117	$ 16	$ 313	$ 159
926	Employee Pensions and Benefits		$ -						
927	Franchise Requirement		$ -						
928	Regulatory Commission Fee		$ -						
929	Duplicate Charges -Credit		$ -						
930.1	General Advertising Expense		$ -						
930.2	Misc. General Expense		$ -						
931	Rents		$ -						

Louisville Gas and Electric
Gas CCOSS
(Salaries and Wages)

Acct. No.	Account Description	Alloc	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
935	Maintenance of General Plant		$ 738,636	$ 521,566	$ 150,724	$ 11,136	$ 1,952	$ 36,023	$ 17,235
Total Administrative and General Labor			$ 3,147,237	$ 2,200,482	$ 661,965	$ 53,307	$ 7,636	$ 149,143	$ 74,704
Total Labor Expense			$ 15,313,282	$ 10,680,829	$ 3,244,289	$ 266,315	$ 36,344	$ 720,523	$ 364,981

Louisville Gas and Electric
Gas Customer Cost Analysis

		Residential
Gross Plant		
380 Services	$	126,896,285
381 Meters	$	17,068,163
382 Meter Installations	$	7,250,423
383 House Regulators	$	3,818,939
384 House Regulators Installations	$	4,094,585
Total Gross Plant		$159,128,396
Depreciation Reserve		
380 Services		42,853,102
381 Meters		5,763,949
382 Meter Installations		2,448,481
383 House Regulators		1,289,663
384 House Regulators Installations		1,382,749
Total Depreciation Reserve		$53,737,944
Total Net Plant		$105,390,452
Operation & Maintenance Expenses		
878 Meter and House Reg. Expense		$14,623
879 Customer Installation Expense		$171,394
892 Maintenance Services		$2,020,361
893 Maintenance Meters and House Reg.		$0
902 Meter Reading		$1,564,441
903 Customer Records and Collection		$3,519,377
Total O&M Expenses		$7,290,195
Depreciation Expense		
380 Services		5,388,735
381 Meters		520,536
382 Meter Installations		224,660
383 House Regulators		90,037
384 House Regulators Installations		85,866
Total Depreciation Reserve		$6,307,834

Revenue Requirement

			PCT	Cost	WGHT Cost
Interest	$2,582,066.07	Debt	47.52%	5.16%	2.45%
Equity return	$5,530,890.92				
Income Tax	$3,339,624	Common	52.48%	10.00%	5.25%
		Total	100.00%		7.70%
Revenue For Return	$11,452,781.25				
O & M Expenses	$7,290,195				
Depreciation Expense	$6,307,834				
Total Customer Revenue Requirement	$25,050,811.08				
Number of Bills	3,599,880				
Monthly Cost	$6.96				