COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES	)	**CASE NO: 2008-00251**
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VOLUME 5 OF 5

DIRECT TESTIMONY AND EXHIBITS

Filed: July 29, 2008

Kentucky Utilities Company
Case No. 2008-00251
Historical Test Year Filing Requirements
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TESTIMONY OF
WILLIAM STEVEN SEELYE
PRINCIPAL & SENIOR CONSULTANT
THE PRIME GROUP, LLC

Filed: July 29, 2008

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is William Steven Seelye and my business address is The Prime Group, LLC, 6001 Claymont Village Dr., Suite 8, Crestwood, Kentucky, 40014.

Q. By whom are you employed?

A. I am a senior consultant and principal for The Prime Group, LLC, a firm located in Crestwood, Kentucky, providing consulting and educational services in the areas of utility marketing, regulatory analysis, cost of service, rate design and depreciation studies.

Q. On whose behalf are your testifying?

A. I am testifying on behalf of Kentucky Utilities Company ("KU").

Q. What is the purpose of your testimony?

A. The purpose of my testimony is (i) to describe the proposed allocation of the revenue increases for KU's KY jurisdictional operations; (ii) to support KU's proposed rates; (iii) to discuss the revenue impact of modifying certain miscellaneous charges and customer deposit requirements, (iv) to sponsor the temperature normalization adjustments, and year-end adjustments; (v) to sponsor KU's jurisdictional separation study; (vi) to sponsor the fully allocated class cost of service study based on KU's embedded cost of providing electric service for the 12 months ended April 30, 2008.

Q. Please summarize your testimony.

A. In developing its proposed rates in this proceeding, KU relied heavily on the results of the cost of service study. The Company's fully allocated, embedded cost of service study for its operations was prepared using cost of service methodologies that have been accepted by the Commission in previous rate cases. The purpose of the study is to determine the contribution that each customer class is making towards KU's overall rate of return. Rates of return are calculated for each rate class. The results of the cost of service study show a significant variation in the class rates of return. Based on the results of the cost of service study, KU is proposing to allocate most of the increase to the residential and lighting rate classes.

KU's sales vary significantly due to changes in temperature. During the test year of the rate case, the summer months were significantly hotter than normal. We are therefore proposing a temperature normalization adjustment in this proceeding to more accurately represent the revenue and expenses on a going-forward basis. KU's affiliate, Louisville Gas and Electric ("LG&E"), is also proposing a temperature normalization adjustment in its rate case application which is filed concurrently with KU's application. This is the fifth time that LG&E has proposed such an adjustment and the second time KU has proposed such an adjustment. In rejecting LG&E's and KU's earlier proposals, the Commission has repeatedly indicated that it endorses the concept of electric temperature normalization and was willing to consider the concept in future rate proceedings. However, in prior LG&E and KU rate case Orders the Commission indicated that the methodologies proposed by LG&E and KU were not adequately supported by a fully documented multiple regression analysis or was determined to be flawed in other respects. In this proceeding, we have fully addressed all of the Commission's concerns that were expressed in prior Orders. The Company is proposing a temperature normalization adjustment that is fully supported by well-established standard statistical analysis, that is thoroughly documented, that is verifiable, and that is accurate, robust, and unbiased. Furthermore, the Company is not proposing to adjust sales to reflect a mean-determined level of degree days, but rather is proposing to adjust sales to the endpoint of a 2 standard deviation bandwidth centered on the mean. This approach places a significant constraint on the magnitude of an electric temperature normalization adjustment in this proceeding and in future rate proceedings. The Commission can accept, with full confidence, the Company's proposed temperature normalization adjustment in this proceeding without being concerned that the adjustment will pose difficulties in future rate proceedings.

Q. Are you supporting certain information required by Commission Regulations 807 KAR 5:001, Section 10(6)(a)-(v)?

A. Yes. I am sponsoring the following schedules for the corresponding Filing Requirements:

• Cost of Service Study	Section 10(6)(u)	Tab 40
• Period-End Customer Additions	Section 10(7)(e)	Tab 46

Q. How is your testimony organized?

A. My testimony is divided into the following sections: (I) Introduction, (II) Qualifications, (III) Rate Design and the Allocation of the Increase, (IV) Increase in Miscellaneous Service Charges and Deposits, (V) Electric Temperature Normalization and Year-End Adjustments, (VI) Jurisdictional Separation Study, and (VII) Electric Cost of Service Study.

II. QUALIFICATIONS

Q. Please describe your educational background and prior work experience.

A. I received a Bachelor of Science degree in Mathematics from the University of Louisville in 1979. I have also completed 54 hours of graduate level course work in Industrial Engineering and Physics. From May 1979 until July 1996, I was employed by LG&E. From May 1979 until December 1990, I held various positions within the Rate Department of LG&E. In December 1990, I became Manager of Rates and Regulatory Analysis. In May 1994, I was given additional responsibilities in the marketing area and was promoted to Manager of Market Management and Rates. I left LG&E in July 1996 to form The Prime Group, LLC, with another former employee of the Company. Since then, we have performed cost of service studies, developed revenue requirements and designed rates for over 130 investor-owned, cooperative and municipal utilities across North America. A more detailed description of my qualifications is included in Seelye Exhibit 1.

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

A. Yes. I have testified in over 45 regulatory proceedings in 11 different jurisdictions. A listing of my testimony in other proceedings is included in Seelye Exhibit 1.

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

A. I have been developing models to measure the effect of temperature on hourly, daily and monthly sales for almost 30 years. The first project that I worked on when I joined LG&E in 1979 as a mathematician in the Rate Department was to develop the Company's load research program in order to comply with the requirements of the Public Utilities Regulatory Policy Act (PURPA). At that same time, I began developing single and multiple variable regression analyses to estimate the effect of temperature on hourly loads and daily sales. In those early days, I would write programs in FORTRAN to perform linear and non-linear regression analysis. A little later, I began using the statistical software package SAS to develop these models. Throughout my career at LG&E and afterwards at The Prime Group, I have developed statistical models to measure temperature/load relationships, to evaluate extreme temperature conditions, to analyze price variability and risk, and numerous other applications in the utility planning process. I have worked regularly in this area as a professional analyst for the last 30 years. I have developed the electric temperature normalization models for LG&E, Cajun Electric Power Cooperative, Inc., Southern Mississippi Electric Power Association, and Lee County Electric Cooperative. I also have experience working with the electric temperature normalization adjustments used for Westar Energy, Inc. and Kansas Gas and Electric Company. I have developed sales and load forecasts for numerous electric utilities using the statistical techniques for weather normalization described in my testimony.

I have performed or supervised the development cost of service and rate studies for over 130 utilities throughout North America. I have also testified on numerous occasions regarding the rates proposed by electric, gas and water utilities, including LG&E in its last rate case. In addition, I have testified on numerous occasions regarding year-end adjustments for gas and electric utilities, including LG&E, Kentucky Utilities Company, Delta Natural Gas Company, Westar Energy, Inc., Kansas Gas and Electric Company, Mobile Gas Company, Northern Neck Electric Cooperative, and Richmond Power Company. I have also testified on numerous occasions regarding temperature normalization adjustments for gas distribution utilities, including LG&E and Delta Natural Gas Company.

III. RATE DESIGN AND THE ALLOCATION OF THE INCREASE

Q. Please summarize how KU proposes to allocate the revenue increase to the classes of service?

A. In developing its proposed rates, KU relied heavily on the results of the cost of service study. Consequently, the only rates that the Company is proposing to increase are the residential and lighting schedules. Specifically, we are asking to increase residential rates by 4.27 percent and to increase lighting rates by 4.22 percent. The cost of service study indicates that both of these customer classes have rates of return well below the overall rate of return. KU is proposing that all of the increase to the residential rate be recovered through the customer charge.

The Company is not proposing any increases to the commercial or industrial rates. We are, however, proposing to eliminate the experimental Small Time of Day rate schedule (Rate STOD), the primary voltage discount for General Service Rate GS, and the special mining power rates. Customers currently taking service under these rate schedules will be transferred to an appropriate existing rate schedule.

We are also proposing to change the way that transmission voltage customers currently served under the Large Power Rate (Rate LP), Large Commercial/ Industrial Time-of-Day (Rate LCI-TOD), Mine Power (Rate MP), and Large Mine Power (Rate LMP-TOD) will be billed. These demand-metered customers are currently billed on the basis of a kW charge, adjusted to account for power factor. We are proposing to bill these customers on the basis of a kVA charge and to eliminate the power factor provision. This modification is designed to be revenue neutral for the class as a whole. However, individual customers served under the new rate (which will be called Retail Transmission Service – Rate RTS) may see somewhat minor increases or decreases in their bill.

Q. What were the ratemaking objectives in developing the proposed rates?

A. In general, we tried to develop rates that more closely reflect the cost of providing service. One of our key objectives was to bring the rates of return more in line by allocating the revenue increase to the customer classes indicating *low* rates of return. Another key objective was to bring the unit charges more in line with the unit costs derived from the cost of service study. While these are two important objectives, we are not proposing to move KU and LG&E's rates fully to cost-based rates in a single step. Significantly, we are not proposing equalized class rates of return in this proceeding, nor are we proposing unit charges that precisely match the companies' cost of providing service. Our approach is therefore consistent with the ratemaking principle of gradualism.

Q. Is KU proposing to bring the residential charges more in line with the unit costs shown in the cost of service study?

A. Yes. KU is proposing to increase the monthly residential customer charge from $5.00 to $8.49 to bring it in line with the cost of providing service. Even considering this increase, the customer charge will be significantly less than the cost of service. The cost of service study indicates that the customer cost for the residential class is $16.61 per customer per month, so KU is proposing to increase the customer charge in a direction that will more accurately reflect the actual cost of providing service. This cost is derived in Seelye Exhibit 2.

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

A. No. The current customer charge of $5.00 per customer per month does not even recover all of the customer-related operating expenses, let alone any of the margins (return) that would normally be assigned as customer-related cost. Based on calculations from the cost of service study, there are about $13.82 in fixed operating expenses per customer per month and $2.79 in margins per customer per month that are not being collected through the customer charge, for a total of $16.61 per customer per month that is not being recovered through the customer charge. When this under-recovery of $11.61 per customer per month is multiplied by the 4,958,111 customer months for the residential rate class during the test year, the result is $57,563,669 in fixed operating expenses and margins that are not being recovered through the customer charge. When this amount is recovered through the energy charge instead, the result is about 0.89 cents per kWh of fixed operating expenses and margins collected through the energy charge (calculated as $57,563,669/ 6,437,809,251 kWh = $0.008941 per kWh). Thus, the customer charge is $11.61 per customer per month too low and the energy charge is 0.89 cents per kWh too high. This recovery of fixed operating expenses and margins through the energy charge results in intra-class subsidies.

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

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

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

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

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

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

Q. What would be the impact of a higher customer charge and a reduced energy

charge on low income customers?

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

To help demonstrate that this is generally the case for KU's low income customers, KU collected sales data on customers who meet the state standards for participating in low income energy assistance programs ("LIHEAP"). The average monthly usage for KU's residential customers is 1,311 kWh per month while the average monthly usage for KU's low income customers is 1,416 kWh per year. Thus, the typical low income customer would actually benefit from a rate design that had a higher customer charge and a lower energy charge, as these customers, because of their higher usage, are currently helping to subsidize low usage customers.

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

A. No. In the 1970s and early 1980s conservation advocates would often argue in favor of higher energy charges and lower service charges as a way to encourage conservation. Utilities in some of the more progressive jurisdictions, however, have moved away from that position. Many conservation advocates have realized that a more constructive approach is to try and align the interests of the customers and the utility in a way that encourages the utility to promote conservation rather than being penalized by it. The problem with recovering fixed costs through the energy charge is that whenever customers take measures to conserve energy they reduce the amount of fixed costs recovered by the utility. In this situation, even though its revenues have been reduced by efforts of its customers to conserve energy, none of the utility's fixed costs have been avoided. What happens in this situation is that the utility's earnings are reduced as a result of customers using less energy. This is exactly what has happened with natural gas distribution companies. As customers have installed more energy efficient furnaces, customer usage has gone down resulting in a corresponding reduction in revenues. The utility's fixed costs, however, will have remained the same or may have even gone up causing its earnings to go down. It is difficult for a utility to favor conservation when it results in earnings deterioration. The reason that regulators in some jurisdictions have moved toward a straight fixed-variable rate design for gas distribution utilities is because a straight fixed-variable rate design, or various forms of decoupling, helps prevent the utility from being harmed by conservation and helps to create an environment where the utility can work with customers to encourage greater energy efficiency.

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

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

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

(*Atmos Energy Corporation, Case No. GR-2006-0387*, Order dated February 22, 2007, at 19-20.) Although these orders relate to the rate design for gas utilities and not for electric utilities, the ratemaking principles are the same in both industries regarding the recovery of fixed distribution costs. Even though KU is not proposing a straight fixed-variable rate design in this proceeding, it is important to point out that regulators in other jurisdictions have concluded that appropriately recovering fixed costs through the customer charge removes disincentives for utilities to promote conservation.

Q. What changes are being proposed to KU's lighting rates?

A. The lighting rates are being increased by 4.22 percent. Except for the incandescent and mercury vapor lights, we are proposing to increase all of the individual lights by the same percentage. The Company is no longer installing or replacing incandescent and mercury vapor lights.

Q. Why is the Company eliminating Rate STOD, the General Service primary voltage discount, and the mining rates?

A. As a general matter, there are standard rate schedules available to serve the customers currently taking service under these special rate schedules. There is no basis in cost of service to offer these customers a special purpose rate design. KU's current Large Power Service Rate and Large Commercial/Time-of-Day Service Rate are entirely suitable for these customers.

Rate STOD was developed as a pilot rate schedule through a negotiated settlement in the Company's last rate case. KU was required by the Commission's Order approving the settlement agreement in Case No. 2003-00434 to perform a study to determine whether the customers served under Rate STOD shifted their demands as a result of implementation of the rate. As indicated in the report that the Company filed with the Commission on April 30, 2008, there was no appreciable reduction or shift in peak demand by the participating customers in the pilot program.

Furthermore, there is no basis in cost of service to have a distinct rate schedule for the small time of day customers. These customers will be eligible to take service under the Company's regular commercial time of day rate, which more accurately reflects the actual cost of providing service to these customers.

KU is proposing to eliminate the primary voltage discount in Rate GS and transfer these customers to a more appropriate rate schedule. Virtually all customers that take primary voltage service are currently served under Rate LP or LCI-TOD. Because these rates include a demand charge, they more accurately reflect the cost of providing service. Given their high-voltage service characteristics, primary service customers are more appropriately served under Rate LP or LCI-TOD.

KU is also proposing to eliminate Coal Mining Power Rate MP and Large Mine Power Service Rate LMP-TOD. The load characteristics of mining customers do not differ in any way that would support serving these customers on a separate rate schedule. These mining customers will be transferred to one of KU's standard large power rates, such as Rate LP (which will be renamed Rate PS) or LCI-TOD (which will be renamed Rate LTOD or Rate RTS in the case of transmission voltage service).

Q. Why is the Company proposing to bill transmission customers on a kVA basis rather than a KW basis?

A. A kVA charge does a better job of reflecting the cost of providing service. The power that the Company actually delivers to its customers is better represented by kVA billing. In terms of generalized vectors, the power $\overline{\mathbf{kVa}}$ supplied to the customer at any given interval includes both a real component $\overline{\mathrm{kW}}$ and a reactive component $\overline{\mathrm{kVar}}$ as follows:

$$\overline{\mathrm{kVa}} = \overline{\mathrm{kW}} + \overline{\mathrm{kVar}}$$

The Customer's kW demand therefore represents only the real component of power $\overline{\mathrm{kW}}$ and does not capture the reactive component of the power $\overline{\mathrm{kVar}}$ that must be supplied to the customer. The Company must provide both real and reactive power, and the generation and transmission system must be adequately sized to provide both components of power on an instantaneous basis. Billing the demand charge on a kVA basis properly charges the individual customers for the cost they impose on the system and thus sends a better price signal. The industry is becoming increasingly aware of the need to charge customers for departures from unity power factor on an instantaneous, peak-demand basis, especially customers with large motor loads. It is important to recognize that we are not proposing to change the overall rate level for transmission voltage customers. KU has developed (as close as we could within rounding) a revenue neutral rate (which will be called Retail Transmission Service Rate RTS) that produces the same annual billings as the current rate, but reflects billing on a kVA basis.

Q. Have you prepared exhibits reconstructing KU's test-year billing determinants and showing the impact of applying the new rates to test-year billing determinants?

A. Yes. The reconstruction of KU's billing determinants is shown on Seelye Exhibit 3. As shown in the column labeled "Calculated Divided by Actual" of Seelye Exhibit 3, page

1, the net base rate revenues calculated on pages 2 through 24 of that exhibit were within a factor of 1.000012 of KU's actual net revenues, thus confirming the accuracy of the test period billing determinants. The revenue increase by rate class is summarized on Seelye Exhibit 4. Seelye Exhibit 5 shows the impact of applying the current and proposed rates to test-year billing units.

IV. MISCELLANEOUS SERVICE CHARGES AND CUSTOMER DEPOSITS

Q. Is KU proposing to change any of its miscellaneous non-recurring charges?

A. Yes. KU is proposing to change a number of miscellaneous non-recurring charges. First, the Company is proposing to increase the disconnect/reconnect charge from \$20.00 to \$25.00. Second, KU is proposing to increase its meter test charge from \$31.40 to \$60.00. Third, the Company is proposing to increase the returned check charge from \$9.00 to \$10.00. Fourth, KU is proposing a meter data processing charge of \$2.75. Fifth, the Company is proposing a meter pulse relay charge of \$9.00. Sixth, KU is also proposing to implement a late payment charge for its customers. Specifically, KU is proposing to implement the same late payment charges as currently set forth in LG&E's tariffs, which have been in place for many years. These miscellaneous charges are discussed in greater detail in Mr. Butch Cockerill's testimony.

Q. Have you prepared an exhibit showing the revenue impact of the proposed changes to the miscellaneous charges?

A. Yes. Seelye Exhibit 6 shows the impact on miscellaneous revenues of the proposed changes. The increase in miscellaneous revenues is included in the Company's proposed revenue increase as shown on Seelye Exhibit 4. Consequently, these increased charges reduce the amount of the increase that would otherwise be recovered through the Company's base rates.

Q. Is KU proposing any changes to its residential customer deposit requirements?

A. Yes. The current deposit requirement is $115.00 for residential customers. The Commission's regulations 807 KAR 5:005, Section 7(b) states that, "The utility may establish an equal amount for each class based on the average bill of customers in that class. Deposit amounts shall not exceed two-twelfths (2/12) of the average bill of customers in the class where bills are rendered monthly...." According to the Commission's regulations, residential customer deposits could not exceed $171.00 for at the proposed rates. See Seelye Exhibit 7. We are proposing a deposit requirement of $150.00 for residential customers, which is less than the amount that could be supported by 807 KAR 5:005, Section 7(b). We are also proposing a deposit requirement of $140.00 for customers served under Rate GS, which is slightly less than 2/12th of the estimated annual average billing amount at the proposed rates for secondary voltage customers with connected loads of less than 50 kVA.

V. TEMPERATURE AND YEAR-END ADJUSTMENT

Q. Is KU proposing a temperature normalization adjustment for operations in this proceeding?

A. Yes.

Q. What is the purpose of making normalization adjustments in a rate case?

A. In a general rate case, service rates are set at a level that will provide the utility a reasonable opportunity to recover its costs on a going-forward basis, including a fair, just and reasonable return on investment. The underlying principle is that when rates go into effect as a result of a general rate case, those rates will represent a level of revenue that will allow the utility to recover its reasonably incurred costs on a going-forward basis. This principle holds regardless of whether a projected test year or a historical test year is used to set rates. When rates are based on a historical test year, normalization adjustments (in the form of pro-forma adjustments) are made to test-year operating results so that revenues and expenses will be representative on a going-forward basis. This is the principle behind adjusting test-year operating results to reflect a going-forward level of expenses and revenues for things such as storm damage expenses, injuries and damages, and year-end levels of customers. (See Reference Schedules 1.18, 1.19, and 1.12 to Rives Exhibit 1.) In this proceeding, the Company has made a number of other normalization adjustments to help ensure that the historical test year will be representative of costs and revenues on a going-forward basis.

Q. Are revenues and expenses fully normalized in the application of a projected test-year rate filing?

A. Yes. In Kentucky, utilities can submit a general rate case application using either a historical test year or a projected test year. When a projected test year is utilized, it is essential that the utility develop projected revenues and expenses based on normal temperatures. If it is reasonable to use temperature models in developing the sales and expense forecasts used to develop projected test-year operating results, then it should be equally reasonable to use such models to adjust historical test-year results.

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

A. It is axiomatic that electric utility sales vary with temperature. Almost everyone has seen the impact on their electric bills of hotter than normal summer temperatures and colder than normal winter temperatures. As temperatures rise during the summer, more electric energy is used by customers to operate the compressors on their air-conditioners. Likewise, as temperatures go down in the winter, more electric energy is used by customers to operate electric furnaces and other space-heating appliances. Consequently, for any day during the summer or winter, KU's sales will increase and decrease as a result of changes in temperature.

The effect of higher than normal temperatures on KU's sales is particularly evident during the summer months of 2007. August 2007 was an especially hot month, with 496 cooling degree days compared to a 30-year average of 324. Thus, during August 2007, there were 172 more cooling degree days than average, based on an average determined over the most recent 30-year period, which is the standard approach used in LG&E's prior gas rate case proceedings. Furthermore, there were 110 more cooling degree days during August 2007 than there were during August 2006, which was also a month in which actual heating degree days exceeded the 30-year average.

Although August cooling degree days represent the most significant departure from normal, the cooling degree days for all of the other summer months except July were also higher than normal, as shown in the following table:

TABLE 1 Cooling Degree Days May through September 2007			
Month	**Monthly Cooling Degree Days 30-Year Average**	**Monthly Cooling Degree Days Actual**	**Difference and Percent Above/Below Average**
May	85	155	70 (82%)
June	235	284	49 (21%)
July	354	309	-45 (-13%)
August	324	496	172 (53%)
September	146	238	92 (63%)
Total	**1144**	**1482**	**338 (30%)**

Because of the significant difference between the actual cooling degree days during the test year and the 30-year average, the impact on test-year revenues should not be ignored. If sales are not adjusted so that they represent a level of sales corresponding to *reasonably normal* cooling and heating degree days, then test-year operating results would not be representative of what they would be on a going-forward basis. Given the considerable difference between actual and normal cooling degree days, it is important to adjust revenues and expenses so that they represent levels that would reflect cooling and heating degree days within a reasonable range reflective of normal conditions.

Q. Just so that we're clear, please explain what you mean by "cooling degree days" and "heating degree days"?

A. A cooling degree day is a standard measure of the cumulative daily difference between the mean temperature as reported by the National Oceanic and Atmospheric Administration (NOAA) for each day during a period less a specified base temperature (most commonly 65° F). If the mean temperature for a particular day is 90° F, then there would be 25 cooling degree days for that particular day, using a base temperature of 65° F. Likewise, a heating degree day is a measure of the cumulative difference between a base temperature (again, most commonly 65° F) and the mean temperature as reported by the NOAA for each day during a period. Cooling and heating degree days can be calculated using a base temperature other than 65° F. It is often appropriate to calculate cooling degree days using a base temperature of 70° F and heating degree days using a base temperature of 60° F. The reason for this is that statistical studies will often indicate that temperature sensitive loads are less significant in the range of temperatures between 60° F and 70° F. In other words, cooling loads are often not significant until mean daily temperatures exceed 70° F, and heating loads are often not significant until mean daily temperatures drop below 60° F. When referring to cooling degree days or heating degree days calculated using a base temperature of 65° F we will refer to them, respectively, as (i) "cooling degree days," "CDDs" or "CDD65," and (ii) "heating degree days," "HDDs" or "HDD65". We will refer to cooling degree days calculated using a base temperature of 70° F as

"CDD70" and heating degree days calculated using a base temperature of 60° F as "HDD60".

Q. What do you mean by saying that revenues and expenses should reflect a *range* of cooling and heating degree days representative of normal conditions?

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

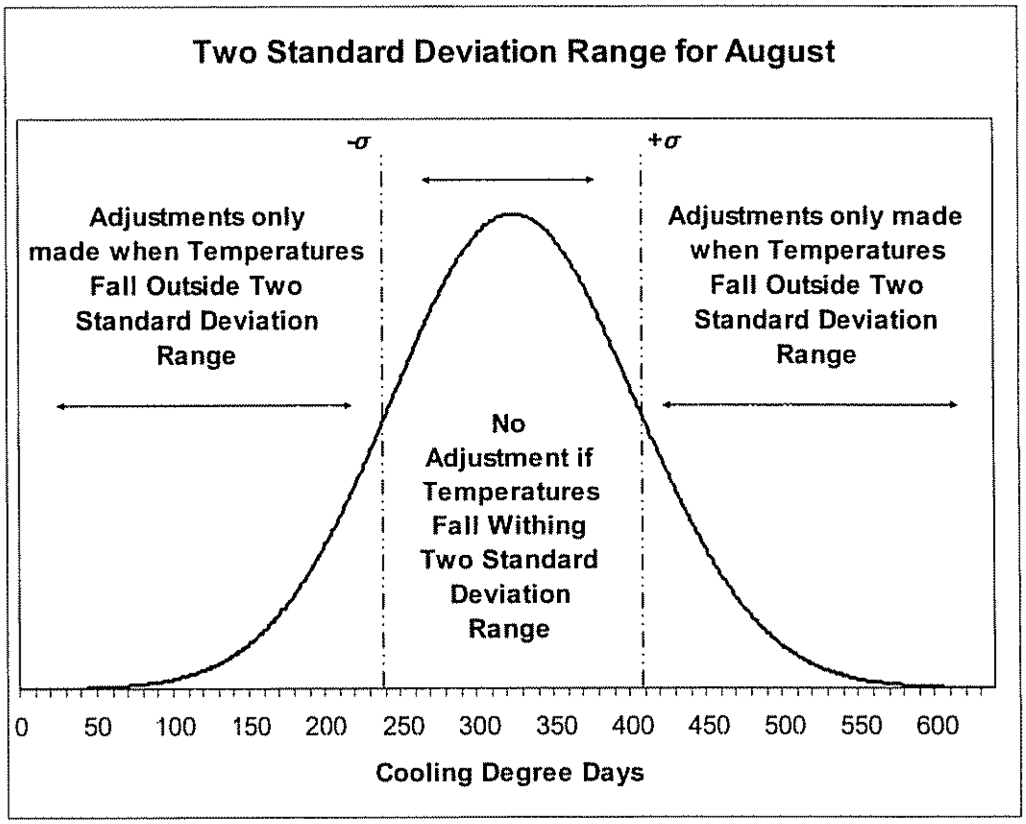
The mean-value approach has been used for decades to calculate the temperature normalization adjustment for LG&E's natural gas operations. In the natural gas temperature normalization adjustment, base rate revenues are adjusted to reflect 30-year average heating degree days. From a statistical perspective, a 30-year mean, or average, would represent a measure of the *expected value* for heating degree days. For a normally-distributed probability density function, the expected value of a random variable is equal to the mean value. Or stated more rigorously, the maximum likelihood estimator for a normally distributed random variable is equal to the sample mean value. (For example, see Robert V. Hogg and Allen T. Craig, *Introduction to Mathematical Statistics*, Third Edition, 1975, at 257.) Therefore, for LG&E's natural gas operations, the 30-year average heating degree days are considered to be representative of a going-forward level of heating degree days for purposes of determining test-year levels of revenues and sales. This is a standard approach for normalizing natural gas revenues and expenses, and is also used in other jurisdictions to normalize electric revenues and expenses. Although it has accepted the mean-value methodology for calculating gas temperature normalization adjustments for many years, the Commission has expressed concerns about using the mean-value approach for electric temperature normalization. In its Order in LG&E's Case No. 10064, the Commission stated as follows:

> The Commission is of the opinion that there is adequate evidence to suggest that a range of temperatures and not a specific mean temperature is a more appropriate measure of normal temperatures. As long as the temperature falls within these bounds then it is inappropriate to adjust sales for temperature. However, if the temperature falls outside those bounds then it is appropriate to adjust sales to the nearest bound. (Order in LG&E's Case No. 10064, dated July 1, 1988, at 39.)

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

Q. Using cooling degree days in August as an example, how the range for the temperature adjustment be determined?

A. The following graph shows a normally-distributed probability density function for August based on a mean level of cooling degree days of 324 and a standard deviation of 80. In this example, no temperature normalization adjustment would be made if the cooling degree days fall between 244 and 404 during August. If cooling degrees fall above 404 during a particular August then a temperature normalization adjustment would be made to reduce sales to what they would have been if there actually had been 404 cooling degree days for the month. If cooling degree days fall below 244, then sales would be adjusted upward to what they would have been if there actually had been 244 cooling degree days for the month. Also, see Seelye Exhibit 8.



Q. Based on this type of statistical analysis, how unusual were the temperatures during August 2007?

A. There are on average 324 cooling degree days in August. The standard deviation of the cooling degree days in August is 80 cooling degree days. Based on these parameters, only 1.58 percent of the time would we expect cooling degrees to be at or above 496 degree days, which is the actual level in August 2007. In other words, cooling degree days at or above 496 degree days for August would only be expected to occur once every 63 years. August 2007 certainly represented an extreme weather situation that is unlikely to re-occur any time soon. So far this summer, we have not experienced the extreme temperatures or the high sales volumes that took place last summer.

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

A. No. Unlike the temperature normalization adjustment for LG&E's natural gas sales, which adjusts base rate revenues to reflect the 30-year average, for KU's operations, the Company is proposing a more conservative approach. Specifically, if heating and cooling degree days during a month are *within* plus or minus one standard deviation of the mean degree days for the month, then no adjustment would be made during that month. If heating or cooling degree days for a month are more than one standard deviation above the average for that month, then sales would be adjusted downward to reflect the cooling degree days at the top end of the range. In other words if the degree days are above the top end of the range, they are not adjusted down to the average but only down to one standard deviation above the average. Likewise if heating or cooling degree days for a month are more than one standard deviation below the average for that month, then sales would be adjusted upward to reflect the cooling degree days at the bottom end of the range. This approach places constraints on the magnitude of the temperature normalization adjustment. First, a constraint is placed on the magnitude of the total revenue and expense adjustment because monthly normalization adjustments would only be made during months when cooling or heating degree days fall outside a particularly wide range of degree days. Second, the methodology would only adjust sales to one of the two end points of the degree day range. This approach would certainly result in lower revenue and expense adjustments than adjusting to the mid-point of the degree-day range (the mean value), as is done within the gas temperature normalization adjustment.

Q. What impact would adjusting to the mean rather than to the end points of the two standard deviation bandwidth have on the Company's proposed temperature normalization adjustment?

A. Adjusting cooling degree days to the 30-year average would result in an adjustment in kWh sales of 302,711,000 and an adjustment in revenues of $16,530,185 for the test year; where adjusting to the endpoints of the two standard deviation bandwidth, as proposed by the Company, results in an adjustment to sales of 158,831,000 kWh and an adjustment to revenues of $8,721,229. Clearly, adjusting to the endpoint of the bandwidth results in a significantly lower adjustment than adjusting to the 30-year average, as was done in the electric temperature normalization methodologies proposed by the Company and intervenors in prior LG&E rate cases.

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

A. Yes, there are several months when no adjustments are required and there are many others when somewhat small adjustments are required. Seelye Exhibit 9 shows the following information for each month during the test year: (1) the actual CDD for the month, (2) the 30-year average CDD for the month, (3) the upper end of the CDD range, determined by adding one standard deviation to the average CDD for the month, (4) the lower end of the CDD range, determined by subtracting one standard deviation from the average CDD for the month, (5) the increase or decrease required to adjust the CDD up to the lower end of the range or down to the upper end of the range, (6) the actual HDD for the month, (7) the 30-year average HDD for the month, (8) the upper end of the HDD range, determined by adding one standard deviation to the average HDD for the month, (9) the lower end of the HDD range, determined by subtracting one standard deviation from the average HDD for the month, (10) the increase or decrease required to adjust the HDD up to the lower end of the range or down to the upper end of the range. As can be seen from this exhibit, no adjustment would be required for eight months during the test year, including June, July, November, December, January, February, March and April.

Q. Why is the Company proposing a different temperature normalization methodology for KU's operations than for LG&E's natural gas operations?

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

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

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

A. For each month in the test year and for each rate class, a rigorous statistical model was developed to measure the relationship between daily customer sales and a wide range of variables -- including various temperature and non-temperature variables -- that might affect customer sales. Our goal was to develop a well-formed multiple linear regression model to determine whether there was a statistically significant temperature dependence on the kWh sales for the class of service being analyzed and, if so, to use that model to measure the temperature-sales relationship. In a multiple linear regression model, the expected value of the response variable (dependent variable) $\boldsymbol{y}$ would be related to a number of regressors (independent variables) $\boldsymbol{x}_1, \boldsymbol{x}_2, \ldots, \boldsymbol{x}_i$, in the following manner:

$$E(y|x) = \beta_0 + \beta_1 x_1 + \beta_2 x_2 + \cdots + \beta_i x_i$$

The parameter β_0 is called the intercept of the model and the parameters $\beta_1, \ldots \beta_k$ provide the linear relationship between the response variable and the various regressors identified in the model. For each month and for each class of service, a rigorous parameter estimation process was followed to develop a multiple regression model to measure the impact of temperature on daily kWh sales. For some classes, the temperature relationship did not prove to be statistically significant. Therefore, the kWh sales for those classes of customers were not normalized. For other rate classes, robust and statistically accurate multiple regression models were developed suitable for use in normalizing test-year electric sales.

Q. Is regression analysis a widely used statistical methodology?

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

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

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

Q. How were the multiple regression models determined for each rate class?

A. A strict procedure was followed in developing a monthly regression model for each rate class. The purpose of these steps is to ensure that well-formed, statistically valid multiple regression models are developed that can be used to accurately measure the relationship between kWh sales and the temperature variables as well as non-temperature variables identified in the model. This rigorous and automatic procedure was designed to remove, as much as possible, all analyst bias from the model selection process. The first step of the process was to perform a step-wise regression procedure to develop a model that includes an optimal set of regressors that best explain the variation in the response variable due to the model. Then, the optimal model developed through step-wise regression was evaluated to determine whether the R-square of the model was adequate and whether the temperature variables were statistically significant. If the model did not have an R-squared of at least 0.60 *and* if the parameter estimates for the temperature variables did not have t-statistics of at least 1.8, then the model was rejected and no temperature adjustment was made for the rate class and month. The model was then evaluated to determine the presence of multicollinearity. If any of the predictor variables were determined to have an unacceptable multicollinear relationship with other variables in the model through the evaluation of the variance inflation factor (VIF), then the variable was eliminated from the model. The model was then evaluated for the presence of auto-correlation, and if auto-correlation was determined to be present by indicating either a Durbin-Watson statistic of less than 1.2 or a first order auto-correlation coefficient greater than 0.3, then an auto-regression procedure was performed using a lag-term of one. The R-squares and t-statistics were reviewed again and the residuals for the model were visually inspected to determine whether there was any other evident pattern to the residuals. The flow diagram included in Seelye Exhibit 10 illustrates how the multiple regression models were determined for each class of service.

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

A. The daily kWh sales for each rate class were obtained from census or sampled load research data. KU has census data (daily kWh readings for each customer) for Rate LP (transmission customers), Rate LCI-TOD, Rate MP (transmission customers), and Rate LMP-TOD. Except for the lighting classes, which are not temperature sensitive, the Company has accurate load research data for all of the rate classes. The load research data is designed to meet the accuracy requirements required by Section 133 of the Public Utilities Regulatory Policy Act (PURPA).

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

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

Q. Please describe the step-wise regression procedures that were used to develop the monthly models in the parameter estimation process?

A. Step-wise regression is a methodology for selecting the optimal set of regressors from a list of independent variables. The step-wise regression procedure was performed using the "Stepwise" model selection method in SAS. Step-wise regression is a combination of forward selection and backward elimination of independent variables. The concept behind step-wise regression is to add variables that contribute positively to the explanatory power of the model and to delete variables that no longer contribute adequately toward the ability of the model to explain the variation seen in the data. With this procedure, regressors are brought into the model one at a time using a forward selection process but do not necessarily remain in the model. The variables are added by evaluating the F-statistic for the variable. To be added to the model, the F-statistic must have significance at the 0.50 level. After a new variable is added to the model, all of the variables already in the model are examined to determine whether their individual F-statistics are still acceptable. The classic text on regression techniques, N.R. Draper and H. Smith, *Applied Regression Analysis*, Second Edition, Wiley Series in Probability and Mathematical Statistics, 1981, at 307-310, still provides one of the best discussions on step-wise regression to be found.

Step-wise regression is a powerful tool for optimizing the variables included in a multiple regression model. It removes the risk of judgment and bias on the part of the analyst in determining which subset of regressors should be included in a model. However, through my experience in modeling electric load and sales data, I have learned to be somewhat cautious about the use of step-wise techniques. First, care must be exercised in developing the set of potential regressors to be brought into the model through step-wise regression. I have found that there should be a strong basis for including the variables in the set of potential regressors used in the step-wise process. Second, it is important to perform several post-step-wise diagnostics to ensure that the variables brought into the model through the step-wise process do not result in an ill-conditioned model. Particularly, it is important to check the resultant model for multicollinearity, auto-correlated errors and for the presence of obvious patterns in the residual terms. Although it is good practice to determine whether these problems exist in developing any type of linear regression model, it is especially important to do so when step-wise regression procedures are used.

Q. What variables were considered in the step-wise regression process?

A. For each rate class and for each month, the step-wise regression procedure selected a subset of regressors from the following variables:

1. **CDD65** – cooling degree days for the day calculated on the basis of a 65° F base temperature.
2. **CDD70** – cooling degree days for the day calculated on the basis of a 70° F base temperature. For many years, my colleagues and I have noticed that

using a base of 70° F for determining cooling degree days produces a better fit than using a 65° F base temperature. The reason for this is that there will not be a significant amount of air-conditioning usage until mean temperatures rise above 70° F.

3. **HDD65** – heating degree days for the day calculated on the basis of a 65° F base temperature.
4. **HDD60** – heating degree days for the day calculated on the basis of a 60° F base temperature. We have also noticed that using a base of 60° F for determining heating degree days produces a better fit than using a 65° F base temperature. The reason for this is that there will not be a significant amount of space-heating usage until mean temperatures drop below 60° F. Mean temperatures between 60° F and 70° F generally represent a range in which there is not a significant amount of air-conditioning or space-heating usage.
5. **MAX** – the maximum temperature for the day as reported by NOAA.
6. **MIN** – the minimum temperature for the day as reported by NOAA. We also have found that daily kWh sales are sometimes affected by the maximum and minimum temperatures for the day. Including MAX or MIN or both in the regression model will sometimes improve the fit of the model. However, because of the potential for a collinear relationship to exist between these variables and the other temperature variables, it is important to run diagnostics to determine whether their inclusion in the model creates unacceptable levels of multicollinearity.

7. **WIND** – the average wind speed for the day as reported by NOAA.

8. **DEWPOINT** – the average dew point for the day as reported by NOAA.

9. **CLOUDY** – a binary indicator variable equal to "1" if snow, rain, haze, fog, freezing rain or other similar condition is reported in the "weather field" for the NOAA daily weather report and equal to "0" otherwise.

10. **WEEKEND** – a binary indicator variable equal to "1" if the day falls on a weekend and "0" otherwise. Sales levels during weekends tend to be significantly different from weekdays. For residential customers, sales levels are often higher on the weekend than weekdays; for industrial customers, sales levels are generally significantly lower during weekend; and for commercial customers, the sales patterns can be somewhat mixed, with many retail businesses using more energy and office buildings using less during weekends. The WEEKEND indicator variable is designed to reflect any such pattern during the month for each rate class to the extent that it is statistically significant.

11. **MONDAY** – a binary indicator variable equal to "1" if the day falls on a Monday and "0" otherwise. We have long observed that sales patterns can be different on Mondays and Fridays than other days of the week. The MONDAY indicator variable is designed to reflect any such pattern during the month for each rate class to the extent that it is statistically significant.

12. **FRIDAY** – a binary indicator variable equal to "1" if the day falls on a Friday and "0" otherwise. The FRIDAY indicator variable is designed to measure the

effect of a different pattern on Fridays during each month and for each rate class to the extent that it is statistically significant.

13. **XMAS_WEEK** – a binary indicator variable equal to "1" if the day falls on a day during the week in December when Christmas occurs and "0" otherwise. As with Mondays and Fridays, we have observed that industrial and commercial sales tend to be lower and residential sales often higher during Christmas week. In my almost 30 years working with class load research data and system loads, I have observed that this pattern has become more pronounced over the years. The XMAS_WEEK indicator variable is designed to measure the effect of a different sales pattern on Christmas week during December for each rate class to the extent that it is statistically significant.

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

A. The term "R-Square" refers to the multiple coefficient of determination and is a measure of the proportion of the variation of the predictor variable (y) explained by the regressors ($x_1, x_2, \ldots, x_{i,}$) in the model. R-Square is the square value of the multiple correlation coefficient (R). Values of R-Square that are close to 1 imply that most of the variation in the response variable is explained by the regression model. Generally, an R-Square above 0.60 is considered adequate. However, with multiple regression analysis it must be considered that the R-square generally can be improved by increasing the degrees of freedom of the model.[1] For this reason, it is also important to look at other statistics, such as the t-statistics, and to be mindful of including too many variables in the model.

Q. What are t-statistics and why are they evaluated in the parameter estimation process?

A. The t-statistic is a test statistic that provides an indication about whether the regression coefficients ($\beta_0, \beta_1, \ldots \beta_k$) in the multiple regression model are significantly different from zero. The t-statistic can be compared to the Student's t distribution[2] to determine how confident we can be that the regression coefficient is something other zero, implying that the regressor associated with the coefficient is important to the model. (For example, see Samprit Chatterjee and Bertram Price, *Regression Analysis by Example*, Wiley Series in Probability and Mathematical Statistics, 1977, at 51-68.)

Q. What is multicollinearity and how is it measured in the parameter estimation process?

A. Multicollinearity relates to the linear dependence of one regressor to the others. If the regressors are linearly independent then they are considered to be *orthogonal*. Orthogonal is analogous to being perpendicular in an n-dimensional Cartesian

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[1] Roughly speaking, "degrees of freedom" refers to the number of moving parts in a model. Adding more variables to a multiple linear regression model will increase the degrees of freedom. Similarly, adding higher order terms in a polynomial or other non-linear model will also increase the degrees of freedom. Likewise, adding nodes to a spline regression model will increase the degrees of freedom. A perennial concern of statistical modeling is how to improve the fit of the model without inflating the degrees of freedom. See T.J. Hastie and R.J. Tibishirami, *Generalized Additive Models*, Monographs in Statistics and Applied Probability 43, Chapman and Hall/CRC, 1999.

[2] The "Student t" distribution was first described in the published work of W.S. Gosset in 1908. Gosset didn't want to use his real name to describe the statistic; consequently, the distribution was called the "Student's t".

setting,[3] and can be analyzed by examining the eigenvalues[4] of the system of least-square normal equations. Except when they are forced to be orthogonal, as in the case of a principal component analysis, it is rare for the regressors in a multiple regression model to be perfectly orthogonal. The lack of orthogonality becomes a problem when the observed values for one variable vary in a nearly direct linear relationship to the observed values of one or more of the other variables in the model. What this implies is that the variation in the response variable can be adequately modeled by eliminating one or more of the multicollinear variables. Another way of saying this is that the information provided by the linear dependent regressors can be captured adequately by other regressors in the model.

The problem with not addressing multicollinearity is that the least squares process used to perform multiple regression will likely produce unreliable parameter estimates. As mentioned earlier, it is particularly important to investigate multicollinearity when the potential model being specified includes more than one daily temperature variable, such as CDD65 and MAX. The inclusion of more than one temperature variable may improve the R-square, and, furthermore, each variable

[3] Two vectors are orthogonal if their inner product is equal to zero. Orthogonality is one of the more elegant and powerful concepts in mathematics, especially in applied mathematics. Not only variables, but also functions can be orthogonal. In the early 1800s the French mathematician Joseph Fourier discovered that almost any function can be represented in terms of a sum of a series of trigonometric functions (specifically cos(nx) and sin(nx)). Later, it was demonstrated that Fourier's result had to do with the fact that the trigonometric functions used in Fourier series were orthogonal functions. Series of orthogonal and near-orthogonal functions are widely used as approximations for complex mathematical functions and integrals. For example, see the classic text, Dunham Jackson, *Fourier Series and Orthogonal Polynomials*, Dover, 2004, and Walter Gautschi, *Orthogonal Polynomial. Computation and Approximation*, Oxford University Press, 2004.

[4] The "eigenvalues" or "characteristic values" of the matrix $A=X'X$ are the roots of the equation $|A-\lambda I| = 0$, where X is the matrix of the observed values for the regressor variables. There is an excellent discussion of the relationship of the eigenvalues of a system of equations and orthogonality in I.T. Jolliffe,

may indicate an acceptable t-statistic, but multicollinearity may nevertheless undermine the accuracy of the individual parameter estimates. There are several methodologies for analyzing the lack of orthogonality of the regressors in a multiple regression model. One of the more popular methodologies is to examine the VIF of each term in the regression model. The VIF measures the combined effect of linear dependencies among the predictor variables in the model. More specifically, the VIF measures the inflation in the variances of the parameter estimates due to collinearities that exist among the regressors. A high VIF indicates multicollinearity problems with a variable. Although we are unaware of formal criteria for deciding if a VIF is large enough to affect the reliability of the regressor coefficients, a typical rule is that none of the VIFs should exceed 10.

Q. What are autocorrelated errors and how are they addressed in the parameter estimation process?

A. A basic assumption in ordinary least-squares estimation (which is the approach used to estimate the coefficients in the multiple regression models described herein) is that the error terms have a mean of zero, a constant standard deviation, and are uncorrelated. Time series data in particular can exhibit error terms that are temporally correlated. When the error terms are correlated they are considered to be autocorrelated. The standard diagnostics for identifying autocorrelated errors are the Durbin-Watson statistic and the autocorrelation coefficients produced by the model. They indicate whether the error terms are correlated.

Principal Component Analysis, Second Edition, 2004, at 5-6. Small eigenvalues indicate near-linear

In modeling daily and hourly electric and gas sales or loads over the years, I have noticed a tendency for the error terms to exhibit serial autocorrelation, particularly first-order autocorrelation. Although there are several possible explanations for the presence of autocorrelated errors in load data models, a likely source is the fact that there is a lag effect in the heat buildup in homes and businesses. I have found that the introduction of one or more lagged variables can significantly improve the results of the model, especially when hourly load data is being modeled. When daily sales data is modeled, the lagged effects of the response variables are less pronounced but are sometimes still evident in the first-order autocorrelated error terms. It is for this reason that we checked for first-order autocorrelation and ran the autoregression procedure in SAS when first-order autocorrelated errors were indicated.

Q. Why is it important to visually inspect the residuals?

A. Even though autocorrelation is the most common error-term problem that we generally encounter in load modeling, it is good practice to visually inspect the residuals to determine whether the residuals indicate any other evident pattern. We visually inspected a graph of the residual terms for each model. In addition, for the heavily temperature sensitive classes, we sorted the residuals by the magnitude of the daily sales to determine whether there was a pattern to the residuals relative to the level of the sales. No pattern was observed. Running monthly models, rather than

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dependence of the data and large eigenvalues indicate greater orthogonality.

annual models, helps correct for some of the nonlinearity that is often seen in modeling electric loads.

Q. After all of these steps are performed, can we be reasonably confident that we have accurately measured the relationship between temperature variables and sales for each month?

A. Yes. The R-squares for each model and the t-statistics for the temperature variables were remarkably good. The R-squares for each selected model exceeded 0.60. In most cases the R-squares exceeded 0.80. Seelye Exhibit 11 shows the parameter estimates, t-statistics, and R-square for each model found to be acceptable in the five-step parameter estimation process.

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

A. Obviously, the residential and commercial rate classes are the most temperature sensitive, and the large industrial and large industrial time-of-day classes less so. The rates classes (using the current rate designations) that were normalized include: (a) Rate RS, (b) Rate GS-Secondary, (c) Rate STOD-Secondary, (d) Rate LP-Secondary, and (e) Rate LP-Primary. The rate classes (again using the current designations) that were not normalized include: (a) Rate GS-Primary, (b) Rate STOD-Primary, (c) Rate LCI-TOD, (d) Rate MP, (e) Rate LMP-TOD, (f) Rate AES, (g) Rate LITOD, and (h) all lighting rates. For some of the classes that were not normalized, there were a small number of months that indicated a temperature relationship. We concluded that the relationship was not strong enough to warrant including a couple of months for those rate classes which did not consistently indicate a significant temperature sensitive load. Normalizing those rate classes would have produced a larger temperature normalization adjustment in this proceeding and therefore would have increased the proposed revenue increase in this proceeding.

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

A. In calculating the kWh sales for the normalization adjustment by class and by month, the parameter estimate for each applicable temperature variable (CDD65, CDD70, HDD65, HDD60, MAX, MIN) from Seelye Exhibit 11 was applied to the difference between the actual value for the temperature variable during the month and the end-point of the two standard deviation range centered on the 30-year average value for the temperature variable to the extent the actual was not within the bandwidth, in which case no adjustment was made. These adjustments are shown on Seelye Exhibit 12.

Q. Is the Company proposing to use a billing-cycle approach for calculating the temperature variables?

A. No. The Commission has expressed concerns with using billing-cycle degree days in prior proceedings for purposes of calculating the electric temperature normalization adjustment. Because we are modeling daily sales, it is appropriate to calculate the temperature variables on a calendar month basis.

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

A. The revenue adjustment was calculated by applying the kWh adjustment for each rate class to the energy charge applicable to the rate schedule. No attempt was made to normalize the demand charges of three-part rate schedules consisting of a customer charge, energy charge and demand charge. Our temperature normalization procedure normalized kWh sales and not maximum individual demands. Had demands been normalized, the revenue adjustment would have been larger without materially changing the expense adjustment. The revenue component of the temperature normalization adjustment is calculated in Seelye Exhibit 13.

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

A. The expense component of the temperature normalization adjustment was calculated by applying the kWh sales adjustment to the variable expenses per kWh during the test year. Variable expenses were determined using the FERC predominance methodology that was used in the Company's embedded cost of service study, which will be discussed later in my testimony. The expense component of the temperature normalization adjustment is calculated in Seelye Exhibit 14.

Q. Has the Commission ever considered an electric temperature normalization adjustment in a KU rate proceeding?

A. Yes, in KU Case No. 98-474. Electric temperature normalization adjustments were also considered in LG&E Case No. 8284, Case No. 8616, Case No. 8924, Case No. 10064, and Case No. 98-426. In each of these proceedings, the Commission denied the adjustment, noting that LG&E had failed to adequately support the adjustment. The Commission, however, continued to endorse the concept of normalization and expressed a willingness to consider temperature adjustments in future rate proceedings. (See Commission's Order in Case No. 98-426, dated January 7, 2000, at 73; Commission Order in Case No. 98-474, dated January 7, 2000, at 70.) In fact, the Commission "reaffirm[ed] that willingness" in its Orders in Case Nos. 98-474 and 98-426.

In Case Nos. 98-426 and 98-474, the Commission expressed concern that LG&E and KU had failed to file the supporting regression analyses, modeling and forecasting assumptions, and calculation details. The Commission also expressed concern about the use of 20-year average degree days rather than a 30-year average, noting that "previous electric weather normalization adjustments proposed in the LG&E rate cases were based on a 30-year average. The 30-year average is typically used in gas weather normalization adjustments." (Ibid., at 74.)

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

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

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

Q. Have the concerns expressed in prior Commission Orders been addressed with the Company's proposed temperature normalization adjustment in this proceeding?

A. Yes. In this proceeding, KU is filing the supporting regression analyses, modeling and forecasting assumptions, and calculation details, which were the concerns expressed in Case Nos. 98-426 and 98-474. In this proceeding, the Company adjusted each month's actual billing-cycle temperature-sensitive load to a temperature-sensitive load determined by the boundaries of a range constructed around the mean instead of a mean determined temperature-sensitive load, which addresses a concern raised in Case No. 10064. In this proceeding, the Company relied on a regression model using more than one variable to adjust test-year sales utilizing multiple variables, which addresses two other concerns raised in Case No. 10064. In this proceeding, the Company did not utilize billing-cycle degree days to calculate the adjustment, thus addressing another concern raised in Case No. 10064. Finally, the Company has provided adequate support to verify the accuracy and appropriateness of its models and has provided full documentation, including adequate statistical analysis, regarding the process used to make the adjustment, which was a requirement stated by the Commission in Case No. 10064.

Q. Have other jurisdictions approved temperature normalization adjustments for electric utilities?

A. Yes. Although we have not performed a comprehensive survey, we have found that electric temperature normalization adjustments have been approved by regulatory commissions in the following jurisdictions: Connecticut, North Carolina, Washington D.C., Indiana, Georgia, and Kansas. I am familiar with the methodology used in Kansas. In the last several rate cases filed by Westar Energy and Kansas Gas and Electric Company, the Commission has utilized weather-normalized sales based on a historical test year. The methodology relies on regression modeling similar to, albeit less sophisticated than, what KU is proposing in this proceeding.

Q. Has an Attorney General witness or a Kentucky Industrial Utility Customers (KIUC) witness ever proposed a temperature normalization adjustment?

A. Yes. Attorney General witness Michael Majoros proposed a temperature normalization adjustment in KU's 2004 rate case, but withdrew his testimony when he was made aware that he had not addressed the criteria set forth by the Commission for assessing the reasonableness of temperature normalization adjustments. In Case No. 8924, KIUC witness Stephen Baron proposed an electric temperature normalization adjustment. The Commission rejected Mr. Baron's proposal but emphasized that its decision to reject his proposal was not a rejection of temperature normalization. In the current proceeding, the Company's proposal has fully addressed all of the Commission's concerns.

Q. Can the Company's proposed model be used by KU and other utilities in future rate proceedings?

A. Yes. KU is proposing a methodology that is fully supported by standard statistical analysis, thoroughly documented, verifiable, accurate, robust, unbiased, and a methodology that can be used regardless of whether temperatures during a historical test year are milder than normal, colder than normal, hotter than normal, or a combination of the three. Particularly, we have developed a procedure that is not subject to analyst judgment or bias and can be used by other electric utilities in the state.

Q. Please summarize your testimony regarding the electric temperature normalization adjustment.

A. KU has presented a well-grounded statistical procedure for normalizing revenues and sales to reflect a range of normal temperatures. This procedure addresses all of the concerns expressed by the Commission about earlier temperature normalization adjustments proposed by the Company. It is my recommendation that the Commission adopt KU's proposed adjustment.

Q. Besides the temperature normalization adjustment, are you also sponsoring the adjustment to annualize for year-end customers?

A. Yes. The numbers of customers served at the end of the test period for the rate classes were lower than the average numbers of customers for the 13-month test period. The differences between the number of customers served at year-end and the average number for each rate class during the test period was multiplied by the average annual kWh usage per customer. The average usage for each rate class was then multiplied by the average revenue per kWh (including customer charges, energy charges, demand charges and minimum bills), resulting in a downward adjustment to KU's operating revenue of $4,243,045.

The additional operating expenses associated with serving the lower number of customers and volumes were calculated by applying an operating ratio to the revenue adjustment. Consistent with the Commission's practice, the operating ratio of 64.75 percent was determined by dividing operation and maintenance expenses, exclusive of wages and salaries, pensions and benefits, and regulatory commission expenses, by base rate revenues calculated at the currently effective rates. When applied to the year-end revenue adjustment, the application of the operating ratio resulted in a downward adjustment to expenses of $2,747,550.

The detailed calculations of the electric year-end adjustment to revenues and expenses are contained in Seelye Exhibit 15. This adjustment is included in Reference Schedule 1.12 of Rives Exhibit 1.

VI. JURISDICTIONAL SEPARATION STUDY

Q. Was a jurisdictional separation study performed to allocate costs between the Kentucky retail jurisdiction and other jurisdictions not regulated by the Commission?

A. Yes. I supervised and participated in the preparation of a jurisdictional separation study based on KU's accounting costs per books for the 12 months ended April 30, 2008.

Q. Please explain how the study was performed.

A. We used the same methodology as in prior jurisdictional separation studies, including the one accepted by the Commission in KU's last general rate case. Continuity in the methodology used to perform the jurisdictional separation study is extremely important because the study is used to allocate costs among four different jurisdictions – Kentucky retail, Virginia retail, Tennessee retail, and FERC wholesale customers. A methodology consistent with the cost allocation principles followed by the FERC was used in the study. If different methodologies were to be used from one study to another or from one jurisdiction to another, the utility could be denied the opportunity to recover prudently incurred costs or perhaps even allowed to over collect its costs.

Q. What were the principal allocators used in the study?

A. Two key allocators were used in the study: (1) a demand allocator based on the Average 12 CP method which uses the 12 monthly system peak demands during the 12 months ended April 30, 2008, to allocate production and transmission fixed costs; (2) and an energy allocator based on the energy used within each jurisdiction. This methodology is consistent with the methodologies utilized at the FERC. Distribution costs are specifically assigned among jurisdictions in the study.

Q. Do the results of the jurisdictional separation study become the starting point for the embedded cost of service study that you performed?

A. Yes. The results of the jurisdictional separation study are entered in the functional assignment section of the cost of service study described below. The revenue requirement exhibits and pro-forma adjustment schedules sponsored by S. Bradford Rives, Valerie L. Scott, and Shannon Charnas also utilize results from the jurisdictional separation study.

Q. Is there an exhibit summarizing the results of the jurisdictional separation study?

A. A copy of the full output of the jurisdictional separation study itself is included as Seelye Exhibit 16.

VII. COST OF SERVICE STUDY

Q. Did you prepare a cost of service study for KU's operations based on financial and operating results for the 12 months ended April 30, 2008?

A. Yes. I supervised the preparation of a fully allocated, time-differentiated, embedded cost of service study for KU. The cost of service study corresponds to the pro-forma financial exhibits included in the testimony of Mr. Rives. The objective in performing the cost of service study is to determine the rate of return on rate base that KU is earning from each customer class, which provides an indication as to whether KU's service rates reflect the cost of providing service to each customer class.

Q. Did you develop the model used to perform the cost of service study?

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

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

A. The three traditional steps of an embedded cost of service study – functional assignment, classification, and allocation – were augmented to include a fourth step, assigning costs to costing periods. The cost of service study was therefore prepared using the following procedure: (1) costs were functionally assigned (*functionalized*) to the major functional groups; (2) costs were then *classified* as commodity-related, demand-related, or customer-related; (3) costs were assigned to the costing periods; and then (4) costs were allocated to the rate classes. These steps are depicted in the following diagram (Figure 1).

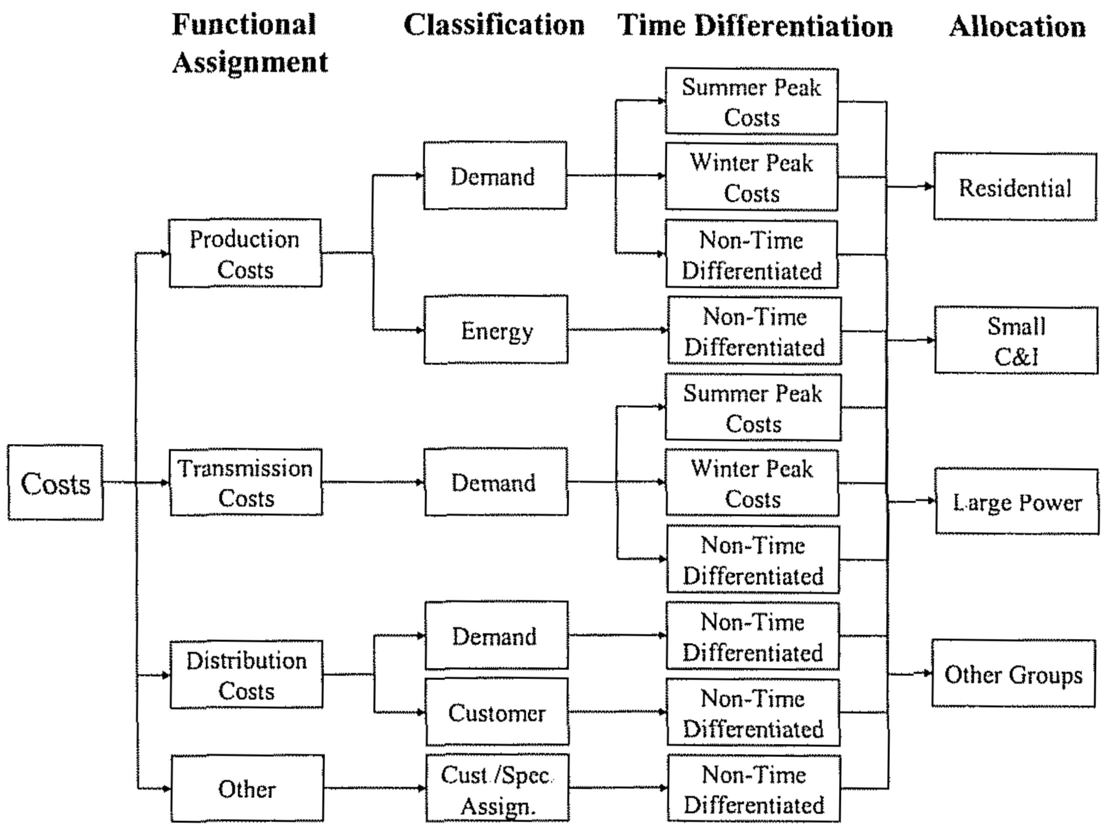

Figure 1

The following functional groups were identified in the cost of service study: (1) Production, (2) Transmission, (3) Distribution Substation (4) Distribution Primary Lines, (5) Distribution Secondary Lines (6) Distribution Line Transformers, (7) Distribution Services, (8) Distribution Meters, (9) Distribution Street and Customer Lighting, (10) Customer Accounts Expense, (11) Customer Service and Information, and (12) Sales Expense.

Q. Did you use the same methodology in KU's cost of service study as was used in LG&E's cost of service study filed concurrently in Case No. 2008-00252?

A. Yes.

Q. How were costs time differentiated in the study?

A. A modified Base-Intermediate-Peak ("BIP") methodology was used to assign production and transmission costs to the costing period.[5] Using this methodology, production and transmission demand-related costs were assigned to three categories of capacity – base, intermediate, and peak. Base costs were determined by dividing the minimum system demand by the maximum (summer) demand. Intermediate costs were calculated by dividing the winter peak demand by the summer peak demand and subtracting the base component. Peak costs included all costs not assigned to base and intermediate components.

Costs that were assigned as base, intermediate, and peak were then either assigned to the summer or winter peak periods or assigned as non-time-differentiated. Base costs were assigned as non-time-differentiated. Intermediate costs were pro-rated to the winter and summer peak periods in the same ratio as the number of hours contained in each costing period to the total. Peak costs are assigned to the summer peak period.

[5] In Case No. 90-158, the Commission found LG&E's cost of service study, which utilized the modified BIP methodology, to be "acceptable and suitable for use as a starting point for electric rate design." (Order in Case No. 90-158, dated December 21, 1990, at 58.)

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

A Demands for the combined KU and LG&E systems were used to determine the costing periods and in determining the percentages of production and transmission fixed cost assigned to the costing periods. Since the two systems are planned jointly it was important to develop costing periods and assign costs to the costing periods based on the combined loads for KU and LG&E. Developing the costing periods and allocation factors in the cost of service study do not result in any shifting in booked expenses of one utility to the other. KU's cost of service study relied on KU's accounting costs, and LG&E's cost of service study relied on LG&E's accounting costs. The modified BIP methodology simply affects how costs are assigned to the costing periods within the KU and LG&E cost of service studies.

Q. What percentages were assigned to the costing periods?

A Seelye Exhibit 17 shows the application of the modified BIP methodology. Using this methodology 50.78% of KU's production and transmission fixed costs were assigned to the summer peak period, 15.32% to the winter peak period, and 33.89% as non-time-differentiated.

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

A. Classification provides a method of arranging costs so that the service characteristics that give rise to the costs can serve as a basis for allocation. Costs classified as *energy related* tend to vary with the amount of kilowatt-hours consumed. Fuel and purchased power expenses are examples of costs typically classified as energy costs. Costs classified as *demand related* tend to vary with the capacity needs of customers, such as the amount of generation, transmission or distribution equipment necessary to meet a customer's needs. Production plant and the cost of transmission lines are examples of costs typically classified as demand costs. Costs classified as *customer related* include costs incurred to serve customers regardless of the quantity of electric energy purchased or the peak requirements of the customers and include the cost of the minimum system necessary to provide a customer with access to the electric grid. As will be discussed later in my testimony, costs related to Distribution Primary Lines, Distribution Secondary Lines and Distribution Line Transformers were classified as demand-related and customer-related using the zero-intercept methodology. Distribution Services, Distribution Meters, Distribution Street and Customer Lighting, Customer Accounts Expense, Customer Service and Information and Sales Expense were classified as customer-related.

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

A. Yes. Seelye Exhibit 18 shows the results of the first three steps of the cost of service study, functional assignment, time differentiation and classification.

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

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

- **E01** – The energy cost component of purchased power costs was allocated on the basis of the kWh sales to each class of customers during the test year.

- **PPWDA and PPSDA** – The winter demand and summer demand cost components of production and transmission fixed costs were allocated on the basis of each class's contribution to the coincident peak demand during the winter and summer peak hour of the test year.
- **NCPP** – The demand cost component is allocated on the basis of the maximum class demands for primary and secondary voltage customers.
- **SICD** – The demand cost component is allocated on the basis of the sum of individual customer demands for secondary voltage customers.
- **C02** – The customer cost component of customer services is allocated on the basis of the average number of customers for the test year.
- **C03** – Meter costs were specifically assigned by relating the costs associated with various types of meters to the class of customers for whom these meters were installed.
- **YECust04** – Costs associated with lighting systems were specifically assigned to the lighting class of

customers.

- **YECust05 and YECust06** – Meter reading, billing costs and customer service expenses were allocated on the basis of a customer weighting factor based on discussions with LG&E's meter reading, billing and customer service departments.
- **Cust05** – The customer cost component is allocated on the basis of the average number of customers for the test year.
- **YECust07** – The customer cost component is allocated on the basis of the year-end number of customers using line transformers and secondary voltage conductor.
- **YECust08** – The customer cost component is allocated on the basis of the year-end number of customers using primary voltage conductor.

Q. In your cost of service model, once costs are functionally assigned and classified, how are these costs allocated to the customer classes?

A. In the cost of service model used in this study, KU's accounting costs are functionally assigned and classified using what are referred to in the model as "functional vectors". These vectors are multiplied (using *scalar multiplication*) by the various accounts in order to simultaneously assign costs to the functional groups and classify costs. Therefore, in the portion of the model included in Seelye Exhibit 18, KU's accounting costs are functionally assigned and classified using the explicitly determined functional vectors of the analysis and using internally generated functional vectors. The explicitly determined functional vectors, which are primarily used to direct where costs are functionally assigned and classified, are shown on pages 49 through 52. Internally generated functional vectors are utilized throughout the study to functionally assign costs on the basis of similar costs or on the basis of internal cost drivers. The internally generated functional vectors are also shown on pages 49 through 52 of Seelye Exhibit 18. An example of this process is the use of total operation and maintenance expenses less purchased power ("OMLPP") to allocate cash working capital included in rate base. Because cash working capital is determined on the basis of 12.5% of operation and maintenance expenses, exclusive of purchased power expenses, it is appropriate to functionally assign and classify these costs on the same basis. (See Seelye Exhibit 18, pages 9 through 12 for the functional assignment of cash working capital on the basis of OMLPP shown on pages 49 through 52.) The functional vector used to allocate a specific cost is identified by the column in the model labeled "Vector" and refers to a vector identified elsewhere in the analysis by the column labeled "Name".

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

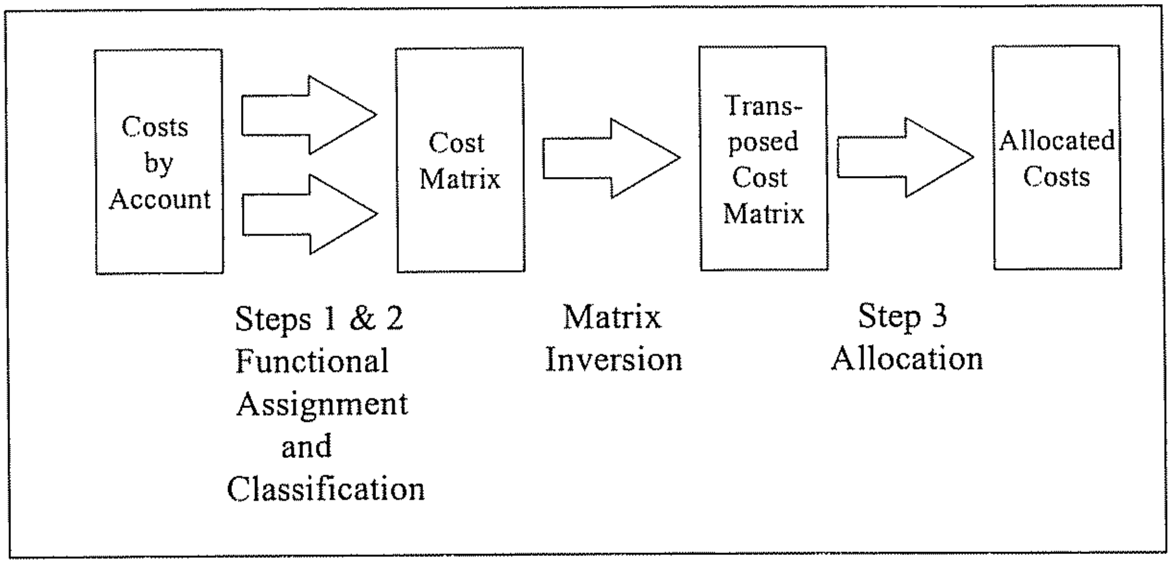

Figure 2

The results of the class allocation step of the cost of service study are included in Seelye Exhibit 19. The costs shown in the column labeled "Total System" in Seelye Exhibit 19 were carried forward *from* the functionally assigned and classified costs shown in Seelye Exhibit 18. The column labeled "Ref" in Seelye Exhibit 19 provides a reference to the results included in Seelye Exhibit 18.

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

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

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

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

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

$$y = a + bx$$

where:

y is the unit cost of the conductor or transformer,

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

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

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

Like most electric utilities, the number of feet of conductor on KU's system is not uniformly distributed over all sizes of wire. For example, KU has over 20.9 million feet of #2 copper overhead conductor, but only 660 feet of 556 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. Without performing a weighted regression analysis both types of conductor would have the same impact on the analysis, even though there is tens of thousands times more #2 copper overhead conductor than 556 MCM overhead conductor.

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

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

is minimized, where **w** is the weighting factor for each size of conductor or transformer, and **y** is the observed value and **ŷ** is the predicted value of the dependent variable.

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

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

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

A. Yes. The zero-intercept analysis for overhead conductor, underground conductor, and line transformers are included in Seelye Exhibits 20, 21, and 22.

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

A. The following table (Table 1) summarizes the rates of return for each customer class before and after reflecting the rate adjustments proposed by KU.

TABLE 1 Class Rates of Return		
Customer Class	**Actual Adjusted Rate of Return**	**Proposed Rate of Return**
Residential	3.58%	4.61%
General Service Rate	11.92%	12.17%
All Electric Schools	6.32%	7.51%
Large Power and STOD	11.43%	11.53%
Large Power TOD	7.90%	7.90%
Coal Mining Power	13.04%	15.53%
Coal Mining TOD	12.81%	12.90%
Large Industrial TOD	25.00%	25.00%
Lighting	8.41%	9.20%
Total Kentucky Jurisdiction	7.15%	7.77%

The Actual Adjusted Rate of Return was calculated by dividing the adjusted net operating income by the adjusted net cost rate base for each customer class. The adjusted net operating income and rate base reflect the pro-forma adjustments discussed in Mr. Rives' testimony. The Proposed Rate of Return was calculated by dividing the net operating income adjusted for the proposed rate increase by the adjusted net cost rate base. Determination of the actual adjusted and proposed rates of return are detailed in Seelye Exhibit 19, pages 40-42 and pages 46-48.

Q. Are the current rates of return for the residential and lighting classes adequate?

A. No. As shown in Table 3, the rate of return for the residential class is below the rates of return for the other customer classes. The proposed rate of return is 7.77%, while the rate of return for the residential class is currently only 3.58%. In my opinion, KU should be allowed to charge rates that bring the rate of return more in line with the overall rate of return.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

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

WILLIAM STEVEN SEELYE

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 21 day of July, 2008.

_______________ (SEAL)
Notary Public

My Commission Expires:

4-21-09

Seelye Exhibit 1

QUALIFICATIONS OF WILLIAM STEVEN SEELYE

Summary of Qualifications

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

Employment

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

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

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

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

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

Education

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

Expert Witness Testimony

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

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

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

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

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

Submitted testimony concerning changes to Vectren Energy's transmission formula rate.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Nevada: Submitted direct and rebuttal testimony in Case No. 03-10001 on behalf of Nevada Power Company regarding cash working capital and rate base adjustments.

Submitted direct and rebuttal testimony in Case No. 03-12002 on behalf of Sierra Pacific Power Company regarding cash working capital.

Submitted direct and rebuttal testimony in Case No. 05-10003 on behalf of Nevada Power Company regarding cash working capital for an electric general rate case.

Submitted direct and rebuttal testimony in Case No. 05-10005 on behalf of Sierra Pacific Power Company regarding cash working capital for a gas general rate case.

Submitted direct and rebuttal testimony in Case Nos. 06-11022 and 06-11023 on behalf of Nevada Power Company regarding cash working capital for a gas general rate case.

Submitted direct and rebuttal testimony in Case No. 07-12001 on behalf of Sierra Pacific Power Company regarding cash working capital for an electric general rate case.

Nova Scotia: Testified on behalf of Nova Scotia Power Company in NSUARB – NSPI – P-887 regarding the development and implementation of a fuel adjustment mechanism.

Submitted testimony in NSUARB – NSPI – P-884 regarding Nova Scotia Power Company's application to approve a demand-side management plan and cost recovery mechanism.

Submitted testimony in NSUARB – NSPI – P-888 regarding a general rate application filed by Nova Scotia Power Company.

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

Virginia: Submitted testimony on behalf of Northern Neck Electric Cooperative regarding revenue requirements, class cost of service, jurisdictional separation and an excess facilities charge rider.

Seelye Exhibit 2

Kentucky Utilities Company
Determination of Residential Customer Cost Unit Revenue Requirement
Based on the 12 Months Ended April 30, 2008

	Total	Residential Rate RS
Distribution Customer Rate Base	$ 446,090,864	$ 299,833,724
Rate of Return	7.77%	4.61%
Return	$ 34,670,124	$ 13,810,098
Customer Related Expenses Before Adjustments	$ 99,282,411	$ 66,877,997
Incremental Income Taxes (Spread on Rate Base)		$ 1,848,862
Incremental Miscellaneous Revenues (Spread on Unadjusted Expenses)	$ (2,536,008)	$ (193,045)
Other Revenue (Spread on Expenses)		
Non-Base Rate Revenue		$ -
		$ 68,533,814
Annual Revenue Requirement		$ 82,343,912
Customer Months		4,958,111
Monthly Customer Charge		$ 16.61
Fixed Operating Expenses		$ 2.79
Margins		13.82
		$ 16 61

Source: Seelye Exhibit 19

Seelye Exhibit 3

KENTUCKY UTILITIES COMPANY
Calculations to Reconstruct Test Period Billing Determinants
Based on Sales for the 12 months ended April 30, 2008

	Revenue As Billed	FAC Billings	DSM Billings	STOD Revenue Billings	ECR Billings	Merger Surcredit Billings	VDT Billings	Actual Net Revenue @ Base Rates	Calculated Net Revenue @ Base Rates	Calculated divided by Actual
Residential Rate - RS (Rate Code 010, 050)	$ 197,003,064	$ 19,060,244	$ 1,864,972	$ -	$ 9,607,997	$ (3,268,410)	$ (600,206)	$ 170,338,466	$ 170,338,463	1.000000
Residential Rate - RS (Rate Code 020, 060, 080)	222,655,120	19,494,791	2,134,596	-	11,018,002	(3,663,349)	(680,911)	194,351,991	194,352,011	1.000000
General Service Rate GS - Secondary	136,859,057	11,275,338	123,092	-	6,655,712	(2,258,368)	(416,427)	121,479,709	121,480,331	1.000005
General Service Rate GS - Primary	3,021,555	274,544	2,670	-	150,004	(50,423)	(9,403)	2,654,163	2,653,580	0.999780
All Electric School Service Rate - AES	7,663,579	787,436	-	-	375,761	(125,127)	(23,364)	6,648,873	6,648,873	1.000000
Large Power Rate LPS - Secondary	217,223,215	24,379,776	240,135	227,817	10,481,169	(3,549,075)	(660,193)	186,103,586	186,103,494	1.000000
Large Power Rate LPP - Primary	83,319,658	10,427,117	45,915	97,494	4,017,666	(1,260,029)	(253,206)	70,244,702	70,244,655	0.999999
Large Power Rate LPT - Transmission	1,313,122	161,188	2,128	1,566	63,713	(21,533)	(3,988)	1,110,048	1,110,048	1.000000
Small Time-of-Day - STODS Secondary	9,082,582	1,224,906	15,427	-	439,535	(149,681)	(27,621)	7,580,016	7,580,016	1.000000
Small Time-of-Day - STODP Primary	729,069	100,431	215	-	35,498	(11,935)	(2,222)	607,081	607,081	1.000000
Small Time-of-Day - STODT Transmission	-	-	-	-	-	-	-	-	-	-
Large Comm./Industrial Time-of-Day - LCI-TOD Primary	129,809,288	17,522,144	-	-	6,234,214	(1,535,989)	(394,429)	107,983,348	107,983,352	1.000000
Large Comm./Industrial Time-of-Day - LCI-TOD Transmission	39,511,303	5,206,819	-	-	1,899,790	(460,770)	(120,177)	32,985,640	32,985,584	0.999998
Curtailable Service Rider Credits - Primary - LCI - TOD Primary	(96,313)	-	-	-	-	-	-	(96,313)	(96,313)	1.000000
Curtailable Service Rider Credits - Transmission - LCI- TOD Transmis:	(5,446,292)	-	-	-	-	-	-	(5,446,292)	(5,446,292)	1.000000
Large Industrial Time of Day - LITOD	22,399,707	2,270,232	-	-	1,074,397	(365,961)	(68,105)	19,489,144	19,489,144	1.000000
Coal Mining Power Service Rate - MP Primary	6,647,736	653,476	-	-	322,307	(108,485)	(20,228)	5,800,666	5,800,623	0.999993
Coal Mining Power Service Rate - MP Transmission	3,858,666	422,307	-	-	185,612	(63,911)	(11,701)	3,326,359	3,326,357	0.999999
Large Mine Power Time-of-Day Rate - LMP-TPD Primary	4,738,075	547,364	-	-	226,784	(77,434)	(14,392)	4,055,754	4,055,754	1.000000
Large Mine Power Time-of-Day Rate - LMP-TPD Transmission	13,387,918	1,666,608	-	-	653,513	(218,899)	(40,804)	11,327,500	11,352,111	1.002173
Street Lighting - SL	7,312,070	257,077	-	-	351,684	(120,138)	(22,193)	6,845,641	6,845,645	1.000001
Decorative Street Lighting - SLDEC	1,378,194	21,385	-	-	62,946	(23,165)	(4,259)	1,321,287	1,321,428	1.000106
Private Outdoor Lighting - POL	4,076,501	191,922	-	-	196,490	(66,864)	(12,408)	3,767,361	3,767,454	1.000025
Customer Outdoor Lighting - OL	6,015,216	294,158	-	-	289,759	(98,990)	(19,315)	5,549,604	5,536,867	0.997705
TOTAL	$ 1,112,462,089	$ 116,239,264	$ 4,429,149	$ 326,877	$ 54,342,552	$ (17,498,536)	$ (3,405,550)	$ 958,028,333	$ 958,040,265	1.000012

KENTUCKY UTILITIES COMPANY
Calculations to Reconstruct Test Period Billing Determinants
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Base Rates Billings During 12 Month Period - As Billed				
	Bills	May 07-Nov07 Pre-Rollin KWH	Dec07-Apr 08 Post-Rollin KWH	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007	Base Rates Billings
RS - Rate Codes 010, 050						
Customer Charges	2,670,330			$ 5.00	$ 5.00	$ 13,351,650
All Energy		1,818,445,872	1,213,529,725	$ 0.04865	$ 0.05646	156,983,280
Minimum Energy						3,533
Total Calculated at Base Rates						$ 170,338,463
Correction Factor						1.000000
Total After Application of Correction Factor						$ 170,338,466
Fuel Clause Billings						19,060,244
Demand Side Management						1,864,972
Environmental Surcharge						9,607,997
Merger Surcredit						(3,268,410)
Value Delivery Surcredit						(600,206)
Total						$ 197,003,064

KENTUCKY UTILITIES COMPANY
Calculations to Reconstruct Test Period Billing Determinants
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)		(7)
		Base Rates Billings During 12 Month Period - As Billed					
	Bills	May 07-Nov07 Pre-Rollin KWH	Dec07-Apr 08 Post-Rollin KWH	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007		Base Rates Billings
RS - Rate Codes 020, 060, 080							
Customer Charges	2,287,781			$ 5.00	$ 5.00		11,438,905
All Energy		1,634,759,465	1,831,074,189	$ 0.04865	$ 0.05646		182,913,497
Minimum Energy							(391)
Total Calculated at Base Rates							194,352,011
Correction Factor							1.000000
Total After Application of Correction Factor						$	194,351,991
Fuel Adjustment Clause							19,494,791
Demand Side Management							2,134,596
Environmental Surcharge							11,018,002
Merger Surcredit							(3,663,349)
Value Delivery Surcredit							(680,911)
Total						$	222,655,120

KENTUCKY UTILITIES COMPANY
Calculations to Reconstruct Test Period Billing Determinants
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
				Base Rates Billings During 12 Month Period - As Billed		
	Bills	May 07-Nov07 Pre-Rollin KWH	Dec07-Apr 08 Post-Rollin KWH	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007	Base Rates Billings
GSS - Rate Codes 110, 113, 150, 153, 710						
Customer Charges	938,420			$ 10.00	$ 10.00	9,384,200
All KWH		1,044,935,068	774,676,043	$ 0.05818	$ 0.06599	111,915,194
Minimum Energy						180,937
Total Calculated at Base Rates						121,480,331
Correction Factor						1.000005
Total After Application of Correction Factor						$ 121,479,709
Fuel Adjustment Clause						11,275,338
Demand Side Management						123,092
Environmental Surcharge						6,655,712
Merger Surcredit						(2,258,368)
Value Delivery Surcredit						(416,427)
Total						$ 136,859,057

KENTUCKY UTILITIES COMPANY
Calculations to Reconstruct Test Period Billing Determinants
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)		(7)
		Base Rates Billings During 12 Month Period - As Billed					
		May 07-Nov07	Dec07-Apr 08	P.S.C. 13	P.S.C. 13		
		Pre-Rollin	Post-Rollin	Effective	Effective		Base Rates
	Bills	KWH	KWH	*3/5/2007*	*12/3/2007*		*Billings*
GSP - Rate Codes 111, 151							
Customer Charges	872			$ 10.00	$ 10.00	$	8,720
All KWH		22,733,271	20,987,413	$ 0.05818	$ 0.06599		2,707,581
Minimum Energy							75,205
Demand Discount							(137,925)
Total Calculated at Base Rates						$	2,653,580
Correction Factor							0.999780
Total After Application of Correction Factor						$	2,654,163
Fuel Adjustment Clause							274,544
Demand Side Management							2,670
Environmental Surcharge							150,004
Merger Surcredit							(50,423)
Value Delivery Surcredit							(9,403)
Total						$	3,021,555

KENTUCKY UTILITIES COMPANY
Calculations to Reconstruct Test Period Billing Determinants
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Base Rates Billings During 12 Month Period - As Billed				
		May 07-Nov07 Pre-Rollin	Dec07-Apr 08 Post-Rollin	P.S.C. 13 Effective	P.S.C. 13 Effective	Base Rates
	Bills	KWH	KWH	3/5/2007	12/3/2007	Billings
AES - Rate Code 220						
Number of Customers	3,668					
All KWH		69,895,101	62,036,824	$ 0.04672	$ 0.05453	$ 6,648,367
Minimum Energy						506
Total Calculated at Base Rates						$ 6,648,873
Correction Factor						1.000000
Total After Application of Correction Factor						$ 6,648,873
Fuel Adjustment Clause						787,436
Demand Side Management						-
Environmental Surcharge						375,761
Merger Surcredit						(125,127)
Value Delivery Surcredit						(23,364)
Total						$ 7,663,579

KENTUCKY UTILITIES COMPANY
Calculations to Reconstruct Test Period Billing Determinants
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
				Base Rates Billings During 12 Month Period - As Billed		
	Bills	May 07-Nov07 Pre-Rollin KWH	Dec07-Apr 08 Post-Rollin KWH	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007	Base Rates Billings
LPS - Rate Codes 562, 568						
Customer Charges	107,045			$ 75.00	$ 75.00	$ 8,028,375
Demand (KW)		5,995,381	3,895,477	$ 7.20	$ 7.20	71,214,175
Minimum Demand Charges						433,877
All KWH		2,331,392,952	1,465,616,331	$ 0.02501	$ 0.03282	106,409,666
Minimum Energy						17,402
Total Calculated at Base Rates						$ 186,103,494
Correction Factor						1.000000
Total After Application of Correction Factor						$ 186,103,586
Fuel Adjustment Clause						24,379,776
Demand Side Management						240,135
STOD						227,817
Environmental Surcharge						10,481,169
Merger Surcredit						(3,549,075)
Value Delivery Surcredit						(660,193)
Total						$ 217,223,215

KENTUCKY UTILITIES COMPANY
Calculations to Reconstruct Test Period Billing Determinants
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Base Rates Billings During 12 Month Period - As Billed				
	Bills	May 07-Nov07 Pre-Rollin KWH	Dec07-Apr 08 Post-Rollin KWH	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007	Base Rates Billings
LPP - Rate Codes 561, 566						
Customer Charges	4,202			$ 75.00	$ 75.00	$ 315,150
Demand (KW)		2,168,901	1,403,453	$ 6.81	$ 6.81	24,327,730
Minimum Demand Charges						62,182
All KWH		994,814,556	630,060,877	$ 0.02501	$ 0.03282	45,558,910
Minimum Energy						(19,317)
Total Calculated at Base Rates						$ 70,244,655
Correction Factor						0.999999
Total After Application of Correction Factor						$ 70,244,702
Fuel Adjustment Clause						10,427,117
Demand Side Management						45,915
STOD						97,494
Environmental Surcharge						4,017,666
Merger Surcredit						(1,260,029)
Value Delivery Surcredit						(253,206)
Total						$ 83,319,658

KENTUCKY UTILITIES COMPANY
Calculations to Reconstruct Test Period Billing Determinants
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Base Rates Billings During 12 Month Period - As Billed				
	Bills	May 07-Nov07 Pre-Rollin KWH	Dec07-Apr 08 Post-Rollin KWH	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007	Base Rates Billings
LPT - Rate Codes 560, 567						
Customer Charges	24			$ 75.00	$ 75.00	$ 1,800
Demand (KW)		33,354	23,822	$ 6.47	$ 6.47	369,929
Minimum Demand Charges						0
All KWH		15,146,285	10,953,981	$ 0.02501	$ 0.03282	738,318
Minimum Energy						(0)
Total Calculated at Base Rates						$ 1,110,048
Correction Factor						1.000000
Total After Application of Correction Factor						$ 1,110,048
Fuel Adjustment Clause						161,188
Demand Side Management						2,128
STOD						1,566
Environmental Surcharge						63,713
Merger Surcredit						(21,533)
Value Delivery Surcredit						(3,988)
Total						$ 1,313,122

KENTUCKY UTILITIES COMPANY
Calculations to Reconstruct Test Period Billing Determinants
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Base Rates Billings During 12 Month Period - As Billed				
	Bills	May 07-Nov07 Pre-Rollin KWH/ KW	Dec07-Apr 08 Post-Rollin KWH/ KW	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007	Base Rates *Billings*
LCIP - Rate Code 563						
Customer Charge	466			$ 120.00	$ 120.00	$ 55,920
On-Peak Demand (KW)		3,152,690	2,043,321	$ 5.16	$ 5.16	26,811,416
Off-Peak Demand (KW)		3,113,365	2,028,544	$ 0.74	$ 0.74	3,805,012
Minimum Demand						-
Energy		1,660,264,625	1,086,994,384	$ 0.02501	$ 0.03282	77,198,374
Minimum Energy						112,630
Total Calculated at Base Rates						$ 107,983,352
Correction Factor						1.000000
Total After Application of Correction Factor						$ 107,983,348
Fuel Adjustment Clause						17,522,144
Demand Side Management						-
STOD						-
Environmental Surcharge						6,234,214
Merger Surcredit						(1,535,989)
Value Delivery Surcredit						(394,429)
Total						$ 129,809,288
CSR-1		18,262	11,836	$ (3.20)	(3.20)	(96,312.96)

KENTUCKY UTILITIES COMPANY
Calculations to Reconstruct Test Period Billing Determinants
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)		(7)
		Base Rates Billings During 12 Month Period - As Billed					
		May 07-Nov07 Pre-Rollin KWH	Dec07-Apr 08 Post-Rollin KWH	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007		Base Rates Billings
	Bills						
LCIT - Rate Code 564							
Customer Charge	79			$ 120.00	$ 120.00	$	9,480
On-Peak Demand (KW)		922,037	668,312	$ 4.97	$ 4.97		7,904,037
Off-Peak Demand (KW)		916,753	660,628	$ 0.74	$ 0.74		1,167,262
Minimum Demand							-
Energy		478,660,031	363,298,346	$ 0.02501	$ 0.03282		23,894,739
Minimum Energy							10,067
Total Calculated at Base Rates						$	32,985,584
Correction Factor							0.999998
Total After Application of Correction Factor						$	32,985,640
Fuel Adjustment Clause							5,206,819
Demand Side Management							-
STOD							-
Environmental Surcharge							1,899,790
Merger Surcredit							(460,770)
Value Delivery Surcredit							(120,177)
Total						$	39,511,303
CSR -3		1,018,580	738,288	$ (3.10)	(3.10)		(5,446,292.04)

KENTUCKY UTILITIES COMPANY
Calculations to Reconstruct Test Period Billing Determinants
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Base Rates Billings During 12 Month Period - As Billed				
		May 07-Nov07	Dec07-Apr 08	P.S.C. 13	P.S.C. 13	
		Pre-Rollin	Post-Rollin	Effective	Effective	Base Rates
	Bills	KWH	KWH	3/5/2007	12/3/2007	Billings
STOD-T Rate Code 580						
Customer	-					
Demand						
Minimum Demand						
On Peak Energy						
Off Peak Energy						
Minimum Energy						
Total Calculated at Base Rates						
Correction Factor						
Total After Application of Correction Factor						
Fuel Adjustment Clause						
Demand Side Management						
STOD						
Environmental Surcharge						
Merger Surcredit						
Value Delivery Surcredit						
Total						

KENTUCKY UTILITIES COMPANY
Calculations to Reconstruct Test Period Billing Determinants
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)		(7)
		Base Rates Billings During 12 Month Period - As Billed					
	Bills	May 07-Nov07 Pre-Rollin KWH	Dec07-Apr 08 Post-Rollin KWH	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007		Base Rates Billings
STOD-P Rate Code 582							
Customer	24			$ 90.00	$ 90.00	$	2,160
Demand (KW)		15,650	11,288	$ 6.81	$ 6.81		183,451
Minimum Demand							0
On Peak Energy		3,504,400	4,483,694	$ 0.03098	$ 0.03879		282,489
Off Peak Energy		5,698,000	2,163,106	$ 0.01815	$ 0.02596		159,573
Minimum Energy							(20,591)
Total Calculated at Base Rates						$	607,081
Correction Factor							1.000000
Total After Application of Correction Factor						$	607,081
Fuel Adjustment Clause							100,431
Demand Side Management							215
STOD							-
Environmental Surcharge							35,498
Merger Surcredit							(11,935)
Value Delivery Surcredit							(2,222)
Total						$	729,069

KENTUCKY UTILITIES COMPANY
Calculations to Reconstruct Test Period Billing Determinants
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
				Base Rates Billings During 12 Month Period - As Billed		
	Bills	May 07-Nov07 Pre-Rollin KWH	Dec07-Apr 08 Post-Rollin KWH	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007	Base Rates Billings
STOD-S Rate Code 584						
Customer	612			$ 90.00	$ 90.00	$ 55,080
Demand (KW)		221,177	130,202	$ 7.20	$ 7.20	2,529,930
Minimum Demand						-
On Peak Energy		46,309,534	48,314,928	$ 0.03098	$ 0.03879	3,308,805
Off Peak Energy		71,038,766	23,641,056	$ 0.01815	$ 0.02596	1,903,075
Minimum Energy						(216,875)
Total Calculated at Base Rates						$ 7,580,016
Correction Factor						1.000000
Total After Application of Correction Factor						$ 7,580,016
Fuel Adjustment Clause						1,224,906
Demand Side Management						15,427
STOD						-
Environmental Surcharge						439,535
Merger Surcredit						(149,681)
Value Delivery Surcredit						(27,621)
Total						$ 9,082,582

KENTUCKY UTILITIES COMPANY

Calculations to Reconstruct Test Period Billing Determinants
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Base Rates Billings During 12 Month Period - As Billed				
	Bills	May 07-Nov07 Pre-Rollin KWH	Dec07-Apr 08 Post-Rollin KWH	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007	Base Rates Billings
MPP - Rate Codes 681, 686						
Customer Charge	364			$ 75.00	$ 75.00	$ 27,300
Demand (KW)		227,977	183,230	$ 5.10	$ 5.10	2,097,153
Minimum demand billings						5,523
All KWH		58,000,865	51,955,814	$ 0.02698	$ 0.03479	3,372,406
Minimum energy billings						298,241
Total Calculated at Base Rates						$ 5,800,623
Correction Factor						0.999993
Total After Application of Correction Factor						$ 5,800,666
Fuel Adjustment Clause						653,476
Demand Side Management						-
Environmental Surcharge						322,307
Merger Surcredit						(108,485)
Value Delivery Surcredit						(20,228)
Total						$ 6,647,736

KENTUCKY UTILITIES COMPANY

Calculations to Reconstruct Test Period Billing Determinants
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Base Rates Billings During 12 Month Period - As Billed				
		May 07-Nov07 Pre-Rollin	Dec07-Apr 08 Post-Rollin	P.S.C. 13 Effective	P.S.C. 13 Effective	Base Rates
	Bills	KWH	KWH	3/5/2007	12/3/2007	Billings
MPT - Rate Codes 680, 687						
Customer Charge	123			$ 75.00	$ 75.00	$ 9,225.00
Demand (KW)		128,261	93,959	$ 4.98	$ 4.98	1,106,652
Minimum demand billings						2,473
All KWH		39,129,000	29,949,000	$ 0.02698	$ 0.03479	2,097,626
Minimum energy billings						110,381
Total Calculated at Base Rates						$ 3,326,357
Correction Factor						0.999999
Total After Application of Correction Factor						$ 3,326,359
Fuel Adjustment Clause						422,307
Demand Side Management						-
Environmental Surcharge						185,612
Merger Surcredit						(63,911)
Value Delivery Surcredit						(11,701)
Total						$ 3,858,666

KENTUCKY UTILITIES COMPANY
Calculations to Reconstruct Test Period Billing Determinants
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Base Rates Billings During 12 Month Period - As Billed				
	Bills	May 07-Nov07 Pre-Rollin KWH	Dec07-Apr 08 Post-Rollin KWH	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007	Base Rates Billings
LMPP - Rate Code 683						
Customer Charge	39			$ 120.00	$ 120.00	$ 4,680
On-Peak Demand (KW)		163,035	108,720	$ 5.75	$ 5.75	1,562,591
Off-Peak Demand (KW)		159,014	105,024	$ 0.74	$ 0.74	195,388
Minimum Demand Charge						-
Energy		50,315,519	36,837,600	$ 0.02301	$ 0.03082	2,293,095
Minimum Energy Charge						0
Total Calculated at Base Rates						$ 4,055,754
Correction Factor						1.000000
Total After Application of Correction Factor						$ 4,055,754
Fuel Adjustment Clause						547,364
Demand Side Management						-
Environmental Surcharge						226,784
Merger Surcredit						(77,434)
Value Delivery Surcredit						(14,392)
Total						$ 4,738,075

KENTUCKY UTILITIES COMPANY
Calculations to Reconstruct Test Period Billing Determinants
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)		(7)
		Base Rates Billings During 12 Month Period - As Billed					
	Bills	May 07-Nov07 Pre-Rollin KWH	Dec07-Apr 08 Post-Rollin KWH	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007		Base Rates Billings
LMPT - Rate Code 684							
Customer Charge	82			$ 120.00	$ 120.00	$	9,840
On-Peak Demand (KW)		408,148	308,670	$ 5.21	$ 5.21		3,734,623
Off-Peak Demand (KW)		398,992	288,449	$ 0.74	$ 0.74		508,706
Minimum Demand Charge							-
Energy		149,682,000	118,584,000	$ 0.02301	$ 0.03082		7,098,942
Minimum Energy Charge							-
Total Calculated at Base Rates						$	11,352,111
Correction Factor							1.002173
Total After Application of Correction Factor						$	11,327,500
Fuel Adjustment Clause							1,666,608
Demand Side Management							-
Environmental Surcharge							653,513
Merger Surcredit							(218,899)
Value Delivery Surcredit							(40,804)
Total						$	13,387,918

KENTUCKY UTILITIES COMPANY

Calculations to Reconstruct Test Period Billing Determinants
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)		(7)
		Base Rates Billings During 12 Month Period - As Billed					
	Bills	May 07-Nov07 Pre-Rollin KWH	Dec07-Apr 08 Post-Rollin KWH	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007		Base Rates Billings
LI-TOD Billing Code 730							
Customer Charge	12			$ 120.00	$ 120.00	$	1,440
On-Peak Demand (KW)		836,325	683,968	$ 4.66	$ 4.66		7,084,567
Off-Peak Demand (KW)		1,016,107	673,454	$ 0.74	$ 0.74		1,250,275
Minimum Demand Charge							-
Energy		205,563,639	183,172,320	$ 0.02501	$ 0.03282		11,152,862
Minimum Energy Charge							0
Total Calculated at Base Rates						$	19,489,144
Correction Factor							1.000000
Total After Application of Correction Factor						$	19,489,144
Fuel Adjustment Clause							2,270,232
Demand Side Management							-
Environmental Surcharge							1,074,397
Merger Surcredit							(365,961)
Value Delivery Surcredit							(68,105)
Total						$	22,399,707

KENTUCKY UTILITIES COMPANY
Calculations to Reconstruct Test Period Billing Determinants
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
				Base Rates Billings During 12 Month Period - As Billed		
	KWH	May 07-Nov07 Pre-Rollin Lights	Dec07-Apr 08 Post-Rollin Lights	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007	Base Rates Billings
Street Lighting						
Incandescent Street Lighting						
01000L INC STD ST LT *	30,601	525	375	$ 2.43	$ 2.70	$ 2,288
02500L INC STD ST LT *	1,028,530	9,078	6,294	$ 3.04	$ 3.56	50,004
04000L INC STD ST LT *	500,061	2,847	1,751	$ 4.40	$ 5.25	21,720
06000L INC STD ST LT *	6,650	31	15	$ 5.88	$ 7.04	288
02500L INC ORN ST LT *	6,432	56	40	$ 3.87	$ 4.39	392
04000L INC ORN ST LT *	52,140	299	185	$ 5.37	$ 6.22	2,756
06000L INC ORN ST LT *	2,561	20	-	$ 6.95	$ 8.11	139
Mercury Vapor Street Lighting						
07000L MV STD ST LT	1,128,653	9,701	6,680	$ 7.04	$ 7.58	118,929
010000L MV STD ST LT	1,119,282	6,762	4,665	$ 8.18	$ 8.95	97,065
020000L MV STD ST LT	3,088,066	12,002	8,460	$ 9.72	$ 10.90	208,873
07000L MV ORN ST LT	103,502	875	625	$ 9.36	$ 9.90	14,378
010000L MV ORN ST LT	634,541	3,796	2,678	$ 10.24	$ 11.01	68,356
020000L MV ORN ST LT	2,649,502	10,291	7,264	$ 11.38	$ 12.56	208,347
High Pressure Sodium Street Lighting						
05800L HPS DEC ACORN	1,992	42	30	$ 11.34	$ 11.56	823
09500L HPS DEC ACORN	64,530	934	716	$ 12.06	$ 12.37	20,121
04000L HPS HISTORIC AC	35,760	1,043	745	$ 16.84	$ 17.00	30,229
05800L HPS HISTORIC AC	23,905	504	360	$ 17.41	$ 17.63	15,121
09500L HPS HISTORIC AC	188,349	2,779	2,040	$ 18.15	$ 18.46	88,097
05800L HPS POL	61,534	1,129	968	$ 4.55	$ 4.77	9,754
04000L HPS STD ST LT	1,685,220	49,211	35,048	$ 5.21	$ 5.37	444,597
05800L HPS STD ST LT	2,822,338	59,470	42,540	$ 5.67	$ 5.89	587,756
09500L HPS STD ST LT	9,120,054	135,679	98,038	$ 6.40	$ 6.71	1,526,181
022000L HPS STD ST LT	5,356,942	38,613	27,786	$ 9.54	$ 10.17	650,952
050000L HPS STD ST LT	1,599,629	5,761	4,133	$ 15.49	$ 16.75	158,466
04000L HPS ORN ST LT	943,032	27,613	19,552	$ 7.90	$ 8.06	375,732
05800L HPS ORN ST LT	2,762,804	58,126	41,697	$ 8.36	$ 8.58	843,694
09500L HPS ORN ST LT	1,278,676	18,871	13,893	$ 9.29	$ 9.60	308,684
022000L HPS ORN ST LT	4,158,893	29,900	21,618	$ 12.41	$ 13.04	652,958
050000L HPS ORN ST LT	859,382	3,108	2,208	$ 18.35	$ 19.61	100,331

KENTUCKY UTILITIES COMPANY
Calculations to Reconstruct Test Period Billing Determinants
Based on Sales for the 12 months ended April 30, 2008

High Pressure Sodium Granville Configurations									-
016000L GRANVILLE STL	75,007	875	625	$	39.52	$	39.92		59,530
016000L GRANVILLE STL	16,201	189	135	$	63.97	$	64.37		20,780
016000L GRANVILLE STL	25,201	294	210	$	43.42	$	43.82		21,968
016000L GRANVILLE STL	3,000	35	25	$	45.15	$	45.55		2,719
016000L GRANVILLE STL	600	7	5	$	46.34	$	46.74		558
016000L GRANVILLE STL	3,600	42	30	$	62.00	$	62.40		4,476
016000L GRANVILLE STL	5,999	70	50	$	60.27	$	60.67		7,252
016000L GRANVILLE STL	-	-	-	$	44.83	$	45.23		-
016000L GRANVILLE STL	1,200	14	10	$	40.72	$	41.12		981
016000L GRANVILLE STL	9,001	105	75	$	56.37	$	56.77		10,177
016000L GRANVILLE STL	-	-	-	$	81.05	$	81.45		-
016000L GRANVILLE STL	600	7	5	$	63.19	$	63.59		760
016000L GRANVILLE STL	12,001	140	100	$	56.37	$	56.77		13,569
016000L GRANVILLE STL	2,400	28	20	$	57.57	$	57.97		2,771
016000L GRANVILLE STL	1,800	21	15	$	60.27	$	60.67		2,176
016000L GRANVILLE STL	15,603	182	130	$	58.79	$	59.19		18,394
016000L GRANVILLE STL	30,602	357	255	$	47.30	$	47.70		29,050
016000L GRANVILLE STL	5,401	63	45	$	40.72	$	41.12		4,416
0107800L MH DIRECTION	381,116	620	437	$	35.77	$	38.58		39,037
Sub-Total	41,902,893	492,115	352,576					$	6,845,645
Total Calculated at Base Rates								$	6,845,645
Correction Factor									1.000001
Total After Application of Correction Factor								$	6,845,641
Fuel Adjustment Clause									257,077
Demand Side Management									-
Environmental Surcharge									351,684
Merger Surcredit									(120,138)
Value Delivery Surcredit									(22,193)
Total								$	7,312,070

KENTUCKY UTILITIES COMPANY
Calculations to Reconstruct Test Period Billing Determinants
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Base Rates Billings During 12 Month Period - As Billed				
	KWH	May 07-Nov07 Pre-Rollin Lights	Dec07-Apr 08 Post-Rollin Lights	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007	Base Rates Billings
Street Lighting -- Decorative						
04000L HPS COLONIAL S'	160,854	4,616	3,406	$ 7.11	$ 7.27	$ 57,581
05800L HPS COLONIAL S'	309,845	6,459	4,730	$ 7.60	$ 7.82	86,077
09500L HPS COLONIAL S'	619,118	8,766	7,020	$ 8.25	$ 8.56	132,411
032000L MH DIRECTION,	388,127	1,431	1,144	$ 21.67	$ 22.84	57,139
05800L HPS CONTEMPOF	1,260,005	37,741	19,360	$ 13.04	$ 13.26	748,856
09500L HPS CONTEMPOF	234,286	4,127	2,520	$ 15.56	$ 15.87	104,209
022000L HPS CONTEMPO	445,967	4,131	2,314	$ 18.16	$ 18.79	118,499
050000L HPS CONTEMPO	102,820	424	265	$ 23.69	$ 24.95	16,656
Sub-Total	3,521,022	67,695	40,759			$ 1,321,428
Partial Month billings						
Total Calculated at Base Rates						$ 1,321,428
Correction Factor						1.000106
Total After Application of Correction Factor						$ 1,321,287
Fuel Adjustment Clause						21,385
Demand Side Management						-
Environmental Surcharge						62,946
Merger Surcredit						(23,165)
Value Delivery Surcredit						(4,259)
Total						$ 1,378,194

KENTUCKY UTILITIES COMPANY
Calculations to Reconstruct Test Period Billing Determinants
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Base Rates Billings During 12 Month Period - As Billed				
	KWH	May 07-Nov07 Pre-Rollin Lights	Dec07-Apr 08 Post-Rollin Lights	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007	Base Rates Billings
Private Outdoor Lighting						
Decorative (Served Underground)						
04000L HPS COLONIAL D	12,031	360	245	$ 7.11	$ 7.27	$ 4,341
05800L HPS COLONIAL D	57,712	1,197	886	$ 7.60	$ 7.82	16,026
09500L HPS COLONIAL D	778,055	11,352	8,575	$ 8.25	$ 8.56	167,056
05800L HPS CONTEMPOF	16,936	357	255	$ 13.04	$ 13.26	8,037
09500L HPS CONTEMPOF	129,472	1,914	1,406	$ 15.56	$ 15.87	52,095
022000 HPS CONTEMPOR	621,161	4,459	3,241	$ 18.16	$ 18.79	141,874
050000 HPS CONTEMPOR	1,706,928	6,100	4,450	$ 23.69	$ 24.95	255,537
Directional (Served Overhead)						
09500L HPS DIRECTIONA	4,867,927	72,353	52,209	$ 6.27	$ 6.58	797,189
022000L HPS DIRECTION	5,933,517	42,702	30,891	$ 8.98	$ 9.61	680,326
050000L HPS DIRECTION	14,702,952	52,740	38,189	$ 13.78	$ 15.04	1,301,120
Metal Halide Contemporary						
012000L MH CONTEMPO	45,669	382	280	$ 10.42	$ 10.96	7,049
012000L MH CONTEMPO	143,197	1,204	872	$ 19.04	$ 19.58	39,998
032000L MH CONTEMPO	522,484	2,010	1,467	$ 14.65	$ 15.82	52,654
032000L MH CONTEMPO	979,440	3,664	2,829	$ 23.25	$ 24.42	154,272
0107800L MH CONTEMP(	207,637	359	225	$ 29.78	$ 32.59	18,024
0107800L MH CONTEMP(	652,302	1,077	741	$ 38.38	$ 41.19	71,857
Sub-Total	31,377,420	202,230	146,761			$ 3,767,454
Total Calculated at Base Rates						$ 3,767,454
Correction Factor						1.000025
Total After Application of Correction Factor						$ 3,767,361
Fuel Adjustment Clause						191,922
Demand Side Management						-
Environmental Surcharge						196,490
Merger Surcredit						(66,864)
Value Delivery Surcredit						(12,408)
Total						$ 4,076,501

KENTUCKY UTILITIES COMPANY
Calculations to Reconstruct Test Period Billing Determinants
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
			Base Rates Billings During 12 Month Period - As Billed			
		May 07-Nov07 Pre-Rollin Lights	Dec07-Apr 08 Post-Rollin Lights	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007	
	KWH					Base Rates Billings
Outdoor Lighting						
02500L INC COL *	-	-	-	$ 5.10	$ 5.10	$ -
03500L MV COL *	-	-	-	$ 6.23	$ 6.23	-
07000L MV COL *	2,484	14	10	$ 7.34	$ 7.34	176
020000L MV SPECIAL LIC	812,654	3,171	2,219	$ 6.76	$ 6.76	36,436
050000L HPS SPECIAL LI(	354,052	1,286	906	$ 9.02	$ 9.02	19,772
Standard (Served Overhead)						
07000L MV POL	8,701,195	74,392	51,820	$ 8.05	$ 8.59	1,043,989
020000L MV POL	984,179	3,857	2,670	$ 9.72	$ 10.90	66,593
09500L HPS POL	15,623,163	232,154	167,488	$ 5.21	$ 5.52	2,134,056
022000L HPS POL	1,404,988	10,126	7,301	$ 9.54	$ 10.17	170,853
050000L HPS POL	4,231,587	15,245	10,922	$ 15.49	$ 16.75	419,089
Decorative (Served Underground)						
04000L HPS DEC ACORN	477	14	10	$ 10.75	$ 10.91	260
05800L HPS DEC ACORN	13,568	294	196	$ 11.34	$ 11.56	5,600
09500L HPS DEC ACORN	113,943	1,693	1,220	$ 12.07	$ 12.38	35,538
04000L HPS HIST ACORN	14,641	427	305	$ -	$ -	-
05800L HPS HIST ACORN	24,675	518	374	$ 16.84	$ 17.00	15,081
09500L HPS HIST ACORN	255,935	3,770	2,779	$ 18.15	$ 18.46	119,726
05800L HPS COACH DEC	7,969	168	120	$ 25.94	$ 26.16	7,497
05800L HPS COACH DEC	*121,707*	*1,770*	*1,350*	$ *26.58*	$ *26.89*	83,348
05800L HPS COACH DEC	6,972	147	105	$ 25.94	$ 26.16	6,560
09500L HPS COACH DEC	4,681	70	50	$ 26.58	$ 26.89	3,205
Metal Halide Directional						
012000L MH DIRECTION/	414,824	3,447	2,554	$ 9.30	$ 9.84	57,188
012000L MH DIRECTION/	98,345	812	613	$ 11.32	$ 11.86	16,462
012000L MH DIRECTION/	9,172	78	55	$ 17.91	$ 18.45	2,412
032000L MH DIRECTION/	*6,984,958*	*26,826*	*19,670*	$ *13.07*	$ *14.24*	630,717
032000L MH DIRECTION/	1,459,773	5,685	4,045	$ 15.09	$ 16.26	151,558
0107800L MH DIRECTIOI	5,071,356	8,276	5,830	$ 27.17	$ 29.98	399,642
0107800L MH DIRECTIOI	1,281,044	2,129	1,443	$ 29.97	$ 32.78	111,108
Sub-Total	47,998,342	396,369	284,055			$ 5,536,867
Total Calculated at Base Rates						$ 5,536,867
Correction Factor						0.997705
Total After Application of Correction Factor						$ 5,549,604
Fuel Adjustment Clause						294,158
Demand Side Management						-
Environmental Surcharge						289,759
Merger Surcredit						(98,990)
Value Delivery Surcredit						(19,315)
Total						$ 6,015,216

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KENTUCKY UTILITIES COMPANY
Summary of Proposed Increase
Based on Sales for the 12 months ended April 30, 2008

	Revenue Adjusted to as Billed Basis	Adjustment to Remove ECR Billings	Adjustment to Remove DSM Billings	Adjustment to Remove Merger Surcredit Billings	Adjustment to Remove Value Delivery Surcredit	Adjustment to Reflect a Full Year of Base Rate Changes for FAC Rollin	Adjustment to Reflect FAC Billings for Full Year of the Rollin	Adjustment to Reflect Full Year of Base Rate Changes for ECR Rollin	Adjustment Reflecting Year-End Number of Customers	Adjustment Reflecting Customer Rate Switching during Test Year	Adjustment Reflecting Temperature Normalization	Adjusted Billings at Current Rates
Total Residential	419,658,185	(20,625,999)	(3,999,568)	6,931,759	1,281,117	26,969,802	(26,968,415)	8,317,267	843,080	-	(6,924,469)	405,482,758
General Service Rate GS - Secondary	136,859,057	(6,655,712)	(123,092)	2,258,368	416,427	8,173,074	(8,163,701)	2,660,581	1,130,662		(1,002,779)	135,552,885
General Service Rate GS - Primary	3,021,555	(150,004)	(2,670)	50,423	9,403	164,763	(198,343)	71,094	(40,127)			2,926,095
Total General Service	139,880,612	(6,805,716)	(125,762)	2,308,790	425,830	8,337,838	(8,362,043)	2,731,675	1,090,535	-	(1,002,779)	138,478,980
All Electric School Service Rate - AES	7,663,579	(375,761)	-	125,127	23,364	545,922	(545,878)	155,692	-			7,592,045
Large Power Rate LPS - Secondary	217,223,215	(10,481,169)	(240,135)	3,549,075	660,193	18,252,448	(18,201,574)	4,461,707	(6,373,654)		(565,554)	208,284,552
Large Power Rate LPP - Primary	83,319,658	(4,017,666)	(45,915)	1,260,029	253,206	7,774,251	(7,768,615)	1,608,542	-		(195,804)	82,187,686
Large Power Rate LPT - Transmission	1,313,122	(63,713)	(2,128)	21,533	3,988	118,293	(118,292)	25,729	-		-	1,298,531
Small Time-of-Day - STODS Secondary	9,082,582	(439,535)	(15,427)	149,681	27,621	889,347	(916,875)	150,385	-		(32,622)	8,895,156
Small Time-of-Day - STODP Primary	729,069	(35,498)	(215)	11,935	2,222	69,199	(71,871)	11,395	-		-	716,236
Small Time-of-Day - STODT Transmission	-	-	-	-		-	-	-	-			-
Total Combined Lighting & Power Service	311,667,645	(15,037,581)	(303,820)	4,992,254	947,229	27,103,538	(27,077,227)	6,257,758	(6,373,654)	-	(793,981)	301,382,162
Large Comm./Industrial Time-of-Day - LCI-TOD Primary	129,809,288	(6,234,214)	-	1,535,989	394,429	12,980,212	(12,959,017)	2,520,001	-		-	128,046,688
Large Comm./Industrial Time-of-Day - LCI-TOD Transmission	39,511,303	(1,899,790)	-	460,770	120,177	3,739,483	(3,738,335)	772,635	-			38,966,242
Curtailable Service Riders - Primary - LCI -TOD Primary	(96,313)	-	-	-		-	-	-	-	-	-	(96,313)
Curtailable Service Riders - Transmission -LCI-TOD Transmission	(5,446,292)	-	-	-		-	-	-	-	-	-	(5,446,292)
Total Comm./Industrial Time-of-Day Service	163,777,986	(8,134,004)	-	1,996,759	514,605	16,719,695	(16,697,352)	3,292,636	-	-	-	161,470,325
Large Industrial Time of Day - LITOD	22,399,707	(1,074,397)	-	365,961	68,105	1,605,452	(1,605,452)	199,393	-			21,958,768
Coal Mining Power Service Rate - MP Primary	6,647,736	(322,307)	-	108,485	20,228	478,023	(451,324)	151,877	215,149			6,847,866
Coal Mining Power Service Rate - MP Transmission	3,858,666	(185,612)	-	63,911	11,701	316,330	(305,597)	80,508	-			3,839,906
Total Coal Mining Power Service	10,506,402	(507,920)	-	172,396	31,929	794,353	(756,922)	232,385	215,149	-	-	10,687,772
Large Mine Power Time-of-Day Rate - LMP-TOD Primary	4,738,075	(226,784)	-	77,434	14,392	392,964	(392,865)	113,845	-			4,717,063
Large Mine Power Time-of-Day Rate - LMP-TOD Transmission	13,387,918	(653,513)	-	218,899	40,804	1,166,482	(1,169,016)	296,131	-			13,287,705
Total Large Mine Power Time-of-Day Service	18,125,994	(880,296)	-	296,333	55,196	1,559,446	(1,561,881)	409,976	-	-	-	18,004,768
Street Lighting - SL	7,312,070	(351,684)	-	120,138	22,193	192,583	(178,863)	131,336	5,438		-	7,253,212
Decorative Street Lighting - SLDEC	1,378,194	(62,946)	-	23,165	4,259	19,268	(14,694)	24,162	(87,063)			1,284,346
Private Outdoor Lighting - POL	4,076,501	(196,490)	-	66,864	12,408	142,318	(133,089)	74,198	65,956			4,108,666
Customer Outdoor Lighting - OL	6,015,216	(289,759)	-	98,990	19,315	214,873	(205,005)	109,176	(2,475)			5,960,330
Total Private Outdoor Lighting Service	18,781,981	(900,879)	-	309,157	58,175	569,042	(531,650)	338,872	(18,144)	-	-	18,606,554
TOTAL ULTIMATE CONSUMERS	$ 1,112,462,089	$ (54,342,552)	$ (4,429,149)	$ 17,498,536	$ 3,405,550	$ 84,205,087	$ (84,106,820)	$ 21,935,653	$ (4,243,034)	$ -	$ (8,721,229)	$ 1,083,664,132
Miscellaneous Service Revenue	6,158,810											8,694,818
TOTAL JURISDICTIONAL	$ 1,118,620,900	$ (54,342,552)	$ (4,429,149)	$ 17,498,536	$ 3,405,550	$ 84,205,087	$ (84,106,820)	$ 21,935,653	$ (4,243,034)	$ -	$ (8,721,229)	$ 1,092,358,950

KENTUCKY UTILITIES COMPANY
Summary of Proposed Increase
Based on Sales for the 12 months ended April 30, 2008

	Adjusted Billings at Current Rates (see page 1)	Increase	Percentage Increase
Total Residential	405,482,758	17,329,356	4.27%
General Service Rate GS - Secondary	135,552,885		
General Service Rate GS - Primary	2,926,095	446,784	15.27%
Total General Service	138,478,980	446,784	0.32%
All Electric School Service Rate - AES	7,592,045	321,938	4.24%
Large Power Rate LPS - Secondary	208,284,552		
Large Power Rate LPP - Primary	82,187,686		
Large Power Rate LPT - Transmission	1,298,531	(70,621)	
Small Time-of-Day - STODS Secondary	8,895,156	82,070	0.92%
Small Time-of-Day - STODP Primary	716,236	6,637	0.93%
Small Time-of-Day - STODT Transmission	-		
Total Combined Lighting & Power Service	301,382,162	18,086	0.01%
Large Comm./Industrial Time-of-Day - LCI-TOD Primary	128,046,688		
Large Comm./Industrial Time-of-Day - LCI-TOD Transmission	38,966,242	(38,022)	
Curtailable Service Riders - Primary - LCI -TOD Primary	(96,313)		
Curtailable Service Riders - Transmission -LCI-TOD Transmission	(5,446,292)		
Total Comm./Industrial Time-of-Day Service	161,470,325	(38,022)	
Large Industrial Time of Day - LITOD	21,958,768		
Coal Mining Power Service Rate - MP Primary	6,847,866	575,463	8.40%
Coal Mining Power Service Rate - MP Transmission	3,839,906	100,123	2.61%
Total Coal Mining Power Service	10,687,772	675,586	6.32%
Large Mine Power Time-of-Day Rate - LMP-TOD Primary	4,717,063	29,196	0.62%
Large Mine Power Time-of-Day Rate - LMP-TOD Transmission	13,287,705	5,099	0.04%
Total Large Mine Power Time-of-Day Service	18,004,768	34,295	0.19%
Street Lighting - SL	7,253,212	304,645	4.20%
Decorative Street Lighting - SLDEC	1,284,346	61,720	4.81%
Private Outdoor Lighting - POL	4,108,666	195,020	4.75%
Customer Outdoor Lighting - OL	5,960,330	224,423	3.77%
Total Private Outdoor Lighting Service	18,606,554	785,809	4.22%
TOTAL ULTIMATE CONSUMERS	$ 1,083,664,132	19,573,832	1.81%
Miscellaneous Service Revenue	8,694,818	2,536,008	
TOTAL JURISDICTIONAL	1,092,358,950	22,109,840	2.02%

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KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
RS - Rate Codes 010, 050						
Customer Charges	2,670,330		$ 5.00	$ 13,351,650	$ 8.49	22,671,102
All Energy		3,031,975,597	$ 0.05774	175,066,271	$ 0.05774	175,066,271
Minimum Energy				3,908		4,101
Total Calculated at Base Rates				$ 188,421,829		$ 197,741,474
Correction Factor				1.0000000		1.000000
Total After Application of Correction Factor				$ 188,421,833		$ 197,741,478
Fuel Clause Billings - proforma for rollin				4,859,674		4,859,674
Adjustment to Reflect Year-End Customers				(550,029)		(577,234)
Adjustment to Reflect Temperature Normalization				(4,501,179)		(4,501,179)
Total				$ 188,230,299		$ 197,522,739
Proposed Increase						9,292,440
Percentage Increase						4.94%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
RS - Rate Codes 020, 060, 080						
Customer Charges	2,287,781		$ 5.00	$ 11,438,905	$ 8.49	19,423,261
All Energy		3,465,833,654	$ 0.05774	200,117,235	$ 0.05774	200,117,235
Minimum Energy				(426)		(442)
Total Calculated at Base Rates				$ 211,555,715		$ 219,540,054
Correction Factor				1.000000		1.000000
Total After Application of Correction Factor				$ 211,555,693		$ 219,540,032
Fuel Clause Billings - proforma for rollin				6,726,947		6,726,947
Adjustment to Reflect Year-End Customers				1,393,109		1,445,686
Adjustment to Reflect Temperature Normalization				(2,423,290)		(2,423,290)
Total				$ 217,252,459		$ 225,289,376
Proposed Increase						8,036,916
Percentage Increase						3.70%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
GSS - Rate Codes 110, 113, 150, 153, 710						
Customer Charges	938,420		$ 10.00	$ 9,384,200	$ 10.00	9,384,200
All KWH		1,819,611,111	$ 0.06745	122,732,769	$ 0.06745	122,732,769
Minimum Energy				197,073		197,073
Total Calculated at Base Rates				$ 132,314,043		$ 132,314,043
Correction Factor				1.000005		1.000005
Total After Application of Correction Factor				$ 132,313,364		$ 132,313,364
Fuel Clause Billings - proforma for rollin				3,111,638		3,111,638
Adjustment to Reflect Year-End Customers				1,130,662		1,130,662
Adjustment to Reflect Temperature Normalization				(1,002,779)		(1,002,779)
Total				$ 135,552,885		$ 135,552,885
Proposed Increase						-
Percentage Increase						0.00%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
GSP - Rate Codes 111, 151 (Customers to be Served Under Rate PS)						
Customer Charges	872		$ 10.00	$ 8,720	$ 75.00	65,400
All KWH		43,720,684	$ 0.06745	2,948,960	$ 0.03282	1,434,913
Minimum Energy				81,888		90,045
Demand (KW)	241,323				7.26	1,752,004
Demand Discount				(150,182)		-
Total Calculated at Base Rates				$ 2,889,386		$ 3,342,361
Correction Factor				0.999780		0.999780
Total After Application of Correction Factor				$ 2,890,020		$ 3,343,095
Fuel Clause Billings - proforma for rollin				76,202		76,202
VDT Amortization & Surcredit Adjustment				-		-
Adjustment to Reflect Year-End Customers				(40,127)		(46,418)
Adjustment to Reflect Temperature Normalization				-		-
Total				$ 2,926,095		3,372,879
Proposed Increase						446,784
Percentage Increase						15.27%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
AES - Rate Code 220						
Number of Customers	3,668					
All KWH		131,931,925	$ 0.05571	$ 7,349,928	$ 0.05815	7,671,841
Minimum Energy				559	(335,544)	584
Total Calculated at Base Rates				$ 7,350,487.00		7,672,425
Correction Factor				1.000000		1.000000
Total After Application of Correction Factor				$ 7,350,487		$ 7,672,425
Fuel Clause Billings - proforma for rollin				241,558		241,558
VDT Amortization & Surcredit Adjustment				-		-
Adjustment to Reflect Year-End Customers				-		-
Adjustment to Reflect Temperature Normalization				-		-
Total				$ 7,592,045		$ 7,913,983
Proposed Increase						321,938
Percentage Increase						4.24%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills /kW	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
LPS - Rate Codes 562, 568 (Renamed Rate PS-Secondary)						
Customer Charges	107,045		$ 75.00	$ 8,028,375	$ 75.00	$ 8,028,375
Demand (KW)	9,890,858		$ 7.65	75,665,061	$ 7.65	75,665,061
Minimum Demand Charges				486,832		486,832
All KWH		3,797,009,283	$ 0.03282	124,617,845	$ 0.03282	124,617,845
Minimum Energy				19,525		19,525
Total Calculated at Base Rates				$ 208,817,638		$ 208,817,638
Correction Factor				1.000000		1.000000
Total After Application of Correction Factor				$ 208,817,741		$ 208,817,741
Fuel Clause Billings - proforma for rollin				6,178,202		6,178,202
STOD Billings				227,817		227,817
Adjustment to Reflect Year-End Customers				(6,373,654)		(6,373,654)
Adjustment to Reflect Temperature Normalization				(565,554)		(565,554)
Total				$ 208,284,552		$ 208,284,552
Proposed Increase						-
Percentage Increase						0.00%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
LPP - Rate Codes 561, 566 (Renamed Rate PS-Primary)						
Customer Charges	4,202		$ 75.00	$ 315,150	$ 75.00	315,150
Demand (KW)	3,572,354		$ 7.26	25,935,289	$ 7.26	25,935,289
Minimum Demand Charges				70,488		70,488
All KWH		1,624,875,433	$ 0.03282	53,328,412	$ 0.03282	53,328,412
Minimum Energy				(21,897)		(21,897)
Total Calculated at Base Rates				$ 79,627,441		$ 79,627,441
Correction Factor				0.999999		0.999999
Total After Application of Correction Factor				$ 79,627,495		$ 79,627,495
Fuel Clause Billings - proforma for rollin				2,658,502		2,658,502
STOD Billings				97,494		97,494
VDT Amortization & Surcredit Adjustment				-		-
Adjustment to Reflect Year-End Customers				-		-
Adjustment to Reflect Temperature Normalization				(195,804)		(195,804)
Total				$ 82,187,686		$ 82,187,686
Proposed Increase						-
Percentage Increase						0.00%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills/ KW	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
LPT - Rate Codes 560, 567 (Customers to be Served Under Rate RTS)						
Customer Charges	24		$ 75.00	$ 1,800	$ 120.00	2,880
Demand (KW)	57,176		$ 6.92	395,659		
On-Peak Demand (KVA)	60,593				$ 4.39	266,002
Off-Peak Demand (KVA)	58,217				$ 1.13	65,786
Minimum Demand Charges				-		-
All KWH		26,100,266	$ 0.03282	856,611	$ 0.03252	848,781
Minimum Energy				-		-
Total Calculated at Base Rates				$ 1,254,069		$ 1,183,448
Correction Factor				1.000000		1.000000
Total After Application of Correction Factor				$ 1,254,069		$ 1,183,448
Fuel Clause Billings - proforma for rollin				42,896		42,896
STOD Billings				1,566		1,566
VDT Amortization & Surcredit Adjustment				-		-
Adjustment to Reflect Year-End Customers				-		-
Adjustment to Reflect Temperature Normalization				-		-
Total				$ 1,298,531		$ 1,227,910
Proposed Increase						(70,621)
Percentage Increase						-5.44%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills/ KW	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
LCIP - Rate Code 563 (Renamed Rate LTOD-Primary)						
Customer Charge	466		$ 120.00	$ 55,920	$ 120.00	$ 55,920
On-Peak Demand (KW)	5,196,011		$ 5.12	26,603,575	$ 5.12	26,603,575
Off-Peak Demand (KW)	5,141,908		$ 1.27	6,530,223	$ 1.27	6,530,223
Minimum Demand				-		-
Energy		2,747,259,009	$ 0.03282	90,165,041	$ 0.03282	90,165,041
Minimum Energy				128,806		128,806
Total Calculated at Base Rates				$ 123,483,565		$ 123,483,565
Correction Factor				1.000000		1.000000
Total After Application of Correction Factor				$ 123,483,561		$ 123,483,561
Fuel Clause Billings - proforma for rollin				4,563,128		4,563,128
VDT Amortization & Surcredit Adjustment				-		-
Adjustment to Reflect Year-End Customers				-		-
Adjustment to Reflect Temperature Normalization				-		-
Total				$ 128,046,689		$ 128,046,689
Proposed Increase						-
Percentage Increase						0.00%
CSR-1	30,098		$ (3.20)	(96,313)	(3.20)	(96,313)

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills/ KW/KVA	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
LCIT - Rate Code 564 (Customers to be Served Under Rate RTS)						
Customer Charge	79		$ 120.00	$ 9,480	$ 120.00	9,480
On-Peak Demand (KW)	1,590,349		$ 4.93	$ 7,840,423		
On-Peak Demand (KVA)	1,824,495				$ 4.39	8,009,534
Off-Peak Demand (KW)	1,577,381		$ 1.27	$ 2,003,274		
Off-Peak Demand (KVA)	1,815,762				$ 1.13	2,051,811
Minimum Demand				-		-
Energy		841,958,377	$ 0.03282	27,633,074	$ 0.03252	27,380,486
Minimum Energy				11,444		8,361
Total Calculated at Base Rates				$ 37,497,694		$ 37,459,673
Correction Factor				0.999998		0.999998
Total After Application of Correction Factor				$ 37,497,758		$ 37,459,736
Fuel Clause Billings - proforma for rollin				1,468,484		1,468,484
VDT Amortization & Surcredit Adjustment				-		
Adjustment to Reflect Year-End Customers				-		-
Adjustment to Reflect Temperature Normalization				-		-
Total				$ 38,966,242		$ 38,928,220
Proposed Increase						(38,022)
Percentage Increase						-0.10%
CSR-3	1,756,868		$ (3.10)	(5,446,292)	$ (3.10)	(5,446,292)

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2) Bills	(3) Total KWH	(4) Present Rates	(5) Calculated Revenue at Present Rates	(6) Proposed Rates	(7) Calculated Revenue at Proposed Rates
STOD-T Rate Code 580						
Customer	-					
Demand						
Minimum Demand						
On Peak Energy						
Off Peak Energy						
Minimum Energy						
Total Calculated at Base Rates			**There are no customers currently served under this rate**			
Correction Factor			**All Transmission Customers must be served under RTS**			
Total After Application of Correction Factor						
Fuel Clause Billings - proforma for rollin						
VDT Amortization & Surcredit Adjustment						
Adjustment to Reflect Year-End Customers						
Adjustment to Reflect Temperature Normalization						
Total						
Proposed Increase						-
Percentage Increase						0.00%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
STOD-P Rate Code 582 (Customers Eligible for Service Under Rate TOD-Primary)						
Customer	24		$ 90.00	$ 2,160	$ 120.00	2,880
Demand (KW)	26,938		$ 7.26	195,573		
On-Peak Demand (KW)	26,938				$ 6.00	161,630
Off-Peak Demand (KW)	26,658				$ 1.27	33,856
Minimum Demand				-		-
On Peak Energy		7,988,094	$ 0.03879	309,858	$ -	-
Off Peak Energy		7,861,106	$ 0.02596	204,074	$ -	-
Minimum Energy				(23,990)		(6,690)
Total Calculated at Base Rates				$ 687,675		$ 191,676
Correction Factor				1.000000		1.000000
Total After Application of Correction Factor				$ 687,675		$ 191,676
Fuel Clause Billings - proforma for rollin				28,561		28,561
VDT Amortization & Surcredit Adjustment				-		-
Adjustment to Reflect Year-End Customers				-		-
Adjustment to Reflect Temperature Normalization				$ -	-	-
Total				$ 716,236		$ 220,237
Proposed Increase						(495,999)
Percentage Increase						-69.25%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
STOD-S Rate Code 584 (Customers Eligible for Service Under Rate TOD-Secondary)						
Customer	612		$ 90.00	$ 55,080	$ 90.00	55,080
Demand (KW)	351,379		$ 7.65	2,688,050		
On-Peak Demand (KW)	351,379				6.39	2,245,312
Off-Peak Demand (KW)	348,514				1.27	442,612
Minimum Demand				-		-
On Peak Energy		94,624,461	$ 0.03879	3,670,483	$ -	-
Off Peak Energy		94,679,823	$ 0.02596	2,457,888	$ -	-
Minimum Energy				(251,753)		(77,844)
Total Calculated at Base Rates				$ 8,619,748		$ 2,665,161
Correction Factor				1.000000		1.000000
Total After Application of Correction Factor				$ 8,619,748		$ 2,665,161
Fuel Clause Billings - proforma for rollin				308,031		308,031
VDT Amortization & Surcredit Adjustment				-		-
Adjustment to Reflect Year-End Customers				-		-
Adjustment to Reflect Temperature Normalization				(32,622)	-	(32,622)
Total				$ 8,895,156		$ 2,940,569
Proposed Increase						(5,954,587)
Percentage Increase						-66.94%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
MPP - Rate Codes 681, 686 (Customers to be Served Under Rate PS-Primary)						
Customer Charge	364		$ 75.00	$ 27,300	$ 75.00	27,300
Demand (KW)	411,206		$ 5.45	2,241,075	$ 7.26	2,985,358
Minimum demand billings				6,123		6,653
All KWH		109,956,679	$ 0.03479	3,825,393	$ 0.03282	3,608,778
Minimum energy billings				330,628		359,257
Total Calculated at Base Rates				$ 6,430,518		$ 6,987,347
Correction Factor				0.999993		0.999993
Total After Application of Correction Factor				$ 6,430,565		$ 6,987,398
Fuel Clause Billings - proforma for rollin				202,151		202,151
VDT Amortization & Surcredit Adjustment				-		-
Adjustment to Reflect Year-End Customers				215,149		233,779
Adjustment to Reflect Temperature Normalization				-		-
Total				$ 6,847,865		$ 7,423,328
Proposed Increase						575,463
Percentage Increase						8.40%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
MPT - Rate Codes 680, 687 (Customers to be Served Under Rate RTS)						
Customer Charge	123		$ 75.00	$ 9,225	$ 120.00	14,760
Demand (KW)	222,219		$ 5.33	1,184,429		
On-Peak Demand (KVA)	269,655				$ 4.39	1,183,785
Off-Peak Demand (KVA)	264,554				$ 1.13	298,946
Minimum demand billings				2,768		1,740
All KWH		69,078,000	$ 0.03479	2,403,224	$ 0.03252	2,246,417
Minimum energy billings				123,549		77,669
Total Calculated at Base Rates				$ 3,723,194		$ 3,823,317
Correction Factor				0.999999		0.999999
Total After Application of Correction Factor				$ 3,723,197		$ 3,823,320
Fuel Clause Billings - proforma for rollin				116,709		116,709
VDT Amortization & Surcredit Adjustment				-		-
Adjustment to Reflect Year-End Customers				-		-
Adjustment to Reflect Temperature Normalization				-		-
Total				$ 3,839,906		$ 3,940,029
Proposed Increase						100,123
Percentage Increase						2.61%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
LMPP - Rate Code 683 (Customers to be Served Under Rate LTOD-Primary)						
Customer Charge	39		$ 120.00	$ 4,680	$ 120.00	4,680
On-Peak Demand (KW)	271,755		$ 5.79	1,573,462	$ 5.12	1,391,386
Off-Peak Demand (KW)	264,038		$ 1.13	298,363	$ 1.27	335,328
Minimum Demand Charge				-		-
Energy		87,153,119	$ 0.03082	2,686,059	$ 0.03282	2,860,365
Minimum Energy Charge				-		-
Total Calculated at Base Rates				$ 4,562,563		$ 4,591,759
Correction Factor				1.000000		1.000000
Total After Application of Correction Factor				$ 4,562,563		$ 4,591,759
Fuel Clause Billings - proforma for rollin				154,499		154,499
VDT Amortization & Surcredit Adjustment				-		-
Adjustment to Reflect Year-End Customers						-
Adjustment to Reflect Temperature Normalization						-
Total				$ 4,717,062		$ 4,746,258
Proposed Increase						29,196
Percentage Increase						0.62%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / Kw	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
LMPT - Rate Code 684 (Customers to be Served Under Rate RTS)						
Customer Charge	82		$ 120.00	$ 9,840	$ 120.00	9,840
On-Peak Demand (KW)	716,818		$ 5.25	3,763,296		
On-Peak Demand (KVA)	744,449				$ 4.39	3,268,129
Off-Peak Demand (KW)	687,441		$ 1.13	776,808		
Off-Peak Demand (KVA)	726,578				$ 1.13	821,033
Minimum Demand Charge				-		-
Energy		268,266,000	$ 0.03082	8,267,958	$ 0.03252	8,724,010
Minimum Energy Charge				-		-
Total Calculated at Base Rates				$ 12,817,902		$ 12,823,013
Correction Factor				1.002173		1.002173
Total After Application of Correction Factor				$ 12,790,113		$ 12,795,212
Fuel Clause Billings - proforma for rollin				497,592		497,592
VDT Amortization & Surcredit Adjustment				-		
Adjustment to Reflect Year-End Customers				-		-
Adjustment to Reflect Temperature Normalization				-		-
Total				$ 13,287,705		$ 13,292,804
Proposed Increase						5,099
Percentage Increase						0.04%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
LI-TOD Billing Code 730 (Renamed Rate IS)						
Customer Charge	12		$ 120.00	$ 1,440	$ 120.00	1,440
On-Peak Demand (KW)	1,520,293		$ 4.58	$ 6,962,943	$ 4.58	6,962,943
Off-Peak Demand (KW)	1,689,560		$ 0.93	$ 1,571,291	$ 0.93	1,571,291
Minimum Demand Charge				-		-
Energy		388,735,959	$ 0.03282	12,758,314	$ 0.03282	12,758,314
Minimum Energy Charge				-		-
Total Calculated at Base Rates				$ 21,293,989		$ 21,293,989
Correction Factor				1.000000		1.000000
Total After Application of Correction Factor				$ 21,293,989		$ 21,293,989
Fuel Clause Billings - proforma for rollin				664,780		664,780
VDT Amortization & Surcredit Adjustment				-		-
Adjustment to Reflect Year-End Customers				-		-
Adjustment to Reflect Temperature Normalization				-		-
Total				$ 21,958,769		$ 21,958,769
Proposed Increase						-
Percentage Increase						0.00%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2) KWH	(3) Total Lights	(4) Present Rates	(5) Calculated Revenue at Present Rates	(6) Proposed Rates	(7) Calculated Revenue at Proposed Rates
Street Lighting Service Rate Schedule						
Incandescent Street Lighting						
01000L INC STD ST LT *	30,601	900	$ 2.76	$ 2,484	$ 2.76	2,484
02500L INC STD ST LT *	1,028,530	15,372	$ 3.64	55,954	$ 3.64	55,954
04000L INC STD ST LT *	500,061	4,598	$ 5.37	24,691	$ 5.37	24,691
06000L INC STD ST LT *	6,650	46	$ 7.19	331	$ 7.19	331
02500L INC ORN ST LT *	6,432	96	$ 4.48	430	$ 4.48	430
04000L INC ORN ST LT *	52,140	484	$ 6.35	3,073	$ 6.35	3,073
06000L INC ORN ST LT *	2,561	20	$ 8.28	166	$ 8.28	166
Mercury Vapor Street Lighting						
07000L MV STD ST LT	1,128,653	16,381	$ 7.73	126,625	$ 7.73	126,625
010000L MV STD ST LT	1,119,282	11,427	$ 9.12	104,214	$ 9.12	104,214
020000L MV STD ST LT	3,088,066	20,462	$ 11.13	227,742	$ 11.13	227,742
07000L MV ORN ST LT	103,502	1,500	$ 10.09	15,135	$ 10.09	15,135
010000L MV ORN ST LT	634,541	6,474	$ 11.22	72,638	$ 11.22	72,638
020000L MV ORN ST LT	2,649,502	17,555	$ 12.81	224,880	$ 12.81	224,880
High Pressure Sodium Street Lighting						
05800L HPS DEC ACORN ST LT	1,992	72	$ 11.77	847	$ 12.34	888
09500L HPS DEC ACORN ST LT	64,530	1,650	$ 12.59	20,774	$ 13.20	21,780
04000L HPS HISTORIC ACORN ST LT	35,760	1,788	$ 17.29	30,915	$ 18.13	32,416
05800L HPS HISTORIC ACORN ST LT	23,905	864	$ 17.94	15,500	$ 18.81	16,252
09500L HPS HISTORIC ACORN ST LT	188,349	4,819	$ 18.78	90,501	$ 19.69	94,886
05800L HPS POL	61,534	2,097	$ 4.86	10,191	$ 5.10	10,695
04000L HPS STD ST LT	1,685,220	84,259	$ 5.46	460,054	$ 5.72	481,961
05800L HPS STD ST LT	2,822,338	102,010	$ 6.00	612,060	$ 6.29	641,643
09500L HPS STD ST LT	9,120,054	233,717	$ 6.84	1,598,624	$ 7.17	1,675,751
022000L HPS STD ST LT	5,356,942	66,399	$ 10.36	687,894	$ 10.86	721,093
050000L HPS STD ST LT	1,599,629	9,894	$ 17.07	168,891	$ 17.90	177,103
04000L HPS ORN ST LT	943,032	47,165	$ 8.20	386,753	$ 8.60	405,619
05800L HPS ORN ST LT	2,762,804	99,823	$ 8.74	872,453	$ 9.16	914,379
09500L HPS ORN ST LT	1,278,676	32,764	$ 9.77	320,104	$ 10.24	335,503
022000L HPS ORN ST LT	4,158,893	51,518	$ 13.29	684,674	$ 13.93	717,646
050000L HPS ORN ST LT	859,382	5,316	$ 19.99	106,267	$ 20.96	111,423

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

Street Lighting Service Rate Schedule						
High Pressure Sodium Granville Configurations						
016000L GRANVILLE STLT-CONFG A	75,007	1,500	$ 40.55	60,825	$ 42.52	63,780
016000L GRANVILLE STLT-CONFG B	16,201	324	$ 65.07	21,083	$ 68.23	22,107
016000L GRANVILLE STLT-CONFG C	25,201	504	$ 44.46	22,408	$ 46.62	23,496
016000L GRANVILLE STLT-CONFG D	3,000	60	$ 46.19	2,771	$ 48.43	2,906
016000L GRANVILLE STLT-CONFG E	600	12	$ 47.39	569	$ 49.69	596
016000L GRANVILLE STLT-CONFG F	3,600	72	$ 63.09	4,542	$ 66.15	4,763
016000L GRANVILLE STLT-CONFG G	5,999	120	$ 61.36	7,363	$ 64.34	7,721
016000L GRANVILLE STLT-CONFG H	-	-	$ 45.75	-	$ 47.97	-
016000L GRANVILLE STLT-CONFG I	1,200	24	$ 41.75	1,002	$ 43.77	1,050
016000L GRANVILLE STLT-CONFG A1	9,001	180	$ 57.45	10,341	$ 60.24	10,843
016000L GRANVILLE STLT-CONFG B1	-	-	$ 81.97	-	$ 85.95	-
016000L GRANVILLE STLT-CONFG E1	600	12	$ 64.29	771	$ 67.41	809
016000L GRANVILLE STLT-CONFG A2	12,001	240	$ 57.45	13,788	$ 60.24	14,458
016000L GRANVILLE STLT-CONFG B3	2,400	48	$ 58.65	2,815	$ 61.49	2,952
016000L GRANVILLE STLT-CONFG G1	1,800	36	$ 61.36	2,209	$ 64.34	2,316
016000L GRANVILLE STLT-CONFG B2	15,603	312	$ 59.87	18,679	$ 62.77	19,584
016000L GRANVILLE STLT-CONFG A3	*30,602*	*612*	*$ 48.35*	*29,590*	*$ 50.69*	*31,022*
016000L GRANVILLE STLT-CONFG A	5,401	108	$ 40.55	4,379	$ 42.52	4,592
0107800L MH DIRECTIONAL -M POL	381,116	1,057	$ 39.32	41,561	$ 41.23	43,580
Sub-Total	41,902,893	844,691		$ 7,169,563		$ 7,473,978
Total Calculated at Base Rates				$ 7,169,563		$ 7,473,978
Correction Factor				1.000001		1.000001
Total After Application of Correction Factor				$ 7,169,559		$ 7,473,973
Fuel Clause Billings - proforma for rollin				78,214		78,214
VDT Amortization & Surcredit Adjustment				-		-
Adjustment to Reflect Year-End Customers				5,438		5,669
Adjustment to Reflect Temperature Normalization				-		-
Total				$ 7,253,211		$ 7,557,856
Proposed Increase						304,645
Percentage Increase						4.20%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2) KWH	(3) Total Lights	(4) Present Rates	(5) Calculated Revenue at Present Rates	(6) Proposed Rates	(7) Calculated Revenue at Proposed Rates
Street Lighting Service Rate Schedule						
Decorative						
04000L HPS COLONIAL ST LT	160,854	8,022	$ 7.40	$ 59,363	$ 7.76	$ 62,251
05800L HPS COLONIAL ST LT	309,845	11,189	$ 7.96	89,064	$ 8.35	93,428
09500L HPS COLONIAL ST LT	619,118	15,786	$ 8.71	137,496	$ 9.13	144,126
032000L MH DIRECTIONAL -M POL	388,127	2,575	$ 23.27	59,920	$ 24.40	62,830
05800L HPS CONTEMPORARY ST LT	1,260,005	57,101	$ 13.50	770,864	$ 14.15	807,979
09500L HPS CONTEMPORARY ST LT	234,286	6,647	$ 16.15	107,349	$ 16.93	112,534
022000L HPS CONTEMPORARY ST LT	445,967	6,445	$ 19.13	123,293	$ 20.06	129,287
050000L HPS CONTEMPORARY ST LT	102,820	689	$ 25.42	17,514	$ 26.65	18,362
Sub-Total	3,521,022	108,454		$ 1,364,863		$ 1,430,796
Total Calculated at Base Rates				$ 1,364,863		$ 1,430,796
Correction Factor				1.000106		1.000106
Total After Application of Correction Factor				$ 1,364,718		$ 1,430,644
Fuel Clause Billings - proforma for rollin				6,691		6,691
VDT Amortization & Surcredit Adjustment				-		-
Adjustment to Reflect Year-End Customers				(87,063)		(91,269)
Adjustment to Reflect Temperature Normalization				-		-
Total				$ 1,284,346		$ 1,346,066
Proposed Increase						61,720
Percentage Increase						4.81%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2) KWH	(3) Total Lights	(4) Present Rates	(5) Calculated Revenue at Present Rates	(6) Proposed Rates	(7) Calculated Revenue at Proposed Rates
Private Outdoor Lighting						
Decorative (Served Underground)						
04000L HPS COLONIAL DEC POL	12,031	605	$ 7.40	$ 4,477	$ 7.76	$ 4,695
05800L HPS COLONIAL DEC POL	57,712	2,083	$ 7.96	16,581	$ 8.35	17,393
09500L HPS COLONIAL DEC POL	778,055	19,927	$ 8.71	173,564	$ 9.13	181,934
05800L HPS CONTEMPORARY DEC POI	16,936	612	$ 13.50	8,262	$ 14.15	8,660
09500L HPS CONTEMPORARY DEC POI	129,472	3,320	$ 16.15	53,618	$ 16.93	56,208
022000 HPS CONTEMPORARY DEC POI	*621,161*	*7,700*	*$ 19.13*	*147,301*	$ 20.06	154,462
050000 HPS CONTEMPORARY DEC POI	1,706,928	10,550	$ 25.42	268,181	$ 26.65	281,158
Directional (Served Overhead)						-
09500L HPS DIRECTIONAL POL	4,867,927	124,562	$ 6.70	834,565	$ 7.02	874,425
022000L HPS DIRECTIONAL POL	5,933,517	73,593	$ 9.79	720,475	$ 10.26	755,064
050000L HPS DIRECTIONAL POL	14,702,952	90,929	$ 15.34	1,394,851	$ 16.08	1,462,138
Metal Halide Contemporary						-
012000L MH CONTEMPORARY POL	45,669	662	$ 11.17	7,395	$ 11.71	7,752
012000L MH CONTEMPORARY -M POL	143,197	2,076	$ 19.94	41,395	$ 20.91	43,409
032000L MH CONTEMPORARY POL	522,484	3,477	$ 16.13	56,084	$ 16.91	58,796
032000L MH CONTEMPORARY -M POL	979,440	6,493	$ 24.87	161,481	$ 26.08	169,337
0107800L MH CONTEMPORARY POL	207,637	584	$ 33.23	19,406	$ 34.84	20,347
0107800L MH CONTEMPORARY -M POL	652,302	1,818	$ 41.99	76,338	$ 44.03	80,047
Sub-Total	31,377,420	348,991		$ 3,983,975		$ 4,175,824
Total Calculated at Base Rates				$ 3,983,975		$ 4,175,824
Correction Factor				1.000025		1.000025
Total After Application of Correction Factor				$ 3,983,877		$ 4,175,721
Fuel Clause Billings - proforma for rollin				58,833		58,833
VDT Amortization & Surcredit Adjustment				-		
Adjustment to Reflect Year-End Customers				65,956		69,132
Adjustment to Reflect Temperature Normalization				-		-
Total				$ 4,108,666		$ 4,303,686
Proposed Increase						195,020
Percentage Increase						4.75%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2) KWH	(3) Total Lights	(4) Present Rates	(5) Calculated Revenue at Present Rates	(6) Proposed Rates	(7) Calculated Revenue at Proposed Rates
Private Outdoor Lighting						
02500L INC COL *	-	-	$ 5.10	$ -	$ 5.10	$ -
03500L MV COL *	-	-	$ 6.23	-	$ 6.23	-
07000L MV COL *	2,484	24	$ 7.47	179	$ 7.47	179
020000L MV SPECIAL LIGHTING *	812,654	5,390	$ 6.88	37,083	$ 6.88	37,083
050000L HPS SPECIAL LIGHTING *	354,052	2,192	$ 9.18	20,123	$ 9.63	21,109
Standard (Served Overhead)						-
07000L MV POL	8,701,195	126,212	$ 8.76	1,105,617	$ 8.76	1,105,617
020000L MV POL	984,179	6,527	$ 11.13	72,646	$ 11.13	72,646
09500L HPS POL	15,623,163	399,642	$ 5.62	2,245,988	$ 5.89	2,353,891
022000L HPS POL	1,404,988	17,427	$ 10.36	180,544	$ 10.86	189,257
050000L HPS POL	4,231,587	26,167	$ 17.07	446,671	$ 17.90	468,389
Decorative (Served Underground)						-
04000L HPS DEC ACORN D/D POL	477	24	$ 11.11	267	$ 11.65	280
05800L HPS DEC ACORN D/D POL	13,568	490	$ 11.77	5,767	$ 12.34	6,047
09500L HPS DEC ACORN D/D POL	113,943	2,913	$ 12.61	36,733	$ 13.22	38,510
04000L HPS HIST ACORN D/D POL	14,641	732	$ -	-		-
05800L HPS HIST ACORN D/D POL	24,675	892	$ 17.29	15,423	$ 18.13	16,172
09500L HPS HIST ACORN D/D POL	255,935	6,549	$ 18.78	122,990	$ 19.69	128,950
05800L HPS COACH DEC POL	7,969	288	$ 26.62	7,667	$ 27.91	8,038
09500L HPS COACH DEC POL	121,707	3,120	$ 27.36	85,363	$ 28.69	89,513
05800L HPS COACH DEC POL	6,972	252	$ 26.62	6,708	$ 27.91	7,033
09500L HPS COACH DEC POL	4,681	120	$ 27.36	3,283	$ 28.69	3,443
Metal Halide Directional						-
012000L MH DIRECTIONAL POL	414,824	6,001	$ 10.03	60,190	$ 10.52	63,131
012000L MH DIRECTIONAL -W POL	98,345	1,425	$ 12.08	17,214	$ 12.67	18,055
012000L MH DIRECTIONAL -M POL	9,172	133	$ 18.78	2,498	$ 19.69	2,619
032000L MH DIRECTIONAL POL	6,984,958	46,496	$ 14.52	675,122	$ 15.22	707,669
032000L MH DIRECTIONAL -W POL	1,459,773	9,730	$ 16.58	161,323	$ 17.38	169,107
0107800L MH DIRECTIONAL POL	5,071,356	14,106	$ 30.58	431,361	$ 32.06	452,238
0107800L MH DIRECTIONAL -W POL	1,281,044	3,572	$ 33.43	119,412	$ 35.05	125,199
Sub-Total	47,998,342	123,010		$ 5,860,172		$ 6,084,174
Total Calculated at Base Rates				$ 5,860,172		$ 6,084,174
Correction Factor				0.997705		0.997705
Total After Application of Correction Factor				$ 5,873,653		$ 6,098,171
Fuel Clause Billings - proforma for rollin				89,152		89,152
VDT Amortization & Surcredit Adjustment				-		-
Adjustment to Reflect Year-End Customers				(2,475)		(2,570)
Adjustment to Reflect Temperature Normalization				-		-
Total				$ 5,960,330		$ 6,184,754
Proposed Increase						224,423
Percentage Increase						3.77%

Seelye Exhibit 6

Kentucky Utilities Company
Summary of Increases (Decreases) to Miscellaneous Charges
Based on the 12 Months Ended April 30, 2008

Miscellaneous Charge		
Disconnect/Reconnect Charge	$	252,110
Returned Check Fee	$	16,856
Meter-Test Charge	$	3,060
Third-Trip Inspection Charge	$	-
Meter Data Processing Reports	$	231
Meter Pulse Relaying	$	1,062
Late Payment Charge	$	2,262,689
Total	$	2,536,008

Kentucky Utilities Company
Disconnect/Reconnect Charges
12 Months Ended April 30, 2008

Description		Current		Proposed
Regular Hours				
Disconnect/Reconnects During Test-Year		50,422		50,422
Disconnect/Reconnect Charge	$	20.00	$	25.00
Total	$	1,008,440.00	$	1,260,550.00
Increase			$	252,110.00

Kentucky Utilities Company
Returned Check Fee
12 Months Ended April 30, 2008

Proposed Fee	$	10.00
Current Fee	$	9.00
Difference	$	1.00
Quantity		16,856
Total Increase	**$**	**16,856.00**

Quantity is the same as used in calculation of proposed
fee for 2003 rate case.

Kentucky Utilities Company
Meter Test Charge
12 Months Ended April 30, 2008

Description		**Current**		**Proposed**
Meter Tests During Test-Year		107		107
Meter Test Charge	$	31.40	$	60.00
Total	$	3,359.80	$	6,420.00
Increase			$	3,060.20

Note: Charges would only be applicable to meters within tolerance.

Kentucky Utilities Company
Meter Data Processing Reports
12 Months Ended April 30, 2008

Description	Current	Proposed
Meter Data Reports During Test-Year	-	84
Meter Data Reports Charge		$ 2.75
Total	$ -	$ 231.00
Increase		$ 231.00

Kentucky Utilities Company
Meter Pulse Relaying
12 Months Ended April 30, 2008

Description	Current	Proposed
Meter Pulse Relays During Test-Year	-	118
Meter Pulse Relay Charge		$ 9.00
Total	$ -	$ 1,062.00
Increase		$ 1,062.00

Kentucky Utilities Company
Late Payment Charge
12 Months Ended April 30, 2008

Description		**Current**		**Proposed**
Late Payment Charges During Test-Year		-		2,262,689
Total	$	-	$	2,262,689
Increase			$	2,262,689

KENTUCKY UTILITIES

Adjustment to Revenues for Estimated Late Payment Charge
For the Twelve Months Ended April 30, 2008

1	Jurisdictional Ultimate Consumer Revenue		$ 1,111,405,132
2	*Louisville Gas and Electric Company* Late Payment Charges (LPC) as a percent of Ultimate Consumer Revenues (a)	0.3026%	
3	Determination of weight of Louisville Gas and Electric Company's LPC to apply to Kentucky Utilities' customers		
4	Estimated Late Payment Charge equal to LG&E	100.0000%	
5	Five year avearge Kentucky Utilities Net Charge-Offs as a percentage of Louisville Gas and Electric Company's Net Charge-Offs (b)	41.9366%	
6	Five year avearge Kentucky Utilities A/R as a percentage of Louisville Gas and Electric Company's A/R (c)	59.9294%	
7	Average weight (average of Line No. 4 through Line No. 6)	67.2887%	
8	Kentucky Utilities Estimated Late Payment Charge as a percent of Ultimate Consumer Revenue Line No. 2 x Line No. 7		0.2036%
9	Kentucky Jurisdictional adjustment (Line No. 1 x Line No. 8)		2,262,689

(a) Estimated percentage is based on 5 year average actual LG&E Electric Late Payment Charge to LG&E Electric Utlimate Consumer Revenue.

	LG&E Ultimate Consumer Billed Electric Revenue ($000)	Forfeited Discounts ($000)	LG&E Forfeited Discounts as a percentage of Ultimate Consumer Billed Electric Revenues
2007	759,840	2,581	0.3397%
2006	693,392	2,120	0.3058%
2005	682,659	2,009	0.2943%
2004	619,480	1,723	0.2782%
2003	578,179	1,652	0.2858%
5 Year Average	666,710	2,017	0.3026%

KENTUCKY UTILITIES

Adjustment to Revenues for Estimated Late Payment Charge
For the Twelve Months Ended April 30, 2008

(b)	LG&E Ultimate Consumer Billed Electric Revenue ($000) (1)	LG&E Net Charge Offs ($000) (2)	LG&E Net Charge Offs as a % of Ult Cons Billed Elec Revenue Col 2 / Col 1 (3)	KU Ultimate Consumer Billed Electric Revenue ($000) (4)	KU Net Charge Offs ($000) (5)	KU Net Charge Offs as a % of Ult Cons Billed Elec Revenue Col 5 / Col 4 (6)	KU Net Charge Offs as a % of LG&E Net Charge-Offs Col 6 / Col 3 (7)
2007	759,840	2,109	0 28%	1,046,999	2,091	0 20%	71 9680%
2006	693,392	3,996	0.58%	952,746	2,248	0 24%	40 9448%
2005	682,659	2,821	0 41%	896,588	1,403	0 16%	37 8582%
2004	619,480	2,771	0 45%	796,193	1,317	0 17%	36 9665%
2003	578,179	3,831	0.66%	736,909	1,594	0.22%	32.6447%
5 Year Average	666,710	3,106	0 47%	885,887	1,731	0 20%	41 9366%

(c)	LG&E Ultimate Consumer Billed Electric Revenue ($000) (1)	LG&E A/R Balance at 12/31 ($000) (2)	LG&E A/R as a % of Ult Cons Billed Elec Revenue Col 2 / Col 1 (3)	KU Ultimate Consumer Billed Electric Revenue ($000) (4)	KU A/R Balance at 12/31 ($000) (5)	KU A/R as a % of Ult Cons Billed Elec Revenue Col 5 / Col 4 (6)	KU A/R as a % of LG&E A/R Col 6 / Col 3 (7)
2007	759,840	87,821	11 56%	1,046,999	88,695	8 47%	73 2951%
2006	693,392	75,033	10 82%	952,746	73,690	7 73%	71 4754%
2005	682,659	110,295	16 16%	896,588	69,383	7 74%	47 8974%
2004	619,480	77,412	12 50%	796,193	55,752	7 00%	56 0359%
2003	578,179	71,763	12.41%	736,909	48,779	6.62%	53.3315%
5 Year Average	666,710	84,465	12 67%	885,887	67,260	7 59%	59 9294%

Seelye Exhibit 7

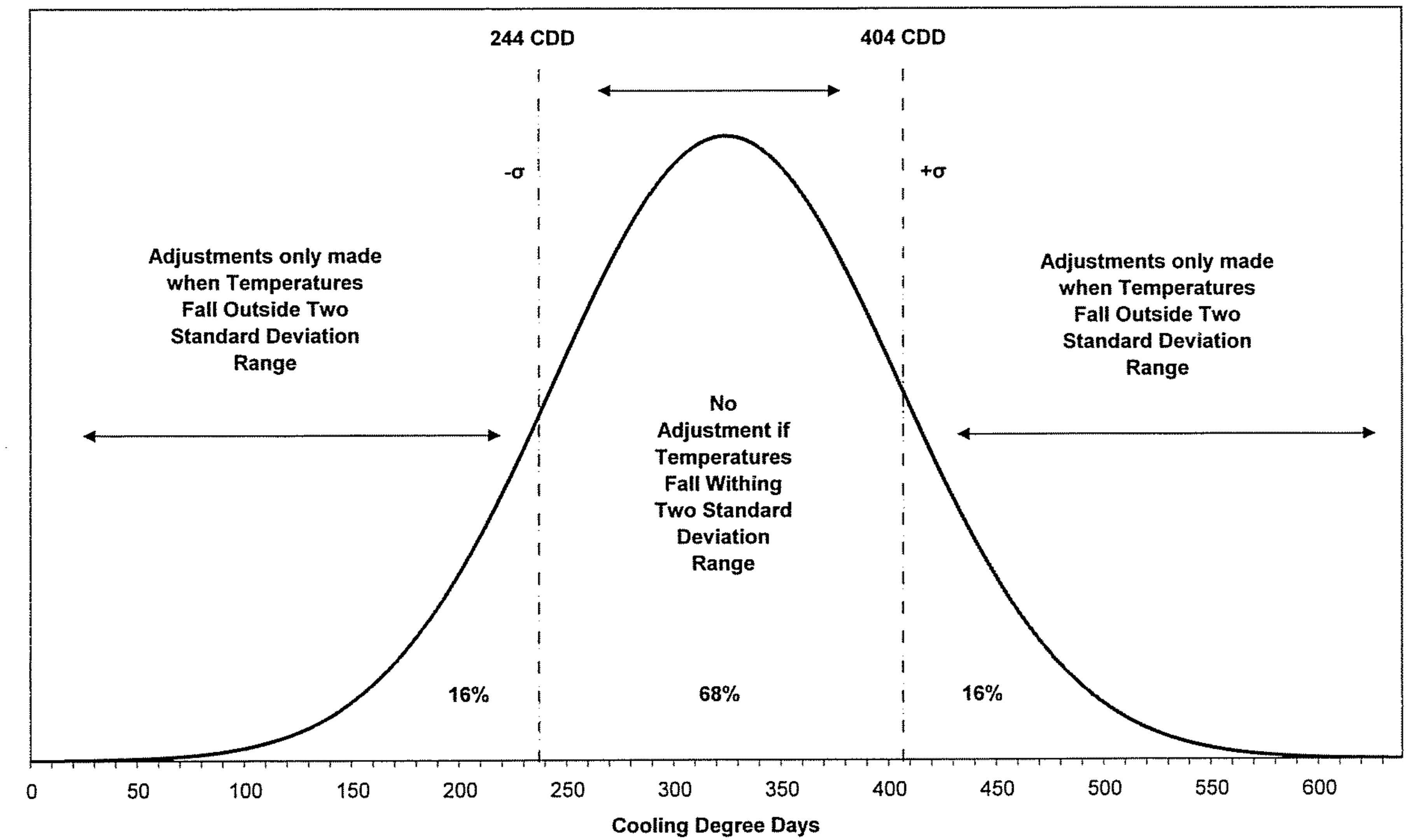
Kentucky Utilities Company
Maximum Deposit Amounts per 807 KAR 5:005

Rate Schedule	Revenues Calculated at the Proposed Rates	Number of Customer Months	Revenue per Month	Maximum Deposit Amount (Rev per Mo x 2)
Rate RS	$ 422,812,115	4,958,111	$ 85.28	$ 170.55

Source: Seelye Exhibit 5

Seelye Exhibit 8

Two Standard Deviation Range for August



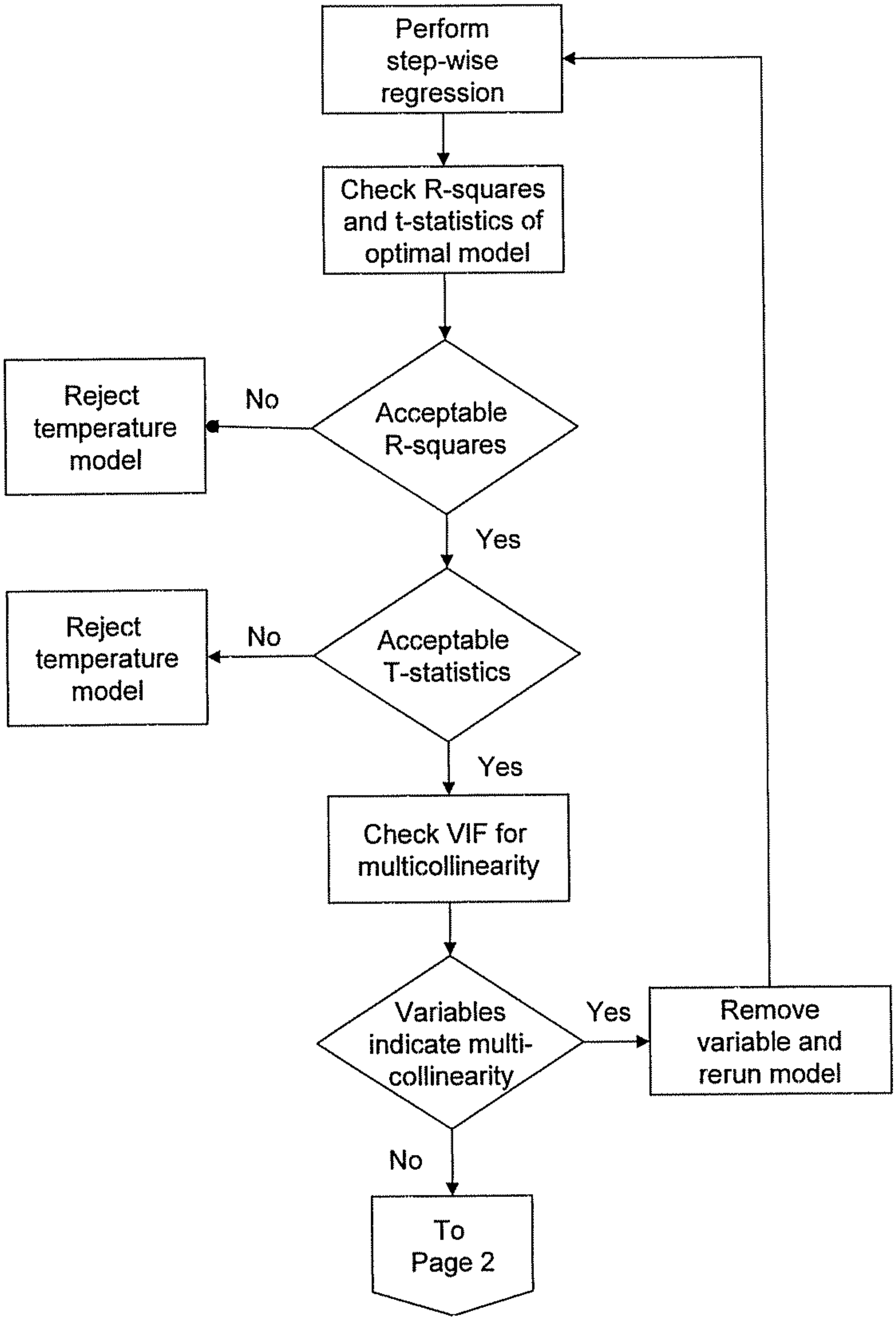
Seelye Exhibit 9

Kentucky Utilities Company
Comparison of Actual Cooling and Heating Degree Days to
Range of Normal Degree Days

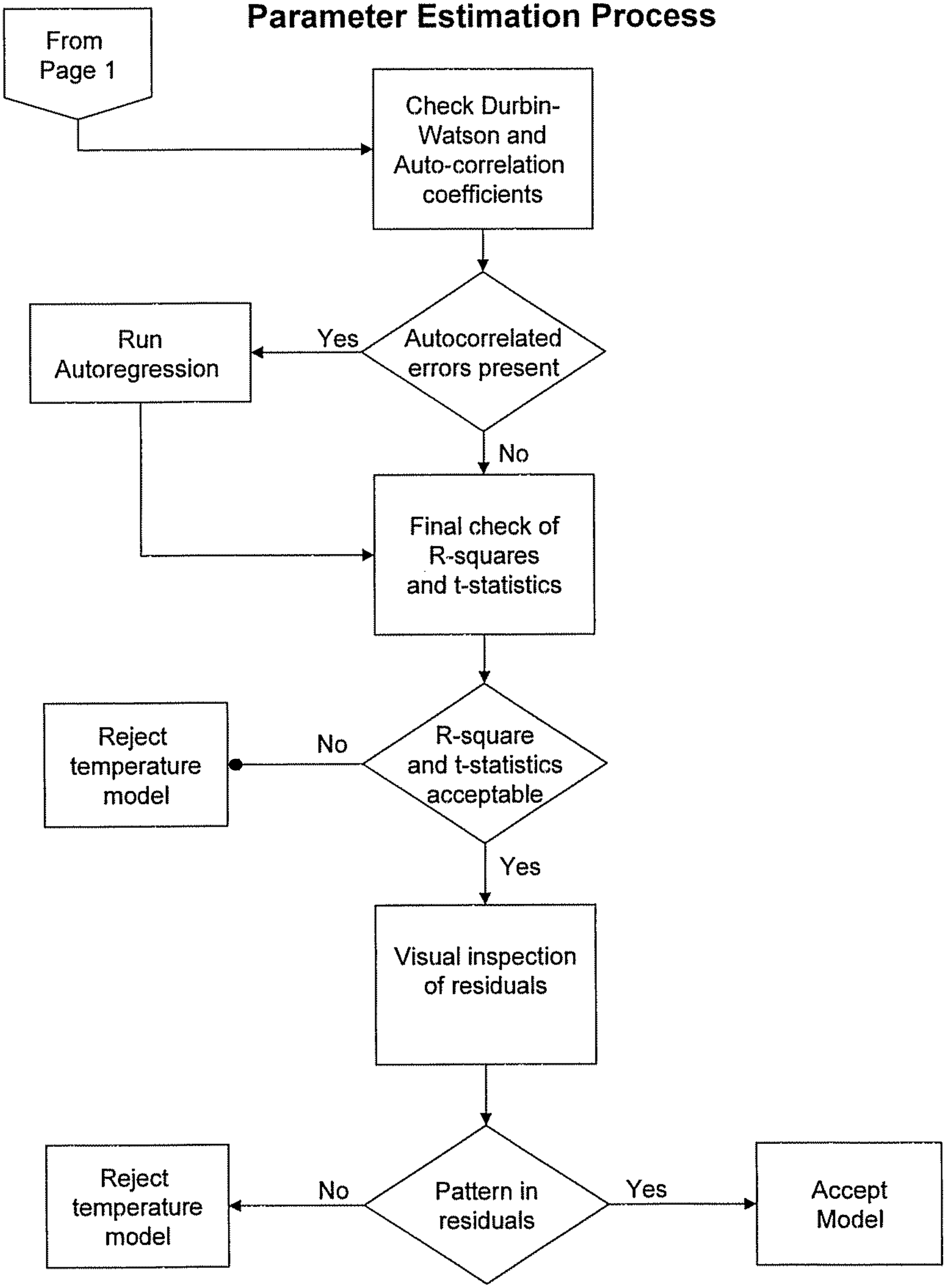
	Cooling Degree Days Using a 65-Degree Base							Heating Degree Days Using a 65-Degree Base						
Month	Actual	30-Year Average	Stdev	Plus One Stdev	Minus One Stdev	Outside of Range	Adjustment to End-Point of Range	Actual	30-Year Average	Stdev	Plus One Stdev	Minus One Stdev	Outside of Range	Adjustment to End-Point of Range
4	21	18	16	34	2	No	0	377	318	76	394	242	No	0
5	155	85	51	136	34	Yes	19	59	113	59	172	54	No	0
6	284	235	54	289	181	No	0	0	0	0	0	0	No	0
7	309	354	64	418	290	No	0	0	0	0	0	0	No	0
8	496	324	80	404	244	Yes	92	0	0	0	0	0	No	0
9	238	146	55	201	91	Yes	37	13	51	26	77	25	Yes	12
10	100	25	22	47	3	Yes	53	164	278	76	354	202	Yes	38
11	0	0	0	0	0	No	0	577	563	102	665	461	No	0
12	0	0	0	0	0	No	0	765	887	158	1045	729	No	0
1	0	0	0	0	0	No	0	1007	1008	171	1179	837	No	0
2	0	0	0	0	0	No	0	849	823	145	968	678	No	0
3	0	0	0	0	0	No	0	639	621	101	722	520	No	0
4	14	18	16	34	2	No	0	319	318	76	394	242	No	0

Seelye Exhibit 10

Flow Diagram of Parameter Estimation Process



Flow Diagram of Parameter Estimation Process



Seelye Exhibit 11

Residential

Jan-08

	Coefficient	t Value
Intercept	5039203	10.40
Hdd65	131167	12.29
Wind	44406	1.89
Weekend	596007	2.90
R-Square	0.9332	

Feb-08

	Coefficient	t Value
Intercept	4230429	15.71
Hdd65	138295	16.70
Weekend	587750	3.25
R-Square	0.9148	

Mar-08

	Coefficient	t Value
Intercept	4287804	20.63
Hdd60	123508	20.76
Wind	51313	3.27
Weekend	637500	5.65
R-Square	0.9592	

Apr-08

	Coefficient	t Value
Intercept	1915288	2.38
Min	58061	3.68
Hdd60	147934	7.98
R-Square	0.8112	

Residential

Apr-07

	Coefficient	t Value
Intercept	4772291	27.59
Cdd65	189665	3.36
Hdd60	85984	8.17
Weekend	1007383	5.82
R-Square	0.8744	

May-07

	Coefficient	t Value
Intercept	-3969541	-3.06
Max	124360	7.23
cdd70	459125	8.35
Weekend	688112	3.56
R-Square	0.9492	

Jun-07

	Coefficient	t Value
Intercept	-23224419	-0.83
Max	116465	3.17
cdd65	158238	3.22
Weekend	724618	3.34
R-Square	0.8593	

Residential

Jul-07

	Coefficient	t Value
Intercept	-2394075	-0.56
Max	129398	2.40
cdd70	212068	2.92
Weekend	453879	1.86
R-Square	0.8613	

Aug-07

	Coefficient	t Value
Intercept	8474433	23.34
cdd70	391299	13.11
Weekend	1055056	3.94
R-Square	0.8600	

Sep-07

	Coefficient	t Value
Intercept	5495060	24.30
Cdd65	348180	15.84
Weekend	576538	2.27
Holiday	1738082	2.56
R-Square	0.9166	

Oct-07

	Coefficient	t Value
Intercept	5007887	17.85
cdd65	296993	12.02
Wind	-40086	-1.43
Weekend	795920	4.54
R-Square	0.9448	

Residential

Nov-07

	Coefficient	t Value
Intercept	4580882	13.24
hdd60	97271	8.17
Wind	53161	2.22
Weekend	759775	4.92
Holiday	701862	2.38
R-Square	0.9133	

Dec-07

	Coefficient	t Value
Intercept	10346009	30.96
Min	-97910	-9.63
Weekend	569870	3.74
R-Square	0.8484	

Residential

Jan-08

	Coefficient	t Value
Intercept	4758923	6.15
hdd60	393679	15.91
R-Square	0.9358	

Feb-08

	Coefficient	t Value
Intercept	4546663	8.46
hdd60	363481	17.85
R-Square	0.9218	

Mar-08

	Coefficient	t Value
Intercept	2802546	4.44
hdd60	344541	20.10
Wind	159080	3.33
R-Square	0.9376	

Apr-08

	Coefficient	t Value
Intercept	4942436	19.19
hdd60	190695	8.43
R-Square	0.8218	

Residential

Apr-07

	Coefficient	t Value
Intercept	4166438	10.10
hdd65	236242	10.63
Weekend	1318146	2.96
R-Square	0.9011	

May-07

	Coefficient	t Value
Intercept	1791113	2.69
Max	48566	5.47
cdd70	264049	9.21
Weekend	551324	5.48
Holiday	305947	2.29
R-Square	0.9484	

Jun-07

	Coefficient	t Value
Intercept	5893240	28.67
cdd65	176387	9.02
Weekend	358269	2.39
R-Square	0.7584	

Residential

Jul-07

	Coefficient	t Value
Intercept	6666985	40.39
cdd70	234869	10.46
Weekend	406719	2.58
Monday	486878	2.92
R-Square	0.8732	

Aug-07

	Coefficient	t Value
Intercept	6134643	16.81
cdd65	218745	10.20
Weekend	571684	2.97
R-Square	0.8427	

Sep-07

	Coefficient	t Value
Intercept	5469057	24.74
cdd65	222786	10.50
Weekend	578742	2.67
Holiday	1090355	2.07
R-Square	0.8946	

Oct-07

	Coefficient	t Value
Intercept	7638731	7.20
cdd70	329137	4.29
Min	-40369	-1.94
R-Square	0.6792	

Residential

Nov-07

	Coefficient	t Value
Intercept	4822664	14.43
hdd60	285527	14.10
Weekend	732840	2.04
R-Square	0.8904	

Dec-07

	Coefficient	t Value
Intercept	23150442	26.22
Min	-335662	-12.62
Weekend	560971	1.48
R-Square	0.9125	

GS Secondary

Jan-08

	Coefficient	t Value
Intercept	4793554	40.67
Hdd65	25612	7.98
Weekend	-1112252	-14.81
Holiday	-1422863	-8.07
R-Square	0.9409	

Feb-08

	Coefficient	*t Value*
Intercept	6351164	36.57
Max	-19113	-5.13
Weekend	-995809	-12.28
R-Square	0.9143	

Mar-08

	Coefficient	t Value
Intercept	4999966	64.71
hdd60	29218	6.71
Friday	-459256	-4.39
Weekend	-1190597	-13.50
R-Square	0.8995	

GS Secondary

Apr-08

	Coefficient	t Value
Intercept	5201026	56.34
cdd65	58798	2.65
cloudy	-165688	-2.26
Wind	-31952	-2.80
Weekend	-992819	-13.19
R-Square	0.9185	

Apr-07

	Coefficient	t Value
Intercept	4418979	32.54
cdd65	249652	4.66
Weekend	-1161169	-6.76
R-Square	0.7775	

May-07

	Coefficient	t Value
Intercept	1721289	3.24
Max	37834	5.75
Monday	-472489	-3.14
Weekend	-1191143	-10.26
R-Square	0.8518	

Jun-07

	Coefficient	t Value
Intercept	1950989	2.90
Max	38202	4.88
Weekend	-1295354	-17.84
R-Square	0.9395	

GS Secondary

Jul-07

	Coefficient	t Value
Intercept	5183089	67.97
cdd70	70989	6.08
Weekend	-1392374	-18.84
Holiday	-1489958	-8.30
R-Square	0.9495	

Aug-07

	Coefficient	t Value
Intercept	5400198	27.87
cdd65	62898	6.10
Wind	-43204	-2.10
Weekend	-1419459	-15.45
R-Square	0.9306	

Sep-07

	Coefficient	t Value
Intercept	5032357	46.77
cdd65	70440	6.86
Weekend	-1288863	-12.61
Holiday	-1684000	-6.91
R-Square	0.9274	

GS Secondary

Oct-07

	Coefficient	t Value
Intercept	4807686	66.87
cdd65	73464	7.06
Weekend	-1356022	-17.45
Friday	-259994	-3.14
R-Square	0.9571	

Nov-07

	Coefficient	t Value
Intercept	4914905	77.65
Weekend	-937324	-7.92
Holiday	-1383215	-6.59
R-Square	0.7724	

Dec-07

	Coefficient	t Value
Intercept	4507571	20.46
hdd65	33243	5.27
cloudy	296166	2.40
Weekend	-1157499	-10.90
Holiday	-947382	-3.11
Xmas Week	-599542	-4.10
R-Square	0.8830	

STOD Secondary

Jan-08

	Coefficient	t Value
Intercept	495268	129.01
hdd65	-808.6201	-7.62
Weekend	-9747	-3.47
R-Square	0.7791	

Feb-08

	Coefficient	t Value
Intercept	484785	71.05
hdd65	-836.8239	-4.13
Weekend	-14651	-3.72
R-Square	0.6838	

Mar-08

	Coefficient	t Value
Intercept	483059	118.52
hdd65	-822.7538	-4.38
Weekend	-14164	-3.89
R-Square	0.6893	

STOD Secondary

Jan-08

	Coefficient	t Value
Intercept	495268	129.01
hdd65	-808.6201	-7.62
Weekend	-9747	-3.47
R-Square	0.7791	

Feb-08

	Coefficient	t Value
Intercept	484785	71.05
hdd65	-836.8239	-4.13
Weekend	-14651	-3.72
R-Square	0.6838	

Mar-08

	Coefficient	t Value
Intercept	483059	118.52
hdd65	-822.7538	-4.38
Weekend	-14164	-3.89
R-Square	0.6893	

STOD Secondary

Apr-08

	Coefficient	t Value
Intercept	497784	166.37
hdd65	-1923	-9.64
ccd65	4036	4.86
Weekend	-13300	-4.56
R-Square	0.9300	

Apr-07

	Coefficient	t Value
Intercept	409855	43.38
Min	1446	6.67
ccd65	4307	3.45
R-Square	0.8951	

May-07

	Coefficient	*t Value*
Intercept	329100	8.21
Max	1266	2.60
cdd65	2591	2.72
DewPoint	1613	4.55
R-Square	0.9100	

STOD Secondary

Jun-07

	Coefficient	t Value
Intercept	159503	6.44
Max	2752.82823	10.31
Wind	-1361.84613	-2.22
DewPoint	2899.01856	13.90
Friday	14915	4.52
Weekday	-10528	-3.82
R-Square	0.9432	

Jul-07

	Coefficient	t Value
Intercept	459401	17.77
cdd65	4924	6.17
DewPoint	1203	2.44
Holiday	-48081	-5.69
Weekend	-15132	-4.20
R-Square	0.9202	

Aug-07

	Coefficient	t Value
Intercept	201741	6.24
Max	1539	4.19
Min	2424	3.90
DewPoint	1747	3.09
Weekend	-14705	-4.16
R-Square	0.9373	

Sep-07

	Coefficient	t Value
Intercept	309533	13.38
min	802.33614	3.22
cdd70	2895.91321	5.84
Dewpoint	3155.70977	19.14
Holiday	-37046	-6.26
Weekend	-9636.00797	-4.10
R-Square	0.9837	

STOD Secondary

Oct-07

	Coefficient	t Value
Intercept	435988	33.18
cdd65	4137	8.40
hdd65	-1339	-4.44
DewPoint	1574	6.19
Weekend	-10521	-3.76
R-Square	0.9803	

Nov-07

	Coefficient	t Value
Intercept	430735	58.72
min	1495.73842	7.99
Holiday	-41158	-6.29
Weekend	-10679	-2.85
R-Square	0.8596	

Dec-07

	Coefficient	t Value
Intercept	439693	65.71
DewPoint	1168.3451	6.25
Holiday	-115263	-10.17
Xmas Week	-18110	-3.35
R-Square	0.902	

LP Secondary

Jan-08

	Coefficient	*t Value*
Intercept	6341081	71.75
Max	-15488	-7.70
Weekend	-1139730	-18.46
Holiday	-1260714	-8.24
R-Square	0.9402	

Feb-08

	Coefficient	t Value
Intercept	5878242	44.40
Max	-10716	-3.53
Weekend	-1023315	-13.90
R-Square	0.9008	

Mar-08

	Coefficient	t Value
Intercept	5347328	125.52
Friday	-250661	-2.57
Weekend	-1134520	-16.21
R-Square	0.9047	

LP Secondary

Apr-08

	Coefficient	t Value
Intercept	4448394	16.33
min	15073	3.64
cdd65	80285	2.91
Friday	-272100	-2.25
Weekday	-1135681	-12.89
R-Square	0.9102	

Apr-07

	Coefficient	t Value
Intercept	5094720	48.28
Min	12264	4.99
cdd65	82453	4.33
Friday	-193321	-2.61
Weekend	-1228417	-22.15
R-Square	0.9684	

May-07

	Coefficient	t Value
Intercept	6354089	63.33
cdd65	42865	3.59
hdd60	-104801	-3.52
Monday	-571008	-3.46
Weekend	-1628344	-14.42
R-Square	0.9042	

LP Secondary

Jun-07

	Coefficient	*t Value*
Intercept	6472678	68.26
cdd65	53486	5.93
Weekend	-1520760	-22.01
R-Square	0.9522	

Jul-07

	Coefficient	t Value
Intercept	6758985	99.24
cdd70	69182	6.38
Holiday	-1557372	-7.66
Weekend	-1596746	-20.54
R-Square	0.9481	

Aug-07

	Coefficient	t Value
Intercept	6756016	43.18
cdd65	68841	7.45
Weekend	-1635829	-19.72
R-Square	0.9531	

LP Secondary

Sep-07

	Coefficient	t Value
Intercept	6400557	97.30
cdd65	67060	10.49
Holiday	-1805824	-9.16
Weekend	-1650536	-22.39
R-Square	0.9624	

Oct-07

	Coefficient	t Value
Intercept	4587744	17.46
Min	33622	4.95
cdd65	38625	2.47
Wind	-35081	-2.60
Friday	-266215	-2.90
Weekend	-1557205	-21.71
R-Square	0.9700	

Nov-07

	Coefficient	t Value
Intercept	5936712	29.02
Max	-11760	-3.30
Holiday	-1541744	-11.95
Weekend	-1315120	-19.66
R-Square	0.9466	

Dec-07

	Coefficient	t Value
Intercept	5103178	29.88
hdd65	17396	2.87
Monday	-285826	-2.48
Holiday	-1012111	-4.54
Weekend	-1267888	-11.94
Xmas week	-660185	-4.36
R-Square	0.9144	

LP Secondary

Jan-08

	Coefficient	t Value
Intercept	5058094	214.17
Holiday	-1684786	-14.87
Weekend	-1248722	-27.30
R-Square	0.9695	

Feb-08

	Coefficient	t Value
Intercept	5483736	68.19
Max	-7423.59138	-4.03
Friday	-154475	-2.86
Weekend	-1248179	-26.77
R-Square	0.9713	

Mar-08

	Coefficient	t Value
Intercept	5435557	28.02
Max	-7605	-2.32
Friday	-373124	-4.51
Weekend	-1324792	-17.92
R-Square	0.9413	

LP Secondary

Apr-08

	Coefficient	t Value
Intercept	4331156	35.54
Min	16718	6.08
Friday	-220745	-3.78
Weekend	-1329932	-29.73
R-Square	0.9783	

Apr-07

	Coefficient	t Value
Intercept	5007260	124.56
hdd65	-14152	-6.56
Friday	-314518	-4.13
Weekend	-1214368	-21.80
R-Square	0.9557	

May-07

	Coefficient	t Value
Intercept	5036411	80.06
Monday	-569743	-3.78
Weekend	-1377412	-11.92
R-Square	0.8365	

LP Secondary

Jun-07

	Coefficient	t Value
Intercept	4116800	9.73
Max	13336	2.70
Weekend	-1278603	-27.01
R-Square	0.965	

Jul-07

	Coefficient	t Value
Intercept	3588848	6.56
Min	22845	2.70
Friday	-251598	-3.35
Holiday	-1084270	-7.70
Weekend	-1195663	-17.93
R-Square	0.9501	

Aug-07

	Coefficient	t Value
Intercept	5226787	94.23
cdd70	20775	4.88
Monday	-145995	-2.79
Friday	-174103	-3.55
Weekend	-1374512	-34.56
R-Square	0.9819	

LP Secondary

Sep-07

	Coefficient	t Value
Intercept	3951348	21.88
Min	19247	6.54
Friday	-192542	-2.83
Holiday	-1643065	-13.02
Weekend	-1352720	-27.29
R-Square	0.9740	

Oct-07

	Coefficient	t Value
Intercept	4278626	37.74
Min	13338	5.65
cdd65	20373	3.95
Monday	-127765	-2.88
Friday	-195489	-4.06
Weekend	-1289720	-38.85
R-Square	0.9845	

Nov-07

	Coefficient	t Value
Intercept	4770028	145.33
Holiday	-1879748	-17.27
Weekend	-1303827	-21.23
R-Square	0.9600	

Dec-07

	Coefficient	t Value
Intercept	4780810	51.54
Monday	-450686	-2.65
Holiday	-935760	-2.52
Weekend	-1321018	-9.47
Xmas Week	-1259577	-6.84
R-Square	0.8336	

LP Primary

Jan-08

	Coefficient	t Value
Intercept	75008	54.55
hdd60	712.0304	16.45
Weekend	2568	2.16
R-Square	0.9462	

Feb-08

	Coefficient	t Value
Intercept	75139	56.83
hdd60	662.90404	13.22
R-Square	0.8923	

Mar-08

	Coefficient	t Value
Intercept	72445	44.46
hdd60	625.64323	13.41
Wind	437.06164	3.55
Weekend	-3719.75127	-4.21
R-Square	0.8700	

LP Primary

Apr-08

	Coefficient	t Value
Intercept	76207	97.77
hdd60	302.4372	4.92
cdd65	877.8009	4.06
Weekend	-3144	-4.11
R-Square	0.7617	

Apr-07

	Coefficient	t Value
Intercept	210908	28.16
cdd65	5090	2.23
Weekend	-52076	-7.49
R-Square	0.7651	

May-07

	Coefficient	t Value
Intercept	233571	41.78
cdd70	9375	5.85
Weekend	-87523	-9.38
R-Square	0.8047	

Jun-07

	Coefficient	t Value
Intercept	260401	15.21
cdd70	4219	1.88
Friday	-31328	-2.07
Weekend	-63183	-4.34
R-Square	0.6659	

LP Primary

Jul-07

	Coefficient	t Value
Intercept	165965	16.60
cdd65	4894	5.54
Holiday	-23487	-1.83
Weekend	-33629	-6.10
R-Square	0.8347	

Aug-07

	Coefficient	t Value
Intercept	282493	12.91
cdd65	4738	3.72
Weekend	-106597	-9.38
R-Square	0.8642	

Sep-07

	Coefficient	t Value
Intercept	247537	37.33
cdd65	4397.80214	6.82
Holiday	-97585	-4.91
Weekend	-72426	-9.74
R-Square	0.8578	

LP Primary

Oct-07

	Coefficient	t Value
Intercept	222110	24.68
cdd65	3950	5.41
Wind	-3842	-4.09
Weekend	-64168	-10.56
R-Square	0.8992	

Nov-07

	Coefficient	t Value
Intercept	161045	19.06
Min	-648.83	-3.03
Holiday	-31080	-4.21
Weekend	-32416	-8.12
R-Square	0.7845	

LP Primary

Jan-08

	Coefficient	t Value
Intercept	4463060	161.93
Holiday	-1561176	-11.81
Weekend	-1068211	-20.01
R-Square	0.9465	

Feb-08

	Coefficient	t Value
Intercept	4376545	153.47
Weekend	-1014472	-18.68
R-Square	0.9282	

Mar-08

	Coefficient	t Value
Intercept	4316002	101.87
Friday	-378193	-3.90
Weekend	-1135637	-16.31
R-Square	0.9049	

LP Primary

Apr-08

	Coefficient	t Value
Intercept	3899879	49.26
Min	11584	6.61
Friday	-230249	-5.37
Monday	-107765	-2.68
Weekend	-1158432	-37.30
R-Square	-0.9844	

Apr-07

	Coefficient	t Value
Intercept	4226867	36.64
Min	12520	5.19
Friday	-311684	-3.59
Weekend	-1192523	-18.58
R-Square	0.9417	

May-07

	Coefficient	t Value
Intercept	4931850	77.46
Monday	-516549	-3.38
Weekend	-1312506	-11.22
R-Square	0.8189	

LP Primary

Jun-07

	Coefficient	t Value
Intercept	4827002	71.70
cdd65	19220	2.97
Weekend	-1151587	-22.10
R-Square	0.9421	

Jul-07

	Coefficient	t Value
Intercept	4766928	59.72
cdd70	21730	1.81
Holiday	-1229863	-6.87
Weekend	-1109893	-14.91
R-Square	0.9204	

Aug-07

	Coefficient	t Value
Intercept	4856340	40.62
cdd65	17922	2.65
Friday	-196434	-2.98
Weekend	-1187933	-18.41
R-Square	0.9524	

LP Primary

Sep-07

	Coefficient	t Value
Intercept	4791919	103.73
cdd65	26267	6.17
Friday	-175621	-2.49
Holiday	-1534618	-11.60
Weekend	-1276593	-24.87
R-Square	0.9680	

Oct-07

	Coefficient	t Value
Intercept	4538526	141.77
cdd65	45764	8.61
Weekend	-1203894	-22.30
R-Square	0.9531	

Nov-07

	Coefficient	t Value
Intercept	4352676	127.85
Holiday	-1649103	-14.60
Weekend	-1174005	-18.43
R-Square	0.9466	

Dec-07

	Coefficient	t Value
Intercept	4386282	48.30
Monday	-437022	-2.62
Holiday	-807078	-2.22
Weekend	-1160189	-8.49
Xmas Week	-1128292	-6.25
R-Square	0.8029	

Seelye Exhibit 12

Kentucky Utilities Company
Electric Temperature Normalization

			1	2	3	4	5	6		
Index	**Month**	**Company**	**HDD60**	**HDD65**	**CDD65**	**CDD70**	**MinTemp**	**MaxTemp**	**Total Adjustment**	**Class Description**
1	4	KU	-515.904	0	0	0	0	0	-515.904	RS
1	5	KU	0	0	0	-5509.5	0	-8481.352	-13990.852	RS
1	6	KU	0	0	0	0	0	0	0	RS
1	7	KU	0	0	0	0	0	0	0	RS
1	8	KU	0	0	0	-34825.6	0	0	-34825.611	RS
1	9	KU	0	0	-12882.7	0	0	0	-12882.66	RS
1	10	KU	0	0	-15740.6	0	0	0	-15740.629	RS
1	11	KU	0	0	0	0	0	0	0	RS
1	12	KU	0	0	0	0	0	0	0	RS
1	1	KU	0	0	0	0	0	0	0	RS
1	2	KU	0	0	0	0	0	0	0	RS
1	3	KU	0	0	0	0	0	0	0	RS
1	4	KU	0	0	0	0	0	0	0	RS
2	4	KU	0	0	0	0	0	0	0	RS (formerly Full Electric)
2	5	KU	0	0	0	-3168.59	0	-3312.2012	-6480.7892	RS (formerly Full Electric)
2	6	KU	0	0	0	0	0	0	0	RS (formerly Full Electric)
2	7	KU	0	0	0	0	0	0	0	RS (formerly Full Electric)
2	8	KU	0	0	-20124.5	0	0	0	-20124.54	RS (formerly Full Electric)
2	9	KU	0	0	-8243.08	0	0	0	-8243.082	RS (formerly Full Electric)
2	10	KU	0	0	0	-9874.11	2753.1658	0	-7120.9442	RS (formerly Full Electric)
2	11	KU	0	0	0	0	0	0	0	RS (formerly Full Electric)
2	12	KU	0	0	0	0	0	0	0	RS (formerly Full Electric)
2	1	KU	0	0	0	0	0	0	0	RS (formerly Full Electric)
2	2	KU	0	0	0	0	0	0	0	RS (formerly Full Electric)
2	3	KU	0	0	0	0	0	0	0	RS (formerly Full Electric)
2	4	KU	0	0	0	0	0	0	0	RS (formerly Full Electric)
3	4	KU	0	0	0	0	0	0	0	C/I GS Sec
3	5	KU	0	0	0	0	0	-2580.2788	-2580.2788	C/I GS Sec
3	6	KU	0	0	0	0	0	0	0	C/I GS Sec
3	7	KU	0	0	0	0	0	0	0	C/I GS Sec
3	8	KU	0	0	-5786.62	0	0	0	-5786.616	C/I GS Sec
3	9	KU	0	0	-2606.28	0	0	0	-2606.28	C/I GS Sec
3	10	KU	0	0	-3893.59	0	0	0	-3893.592	C/I GS Sec
3	11	KU	0	0	0	0	0	0	0	C/I GS Sec
3	12	KU	0	0	0	0	0	0	0	C/I GS Sec
3	1	KU	0	0	0	0	0	0	0	C/I GS Sec
3	2	KU	0	0	0	0	0	0	0	C/I GS Sec
3	3	KU	0	0	0	0	0	0	0	C/I GS Sec
3	4	KU	0	0	0	0	0	0	0	C/I GS Sec
7	4	KU	0	0	0	0	0	0	0	C/I LP STOD Sec
7	5	KU	0	0	-49.229	0	0	-86.3412	-135.5702	C/I LP STOD Sec
7	6	KU	0	0	0	0	0	0	0	C/I LP STOD Sec
7	7	KU	0	0	0	0	0	0	0	C/I LP STOD Sec
7	8	KU	0	0	0	0	-57.2508	-255.4896	-312.7404	C/I LP STOD Sec

Kentucky Utilities Company
Electric Temperature Normalization

			1	2	3	4	5	6		
Index	**Month**	**Company**	**HDD60**	**HDD65**	**CDD65**	**CDD70**	**MinTemp**	**MaxTemp**	**Total Adjustment**	**Class Description**
7	9	KU	0	0	0	-69.504	0	-52.998	-122.502	C/I LP STOD Sec
7	10	KU	0	-50.882	-219.261	0	0	0	-270.143	C/I LP STOD Sec
7	11	KU	0	0	0	0	0	0	0	C/I LP STOD Sec
7	12	KU	0	0	0	0	0	0	0	C/I LP STOD Sec
7	1	KU	0	0	0	0	0	0	0	C/I LP STOD Sec
7	2	KU	0	0	0	0	0	0	0	C/I LP STOD Sec
7	3	KU	0	0	0	0	0	0	0	C/I LP STOD Sec
7	4	KU	0	0	0	0	0	0	0	C/I LP STOD Sec
9	4	KU	0	0	0	0	0	0	0	C/I LP Sec
9	5	KU	0	0	-814.435	0	0	0	-814.435	C/I LP Sec
9	6	KU	0	0	0	0	0	0	0	C/I LP Sec
9	7	KU	0	0	0	0	0	0	0	C/I LP Sec
9	8	KU	0	0	-6333.37	0	0	0	-6333.372	C/I LP Sec
9	9	KU	0	0	-2481.22	0	0	0	-2481.22	C/I LP Sec
9	10	KU	0	0	-2047.13	0	-2293.0204	0	-4340.1454	C/I LP Sec
9	11	KU	0	0	0	0	0	0	0	C/I LP Sec
9	12	KU	0	0	0	0	0	0	0	C/I LP Sec
9	1	KU	0	0	0	0	0	0	0	C/I LP Sec
9	2	KU	0	0	0	0	0	0	0	C/I LP Sec
9	3	KU	0	0	0	0	0	0	0	C/I LP Sec
9	4	KU	0	0	0	0	0	0	0	C/I LP Sec
10	4	KU	0	0	0	0	0	0	0	C/I LP Sec PF
10	5	KU	0	0	0	0	0	0	0	C/I LP Sec PF
10	6	KU	0	0	0	0	0	0	0	C/I LP Sec PF
10	7	KU	0	0	0	0	566.556	0	566.556	C/I LP Sec PF
10	8	KU	0	0	0	-1848.98	0	0	-1848.975	C/I LP Sec PF
10	9	KU	0	0	0	0	0	0	0	C/I LP Sec PF
10	10	KU	0	0	-1093.13	0	-887.5548	0	-1980.6798	C/I LP Sec PF
10	11	KU	0	0	0	0	0	0	0	C/I LP Sec PF
10	12	KU	0	0	0	0	0	0	0	C/I LP Sec PF
10	1	KU	0	0	0	0	0	0	0	C/I LP Sec PF
10	2	KU	0	0	0	0	0	0	0	C/I LP Sec PF
10	3	KU	0	0	0	0	0	0	0	C/I LP Sec PF
10	4	KU	0	0	0	0	0	0	0	C/I LP Sec PF
11	4	KU	0	0	0	0	0	0	0	C/I LP Pri
11	5	KU	0	0	0	-112.5	0	0	-112.5	C/I LP Pri
11	6	KU	0	0	0	0	0	0	0	C/I LP Pri
11	7	KU	0	0	0	0	0	0	0	C/I LP Pri
11	8	KU	0	0	-435.896	0	0	0	-435.896	C/I LP Pri
11	9	KU	0	0	-162.689	0	0	0	-162.689	C/I LP Pri
11	10	KU	0	0	-209.35	0	0	0	-209.35	C/I LP Pri
11	11	KU	0	0	0	0	0	0	0	C/I LP Pri
11	12	KU	0	0	0	0	0	0	0	C/I LP Pri
11	1	KU	0	0	0	0	0	0	0	C/I LP Pri

Kentucky Utilities Company
Electric Temperature Normalization

Index	Month	Company	1 HDD60	2 HDD65	3 CDD65	4 CDD70	5 MinTemp	6 MaxTemp	Total Adjustment	Class Description
11	2	KU	0	0	0	0	0	0	0	C/I LP Pri
11	3	KU	0	0	0	0	0	0	0	C/I LP Pri
11	4	KU	0	0	0	0	0	0	0	C/I LP Pri
12	4	KU	0	0	0	0	0	0	0	C/I LP Pri PF
12	5	KU	0	0	0	0	0	0	0	C/I LP Pri PF
12	6	KU	0	0	0	0	0	0	0	C/I LP Pri PF
12	7	KU	0	0	0	0	0	0	0	C/I LP Pri PF
12	8	KU	0	0	-1648.82	0	0	0	-1648.824	C/I LP Pri PF
12	9	KU	0	0	-971.879	0	0	0	-971.879	C/I LP Pri PF
12	10	KU	0	0	-2425.49	0	0	0	-2425.492	C/I LP Pri PF
12	11	KU	0	0	0	0	0	0	0	C/I LP Pri PF
12	12	KU	0	0	0	0	0	0	0	C/I LP Pri PF
12	1	KU	0	0	0	0	0	0	0	C/I LP Pri PF
12	2	KU	0	0	0	0	0	0	0	C/I LP Pri PF
12	3	KU	0	0	0	0	0	0	0	C/I LP Pri PF
12	4	KU	0	0	0	0	0	0	0	C/I LP Pri PF

Kentucky Utilities
Normals and Standard Deviations

Lookup	Index	Calendar Month	Variable	Month	Actual	Normal	Stdev	Normal +/- Stdev	20-Year Normal	20-Year Stdev
2008_1_1	1	1/1/2008	HDD60	1	857	854	171	857	790	152
2008_2_1	1	2/1/2008	HDD60	2	705	683	145	705	648	115
2008_3_1	1	3/1/2008	HDD60	3	485	477	93	485	473	93
2007_4_1	1	4/1/2007	HDD60	4	274	205	63	268	203	63
2007_5_1	1	5/1/2007	HDD60	5	17	50	36	17	48	36
2007_6_1	1	6/1/2007	HDD60	6	0	0	0	0	0	0
2007_7_1	1	7/1/2007	HDD60	7	0	0	0	0	0	0
2007_8_1	1	8/1/2007	HDD60	8	0	0	0	0	0	0
2007_9_1	1	9/1/2007	HDD60	9	1	18	15	3	18	15
2007_10_1	1	10/1/2007	HDD60	10	91	166	60	106	169	57
2007_11_1	1	11/1/2007	HDD60	11	432	421	97	432	427	104
2007_12_1	1	12/1/2007	HDD60	12	610	734	155	610	737	155
2008_4_1	1	4/1/2008	HDD60	4	200	205	63	200	203	63
2008_1_2	2	1/1/2008	HDD65	1	1007	1008	171	1007	945	152
2008_2_2	2	2/1/2008	HDD65	2	849	823	145	849	788	116
2008_3_2	2	3/1/2008	HDD65	3	639	621	101	639	616	102
2007_4_2	2	4/1/2007	HDD65	4	377	318	76	377	314	73
2007_5_2	2	5/1/2007	HDD65	5	59	113	59	59	112	60
2007_6_2	2	6/1/2007	HDD65	6	0	0	0	0	0	0
2007_7_2	2	7/1/2007	HDD65	7	0	0	0	0	0	0
2007_8_2	2	8/1/2007	HDD65	8	0	0	0	0	0	0
2007_9_2	2	9/1/2007	HDD65	9	13	51	26	25	52	26
2007_10_2	2	10/1/2007	HDD65	10	164	278	76	202	280	66
2007_11_2	2	11/1/2007	HDD65	11	577	563	102	577	570	107
2007_12_2	2	12/1/2007	HDD65	12	765	887	158	765	891	155
2008_4_2	2	4/1/2008	HDD65	4	319	318	76	319	314	73
2008_1_3	3	1/1/2008	CDD65	1	0	0	0	0	0	0
2008_2_3	3	2/1/2008	CDD65	2	0	0	0	0	0	0
2008_3_3	3	3/1/2008	CDD65	3	0	0	0	0	0	0
2007_4_3	3	4/1/2007	CDD65	4	21	18	16	21	19	18
2007_5_3	3	5/1/2007	CDD65	5	155	85	51	136	85	49
2007_6_3	3	6/1/2007	CDD65	6	284	235	54	284	235	51
2007_7_3	3	7/1/2007	CDD65	7	309	354	64	309	352	64
2007_8_3	3	8/1/2007	CDD65	8	496	324	80	404	328	81
2007_9_3	3	9/1/2007	CDD65	9	238	146	55	201	141	61
2007_10_3	3	10/1/2007	CDD65	10	100	25	22	47	25	23
2007_11_3	3	11/1/2007	CDD65	11	0	0	0	0	0	0
2007_12_3	3	12/1/2007	CDD65	12	0	0	0	0	0	0
2008_4_3	3	4/1/2008	CDD65	4	14	18	16	14	19	18
2008_1_4	4	1/1/2008	CDD70	1	0	0	0	0	0	0
2008_2_4	4	2/1/2008	CDD70	2	0	0	0	0	0	0
2008_3_4	4	3/1/2008	CDD70	3	0	0	0	0	0	0

Kentucky Utilities
Normals and Standard Deviations

Lookup	Index	Calendar Month	Variable	Month	Actual	Normal	Stdev	Normal +/- Stdev	20-Year Normal	20-Year Stdev
2007_4_4	4	4/1/2007	CDD70	4	2	2	5	2	3	6
2007_5_4	4	5/1/2007	CDD70	5	64	27	25	52	27	23
2007_6_4	4	6/1/2007	CDD70	6	148	116	42	148	116	40
2007_7_4	4	7/1/2007	CDD70	7	157	204	61	157	202	61
2007_8_4	4	8/1/2007	CDD70	8	341	180	72	252	184	71
2007_9_4	4	9/1/2007	CDD70	9	124	63	37	100	59	39
2007_10_4	4	10/1/2007	CDD70	10	44	5	9	14	6	10
2007_11_4	4	11/1/2007	CDD70	11	0	0	0	0	0	0
2007_12_4	4	12/1/2007	CDD70	12	0	0	0	0	0	0
2008_4_4	4	4/1/2008	CDD70	4	3	2	5	3	3	6
2008_1_5	5	1/1/2008	MinTemp	1	745	759.5	167.4	745	818.4	151.9
2008_2_5	5	2/1/2008	MinTemp	2	805	762.75	141.25	805	796.65	113
2008_3_5	5	3/1/2008	MinTemp	3	1058	1091.2	93	1058	1094.3	96.1
2007_4_5	5	4/1/2007	MinTemp	4	1290	1335	84	1290	1338	90
2007_5_5	5	5/1/2007	MinTemp	5	1736	1674	102.3	1736	1674	102.3
2007_6_5	5	6/1/2007	MinTemp	6	1920	1872	54	1920	1872	48
2007_7_5	5	7/1/2007	MinTemp	7	1984	2064.6	55.8	2008.8	2064.6	52.7
2007_8_5	5	8/1/2007	MinTemp	8	2139	2027.4	74.4	2101.8	2027.4	74.4
2007_9_5	5	9/1/2007	MinTemp	9	1800	1731	69	1800	1725	66
2007_10_5	5	10/1/2007	MinTemp	10	1612	1438.4	105.4	1543.8	1435.3	83.7
2007_11_5	5	11/1/2007	MinTemp	11	1080	1119	99	1080	1107	93
2007_12_5	5	12/1/2007	MinTemp	12	992	877.3	155	992	877.3	145.7
2008_4_5	5	4/1/2008	MinTemp	4	1330	1335	84	1330	1338	90
2008_1_6	6	1/1/2008	MaxTemp	1	1256	1252.4	179.8	1256	1323.7	158.1
2008_2_6	6	2/1/2008	MaxTemp	2	1254	1259.95	155.375	1254	1299.5	124.3
2008_3_6	6	3/1/2008	MaxTemp	3	1676	1701.9	117.8	1676	1708.1	117.8
2007_4_6	6	4/1/2007	MaxTemp	4	1890	1962	93	1890	1971	84
2007_5_6	6	5/1/2007	MaxTemp	5	2480	2300.2	111.6	2411.8	2300.2	105.4
2007_6_6	6	6/1/2007	MaxTemp	6	2550	2478	78	2550	2475	84
2007_7_6	6	7/1/2007	MaxTemp	7	2635	2672.2	80.6	2635	2672.2	80.6
2007_8_6	6	8/1/2007	MaxTemp	8	2852	2647.4	99.2	2746.6	2656.7	99.2
2007_9_6	6	9/1/2007	MaxTemp	9	2520	2358	96	2454	2352	105
2007_10_6	6	10/1/2007	MaxTemp	10	2263	2086.3	80.6	2166.9	2086.3	83.7
2007_11_6	6	11/1/2007	MaxTemp	11	1650	1659	117	1650	1653	129
2007_12_6	6	12/1/2007	MaxTemp	12	1488	1376.4	164.3	1488	1370.2	164.3
2008_4_6	6	4/1/2008	MaxTemp	4	1943	1962	93	1943	1971	84

Seelye Exhibit 13

KENTUCKY UTILITIES COMPANY
Adjustment to Reflect Weather Normalized Electric Sales Margins
12 Months Ended April 30, 2008

	(1) kiloWatt-Hour Adjustment to Usage	(2) Energy Rate		(3) Revenue Adjustment		(4) Revenue Adjustment
				(2) * (1)		(3)
Residential Rate R	(77,956,000)	0.05774	$	(4,501,179)	$	(4,501,179)
Residential Rate FERS	(41,969,000)	0.05774	$	(2,423,290)	$	(2,423,290)
General Service Rate GS	(14,867,000)	0.06745	$	(1,002,779)	$	(1,002,779)
Large Power Rate LP	(24,039,000)		$	(793,981)	$	(793,981)
Secondary	(17,232,000)	0.03282	$	(565,554)		
Primary	(5,966,000)	0.03282	$	(195,804)		
Transmission	-	0.03282	$	-		
Secondary Small Time of Day	(841,000)	0.03879	$	(32,622)		
Primary Small Time of Day	-	0.03879	$	-		
Large Power Rate LCTOD	-		$	-	$	-
Primary	-	0.03282	$	-		
Transmission	-	0.03282	$	-		
Large Mine Power TOD	-		$	-	$	-
Primary	-	0.03082	$	-		
Transmission	-	0.03082	$	-		
Street Lighting	-		$	-	$	-
Total	(158,831,000)		$	(8,721,229)	$	(8,721,229)
Expenses (variable only)	(158,831,000)	0.02742	$	(4,355,146)	$	(4,355,146)
ADJUSTMENT TO NET OPERATING INCOME BEFORE TAXES					$	(4,366,083)

Seelye Exhibit 14

Kentucky Utilities
Base Fuel Cost and Variable O&M Expenses
12 Months Ended April 30, 2008

Acct	Description	Test-Year Expenses
512	Maintenance of Boiler Plant	24,647,620
513	Maintenance of Electric Plant	9,390,527
514	Maintenance of Misc Steam Plant	991,695
544	Maintenance of Electric Plant - Hydro	136,478
545	Maintenance of Misc Hydro Plant	5,457
558	Duplicate Charge	-
Total Variable Prod Expenses		35,171,777
Total Sales		23,267,663,774
Variable O&M Expenses per kWh		0.00151
FAC Base		0.02591
Total		0.02742

Seelye Exhibit 15

KENTUCKY UTILITIES
Year-end Adjustment
Based on 12 Months ended April 30, 2008

	Avg. Number of Customers 13 months Ended April 30, 2008 (1)	Number of Customers Served at April 30, 2008 (2)	Year-End Over/(Under) Average (Col. 2 - 1) (3)	Actual kWh (4)	Average kWh per Customer (Col. 4 / 1) (5)	Year-End kWh Adjustment (Col. 3 x 5) (6)	Current Rates Net Revenues (Base Rates + FAC) (7)		Average Revenue per kWh (8)	Revenue Adjustment (9)
Residential Rate - RS (Rate Code 010, 050)	222,563	221,917	(646)	3,031,975,597	13,623	(8,800,458)	189,398,711	$	0.0625	(550,029)
Residential Rate - RS (Rate Code 020, 060, 080)	190,488	191,729	1,241	3,465,833,654	18,194	22,578,754	213,846,783	$	0.0617	1,393,109
General Service - GS										
Secondary	78,125	78,790	665	1,819,611,111	23,291	15,488,515	132,755,047	$	0.0730	1,130,662
Primary	73	72	(1)	43,720,684	598,913	(598,913)	2,928,707	$	0.0670	(40,127)
All Electric Schools - AES	306	306	-	131,931,925	431,150	-	7,436,309	$	0.0564	-
Large Power Rate - LP								$		
Secondary	8,944	8,673	(271)	3,797,009,283	424,531	(115,047,901)	210,483,362	$	0.0554	(6,373,654)
Primary	349	349	-	1,624,875,433	4,655,804	-	80,671,819	$	0.0496	-
Transmission	2	2	-	26,100,266	13,050,133	-	1,271,236	$	0.0487	-
Small TOD - Secondary	51	51	-	94,624,461	1,855,382	-	8,804,922	$	0.0931	-
Small TOD - Primary	2	2	-	7,988,094	3,994,047	-	707,513	$	0.0886	-
Small TOD - Transmission	-	-	-	-	0	-	-	$		-
Large Comm/Ind TOD										
Primary - LCI-TOD	40	40	-	2,747,259,009	68,681,475	-	125,505,492	$	0.0457	-
Transmission - LCI-TOD	8	8	-	841,958,377	105,244,797	-	38,192,459	$	0.0454	-
Large Industrial TOD	1	1	-	388,735,959	388,735,959	-	21,759,375	$	0.0560	-
Mine Power - MP										
Primary	30	31	1	109,956,679	3,665,223	3,665,223	6,454,141	$	0.0587	215,149
Transmission	10	10	-	69,078,000	6,907,800	-	3,748,666	$	0.0543	-
Large Mine Power - LMP TOD										
Primary	3	3	-	87,153,119	29,051,040	-	4,603,119	$	0.0528	-
Transmission	6	6	-	268,266,000	44,711,000	-	12,994,108	$	0.0484	-
	Lights	Lights							per Light per year	
Street Lighting - SL	70,531	70,585	54				7,102,718	$	100.7000	5,438
Decorative Street Lighting - SLDEC	8,775	8,206	(569)				1,342,851	$	153.0314	(87,075)
Private Outdoor Lighting - POL	29,054	29,538	484				3,959,304	$	136.2740	65,957
Customer Outdoor Lighting - OL	56,676	56,652	(24)				5,843,762	$	103.1082	(2,475)
TOTAL	666,037	666,971	934	18,556,077,651			1,079,810,402			$ (4,243,045)
Expenses at an Operating Ratio of		0.6475	(see page 2)							(2,747,550)
ADJUSTMENT TO NET OPERATING INCOME BEFORE TAXES										$ (1,495,495)

KENTUCKY UTILITIES
Year-end Adjustment
Based on 12 Months ended April 30, 2008

CALCULATION OF ELECTRIC OPERATING RATIO

TOTAL ELECTRIC OPERATING EXPENSES	788,754,775
LESS WAGES AND SALARIES	55,166,658
LESS PENSIONS AND BENEFITS	19,877,328
LESS REGULATORY COMMISSION EXPENSE	1,026,991
NET EXPENSES	712,683,797
TOTAL ELECTRIC OPERATIONS REVENUES (AS BILLED)	1,100,598,589
OPERATING RATIO	0.6475

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KENTUCKY UTILITIES COMPANY
Electric Cost of Service Study
12 months Ended April 30, 2008

Jurisdictional Separation Study

	ALLOC	TOTAL KENTUCKY UTILITIES (1)-1	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)	PARIS (9)
ALLOCATION FACTOR TABLE										
DEMAND RELATED										
PRODUCTION ALLOCATORS										
1 DEMAND (12 CP GEN LEV)-PROD	DEMPROD	3,750,110	3,245,229	179,446	325,435	28	325,407	99,139	226,268	
2 DEMAND (12 CP GEN LEV)-FERC	DEMFERC	504,853		179,446	325,407	-	325,407	99,139	226,268	-
3 DEMAND (12 CP GEN)-PROD VA	DPRODVA	179,446	-	179,446	-	-	-	-	-	-
4 DEMAND (12 CP GEN)-PROD KY	DPRODKY	3,570,636	3,245,229	-	325,407	-	325,407	99,139	226,268	-
5 DEM (12 CP GEN LV)-FERC POST	DEMFERCP	325,407	-		325,407		325,407	99,139	226,268	-
6 DEM (12 CP GEN LV)-NON VA	DEMPRODNV	3,570,664	3,245,229	-	325,435	28	325,407	99,139	226,268	-
TRANSMISSION ALLOCATORS										
7 DEMAND (12 CP GEN LEV)-TRAN	DEMTRAN	3,750,110	3,245,229	179,446	325,435	28	325,407	99,139	226,268	-
8 DEMAND (12 CP GEN LEV)-VA	DEMVA	179,446	-	179,446	-	-	-	-	-	
9 DEM (12 CP GEN LEV)-VA NON J	DEMVAN	3,570,664	3,245,229	-	325,435	28	325,407	99,139	226,268	
10 DEM (12 CP GN LEV)-TRAN FERC	DEMFERCT	504,853		179,446	325,407	-	325,407	99,139	226,268	
11 DEM (12 CP GN)-TR FERC POST	DFERCTP	325,407		-	325,407	-	325,407	99,139	226,268	
12										
DISTRIBUTION ALLOCATORS										
13 DIR ASSIGN 360-362-RETAIL KY	DEM3602K	105,077,989	105,077,989	-	-	-	-	-	-	-
14 DIR ASSIGN 360-362-FERC KY	DIR3602K	2,461,517		-	2,461,517	-	2,461,517	2,461,517	-	-
15 DIR ASSIGN 364-365-RETAIL KY	DEM3645K	383,711,763	383,711,763	-	-	-	-	-	-	-
16 DIR ASSIGN 366-367-RETAIL KY	DEM3667K	86,588,726	86,588,726	-	-	-	-	-		-
17 DIR ASSIGNMENT 368-RETAIL KY	DEM368K	235,950,120	235,950,120	-	-	-		-		-
18 DIR ASSIGN 360-362-RETAIL VA	DEM3602V	6,857,483	-	6,857,483	-			-		-
19 DIR ASSIGN 360-362-FERC VA	DIR3602V	-	-	-		-				
20 DIR ASSIGN 364-365-RETAIL VA	DEM3645V	28,782,310	-	28,782,310		-	-	-	-	-
21 DIR ASSIGN 366-367-RETAIL VA	DEM3667V	1,362,022	-	1,362,022		-	-	-	-	-
22 DIR ASSIGNMENT 368-RETAIL VA	DEM368V	12,522,631	-	12,522,631	-	-	-	-	-	-
23 DIRECT ASSIGNMENT RETAIL TENN	DEMTENND	163,472		-	163,472	163,472	-	-	-	-
24 DIR ASSIGN ACC.DEPRC.DIST.VA&TN	DIRACDEP	34,518,882	-	34,352,623	166,258	166,258	-	-	-	-
25 DIR ASSIGN CWIP DIST VA & TN	DIRCWIP	3,198,663	-	3,198,663	-	-	-	-	-	-
26 DIR ASSIGN ACC.DFDTX DIST.VA&TN	DIRACDFTX	3,959,278	-	3,959,278	-		-	-	-	-
27 DIR ASSIGN ACC.ITC.DIST.VA & TN	DIRACITC	6,525	-	6,525	-	-		-	-	-
28 DIR ASSION POLE ATTACH. REVENUE	DIRPOLREV	465,970	443,294	22,528	148	148		-	-	-
29 DIR ASSIGN FACILITY LEASE REV.	DIRFACL	1,695,159	1,551,518	143,641	-		-	-		
30 DIR ASSIGN MATERIAL SALES REV.	DIRMATREV	72,230	71,449	781	-			-		
31 DIR ASSIGN SERVICE ON/OFF REV.	DIRSERREV	1,614,240	1,578,059	36,181	-	-				
32 DIR ASSIGN 203(E) EXCESS	DIR203E	37,799	-	37,799	-	-			-	
33 DIR ASSIGN ITC ADJ	DIRITCADJ	22,461		22,461	-					
34 DIR ASSIGN DEFERRED FUEL-VIRGINIA	DFUELVA	58,053		58,053		-	-		-	
35										

KENTUCKY UTILITIES COMPANY
Electric Cost of Service Study
12 months Ended April 30, 2008

Jurisdictional Separation Study

	ALLOC	TOTAL KENTUCKY UTILITIES (1)-1	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)	PARIS (9)
ENERGY										
1 ENERGY (MWH AT GEN LEVEL)	ENERGY	23,012,408	19,984,282	987,026	2,041,100	159	2,040,941	648,678	1,392,263	-
2 ENERGY (MWH RETAIL @ GEN LEVEL)	ENERGY1	20,971,467	19,984,282	987,026	159	159	-	-	-	-
3										
4										
CUSTOMER										
1 DIR ASSIGN ACCT 369-SERV KY	CUST369K	78,030,101	78,030,101	-	-	-				
2 DIR ASSIGN ACCT 370 METERS KY	CUST370K	61,734,498	61,476,425	-	258,073	-	258,073	66,549	191,524	-
3 DIR ASN ACCT 371 CUST INST KY	CUST371K	17,415,370	17,415,370	-	-	-	-	-	-	-
4 DIR ASGN ACCT 373 ST LIGHT KY	CUST373K	52,453,968	52,453,968	-	-	-	-	-	-	-
5 CUSTOMER ADVANCES	CUSTADV	2,420,052	2,405,862	14,190	-	-	-	-	-	-
6 CUSTOMER DEPOSITS	CUSTDEP	759,207	-	759,207	-			-	-	-
7 DIR ASSIGN 902-METER READING	CUST902	598,123	562,650	35,184	289	48	241	145	96	-
8 DIR ASSIGN 903-CUSTOMER REC	CUST903	598,123	562,650	35,184	289	48	241	145	96	-
9 DIR ASSIGN 904-UNCOLL ACCTS	CUST904	598,123	562,650	35,184	289	48	241	145	96	-
10 DIR ASSIGN ACCT 369-SERV VA	CUST369V	5,091,007		5,091,007	-	-	-	-	-	-
11 DIR ASSIGN ACCT 370 METERS VA	CUST370V	3,616,919		3,616,919	-	-	-	-	-	
12 DIR ASN ACCT 371 CUST INST VA	CUST371V	868,638		868,638	-	-	-	-	-	
13 DIR ASGN ACCT 373 ST LIGHT VA	CUST373V	1,317,576	-	1,317,576	-	-	-	-	-	
14 DIR ASSIGN 908-CUST ASSIST	CUST908	535,117	505,195	29,894	28	8	20	12	8	
15 DIR ASSIGN 909-INFO & INSTRCT	CUST909	535,097	505,195	29,894	8	8	-		-	
16 DIR ASSIGN 912-DEM & SELLING	CUST912	535,097	505,195	29,894	8	8	-	-	-	
17 DIR ASSIGN 913-ADVERTISING	CUST913	535,097	505,195	29,894	8	8	-			
18 CUSTOMER ANNUALIZATION	CUSTANN		-	-	-		-	-		
19 CUSTOMER DEPOSITS INTEREST	CUSTDEPI	1,111,987	1,077,634	34,354	-		-		-	-
20										
21										
22										
23										
24										
25										

KENTUCKY UTILITIES COMPANY
Electric Cost of Service Study
12 months Ended April 30, 2008

Jurisdictional Separation Study

INTERNALLY DEVELOPED	ALLOC	TOTAL KENTUCKY UTILITIES (1)-1	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)	PARIS (9)
1 PROD-TRANSM-DISTR-GENL PLT	PTDGPLT	3,891,516,686	3,397,414,598	235,237,723	258,864,365	188,875	258,675,490	80,577,655	178,097,835	0
2 PROD-TRANSM-DISTR-GENL PLT KY	KURETPLT	3,397,414,598	3,397,414,598		-	-	-	-	-	
3 ALLOCATED O&M LABOR EXPENSE	LABOR	61,887,021	55,165,360	3,373,976	3,347,684	3,507	3,344,178	1,062,192	2,281,986	0
4 TOTAL STEAM PROD PLANT-SYSTEM	STMSYS	1,658,021,682	1,434,800,591	79,337,768	143,883,323	12,380	143,870,943	43,831,944	100,038,999	
5 ALLOCATED NON A&G LABOR EXPENSE	PTDCUSTLABOR	50,730,740	45,220,783	2,765,755	2,744,202	2,874	2,741,328	870,712	1,870,616	
6 TOT HYDRAULIC PROD PLANT-SYS	HYDSYS	11,031,938	9,546,697	527,888	957,355	82	957,273	291,644	665,627	-
7 TOTAL OTHER PROD PLANT-SYS	OTHSYS	495,510,433	428,799,376	23,710,602	43,000,455	3,700	42,996,756	13,099,458	29,897,298	-
8 TRANSM KENTUCKY SYSTEM PROP	KYTRPLT	474,259,390	410,409,382	22,693,721	41,156,287	3,541	41,152,746	12,537,659	28,615,087	-
9 TRANSM VIRGINIA PROPERTY	VATRPLT	35,627,686	-	35,627,686	-	-	-	-	-	-
10 TRANSM VIRGINIA PROP TOTAL	VATRPLTT	43,853,230	7,475,857	35,627,686	749,687	65	749,622	228,381	521,241	-
11 TOTAL DISTRIBUTION PLANT	DISTPLT	1,081,564,173	1,017,723,773	60,418,589	3,421,811	163,472	3,258,339	2,692,202	566,137	-
12 TOTAL DIST PLANT KY & FERC	DISTPLTKF	1,020,982,112	1,017,723,773	-	3,258,339	-	3,258,339	2,692,202	566,137	
13 TOTAL GENERAL PLANT	GENPLT	99,461,628	88,658,922	5,422,480	5,380,226	5,636	5,374,590	1,707,099	3,667,491	0
14 ACCT 302-FRANCHISE	PLT302	83,453	83,453	-	-	-	-	-	-	
15 ACCT 303-SOFTWARE	PLT303	25,536,344	22,294,019	1,543,643	1,698,682	1,239	1,697,443	528,755	1,168,688	0
16 TOTAL PRODUCTION PLANT SYSTEM	PRODSYS	2,164,564,053	1,873,146,664	103,576,258	187,841,131	16,162	187,824,969	57,223,046	130,601,923	
17 TOTAL PRODUCTION PLANT	PRODPLT	2,188,712,550	1,873,146,664	109,899,917	205,665,969	16,162	205,649,807	62,653,588	142,996,219	
18 TOTAL TRANSMISSION PLANT	TRANPLT	521,778,335	417,885,239	59,496,737	44,396,359	3,606	44,392,754	13,524,365	30,867,989	
19 MAT & SUPPLIES DISTRIBUTED	M_S	26,744,547	23,046,621	1,664,682	2,033,243	890	2,032,353	626,775	1,405,578	-
20 ACCT 924 & 925 INSURANCE	EXP9245	4,401,205	3,864,212	258,996	277,997	223	277,774	86,920	190,854	0
21 REVENUE SALE OF ELECT-KY	REVKU	1,100,598,589	1,100,598,589				-	-	-	-
22 CWIP PROD FERC-POST ALLOC	CWIPPP	85,319,600	-		85,319,600		85,319,600	25,993,601	59,325,999	-
23 CWIP TRAN FERC-POST ALLOC	CWIPTP	6,012,718	-		6,012,718	-	6,012,718	1,831,844	4,180,874	-
24 ACC DEF INC TX PROD FERC-POST	ADITPP	2,425,176	-	-	2,425,176	-	2,425,176	738,858	1,686,318	-
25 ACC DEF INC TX TRAN FERC-POST	ADITTP	2,859,186	-	-	2,859,186	-	2,859,186	871,084	1,988,102	-
26 TRANSMISSION PLANT EXCL VA	TRANPLTX	477,925,105	410,409,382	23,869,051	43,646,673	3,541	43,643,132	13,296,384	30,346,748	-
27 TRANSM PLANT VA	TRPLTVA	43,853,230	7,475,857	35,627,686	749,687	65	749,622	228,381	521,241	
28 TOT ACCT 364 & 365-OVHD LINE	PLT3645	412,513,645	383,731,335	28,782,310	-	-	-			-
29 TOTAL ELECTRIC PLANT	PLANT	3,917,180,938	3,419,830,881	236,784,053	260,566,004	190,116	260,375,888	81,107,330	179,268,557	0
30 TOTAL ELECTRIC PLANT KY	PLANTKY	3,419,830,881	3,419,830,881	-		-	-		-	
31 TOTAL ELECTRIC PLANT KY & FERC	PLANTKF	3,680,206,769	3,419,830,881	-	260,375,888	-	260,375,888	81,107,330	179,268,557	0
32 TOTAL ELECTRIC PLANT VA	PLANTVA	236,784,053	-	236,784,053			-		-	-
33 TOTAL STEAM PROD PLANT	STMPLT	1,680,088,593	1,434,800,591	85,660,708	159,627,294	12,380	159,614,914	48,628,527	110,986,388	-
34 TOTAL HYDRAULIC PROD PLANT	HYDPLT	11,033,232	9,546,697	527,888	958,647	82	958,565	292,038	666,527	-
35 TOTAL OTHER PROD PLANT	OTHPLT	497,590,725	428,799,376	23,711,321	45,080,028	3,700	45,076,328	13,733,024	31,343,304	-
36 TOT ACCT 360-362 SUBSTATIONS	PLT3602	111,935,478	102,616,477	6,857,483	2,461,517	-	2,461,517	2,461,517	-	-
37 TOT ACCT 366 & 367-UG LINES	PLT3667	87,950,748	86,588,726	1,362,022	-	-	-	-	-	
38 TOT ACCT 373-STREET LIGHTING	PLT373	53,771,544	52,453,968	1,317,576	-	-	-	-	-	
39 TOTAL ACCT 370-METERS	PLT370	65,351,417	61,476,425	3,616,919	258,073	-	258,073	66,549	191,524	
40 TOT ACCT 371-CUSTOMER INSTALL	PLT371	18,284,008	17,415,370	868,638		-	-	-	-	
41 TOT ACCT 368-LINE TRANSFORMER	PLT368	248,472,751	235,411,377	12,522,631	538,749		538,749	164,136	374,613	
42 TOT ACCT 902-904 CUST ACCTS	EXP9024	19,730,752	18,560,576	1,160,642	9,533	1,583	7,950	4,783	3,167	
43 TOT ACCT 908-909 CUST SERV	EXP9089	5,489,484	5,182,547	306,668	269	82	187	112	75	-
44 TOTAL TRANS & DISTRIB PLANT	TRDSPLT	1,603,342,508	1,435,609,032	119,915,326	47,818,171	167,078	47,651,093	16,216,967	31,434,126	

KENTUCKY UTILITIES COMPANY
Electric Cost of Service Study
12 months Ended April 30, 2008

Jurisdictional Separation Study

INTERNALLY DEVELOPED-CONT	ALLOC	TOTAL KENTUCKY UTILITIES (1)-1	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)	PARIS (9)
1 TOT ACCT 912-913 SALES EXP	EXP9123	70,495	66,555	3,938	1	1	-			
2 REVENUE SALE OF ELECT-FERC	REVFERC	89,126,914	-	-	89,126,914	-	89,126,914	28,107,483	61,019,431	-
3 REVENUE SALE OF ELECT-VA	REVVA	54,974,817	-	54,974,817	-	-	-	-	-	-
4 REVENUE SALE OF ELECT	REVENUE	1,244,702,734	1,100,598,589	54,974,817	89,129,328	2,414	89,126,914	28,107,483	61,019,431	-
5 REV SALE OF ELECT-VA NON JUR	REVNJVA	1	-	1	-	-	-	-	-	-
6 REV SALE OF ELECT-EXCL FERC	REVENUEX	1,155,575,820	1,100,598,589	54,974,817	2,414	2,414	-	-	-	-
7 KENTUCKY DISTRIBUTION PLANT	KYDIST	1,020,982,112	1,017,723,773	-	3,258,339	-	3,258,339	2,692,202	566,137	-
8 VIRGINIA DISTRIBUTION PLANT	VADIST	60,418,589	-	60,418,589	-	-	-	-	-	-
9 *TENNESSEE DISTRIBUTION PLT*	TNDIST	163,472	-	-	163,472	163,472	-	-	-	-
10 NET ELECTRIC PLANT IN SERVICE	NETPLANT	1,944,818,293	1,712,175,283	107,577,745	125,065,265	10,005	125,055,260	39,045,023	86,010,237	0
11 *RATE BASE*	RATEBASE	2,994,552,085	2,634,042,250	147,664,107	212,845,727	6,950	212,838,777	66,036,555	146,782,223	(0)
12 TOTAL CWIP FERC-AFUDC POST	*AFUDC*	5,822,612	-	-	5,822,612	-	5,822,612	1,773,926	4,048,686	-
13 TOTAL 203(E) EXCESS	DEFTAX	(1,608,713)	(1,423,281)	(87,940)	(97,492)	(83)	(97,409)	(30,460)	(66,949)	(0)
14 STEAM OPERATING EXP 501-507	EXP5017	440,534,194	382,190,376	19,105,838	39,237,980	3,056	39,234,924	12,437,549	26,797,375	-
15 STEAM MAINTENANCE EXP 511-514	EXP5114	45,600,317	39,507,632	2,007,688	4,084,997	318	*4,084,679*	*1,290,231*	*2,794,448*	-
16 *HYDRO OPERATING EXP 536-540*	EXP5360	41,627	36,018	1,992	3,617	0	3,617	1,102	2,515	-
17 HYDRO MAINTENANCE EXP 542-545	EXP5425	320,455	277,774	14,554	28,128	2	28,125	8,752	19,373	
18 OTHER PROD OPER EXP 547-549	EXP5479	59,497,362	51,657,016	*2,559,970*	*5,280,376*	412	*5,279,964*	*1,676,125*	*3,603,840*	
19 OTHER PROD MAINT EXP 552-554	*EXP5524*	3,139,159	2,705,174	149,588	284,397	23	284,374	86,638	197,736	
20 TOT STEAM OPERATIONS LABOR	LABSTMOP	-	-	-	-	-	-	-	-	
21 TOT STEAM MAINTENANCE LABOR	LABSTMMN	-	-	-	-	-	-	-	-	
22 TOT HYDRO OPERATIONS LABOR	LABHYDOP	-	-	-	-	-	-	-	-	
23 TOT HYDRO MAINTENANCE LABOR	LABHYDMN	-	-	-	-	-	-	-	-	
24 TOT OTHER OPERATIONS LABOR	LABOTHOP	-	-	-	-	-	-	-	-	
25 TOT OTHER MAINTENANCE LABOR	LABOTHMN	-	-	-	-	-	-	-	-	-
26 TRANSM OPER EXP 562-567	EXP5627	12,520,600	10,027,580	1,427,684	1,065,336	87	1,065,249	324,540	740,709	
27 TRANSM MAINT EXP 569-573	EXP5693	5,483,092	4,391,335	625,220	466,538	38	466,500	142,125	324,375	
28 *TOT TRANSM OPERATIONS LABOR*	LABTROP	2,492,461	1,996,178	284,207	*212,075*	17	*212,058*	64,606	*147,452*	-
29 TOT TRANSM MAINTENANCE LABOR	LABTRMN	-	-	-	-	-	-	-	-	
30 DISTR OPER EXP 582-589	EXP5829	15,505,295	14,529,571	911,347	64,377	705	63,671	42,236	21,435	-
31 DISTR MAINT EXP 591-598	EXP5918	23,976,733	22,328,441	1,627,452	20,840	1	20,839	20,659	*180*	
32 *TOT DISTR OPERATIONS LABOR*	LABDISOP	13,821,911	13,006,059	772,123	43,729	2,089	41,640	34,405	7,235	-
33 TOT DISTR MAINTENANCE LABOR	LABDISMN	-	-	-	-	-	-	-	-	
34 CUST ACCT EXP 902, 903 & 905	EXP9025	16,641,666	15,654,696	978,930	8,041	1,336	6,705	4,034	2,671	-
35 *TOTAL CUST ACCOUNTS LABOR*	*LABCA*	*1,413,255*	1,329,439	83,133	683	113	569	343	227	-
36 CUST SERVICES & SALES EXP	EXP9080	6,392,488	6,035,062	357,114	311	96	216	129	86	-
37 TOTAL CUST SERVICES LABOR	LABCS	1,413,255	1,329,439	83,133	683	113	569	343	227	
38 SALES EXPENSE 912-916	EXP9126	70,495	66,555	3,938	1	*1*	-			
39 *TOTAL SALES EXP LABOR*	LABSA	248,589	234,689	13,887	12	4	8	5	1	
40 TOT ADMINISTRATIVE & GEN EXP	A_GEXP	70,241,795	62,547,515	3,834,978	3,859,302	3,876	3,855,426	1,223,291	2,632,136	0

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INTERNALLY DEVELOPED-CONT										
1 ACCT 930-EPRI & ADVERTISING	EXP930A	387,987	369,723	18,261	1	3	-	-		
2 TOTAL CUSTOMER SERVICES EXP	CUSTSER	6,552,768	6,186,379	366,068	322	98	224	134	89	
3 DISTRIBUTION PLANT EXCL VA	DPLTXVA	1,021,145,584	1,017,723,773		3,421,811	163,472	3,258,339	2,692,202	566,137	
4 ACCT 926 DIR ASSIGN COMP.KY RET	LABPTDKY	38,306,996	38,306,996		-	-	-	-		
5 ACCT 926 DIR ASSIGN COMP.VAJ	LABPTDVAJ	2,334,205	-	2,334,205	-	-		-	-	
6 ACCT 926 DIR ASSIGN COMP.VANJ	LABPTDVNJ	-	-	-	-	-		-	-	-
7 ACCT 926 DIR ASSIGN COMP.FERC	LABPTDFER	2,738,459	-	-	2,738,459	-	2,738,459	868,986	1,869,473	
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KENTUCKY UTILITIES COMPANY
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	ALLOC	TOTAL KENTUCKY UTILITIES (1)-I	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)	PARIS (9)
REVENUES FROM ELECTRIC SALES										
1 SALES TO ULTIMATE CONSUMERS		1,244,702,734	1,100,598,589	54,974,817	89,129,328	2,414	89,126,914	28,107,483	61,019,431	-
2 ANNUALIZATION				-		-			-	-
3										
4										
5										
REVENUE REQUIREMENTS INPUTS										
1 CLAIMED RATE OF RETURN - not 3/98 #		0	0	0	0	0	0	0	0	0
2 ANNUAL BOOKED KWH SALES - not 3/98 #		16,476,965,319	14,005,808,602	795,303,005	1,675,853,712	114,290	1,675,739,422	526,560,080	1,111,118,832	38,060,510
3 PROPOSED SALES REVENUE - not 3/98 #		588,604,296	501,250,147	42,341,280	45,012,868	23,822	44,989,046	14,996,349	14,996,349	14,996,349
4 MONTHLY AVERAGE CUSTOMERS - not 3/98 #		527,408	494,863	32,516	29	9	20	12	7	1
5 ANNUAL BILLING DEMANDS - not 3/98 #		28,388,088	24,042,091	933,841	3,412,156	0	3,412,156	1,091,062	2,236,942	84,152

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RATIO TABLE	ALLOC	TOTAL KENTUCKY UTILITIES (1)-1	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)	PARIS (9)
CAPACITY RELATED										
PRODUCTION ALLOCATORS										
1 DEMAND (12 CP GEN LEV)-PROD	DEMPROD	1.000000000	0.865369016	0.047850863	0.086780121	0.000007466	0.086772655	0.026436291	0.060336363	
2 DEMAND (12 CP GEN LEV)-FERC	DEMFERC	1.000000000	-	0.355442079	0.644557921	-	0.644557921	0.196372013	0.448185908	
3 DEMAND (12 CP GEN)-PROD VA	DPRODVA	1.000000000	-	1.000000000	-			-	-	
4 DEMAND (12 CP GEN)-PROD KY	DPRODKY	1.000000000	0.908865816	-	0.091134184	-	0.091134184	0.027765082	0.063369103	
5 DEM (12 CP GEN LV)-FERC POST	DEMFERCP	1.000000000	-		1.000000000	-	1.000000000	0.304661547	0.695338453	
6 DEM (12 CP GEN LV)-NON VA	DEMPRODNV	1.000000000	0.908858688		0.091141312	0.000007842	0.091133470	0.027764864	0.063368606	
TRANSMISSION ALLOCATORS										
7 DEMAND (12 CP GEN LEV)-TRAN	DEMTRAN	1.000000000	0.865369016	0.047850863	0.086780121	0.000007466	0.086772655	0.026436291	0.060336363	-
8 DEMAND (12 CP GEN LEV)-VA	DEMVA	1.000000000	-	1.000000000	-	-	-	-	-	-
9 DEM (12 CP GEN LEV)-VA NON J	DEMVAN	1.000000000	0.908858688	-	0.091141312	0.000007842	0.091133470	0.027764864	0.063368606	-
10 DEM (12 CP GN LEV)-TRAN FERC	DEMFERCT	1.000000000	-	0.355442079	0.644557921	-	0.644557921	0.196372013	0.448185908	-
11 DEM (12 CP GN)-TR FERC POST	DFERCTP	1.000000000	-	-	1.000000000	-	1.000000000	0.304661547	0.695338453	-
12										
DISTRIBUTION ALLOCATORS										
13 DIR ASSIGN 360-362-RETAIL KY	DEM3602K	1.000000000	1.000000000	-	-		-	-	-	
14 DIR ASSIGN 360-362-FERC KY	DIR3602K	1.000000000	-	-	1.000000000	-	1.000000000	1.000000000	-	
15 DIR ASSIGN 364-365-RETAIL KY	DEM3645K	1.000000000	1.000000000	-	-			-	-	
16 DIR ASSIGN 366-367-RETAIL KY	DEM3667K	1.000000000	1.000000000	-	-			-	-	
17 DIR ASSIGNMENT 368-RETAIL KY	DEM368K	1.000000000	1.000000000	-	-	-		-	-	
18 DIR ASSIGN 360-362-RETAIL VA	DEM3602V	1.000000000	-	1.000000000	-	-		-	-	-
19 DIR ASSIGN 360-362-FERC VA	DIR3602V	-	-	-				-	-	-
20 DIR ASSIGN 364-365-RETAIL VA	DEM3645V	1.000000000	-	1.000000000	-			-	-	
21 DIR ASSIGN 366-367-RETAIL VA	DEM3667V	1.000000000	-	1.000000000	-	-	-	-	-	
22 DIR ASSIGNMENT 368-RETAIL VA	DEM368V	1.000000000	-	1.000000000		-	-	-		-
23 DIRECT ASSIGNMENT RETAIL TENN	DEMTENND	1.000000000	-	-	1.000000000	1.000000000	-	-	-	-
24 DIR ASSIGN ACCUM DEPREC.VA & TN	DIRACDEP	1.000000000	-	0.995183552	0.004816448	0.004816448	-			-
25 DIR ASSIGN CWIP VA & TN	DIRCWIP	1.000000000	-	1.000000000	-	-	-		-	-
26 DIR ASSIGN ACC DFD TAX VA	DIRACDFTX	1.000000000	-	1.000000000		-	-			-
27 DIR ASSIGN ACC ITC VA	DIRACITC	1.000000000	-	1.000000000	-	-	-			-
28 DIR ASSIGN POLE ATTACH. REVENUE	DIRPOLREV	1.000000000	0.951335923	0.048346460	0.000317617	0.000317617	-			-
29 DIR ASSIGN FACILITY LEASE REV.	DIRFACL	1.000000000	0.915263996	0.084736004	-	-	-			-
30 DIR ASSIGN MATERIAL SALES REV.	DIRMATREV	1.000000000	0.989187318	0.010812682	-	-			-	-
31 DIR ASSIGN SERVICE ON/OFF REV.	DIRSERREV	1.000000000	0.977586356	0.022413644	-	-	-	-	-	-
32 DIR ASSIGN 203(E) EXCESS	DIR203E	1.000000000	-	1.000000000	-	-	-		-	-
33 DIR ASSIGN ITC ADJ	DIRITCADJ	1.000000000		1.000000000	-	-	-	-	-	-
34 DIR ASSIGN DEFERRED FUEL-VIRGINIA	DFUELVA	1.000000000	-	1.000000000	-					
35									-	-

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ENERGY										
1 ENERGY (MWH AT GEN LEVEL)	ENERGY	1.000000000	0.868413336	0.042891035	0.088695629	0.000006909	0.088688720	0.028188184	0.060500535	
2 ENERGY (MWH RETAIL @ GEN LEVEL)	ENERGY1	1.000000000	0.952927232	0.047065186	0.000007582	0.000007582				
3										
4										
CUSTOMER										
1 DIR ASSIGN ACCT 369-SERV KY	CUST369K	1.000000000	1.000000000							
2 DIR ASSIGN ACCT 370 METERS KY	CUST370K	1.000000000	0.995819631		0.004180369		0.004180369	0.001077987	0.003102382	
3 DIR ASN ACCT 371 CUST INST KY	CUST371K	1.000000000	1.000000000							
4 DIR ASGN ACCT 373 ST LIGHT KY	CUST373K	1.000000000	1.000000000							
5 CUSTOMER ADVANCES	CUSTADV	1.000000000	0.994136457	0.005863543						
6 CUSTOMER DEPOSITS	CUSTDEP	1.000000000		1.000000000						
7 DIR ASSIGN 902-METER READING	CUST902	1.000000000	0.940692801	0.058824021	0.000483178	0.000080251	0.000402927	0.000242425	0.000160502	
8 DIR ASSIGN 903-CUSTOMER REC	CUST903	1.000000000	0.940692801	0.058824021	0.000483178	0.000080251	0.000402927	0.000242425	0.000160502	
9 DIR ASSIGN 904-UNCOLL ACCTS	CUST904	1.000000000	0.940692801	0.058824021	0.000483178	0.000080251	0.000402927	0.000242425	0.000160502	
10 DIR ASSIGN ACCT 369-SERV VA	CUST369V	1.000000000		1.000000000						
11 DIR ASSIGN ACCT 370 METERS VA	CUST370V	1.000000000		1.000000000						
12 DIR ASN ACCT 371 CUST INST VA	CUST371V	1.000000000		1.000000000						
13 DIR ASGN ACCT 373 ST LIGHT VA	CUST373V	1.000000000		1.000000000						
14 DIR ASSIGN 908-CUST ASSIST	CUST908	1.000000000	0.944083257	0.055864418	0.000052325	0.000014950	0.000037375	0.000022425	0.000014950	
15 DIR ASSIGN 909-INFO & INSTRCT	CUST909	1.000000000	0.944118543	0.055866506	0.000014951	0.000014951				
16 DIR ASSIGN 912-DEM & SELLING	CUST912	1.000000000	0.944118543	0.055866506	0.000014951	0.000014951				
17 DIR ASSIGN 913-ADVERTISING	CUST913	1.000000000	0.944118543	0.055866506	0.000014951	0.000014951				
18 CUSTOMER ANNUALIZATION	CUSTANN	-								
19 CUSTOMER DEPOSITS INTEREST	CUSTDEPI	1.000000000	0.969106112	0.030893888						
20										
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		ALLOC	TOTAL KENTUCKY UTILITIES (1)-1	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)	PARIS (9)
	INTERNALLY DEVELOPED										
1	PROD-TRANSM-DISTR-GENL PLT	PTDGPLT	1.000000000	0.873030973	0.060448854	0.066520174	0.000048535	0.066471638	0.020705977	0.045765661	0.000000000
2	PROD-TRANSM-DISTR-GENL PLT KY	KURETPLT	1.000000000	1.000000000	-			-		-	
3	ALLOCATED O&M LABOR EXPENSE	LABOR	1.000000000	0.891388203	0.054518316	0.054093481	0.000056661	0.054036821	0.017163397	0.036873423	0.000000000
4	ALLOCATED O&M LABOR EXPENSE	PTDCUSTLABOR	1.000000000	0.891388203	0.054518316	0.054093481	0.000056661	0.054036821	0.017163397	0.036873423	-
5	*TOTAL STEAM PROD PLANT-SYSTEM*	STMSYS	1.000000000	0.865369016	0.047850863	0.086780121	0.000007466	0.086772655	0.026436291	0.060336363	-
6	TOT HYDRAULIC PROD PLANT-SYS	HYDSYS	1.000000000	0.865369016	0.047850863	0.086780121	0.000007466	0.086772655	0.026436291	0.060336363	-
7	TOTAL OTHER PROD PLANT-SYS	OTHSYS	1.000000000	0.865369016	0.047850863	0.086780121	0.000007466	0.086772655	0.026436291	0.060336363	-
8	TRANSM KENTUCKY SYSTEM PROP	KYTRPLT	1.000000000	0.865369016	0.047850863	0.086780121	0.000007466	0.086772655	0.026436291	0.060336363	-
9	TRANSM VIRGINIA PROPERTY	VATRPLT	1.000000000	-	1.000000000	-	-	-	-	-	-
10	TRANSM VIRGINIA PROP TOTAL	VATRPLTT	1.000000000	0.170474488	0.812430150	0.017095362	0.000001471	0.017093891	0.005207851	0.011886040	-
11	TOTAL DISTRIBUTION PLANT	DISTPLT	1.000000000	0.940974007	0.055862232	0.003163762	0.000151144	0.003012617	0.002489175	0.000523443	
12	TOTAL DIST PLANT KY & FERC	DISTPLTKF	1.000000000	0.996808623	-	0.003191377	-	0.003191377	0.002636875	0.000554502	-
13	TOTAL GENERAL PLANT	GENPLT	1.000000000	0.891388203	0.054518316	0.054093481	0.000056661	0.054036821	0.017163397	0.036873423	0.000000000
14	ACCT 302-FRANCHISE	PLT302	1.000000000	1.000000000	-	-	-	-	-	-	-
15	ACCT 303-SOFTWARE	PLT303	1.000000000	0.873030973	0.060448854	0.066520174	0.000048535	0.066471638	0.020705977	0.045765661	0.000000000
16	TOTAL PRODUCTION PLANT SYSTEM	PRODSYS	1.000000000	0.865369016	0.047850863	0.086780121	0.000007466	0.086772655	0.026436291	0.060336363	
17	TOTAL PRODUCTION PLANT	PRODPLT	1.000000000	0.855821229	0.050212129	0.093966642	0.000007384	0.093959258	0.028625773	0.065333485	
18	TOTAL TRANSMISSION PLANT	TRANPLT	1.000000000	0.800886527	0.114026845	0.085086629	0.000006910	0.085079719	0.025920519	0.059159200	
19	MAT & SUPPLIES DISTRIBUTED	M_S	1.000000000	0.861731605	0.062243807	0.076024588	0.000033283	0.075991305	0.023435602	0.052555703	-
20	ACCT 924 & 925 INSURANCE	EXP9245	1.000000000	0.877989569	0.058846614	0.063163817	0.000050728	0.063113089	0.019749126	0.043363963	0.000000000
21	REVENUE SALE OF ELECT-KY	REVKU	1.000000000	1.000000000	-	-		-		-	-
22	CWIP PROD FERC-POST ALLOC	CWIPPP	1.000000000	-		1.000000000		1.000000000	0.304661547	0.695338453	
23	CWIP TRAN FERC-POST ALLOC	CWIPTP	1.000000000	-	-	1.000000000	-	1.000000000	0.304661547	0.695338453	-
24	ACC DEF INC TX PROD FERC-POST	ADITPP	1.000000000	-	-	1.000000000		1.000000000	0.304661547	0.695338453	-
25	ACC DEF INC TX TRAN FERC-POST	ADITTP	1.000000000	-	-	1.000000000	-	1.000000000	0.304661547	0.695338453	-
26	TRANSMISSION PLANT EXCL VA	TRANPLTX	1.000000000	0.858731582	0.049943078	0.091325340	0.000007409	0.091317931	0.027821062	0.063496869	-
27	TRANSM PLANT VA & 500 KV	TRPLTVA	1.000000000	0.170474488	0.812430150	0.017095362	0.000001471	0.017093891	0.005207851	0.011886040	-
28	TOT ACCT 364 & 365-OVHD LINE	PLT3645	1.000000000	0.930227010	0.069772990	-	-	-	-	-	-
29	TOTAL ELECTRIC PLANT	PLANT	1.000000000	0.873033678	0.060447566	0.066518756	0.000048534	0.066470222	0.020705536	0.045764686	0.000000000
30	TOTAL ELECTRIC PLANT KY	PLANTKY	1.000000000	1.000000000	-		-	-		-	
31	TOTAL ELECTRIC PLANT KY & FERC	PLANTKF	1.000000000	0.929249658	-	0.070750342	-	0.070750342	0.022038797	0.048711545	0.000000000
32	TOTAL ELECTRIC PLANT VA	PLANTVA	1.000000000	-	1.000000000	-	-	-	-	-	-
33	TOTAL STEAM PROD PLANT	STMPLT	1.000000000	0.854002936	0.050985828	0.095011236	0.000007368	0.095003868	0.028944025	0.066059842	
34	TOTAL HYDRAULIC PROD PLANT	HYDPLT	1.000000000	0.865267518	0.047845251	0.086887231	0.000007466	0.086879766	0.026468924	0.060410842	-
35	TOTAL OTHER PROD PLANT	OTHPLT	1.000000000	0.861751143	0.047652257	0.090596600	0.000007435	0.090589165	0.027599035	0.062990130	-
36	TOT ACCT 360-362 SUBSTATIONS	PLT3602	1.000000000	0.916746679	0.061262822	0.021990499	-	0.021990499	0.021990499		
37	TOT ACCT 366 & 367-UG LINES	PLT3667	1.000000000	0.984513805	0.015486195	-		-	-	-	-
38	TOT ACCT 373-STREET LIGHTING	PLT373	1.000000000	0.975496771	0.024503229	-			-		-
39	TOTAL ACCT 370-METERS	PLT370	1.000000000	0.940705306	0.055345690	0.003949004		0.003949004	0.001018325	0.002930679	-
40	TOT ACCT 371-CUSTOMER INSTALL	PLT371	1.000000000	0.952491918	0.047508082	-	-	-	-	-	-
41	TOT ACCT 368-LINE TRANSFORMER	PLT368	1.000000000	0.947433350	0.050398409	0.002168242	-	0.002168242	0.000660580	0.001507662	-
42	TOT ACCT 902-904 CUST ACCTS	EXP9024	1.000000000	0.940692801	0.058824021	0.000483178	0.000080251	0.000402927	0.000242425	0.000160502	-
43	TOT ACCT 908-909 CUST SERV	EXP9089	1.000000000	0.944086316	0.055864599	0.000049085	0.000014950	0.000034135	0.000020481	0.000013654	-
44	TOTAL TRANS & DISTRIB PLANT	TRDSPLT	1.000000000	0.895385112	0.074790835	0.029824052	0.000104206	0.029719846	0.010114475	0.019605372	-

KENTUCKY UTILITIES COMPANY
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INTERNALLY DEVELOPED-CONT	ALLOC	TOTAL KENTUCKY UTILITIES (1)-1	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)	PARIS (9)
1 TOT ACCT 912-913 SALES EXP	EXP9123	1.000000000	0.944118543	0.055866506	0.000014951	0.000014951		-		
2 REVENUE SALE OF ELECT-FERC	REVFERC	1.000000000	-	-	1.000000000	-	1.000000000	0.315364706	0.684635294	
3 REVENUE SALE OF ELECT-VA	REVVA	1.000000000		1.000000000	-			-		
4 REVENUE SALE OF ELECT	REVENUE	1.000000000	0.884226056	0.044167025	0.071606919	0.000001939	0.071604980	0.022581683	0.049023296	
5 REV SALE OF ELECT-VA NON JUR	REVNJVA	1.000000000	-	1.000000000	-	-	-	-	-	
6 REV SALE OF ELECT-EXCL FERC	*REVENUEX*	*1.000000000*	*0.952424384*	*0.047573527*	*0.000002089*	*0.000002089*		-	-	
7 KENTUCKY DISTRIBUTION PLANT	KYDIST	1.000000000	0.996808623	-	0.003191377		0.003191377	0.002636875	0.000554502	
8 VIRGINIA DISTRIBUTION PLANT	VADIST	1.000000000	-	1.000000000	-			-	-	
9 TENNESSEE DISTRIBUTION PLT	TNDIST	1.000000000	-	-	1.000000000	1.000000000		-	-	
10 NET ELECTRIC PLANT IN SERVICE	NETPLANT	1.000000000	0.880378022	0.055315062	0.064306915	0.000005144	0.064301771	0.020076438	0.044225333	0.000000000
11 RATE BASE	RATEBASE	1.000000000	0.879611433	0.049310916	0.071077651	0.000002321	0.071075330	0.022058910	0.049016420	(0.000000000)
12 TOTAL CWIP FERC-AFUDC POST	AFUDC	1.000000000			1.000000000	-	1.000000000	0.304661547	0.695338453	
13 TOTAL 201(E) EXCESS	DEFTAX	1.000000000	0.884732991	0.054664754	0.060602255	0.000051571	0.060550685	0.018934322	0.041616362	0.000000000
14 STEAM OPERATING EXP 501-507	EXP5017	1.000000000	0.867561204	0.043369705	0.089069090	0.000006936	0.089062154	0.028232880	0.060829274	-
15 STEAM MAINTENANCE EXP 511-514	EXP5114	1.000000000	0.866389407	0.044027942	0.089582651	0.000006974	0.089575677	0.028294342	0.061281335	
16 HYDRO OPERATING EXP 536-540	EXP5360	1.000000000	0.865267518	0.047845251	0.086887231	0.000007466	0.086879766	0.026468924	0.060410842	
17 HYDRO MAINTENANCE EXP 542-545	*EXP5425*	*1.000000000*	0.866810292	0.045415602	0.087774106	0.000007193	0.087766914	0.027312084	0.060454829	
18 OTHER PROD OPER EXP 547-549	EXP5479	1.000000000	0.868223638	0.043026606	0.088749757	0.000006924	0.088742833	0.028171409	0.060571424	
19 OTHER PROD MAINT EXP 552-554	EXP5524	1.000000000	0.861751143	0.047652257	0.090596600	0.000007435	0.090589165	0.027599035	0.062990130	
20 TOTAL STEAM OPERATIONS LABOR	LABSTMOP	-	-	-	-	-		-	-	
21 TOTAL STEAM MAINTENANCE LABOR	LABSTMMN	-	-	-	-	-		-		
22 TOTAL HYDRO OPERATIONS LABOR	LABHYDOP	-	-	-	-	-		-		
23 TOTAL HYDRO MAINTENANCE LABOR	LABHYDMN		-	-	-	-		-	-	
24 TOTAL OTHER OPERATIONS LABOR	LABOTHOP	-	-	-	-	-	-	-	-	
25 TOTAL OTHER MAINTENANCE LABOR	LABOTHMN	-	-	-	-	-		-	-	
26 TRANSM OPER EXP 562-567	EXP5627	1.000000000	0.800886527	0.114026845	0.085086629	0.000006910	0.085079719	0.025920519	0.059159200	
27 TRANSM MAINT EXP 569-573	EXP5693	1.000000000	0.800886527	0.114026845	0.085086629	0.000006910	0.085079719	0.025920519	0.059159200	
28 TOT TRANSM OPERATIONS LABOR	LABTROP	1.000000000	0.800886527	0.114026845	0.085086629	0.000006910	0.085079719	0.025920519	0.059159200	-
29 TOT TRANSM MAINTENANCE LABOR	LABTRMN	-	-	-	-	-		-		
30 DISTR OPER EXP 582-589	EXP5829	1.000000000	0.937071559	0.058776523	0.004151919	0.000045498	0.004106420	0.002723960	0.001382460	
31 DISTR MAINT EXP 591-598	EXP5918	1.000000000	0.931254516	0.067876316	0.000869169	0.000000052	0.000869117	0.000861608	0.000007509	-
32 TOT DISTR OPERATIONS LABOR	*LABDISOP*	*1.000000000*	*0.940974007*	*0.055862232*	*0.003163762*	*0.000151144*	*0.003012617*	*0.002489175*	*0.000523443*	
33 TOT DISTR MAINTENANCE LABOR	LABDISMN	-	-	-	-	-		-	-	
34 CUST ACCT EXP 902, 903 & 905	EXP9025	1.000000000	0.940692801	0.058824021	0.000483178	0.000080251	0.000402927	0.000242425	0.000160502	
35 TOTAL CUST ACCOUNTS LABOR	LABCA	1.000000000	0.940692801	0.058824021	0.000483178	0.000080251	0.000402927	0.000242425	0.000160502	-
36 CUST SERVICES EXP 908-910	EXP9080	1.000000000	0.944086671	0.055864621	0.000048708	0.000014950	0.000033758	0.000020255	0.000013503	
37 TOTAL CUST SERVICES LABOR	LABCS	1.000000000	0.940692801	0.058824021	0.000483178	0.000080251	0.000402927	0.000242425	0.000160502	
38 SALES EXPENSE 912-916	EXP9126	1.000000000	0.944118543	0.055866506	0.000014951	0.000014951	-	-	-	
39 TOTAL SALES EXP LABOR	LABSA	1.000000000	0.944086671	0.055864621	0.000048708	0.000014950	0.000033758	0.000020255	0.000013503	
40 TOT ADMINISTRATIVE & GEN EXP	A_GEXP	1.000000000	0.890460091	0.054596808	0.054943101	0.000055178	0.054887923	0.017415423	0.037472500	0.000000000

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Jurisdictional Separation Study

		ALLOC	TOTAL KENTUCKY UTILITIES (1)-1	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)	PARIS (9)
	INTERNALLY DEVELOPED-CONT										
1	ACCT 930-EPRI & ADVERTISING	EXP930A	1.000000000	0.952927232	0.047065186	0.000007582	0.000007582	-	-		-
2	TOTAL CUSTOMER SERVICES EXP	CUSTSER	1.000000000	0.944086328	0.055864600	0.000049071	0.000014950	0.000034121	0.000020473	0.000013648	-
3	DISTRIBUTION PLANT EXCL VA	DPLTXVA	1.000000000	0.996649047		0.003350953	0.000160087	0.003190866	0.002636453	0.000554413	
4	ACCT 926 DIR ASSIGN COMP.KY RET	LABPTDKY	1.000000000	1.000000000	-	-		-		-	
5	ACCT 926 DIR ASSIGN COMP.VAJ	LABPTDVAJ	1.000000000	-	1.000000000	-		-			
6	ACCT 926 DIR ASSIGN COMP.VANJ	LABPTDVNJ	-	-		-		-		-	
7	ACCT 926 DIR ASSIGN COMP.FERC	LABPTDFER	1.000000000	-	-	1.000000000	-	1.000000000	0.317326517	0.682673483	
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KENTUCKY UTILITIES COMPANY
Electric Cost of Service Study
12 months Ended April 30, 2008

Jurisdictional Separation Study

		ALLOC	TOTAL KENTUCKY UTILITIES (1)-1	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)	PARIS (9)
	REVENUES FROM ELECTRIC SALES										
1	SALES TO ULTIMATE CONSUMERS		(	(	0	0	0	0	0	0	
2	ANNUALIZATION										
3											
4											
5											
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KENTUCKY UTILITIES COMPANY
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Junsdictional Separation Study

SUMMARY OF RESULTS AS ALLOCATED	ALLOC	TOTAL KENTUCKY UTILITIES (1)-1	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)	PARIS (9)
ELEMENTS OF RATE BASE										
1 PLANT IN SERVICE		3,917,180,938	3,419,830,881	236,784,053	260,566,004	190,116	260,375,888	81,107,330	179,268,557	0
2 LESS RESERVE FOR DEPRECIATION		1,972,362,645	1,707,655,598	129,206,308	135,500,739	180,111	135,320,628	42,062,307	93,258,320	0
3 NET PLANT IN SERVICE		1,944,818,293	1,712,175,283	107,577,745	125,065,265	10,005	125,055,260	39,045,023	86,010,237	0
4 CONST WORK IN PROGRESS		1,234,053,513	1,075,862,772	58,908,640	99,282,101	9,618	99,272,483	30,495,609	68,776,874	0
5 NET PLANT		3,178,871,807	2,788,038,055	166,486,385	224,347,367	19,623	224,327,744	69,540,633	154,787,111	0
ADD:										
6 MATERIALS & SUPPLIES		33,124,214	28,544,182	2,061,777	2,518,255	1,102	2,517,152	776,286	1,740,866	
7 FUEL INVENTORY		52,838,865	45,885,975	2,266,314	4,686,576	365	4,686,211	1,489,432	3,196,780	
8 PREPAYMENTS		1,664,279	1,461,220	97,937	105,122	84	105,038	32,868	72,170	0
9 WORKING CASH		87,541,433	78,937,746	1,629,974	6,973,712	1,337	6,972,376	2,211,531	4,760,845	0
10 EMISSION ALLOWANCES		223,085	193,051	10,675	19,359	2	19,358	5,898	13,460	
11 TOTAL ADDITIONS		175,391,876	155,022,174	6,066,677	14,303,025	2,890	14,300,135	4,516,014	9,784,120	0
DEDUCT:										
12 RESERVE FOR DEF TAXES		293,644,797	256,897,609	16,389,171	20,358,017	15,118	20,342,898	6,340,662	14,002,236	0
13 RESERVE FOR ITC		58,094,148	49,714,508	2,933,193	5,446,648	445	5,446,202	1,659,430	3,786,772	0
14 CUSTOMER ADVANCES		2,420,052	2,405,862	14,190	-	-	-			-
15 CUSTOMER DEPOSITS		759,207	-	759,207		-		-	-	-
16 DEFERRED FUEL-VIRGINIA		58,053	-	58,053	-	-	-		-	-
17 OPEB UNFUNDED		4,735,141	-	4,735,141	0	-	0	-		0
18 TOTAL DEDUCTIONS		359,711,598	309,017,979	24,888,955	25,804,664	15,564	25,789,101	8,000,092	17,789,009	0
19 NET ORIGINAL COST RATE BASE		2,994,552,085	2,634,042,250	147,664,107	212,845,727	6,950	212,838,777	66,056,555	146,782,223	(0)
DEVELOPMENT OF RETURN										
20 OPERATING REVENUES		1,306,033,927	1,154,156,041	57,657,006	94,220,880	2,961	94,217,920	29,722,275	64,495,645	
OPERATING EXPENSES										
21 OPERATION & MAINT EXPENSE		903,348,115	788,744,613	42,781,655	71,821,846	11,955	71,809,891	22,767,538	49,042,353	0
22 DEPRECIATION & AMORT EXP		124,356,219	108,757,794	7,371,432	8,226,993	5,568	8,221,425	2,561,576	5,659,849	0
23 REGULATORY CREDITS		(2,196,420)	(1,901,684)	(104,747)	(189,988)	(16)	(189,972)	(57,889)	(132,083)	
24 TAXES OTHER THAN INC TAX		18,993,835	16,998,492	947,853	1,047,490	390	1,047,101	328,647	718,454	0
25 INCOME TAXES		71,242,332	66,273,491	1,209,512	3,759,329	(6,032)	3,765,361	1,160,059	2,605,303	(0)
26 GAIN DISPOSITION ALLOWANCES		(583,107)	(504,602)	(27,902)	(50,602)	(4)	(50,598)	(15,415)	(35,183)	-
27 ACCRETION EXPENSE		1,901,344	1,646,311	90,636	164,397	14	164,383	50,093	114,290	-
28 TOTAL OPERATING EXPENSES		1,117,062,318	980,014,414	52,268,439	84,779,465	11,874	84,767,592	26,794,608	57,972,984	0
29 RETURN		188,971,609	174,141,627	5,388,567	9,441,415	(8,913)	9,450,328	2,927,667	6,522,661	(0)
30 RATE OF RETURN		0	0	0	0	(1)	0	0	0	0

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	ALLOC	TOTAL KENTUCKY UTILITIES (1)-1	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)	PARIS (9)
SUMMARY OF RESULTS AFTER ADJUSTMENT										
ELEMENTS OF RATE BASE										
1 PLANT IN SERVICE		3,917,180,938	3,419,830,881	236,784,053	260,566,004	190,116	260,375,888	81,107,330	179,268,557	0
2 LESS RESERVE FOR DEPRECIATION		1,972,362,645	1,707,655,598	129,206,308	135,500,739	180,111	135,320,628	42,062,307	93,258,320	0
3 NET PLANT IN SERVICE		1,944,818,293	1,712,175,283	107,577,745	125,065,265	10,005	125,055,260	39,045,023	86,010,237	0
4 CONST WORK IN PROGRESS		1,234,053,513	1,075,862,772	58,908,640	99,282,101	9,618	99,272,483	30,495,609	68,776,874	0
5 NET PLANT		3,178,871,807	2,788,038,055	166,486,385	224,347,367	19,623	224,327,744	69,540,633	154,787,111	0
ADD:										
6 MATERIALS & SUPPLIES		33,124,214	28,544,182	2,061,777	2,518,255	1,102	2,517,152	776,286	1,740,866	-
7 *FUEL INVENTORY*		*52,838,865*	*45,885,975*	*2,266,314*	*4,686,576*	*365*	*4,686,211*	*1,489,432*	*3,196,780*	-
8 PREPAYMENTS		1,664,279	1,461,220	97,937	105,122	84	105,038	32,868	72,170	0
9 WORKING CASH		87,541,433	78,937,746	1,629,974	6,973,712	1,337	6,972,376	2,211,531	4,760,845	0
10 EMISSION ALLOWANCES		223,085	193,051	10,675	19,359	*1*	19,358	5,898	13,460	-
11 TOTAL ADDITIONS		175,391,876	155,022,174	6,066,677	14,303,025	2,890	14,300,135	4,516,014	9,784,120	0
DEDUCT:										
12 RESERVE FOR DEF TAXES		293,644,797		16,389,171	20,358,017	15,118	20,342,898	6,340,662	14,002,236	0
13 RESERVE FOR ITC		58,094,348	49,714,508	2,933,193	5,446,648	445	5,446,202	1,659,430	3,786,772	0
14 CUSTOMER ADVANCES		2,420,052	2,405,862	14,190	-	-	-	-	-	
15 CUSTOMER DEPOSITS		759,207	-	759,207	-	-	-		-	
16 DEFERRED FUEL-VIRGINIA		58,053	-	58,053	-	-	-	-	-	
17 OPEB UNFUNDED		4,735,141	-	4,735,141	0	-	0	-	-	0
18 TOTAL DEDUCTIONS		359,711,598	309,017,979	24,888,955	25,804,664	15,564	25,789,101	8,000,092	17,789,009	0
19 NET ORIGINAL COST RATE BASE		2,994,552,085	2,634,042,250	147,664,107	212,845,727	6,950	212,838,777	66,056,555	146,782,223	(0)
DEVELOPMENT OF RETURN										
20 OPERATING REVENUES		1,306,033,927	1,154,156,041	57,657,006	94,220,880	2,961	94,217,920	29,722,275	64,495,645	
OPERATING EXPENSES										
21 OPERATION & MAINT EXPENSE		903,348,115	788,744,613	42,781,655	71,821,846	11,955	71,809,891	22,767,538	49,042,353	0
22 DEPRECIATION & AMORT EXP		124,356,219	108,757,794	7,371,432	8,226,993	5,568	8,221,425	2,561,576	5,659,849	0
23 REGULATORY CREDITS		(2,196,420)	(1,901,684)	(104,747)	(189,988)	(16)	(189,972)	(57,889)	(132,083)	-
24 TAXES OTHER THAN INC TAX		18,993,835	16,998,492	947,853	1,047,490	390	1,047,101	328,647	718,454	0
25 INCOME TAXES		71,242,332	66,273,491	1,209,512	3,759,329	(6,032)	3,765,361	1,160,059	2,605,303	(0)
26 GAIN DISPOSITION ALLOWANCES		(583,107)	(504,602)	(27,902)	(50,602)	(4)	(50,598)	(15,415)	(35,183)	-
27 ACCRETION EXPENSE		1,901,344	*1,646,311*	*90,636*	*164,397*	*14*	*164,383*	*50,093*	*114,290*	-
28 TOTAL OPERATING EXPENSES		1,117,062,318	980,014,414	52,268,439	84,779,465	11,874	84,767,592	26,794,608	57,972,984	0
29 RETURN		188,971,609	174,141,627	5,388,567	9,441,415	(8,913)	9,450,328	2,927,667	6,522,661	(0)

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	ALLOC	TOTAL KENTUCKY UTILITIES (1)-I	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)	PARIS (9)
ELECTRIC PLANT IN SERVICE										
INTANGIBLE PLANT										
1 301-ORGANIZATION	PTDGPLT	44,456	38,811	2,687	2,957	1	2,955	920	2,035	0
2 302-FRANCHISE	KURETPLT	83,453	83,453	-	-		-	-	-	
3 303-SOFTWARE	PTDGPLT	25,516,344	22,294,019	1,543,643	1,698,682	1,239	1,697,443	528,755	1,168,688	0
4 TOTAL INTANGIBLE PLANT		25,664,252	22,416,283	1,546,330	1,701,639	1,242	1,700,398	529,675	1,170,722	0
PRODUCTION PLANT										
5 STEAM PRODUCTION PLANT	DEMPROD	1,658,021,682	1,434,800,591	79,337,768	143,883,322	12,380	143,870,943	43,831,944	100,038,999	
6 FERC-AFUDC PRE	DEMFERC	17,788,946	-	6,322,940	11,466,006	-	11,466,006	3,493,251	7,972,755	
7 FERC-AFUDC POST	DEMFERCP	4,277,966	-	-	4,277,966	-	4,277,966	1,303,332	2,974,634	-
8 TOTAL STEAM PROD PLANT		1,680,088,593	1,434,800,591	85,660,708	159,627,294	12,380	159,614,914	48,628,527	110,986,388	-
9 HYDRAULIC PRODUCTION PLANT	DEMPROD	11,031,938	9,546,697	527,888	957,353	82	957,271	291,644	665,627	-
10 FERC-AFUDC PRE	DEMFERC	-	-	-		-	-	-	-	
11 FERC-AFUDC POST	DEMFERCP	1,294	-	-	1,294	-	1,294	394	900	-
12 TOTAL HYDRAULIC PROD PLANT		11,033,232	9,546,697	527,888	958,647	82	958,565	292,038	666,527	-
13 OTHER PRODUCTION PLANT	DEMPROD	495,510,433	428,799,376	23,710,602	43,000,455	3,700	42,996,756	13,099,458	29,897,298	-
14 FERC-AFUDC PRE	DEMFERC	2,023	-	719	1,304		1,304	397	907	
15 FERC-AFUDC POST	DEMFERCP	2,078,269	-		2,078,269		2,078,269	633,169	1,445,100	
16 TOTAL OTHER PROD PLANT		497,590,725	428,799,376	23,711,321	45,080,028	3,700	45,076,328	13,733,024	31,343,304	-
17 TOTAL PRODUCTION PLANT		2,188,712,550	1,873,146,664	109,899,917	205,665,969	16,162	205,649,807	62,653,588	142,996,219	
TRANSMISSION PLANT										
18 KENTUCKY SYSTEM PROPERTY	DEMTRAN	474,259,390	410,409,382	22,693,721	41,156,287	3,541	41,152,746	12,537,659	28,615,087	
19 VIRGINIA PROPERTY-500 KV LINE	DEMPRODNV	8,225,544	7,475,857	-	749,687	65	749,622	228,381	521,241	-
20 VIRGINIA PROPERTY	DEMVA	35,627,686	-	35,627,686	-	-		-	-	
21 FERC-AFUDC PRE	DEMFERCT	3,306,670	-	1,175,330	2,131,340	-	2,131,340	649,337	1,482,003	-
22 FERC-AFUDC POST	DFERCTP	359,045	-	-	359,045	-	359,045	109,387	249,658	-
23 TOTAL TRANSMISSION PLANT		521,778,335	417,885,239	59,496,737	44,396,359	3,606	44,392,754	13,524,765	30,867,989	

KENTUCKY UTILITIES COMPANY
Electric Cost of Service Study
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Jurisdictional Separation Study

		ALLOC	TOTAL KENTUCKY UTILITIES (1)-1	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)	PARIS (9)
	ELECTRIC PLANT IN SERVICE CONT										
	DISTRIBUTION PLANT										
	KENTUCKY DISTRIBUTION PLANT										
	360-362 SUBSTATIONS										
1	DISTRIBUTION	DEM3602K	102,616,477	102,616,477		-	-	-	-	-	-
2	DIRECT ASSIGNMENT	DIR3602K	2,461,517	-	-	2,461,517	-	2,461,517	2,461,517	-	-
3	TOTAL ACCTS 360-362		105,077,994	102,616,477	-	2,461,517	-	2,461,517	2,461,517	-	
4	364 & 365-OVERHEAD LINES	DEM3645K	383,731,335	383,731,335	-	-		-			
5	366 & 367-UNDERGROUND LINES	DEM3667K	86,588,726	86,588,726	-	-					
	368-TRANSFORMERS										
6	POWER POOL	DPRODKY	5,911,602	5,372,853		538,749	-	538,749	164,136	374,613	-
7	ALL OTHER	DEM368K	230,038,518	230,038,518		-	-	-	-	-	-
8	TOTAL ACCT 368		235,950,120	235,411,371	-	538,749	-	538,749	164,136	374,613	
9	369-SERVICES	CUST369K	78,030,101	78,030,101	-	-		-		-	
10	370-METERS	CUST370K	61,734,498	61,476,425	-	258,073		258,073	66,549	191,524	-
11	371-CUSTOMER INSTALLATION	CUST371K	17,415,370	17,415,370	-		-	-	-	-	-
12	373-STREET LIGHTING	CUST373K	52,453,968	52,453,968		-	-	-	-	-	-
13	TOTAL KENTUCKY DISTRIB PLANT		1,020,982,112	1,017,723,773		3,258,339	-	3,258,339	2,692,202	566,137	-
	VIRGINIA DISTRIBUTION PLANT										
	360-362 SUBSTATIONS										
14	DISTRIBUTION	DEM3602V	6,857,483	-	6,857,483				-	-	-
15	DIRECT ASSIGNMENT	DIR3602V	-	-							-
16	TOTAL ACCTS 360-362		6,857,483		6,857,483	-	-		-	-	-
17	364 & 365-OVERHEAD LINES	DEM3645V	28,782,310		28,782,310	-	-	-	-		-
18	366 & 367-UNDERGROUND LINES	DEM3667V	1,362,022	-	1,362,022	-	-	-			-
	368-TRANSFORMERS										
19	POWER POOL	DPRODVA	125,618	-	125,618	-			-	-	-
20	ALL OTHER	DEM368V	12,397,013	-	12,397,013	-	-		-	-	-
21	TOTAL ACCT 368		12,522,631		12,522,631	-	-	-	-	-	
22	369-SERVICES	CUST369V	5,091,007	-	5,091,007	-	-	-	-	-	
23	370-METERS	CUST370V	3,616,919	-	3,616,919	-	-				
24	371-CUSTOMER INSTALLATION	CUST371V	868,638	-	868,638	-	-				-
25	373-STREET LIGHTING	CUST373V	1,317,576	-	1,317,576	-	-	-	-	-	-
26	TOTAL VIRGINIA DISTRIB PLANT		60,418,589	-	60,418,589						
27	TENNESSEE PROPERTY	DEMTENND	163,472	-	-	163,472	163,472	-			
28	TOTAL DISTRIBUTION PLANT		1,081,564,173	1,017,723,773	60,418,589	3,421,811	163,472	3,258,339	2,692,202	566,137	-
29	TOTAL GENERAL PLANT	LABOR	99,461,628	88,658,922	5,422,480	5,380,226	5,636	5,374,590	1,707,099	3,667,491	0
30	TOTAL ELECTRIC PLANT		3,917,180,938	3,419,830,881	236,784,053	260,566,004	190,116	260,375,888	81,107,330	179,268,557	0

KENTUCKY UTILITIES COMPANY
Electric Cost of Service Study
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Jurisdictional Separation Study

		ALLOC	TOTAL KENTUCKY UTILITIES (1)-1	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)	PARIS (9)
	ELECTRIC PLANT IN SERVICE CON'T										
	ACCUMULATED PROVISION FOR DEP										
	PRODUCTION PLANT										
	STEAM PRODUCTION PLANT										
1	SYSTEM	STMSYS	926,265,475	801,561,442	44,322,602	80,381,430	6,916	80,374,514	24,487,024	55,887,490	-
2	FERC-AFUDC PRE	DEMFERC	13,838,960		4,918,949	8,920,011	-	8,920,011	2,717,584	6,202,427	-
3	FERC-AFUDC POST	DEMFERCP	1,149,681		-	1,149,681	-	1,149,681	350,264	799,417	-
4	TOTAL STEAM PROD PLT		941,254,115	801,561,442	49,241,551	90,451,122	6,916	90,444,206	27,554,872	62,889,334	-
	HYDRAULIC PRODUCTION PLANT										
5	SYSTEM	HYDSYS	8,265,760	7,152,933	395,524	717,304	62	717,242	218,516	498,726	-
6	FERC-AFUDC PRE	DEMFERC	3,230	-	1,148	2,082	-	2,082	634	1,448	-
7	FERC-AFUDC POST	DEMFERCP	253	-	-	253	-	253	77	176	-
8	TOTAL HYDRO PROD PLT		8,269,243	7,152,933	396,672	719,639	62	719,577	219,227	500,349	-
	OTHER PRODUCTION PLANT										
9	SYSTEM	OTHSYS	121,542,374	105,179,005	5,815,908	10,547,462	907	10,546,554	3,213,130	7,333,425	-
10	FERC-AFUDC PRE	DEMFERC	998	-	355	643	-	643	196	447	-
11	FERC-AFUDC POST	DEMFERCP	613,499	-		613,499	-	613,499	186,909	426,589	-
12	TOTAL OTHER PROD PLT		122,156,871	105,179,005	5,816,262	11,161,604	907	11,160,697	3,400,235	7,760,462	
13	TOTAL PRODUCTION PLANT		1,071,680,230	913,893,380	55,454,485	102,332,365	7,885	102,324,480	31,174,334	71,150,145	-
	TRANSMISSION PLANT										
14	KENTUCKY SYSTEM PROPERTY	KYTRPLT	294,027,753	254,442,507	14,069,482	25,515,764	2,195	25,513,569	7,773,003	17,740,565	
15	VIRGINIA PROPERTY	TRPLTVA	25,421,315	4,333,686	20,653,043	434,587	37	434,549	132,390	302,159	
16	FERC-AFUDC PRE	DEMFERCT	2,335,117	-	829,999	1,505,118		1,505,118	458,552	1,046,566	-
17	FERC-AFUDC POST	DFERCTP	91,539	-	-	91,539	-	91,539	27,888	63,650	
18	TOTAL TRANSMISSION PLANT		321,875,723	258,776,193	35,552,523	27,547,007	2,233	27,544,774	8,391,834	19,152,941	
19	DISTRIBUTION PLANT- VA & TN	DIRACDEP	34,518,882	-	34,352,623	166,258	166,258		-	-	
20	DISTRIBUTION PLANT KY & FERC	DISTPLTKF	475,683,487	474,165,401	-	1,518,085	-	1,518,085	1,254,318	263,768	
21	TOTAL DISTRIBUTION PLANT		510,202,368	474,165,401	34,352,623	1,684,344	166,258	1,518,085	1,254,318	263,768	
22	GENERAL PLANT	GENPLT	50,165,665	44,717,082	2,734,948	2,713,635	2,842	2,710,793	861,013	1,849,780	0
23	INTANGIBLE PLANT-FRANCHISES	PLT302	47,430	47,430	-	-	-	-	-	-	
24	INTANGIBLE PLANT-SOFTWARE	PLT303	18,391,228	16,056,112	1,111,729	1,223,388	893	1,222,495	380,808	841,687	0
25	TOTAL DEPRECIATION RESERVE		1,972,362,645	1,707,655,598	129,206,308	135,500,739	180,111	135,320,628	42,062,307	93,258,320	0
26	NET ELECTRIC PLANT IN SERVICE		1,944,818,293	1,712,175,283	107,577,745	125,065,265	10,005	125,055,260	39,045,023	86,010,237	0

KENTUCKY UTILITIES COMPANY
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Jurisdictional Separation Study

	ALLOC	TOTAL KENTUCKY UTILITIES (1)-1	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)	PARIS (9)
ADDITIONS TO NET PLANT										
CONSTRUCTION WORK IN PROGRESS										
PRODUCTION PLANT										
1 SYSTEM	PRODSYS	983,254,462	850,877,946	47,049,575	85,326,941	7,341	85,319,600	25,993,601	59,325,999	
2 FERC-AFUDC PRE	DEMFERC	-		-	-			-	-	
3 FERC-AFUDC POST	DEMFERCP	5,556,957	-	-	5,556,957	-	5,556,957	1,692,991	3,863,966	
4 TOTAL PRODUCTION PLANT		988,811,420	850,877,946	47,049,575	90,883,899	7,341	90,876,557	27,686,593	63,189,965	
TRANSMISSION PLANT										
5 SYSTEM	KYTRPLT	69,292,774	59,963,820	3,315,719	6,013,235	517	6,012,718	1,831,844	4,180,874	
6 TRANS VIRGINIA-KY SYSTEM	KYTRPLT	-	-	-	-	-	-	-	-	-
7 TRANS VIRGINIA	VATRPLT	3,651,814	-	3,651,814		-	-	-	-	-
8 FERC-AFUDC PRE	DEMFERCT	-	-	-	-	-			-	-
9 FERC-AFUDC POST	DFERCTP	265,655	-	-	265,655	-	265,655	80,935	184,720	-
10 TOTAL TRANSMISSION PLT		73,210,243	59,963,820	6,967,533	6,278,890	517	6,278,373	1,912,779	4,365,594	-
		1,062,021,663					97,154,930			
11 DISTRIBUTION - VA & TN	DIRCWIP	3,198,747	-	3,198,747	-	-	-	-		-
12 DISTRIBUTION PLANT KY & FERC	*DISTPLTKF*	*137,783,260*	*137,343,542*	-	*439,718*		439,718	363,317	76,401	-
13 TOTAL DISTRIBUTION PLT		140,982,007	137,343,542	3,198,747	439,718		439,718	363,317	76,401	-
14 GENERAL	GENPLT	31,049,844	27,677,464	1,692,785	1,679,594	1,759	1,677,835	532,921	1,144,914	0
15 TOTAL CWIP		1,234,053,513	1,075,862,772	58,908,640	99,282,101	9,618	99,272,483	30,495,609	68,776,874	0
			0 871812							
WORKING CAPITAL										
MATERIALS & SUPPLIES										
16 FUEL STOCK	ENERGY	52,838,865	45,885,975	2,266,314	4,686,576	365	4,686,211	1,489,432	3,196,780	-
PLANT MATERIAL & SUPPLIES										
17 PRODUCTION	PRODPLT	17,296,768	14,802,942	868,508	1,625,319	128	1,625,192	495,133	1,130,058	-
18 TRANSMISSION	TRANPLT	4,614,504	3,695,694	526,177	392,633	32	392,601	119,610	272,990	-
19 DISTRIBUTION	DISTPLT	4,833,275	4,547,986	269,998	15,291	731	14,561	12,031	2,530	-
20 GENERAL	GENPLT	-	-	-	-	-	-		-	
21 STORES UNDISTRIBUTED	M_S	6,379,667	5,497,561	397,095	485,012	212	484,799	149,511	335,288	
22 TOTAL PLT MAT & SUPPLIES		33,124,214	28,544,182	2,061,777	2,518,255	1,102	2,517,152	776,286	1,740,866	
23 TOTAL MATERIALS & SUPPLIES		85,963,079	74,430,157	4,328,091	7,204,831	1,468	7,203,364	2,265,718	4,937,646	-
PREPAYMENTS										
24 INSURANCE PREMIUMS	EXP9245	1,664,279	1,461,220	97,937	105,122	84	105,038	32,868	72,170	0
25 PUBLIC SERVICE COMM TAX	REVKU	-	-	-	-		-	-	-	
26 TOTAL PREPAYMENTS		1,664,279	1,461,220	97,937	105,122	84	105,038	32,868	72,170	0
27 WORKING CASH - CALC BY JURIS		87,541,433	78,937,746	1,629,974	6,973,712	1,337	6,972,376	2,211,531	4,760,845	0
28 TOTAL WORKING CAPITAL		175,168,791	154,829,123	6,056,002	14,283,666	2,889	14,280,777	4,510,117	9,770,660	0
29 EMISSION ALLOWANCES	DEMPROD	223,085	193,051	10,675	19,359	2	19,358	5,898	13,460	
30 TOTAL ADDITIONS TO NET PLANT		1,409,445,390	1,230,884,947	64,975,317	113,585,126	12,508	113,572,618	35,011,623	78,560,994	0

KENTUCKY UTILITIES COMPANY
Electric Cost of Service Study
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Jurisdictional Separation Study

	ALLOC	TOTAL KENTUCKY UTILITIES (1)-1	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)	PARIS (9)
DEDUCTIONS FROM NET PLANT										
ACCUMULATED DEFERRED INC TAX										
PRODUCTION PLANT										
1 SYSTEM	PRODSYS	165,624,620	143,326,414	7,925,281	14,372,925	1,237	14,371,688	4,378,501	9,993,187	-
2 FERC-AFUDC PRE	DEMFERC	3,389,094	-	1,204,627	2,184,467	-	2,184,467	665,523	1,518,944	-
3 FERC-AFUDC POST	DEMFERCP	240,709	-	-	240,709	-	240,709	73,335	167,374	-
4 TOTAL PRODUCTION PLANT		169,254,423	143,326,414	9,129,908	16,798,101	1,237	16,796,864	5,117,359	11,679,506	-
TRANSMISSION PLANT										
5 *KENTUCKY SYSTEM PROPERTY*	*KYTRPLT*	*26,742,127*	*23,141,808*	*1,279,634*	*2,320,685*	200	2,320,485	706,963	1,613,523	
6 VIRGINIA PROPERTY-500 KV LINE	DEMPRODNV	1,413,592	1,284,755	-	128,837	11	128,826	39,248	89,577	
7 VIRGINIA PROPERTY-OTHER	VATRPLT	1,386,115	-	1,386,115	-	-	-	-	-	
8 FERC-AFUDC PRE	DEMFERCT	635,901	-	226,026	409,875	-	409,875	124,873	285,002	
9 FERC-AFUDC POST	DFERCTP	18,206	-		18,206	-	18,206	5,547	12,659	
10 TOTAL TRANSMISSION PLANT		30,195,941	24,426,563	2,891,775	2,877,603	211	2,877,392	876,631	2,000,761	
11 DISTRIBUTION - VA	DIRACDFTX	3,959,278	-	3,959,278	-	-	-			
12 DISTRIBUTION PLT KY,FERC & TN	DPLTXVA	82,747,564	82,470,281	-	277,283	13,247	264,036	218,160	45,876	
13 TOTAL DISTRIBUTION PLANT		86,706,842	82,470,281	3,959,278	277,283	13,247	264,036	218,160	45,876	-
14 GENERAL	GENPLT	7,487,591	6,674,350	408,211	405,030	424	404,606	128,512	276,093	0
15 TOTAL DEFERRED INCOME TAX		293,644,797	256,897,609	16,389,171	20,358,017	15,118	20,342,898	6,340,662	14,002,236	0
ACCUM DEFER INVEST TAX CREDITS										
16 PRODUCTION	PRODPLT	57,862,001	49,519,529	2,905,374	5,437,098	427	5,436,671	1,656,345	3,780,326	
17 TRANSMISSION	TRANPLTX	86,370	74,169	4,314	7,888	1	7,887	2,403	5,484	
18 TRANSMISSION VA	TRPLTVA	19,678	3,355	15,987	336	0	336	102	234	
18 DISTRIBUTION - VA	DIRACITC	6,525	-	6,525	-		-	-	-	-
20 *DISTRIBUTION PLT KY,FERC & TN*	*DPLTXVA*	*101,561*	*101,221*	-	*340*	*16*	*324*	268	56	-
21 GENERAL	GENPLT	18,213	16,235	993	985	1	984	313	672	0
22 TOTAL DEFERRED INVEST CREDIT		58,094,348	49,714,508	2,933,193	5,446,648	445	5,446,202	1,659,430	3,786,772	0
23 CUSTOMER ADVANCES	CUSTADV	2,420,052	2,405,862	14,190	-			-	-	-
24 CUSTOMER DEPOSITS	CUSTDEP	759,207	-	759,207	-		-		-	-
25 DEFERRED FUEL-VIRGINIA	DFUELVA	58,053	-	58,053	-	-	-		-	
26 OPEB UNFUNDED	*LABOR*	*4,735,141*	-	*4,735,141*	*0*		*0*	-	-	*0*
27 TOTAL DEDUCTIONS FROM NET PLT		359,711,598	309,017,979	24,888,955	25,804,664	15,564	25,789,101	8,000,092	17,789,009	0
28 RATE BASE		2,994,552,085	2,634,042,250	147,664,107	212,845,727	6,950	212,838,777	66,056,555	146,782,223	(0)

KENTUCKY UTILITIES COMPANY
Electric Cost of Service Study
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Jurisdictional Separation Study

	ALLOC	TOTAL KENTUCKY UTILITIES (1)-1	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)	PARIS (9)
OPERATING REVENUES										
SALES OF ELECTRICITY										
1 SALES TO ULTIMATE CONSUMERS		1,244,702,734	1,100,598,589	54,974,817	89,129,328	2,414	89,126,914	28,107,483	61,019,431	
2										
INTERSYSTEM SALES										
3 DEMAND	DEMPROD		-	-	-	-			-	
4 ENERGY	ENERGY	52,018,782	45,173,804	2,231,139	4,613,839	359	4,613,479	1,466,315	3,147,164	-
5 PARIS REVENUES	ENERGY	2,561,957	2,224,838	109,885	227,234	18	227,217	72,217	155,000	-
6 TOTAL INTERSYSTEM SALES		54,580,739	47,398,642	2,341,024	4,841,073	377	4,840,696	1,538,532	3,302,164	-
7 TOTAL ELECTRIC REVENUES		1,299,283,473	1,147,997,231	57,315,841	93,970,401	2,791	93,967,610	29,646,015	64,321,595	
OTHER OPERATING REVENUES										
8 POLE ATTACHMENT - DIRECT	DIRPOLREV	465,970	443,294	22,528	148	148	-			-
9 FACILITY LEASE - DIRECT	DIRFACL	1,695,159	1,551,518	143,641	-	-	-			-
10 POWER CHARGES	DEMTRAN	2,884,661	2,496,296	138,034	250,331	22	250,310	76,260	174,050	-
11 MATERIAL SALES-KYRET & FERC	PLANTKF	-	-	-	-	-	-	-	-	-
12 MATERIAL SALES - DIRECT	DIRMATREV	72,230	71,449	781	-	-	-	-	-	-
13 SERVICE ON/OFF - DIRECT	DIRSERREV	1,614,240	1,578,059	36,181	-	-	-	-	-	
14 SALES TAX COLLECT'N FEES KY	REVKU	18,194	18,194		-	-	-	-	-	
15 TOTAL OTHER REVENUES		6,750,454	6,158,810	341,165	250,479	170	250,310	76,260	174,050	-
16 TOTAL OPERATING REVENUES		1,306,033,927	1,154,156,041	57,657,006	94,220,880	2,961	94,217,920	29,722,275	64,495,645	-

KENTUCKY UTILITIES COMPANY
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Jurisdictional Separation Study

	ALLOC	TOTAL KENTUCKY UTILITIES (1)-1	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)	PARIS (9)
OPERATION & MAINTENANCE EXP										
PRODUCTION EXPENSE-STEAM										
1 500-SUPERV & ENGINEERING	STMPLT	3,920,730	3,348,315	199,902	372,513	29	372,485	113,482	259,003	-
2 501-FUEL	ENERGY	414,484,042	359,943,470	17,777,650	36,762,923	2,864	36,760,059	11,683,553	25,076,506	
3 501-I/S SALES & PARIS VAR EXP.	REVFERC	-	-	-	-	-		-		-
4 502 & 504-STEAM EXPENSES	STMPLT	10,567,904	9,025,021	538,813	1,004,070	78	1,003,992	305,878	698,114	-
5 505-ELECTRIC EXPENSES	STMPLT	5,721,714	4,886,361	291,726	543,627	42	543,585	165,609	377,976	-
6 506-MISC STEAM POWER EXP	STMPLT	7,521,763	6,423,607	383,503	714,652	55	714,597	217,710	496,886	
7 507 & 509 - RENTS & ALLOWANCE	STMPLT	2,238,771	1,911,917	114,146	212,708	16	212,692	64,799	147,893	-
8 TOTAL STEAM OPERATIONS		444,454,924	385,538,691	19,305,740	39,610,493	3,085	39,607,409	12,551,031	27,056,378	-
9 510-SUPERV & ENGINEERING	STMPLT	5,476,978	4,677,355	279,248	520,374	40	520,334	158,526	361,808	
10 511-STRUCTURES	STMPLT	5,243,296	4,477,790	267,334	498,172	39	498,133	151,762	346,371	
11 512-BOILER PLANT	ENERGY	28,382,360	24,647,620	1,217,349	2,517,391	196	2,517,195	800,047	1,717,148	
12 513-ELECTRIC PLANT	ENERGY	10,813,430	9,390,527	463,799	959,104	75	959,029	304,811	654,218	
13 514-MISC STEAM PLANT	STMPLT	1,161,231	991,695	59,206	110,330	9	110,321	33,611	76,711	
14 TOTAL STEAM MAINTENANCE		51,077,295	44,184,987	2,286,936	4,605,372	358	4,605,013	1,448,757	3,156,257	
15 TOTAL STEAM GENERATION		495,532,219	429,723,678	21,592,676	44,215,865	3,443	44,212,422	13,999,787	30,212,635	
PRODUCTION EXPENSE-HYDRO										
16 535-SUPERV & ENGINEERING	HYDPLT	8,344	7,220	399	725	0	725	221	504	
17 536-WATER FOR POWER	HYDPLT	-	-	-	-	-		-	-	-
18 537-HYDRAULIC EXPENSES	HYDPLT	-	-	-	-			-	-	-
19 538-ELECTRIC EXPENSES	HYDPLT	-	-	-	-			-	-	-
20 539-MISC HYDR POWER GENER	HYDPLT	41,627	36,018	1,992	3,617	0	3,617	1,102	2,515	-
21 540-RENTS	HYDPLT	-	-	-	-	-	-	-	-	-
22 TOTAL HYDRO OPERATIONS		49,971	43,238	2,391	4,342	0	4,341	1,323	3,019	-
23 541-SUPERV & ENGINEERING	HYDPLT	120,462	104,232	5,764	10,467	1	10,466	3,189	7,277	-
23 542-STRUCTURES	HYDPLT	156,990	135,839	7,511	13,640	1	13,639	4,155	9,484	-
25 543-RESERV, DAMS & WATERWAY	HYDPLT	-	-	-	-	-	-	-	-	-
26 544-ELECTRIC PLANT	ENERGY	157,158	136,478	6,741	13,939	1	13,938	4,430	9,508	-
27 545-MISC HYDRAULIC PLANT	HYDPLT	6,307	5,457	302	548	0	548	167	381	
28 TOTAL HYDRO MAINTENANCE		440,918	382,006	20,317	38,594	1	38,591	11,941	26,650	-
29 TOTAL HYDRO GENERATION		490,888	425,244	22,708	42,936	4	42,933	13,263	29,669	-
PRODUCTION EXPENSE-OTHER										
30 546-SUPERV & ENGINEERING	OTHPLT	114,917	99,030	5,476	10,411	1	10,410	3,172	7,239	
31 547-FUEL	ENERGY	57,803,242	50,197,106	2,479,241	5,126,895	399	5,126,496	1,629,368	3,497,127	
32 548-GENERATION EXPENSES	OTHPLT	1,694,120	1,459,910	80,729	153,482	13	153,469	46,756	106,713	
33 549-550 MISC & RENTS	OTHPLT	132,349	114,052	6,307	11,990	1	11,989	3,653	8,337	
34 TOTAL OTHER OPERATIONS		59,744,628	51,870,098	2,571,752	5,302,778	414	5,302,364	1,682,949	3,619,415	
35 551-SUPERV & ENGINEERING	OTHPLT	39,193	33,775	1,868	3,551	0	3,550	1,082	2,469	
36 552-STRUCTURES	OTHPLT	167,078	143,980	7,962	15,137	1	15,135	4,611	10,524	
37 553-GENERATING & ELECT PLT	OTHPLT	2,685,197	2,313,971	127,956	243,270	20	243,250	74,109	169,141	
38 554-MISC OTH POWER GEN PLT	OTHPLT	286,884	247,222	13,671	25,991	2	25,989	7,918	18,071	-
39 TOTAL OTHER MAINTENANCE		3,178,352	2,738,948	151,456	287,948	24	287,924	87,719	200,205	-
40 TOTAL OTHER GENERATION		62,922,980	54,609,046	2,723,208	5,590,726	437	5,590,288	1,770,668	3,819,620	-
555-PURCHASED POWER										
41 CAPACITY COMPONENT	DEMPROD	17,369,767	15,031,258	831,158	1,507,350	130	1,507,221	459,192	1,048,029	
42 ENERGY COMPONENT	ENERGY	163,760,019	142,211,384	7,023,837	14,524,798	1,131	14,523,666	4,616,098	9,907,569	-
43 TOTAL ACCT 555		181,129,786	157,242,642	7,854,995	16,032,148	1,261	16,030,887	5,075,290	10,955,597	-
44 556-SYSTEM CONTROL & DISP	DEMPROD	1,550,748	1,341,969	74,205	134,574	12	134,563	40,996	93,567	-
45 557-OTHER EXPENSES	PRODPLT	1,216,300	1,040,935	61,073	114,292	9	114,283	34,818	79,465	-
46 TOTAL PRODUCTION EXPENSES		742,842,921	644,383,515	32,328,865	66,130,541	5,166	66,125,375	20,934,822	45,190,553	-

KENTUCKY UTILITIES COMPANY
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Jurisdictional Separation Study

		ALLOC	TOTAL KENTUCKY UTILITIES (1)-1	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)	PARIS (9)
	OPERATION & MAINT EXP CONT										
	TRANSMISSION EXPENSES										
1	560-SUPERV & ENGINEERING	LABTROP	1,109,415	888,516	126,503	94,396	8	94,389	28,757	65,632	-
2	561-LOAD DISPATCHING	TRANPLT	1,052,276	842,754	119,988	89,535	7	89,527	27,276	62,252	
3	562-STATION EXPENSES	TRANPLT	450,782	361,023	51,401	38,356	5	38,351	11,685	26,668	
4	563-OVERHEAD LINE EXPENSES	TRANPLT	419,243	335,766	47,805	35,672	3	35,669	10,867	24,802	
5	564-UNDERGROUND LINE EXP	TRANPLT	-	-	-	-	-	-	-	-	
6	565-TRANSM OF ELECT BY OTH	TRANPLT	5,765,993	4,617,906	657,478	490,609	40	490,569	149,458	341,112	
7	566-MISC TRANSMISSION EXP	TRANPLT	5,773,676	4,624,059	658,354	491,263	40	491,223	149,657	341,566	-
8	567-RENTS	TRANPLT	110,906	88,823	12,646	9,437	1	9,436	2,875	6,561	-
9	575.7-MISO DAY 1&2 EXP	TRANPLT	12,717	10,185	1,450	1,082	0	1,082	330	752	-
10	TOTAL TRANSM OPERATIONS		14,695,008	11,769,034	1,675,625	1,250,349	102	1,250,247	380,902	869,345	-
11	568-SUPERV & ENGINEERING	TRANPLT	-	-	-	-	-	-	-	-	-
12	569-MAINT OF STRUCTURES	TRANPLT	-	-	-	-	-	-	-	-	-
13	570-MAINT OF STATION EQUIP	TRANPLT	1,143,147	915,531	130,349	97,267	8	97,259	29,631	67,628	-
14	571-MAINT OF OH LINES	TRANPLT	4,121,213	3,300,624	469,929	350,660	28	350,632	106,824	243,808	-
15	572-MAINT OF UG LINES	TRANPLT	-	-	-	-	-	-	-	-	-
16	573-MAINT OF MISC TRAN PLT	TRANPLT	218,732	175,179	24,941	18,611	2	18,610	5,670	12,940	-
17	TOTAL TRANSM MAINTENANCE		5,483,092	4,391,335	625,220	466,538	38	466,500	142,125	324,375	-
18	TOTAL TRANSMISSION EXPENSES		20,178,101	16,160,369	2,300,845	1,716,887	139	1,716,747	523,027	1,193,720	-
	DISTRIBUTION EXPENSES										
19	580-SUPERV & ENGINEERING	DISTPLT	1,364,622	1,284,074	76,231	4,317	206	4,111	3,397	714	-
20	581-DIST SYSTEM CONTROL	PLT3602	665,570	610,159	40,775	14,636	-	14,636	14,636	-	-
21	582-STATION EXPENSES	PLT3602	1,092,214	1,001,284	66,912	24,018	-	24,018	24,018	-	-
22	583-OVERHEAD LINES	PLT3645	3,257,419	3,030,139	227,280	-	-	-	-	-	-
23	584-UNDERGROUND LINES	PLT3667	73,635	72,494	1,140	-	-	-	-	-	-
24	585-STREET LIGHTING	PLT373	11,105	10,832	272	-	-	-	-		-
25	586-METERS	PLT370	6,480,508	6,096,249	358,668	25,592	-	25,592	6,599	18,992	-
26	587-CUSTOMER INSTALLATIONS	PLT371	(77,078)	(73,416)	(3,662)	-		-			-
27	588-MISCELLANEOUS EXP	DISTPLT	4,654,044	4,379,334	259,985	14,724	703	14,021	11,585	2,436	-
28	589-RENTS	DISTPLT	13,447	12,654	751	43	2	41	33	7	-
29	TOTAL DISTR OPERATIONS		17,535,487	16,423,804	1,028,353	83,330	912	82,419	60,269	22,150	-
30	590-SUPERV & ENGINEERING	DISTPLT	6,788	6,387	379	21	1	20	17	4	
31	591-MAINT OF STRUCTURES	PLT3602	685	628	42	15		15	15	-	
32	592-MAINT OF STATION EQUIP	PLT3602	934,319	856,534	57,239	20,546		20,546	20,546	-	-
33	593-MAINT OF OH LINES	PLT3645	22,260,026	20,706,877	1,553,149	-	-		-	-	-
34	594-MAINT OF UG LINES	PLT3667	599,594	590,308	9,285		-		-	-	-
35	595-MAINT OF LINE TRANSF	PLT368	116,571	110,444	5,875	253	-	253	77	176	-
36	596-MAINT OF ST LIGHTING	PLT373	57,361	55,955	1,406		-		-	-	-
37	597-MAINT OF METERS	PLT370	-	-	-		-	-	-	-	-
38	598-MISCELLANEOUS	DISTPLT	8,177	7,695	457	26	1	25	20	4	-
39	TOTAL DISTR MAINTENANCE		23,983,521	22,334,828	1,627,831	20,861	2	20,859	20,675	184	-
40	TOTAL DISTRIBUTION EXPENSES		41,519,008	38,758,632	2,656,184	104,192	914	103,278	80,944	22,333	

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OPERATION & MAINT EXP CONT										
CUSTOMER ACCOUNTING EXPENSES										
1 901-SUPERVISION	LABCA	1,970,408	1,853,549	115,907	952	158	794	478	316	
2 902-METER READING	CUST902	4,386,792	4,126,623	258,049	2,120	352	1,768	1,063	704	
3 903-CUSTOMER RECORDS	CUST903	12,013,007	11,300,549	706,653	5,804	964	4,840	2,912	1,928	
4 904-UNCOLLECTIBLE ACCOUNTS	CUST904	3,330,953	3,133,404	195,940	1,609	267	1,342	808	535	
5 905-MISCELLANEOUS	EXP9024	241,868	227,523	14,228	117	19	97	59	39	
6 TOTAL CUSTOMER ACCOUNTS		21,943,028	20,641,648	1,290,777	10,602	1,761	8,841	5,320	3,522	
CUSTOMER SERVICES										
7 907-SUPERVISION	LABSA	230,775	217,872	12,892	11	3	8	1	1	
8 908-CUSTOMER ASSISTANCE	CUST908	5,013,533	4,733,193	280,078	262	75	187	112	75	-
9 909-INFORMATION & INSTRUCT	CUST909	475,951	449,354	26,590	7	7	-		-	-
10 910-MISCELLANEOUS	EXP9089	832,509	785,960	46,508	41	12	28	17	11	-
11 TOTAL CUSTOMER SERVICE		6,552,768	6,186,379	366,068	322	98	224	134	89	
SALES EXPENSE										
12 911-SUPERVISION	LABSA		-		-		-	-	-	
13 912-DEMONSTRATING & SELLING	CUST912	-				-	-	-	-	
14 913-ADVERTISING	CUST913	70,495	66,555	3,938	1	1	-			-
15 916-MISCELLANEOUS	EXP9123	-	-			-	-			
16 TOTAL SALES EXPENSE		70,495	66,555	3,938	1	1	-			-
ADMINISTRATIVE & GENERAL										
PLANT COMPONENT										
17 924-PROPERTY INSURANCE	PLANT	3,212,839	2,804,917	194,208	213,714	156	213,558	66,524	147,035	0
18 TOTAL NET PLT COMPONENT		3,212,839	2,804,917	194,208	213,714	156	213,558	66,524	147,035	0
LABOR COMPONENT										
19 920-ADMIN & GENERAL EXP	LABOR	15,929,316	14,199,205	868,439	861,672	903	860,770	273,401	587,368	0
20 921-OFFICE SUPPLIES & EXP	LABOR	7,564,089	6,742,540	412,381	409,168	429	408,739	129,825	278,914	0
21 922-ADMIN EXP TRANSF-CRED	LABOR	(1,580,914)	(1,409,208)	(86,189)	(85,517)	(90)	(85,428)	(27,134)	(58,294)	(0)
22 923-OUTSIDE SERVICES	LABOR	10,721,524	9,557,040	584,519	579,965	607	579,357	184,018	395,339	0
23 925-INJURIES & DAMAGES	LABOR	1,188,366	1,059,295	64,788	64,283	67	64,216	20,396	43,819	0
24 926-PENSIONS & BENEFITS	LABOR	22,298,770	19,876,861	1,215,691	1,206,218	1,263	1,204,955	382,723	822,232	0
25 926-PENSIONS & BENES-DIR KY	LABPTDKY	-	-	-	-	-	-	-	-	
26 926-PENSIONS & BENES-DIR VAJ	LABPTDVAJ	-		-	-	-		-	-	
27 926-PENSIONS & BENES-DIR VNJ	LABPTDVNJ	-		-	-			-	-	
28 926-PENSIONS & BENES-DIR FERC	LABPTDFER	-		-	-		-	-		-
25 929-DUPLICATE CHARGES-CR	LABOR	(3,285)	(2,928)	(179)	(178)	(0)	(178)	(56)	(121)	(0)
26 930-MISC GENERAL EXPENSE	LABOR	1,467,448	1,308,066	80,003	79,379	83	79,296	25,186	54,110	0
27 931-RENTS	LABOR	1,566,297	1,396,179	85,392	84,726	89	84,638	26,883	57,755	0
28 935-MAINTENANCE	LABOR	6,303,464	5,618,834	343,654	340,976	357	340,619	108,189	232,430	0
29 TOTAL LABOR COMPONENT		65,455,077	58,345,884	3,568,501	3,540,693	3,709	3,536,984	1,123,431	2,413,553	0
928-REGULATORY COMMISSION										
30 STATE JURISDICTION	REVKU		-	-		-				-
31 FEDERAL JURISDICTION	REVFERC		-	-	-	-		-	-	
32 VIRGINIA JURISDICTION	REVVA	-	-			-			-	
33 928 ALLOCATED	ENERGY	1,182,607	1,026,991	50,723	104,892	8	104,884	33,336	71,548	
34 TOTAL ACCOUNT 928		1,182,607	1,026,991	50,723	104,892	8	104,884	33,336	71,548	
35 927-FRANCHISE NJ VA	REVNJVA	3,285		3,285	-		-	-		-
36 930-EPRI & ADVERTISING	ENERGY1	387,987	369,723	18,261	1	1	-			-
37 TOTAL ADMINISTRATIVE & GEN		70,241,795	62,547,515	3,834,978	3,859,302	3,876	3,855,426	1,223,291	2,632,136	0
38 TOTAL OPERATION & MAINTENANCE		903,348,115	788,744,613	42,781,655	71,821,846	11,955	71,809,891	22,767,538	49,042,353	0
TOTAL OPERATION		812,881,473	709,093,676	37,726,241		11,172	66,050,384			
TOTAL MAINTENANCE		90,466,642	79,650,938	5,055,415		783	5,759,507			
TOTAL OPERATION LESS FUEL AND PURCHASED POWER		159,464,403	141,710,457	9,614,355		6,648	8,132,943			
DEPRECIATION & AMORT EXPENSE										

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DEPRECIATION EXPENSE										
PRODUCTION PLANT										
STEAM PRODUCTION PLANT										
1 SYSTEM	STMSYS	48,444,776	41,922,608	2,318,124	4,204,044	362	4,203,682	1,280,700	2,922,982	-
2 *FERC-AFUDC PRE*	DEMFERC	392,534	-	139,523	253,011	-	253,011	77,083	175,928	-
3 FERC-AFUDC POST	DEMFERCP	165,808	-	-	165,808	-	165,808	50,515	115,292	-
4 TOTAL STEAM PROD PLT		49,003,118	41,922,608	2,457,648	4,622,862	362	4,622,501	1,408,298	3,214,202	-
HYDRAULIC PRODUCTION PLANT										
5 *SYSTEM*	*HYDSYS*	*174,076*	*150,640*	*8,330*	*15,106*	1	*15,105*	*4,602*	*10,503*	
6 FERC-AFUDC PRE	DEMFERC	-	-		-			-	-	
7 FERC-AFUDC POST	DEMFERCP	21			21	-	21	6	15	
8 TOTAL HYDRO PROD PLT		174,097	150,640	8,330	15,127	1	15,126	4,608	10,518	-
OTHER PRODUCTION PLANT										
9 SYSTEM	OTHSYS	17,000,105	14,711,364	813,470	1,475,271	127	1,475,144	449,420	1,025,725	
10 FERC-AFUDC PRE	DEMFERC	70	-	25	45	-	45	14	31	
11 FERC-AFUDC POST	DEMFERCP	71,750	-		71,750	-	71,750	21,859	49,891	-
12 *TOTAL OTHER PROD PLT*		17,071,925	14,711,364	813,495	1,547,066	127	1,546,939	471,293	1,075,646	-
13 TOTAL PRODUCTION PLANT		66,249,140	56,784,612	3,279,472	6,185,056	490	6,184,566	1,884,199	4,300,367	
TRANSMISSION PLANT										
14 *KENTUCKY SYSTEM PROPERTY*	KYTRPLT	14,066,886	12,173,047	673,113	1,220,726	105	1,220,621	371,876	848,745	-
15 VIRGINIA PROPERTY	TRPLTVA	1,267,300	216,042	1,029,593	21,665	2	21,663	6,600	15,063	-
17 FERC-AFUDC PRE	DEMFERCT	97,554	-	34,675	62,879	-	62,879	19,157	43,722	-
18 *FERC-AFUDC POST*	*DFERCTP*	*10,418*	-	-	10,418	-	10,418	3,174	7,244	-
19 TOTAL TRANSMISSION PLANT		15,442,157	12,389,089	1,737,380	1,315,688	107	1,315,581	400,807	914,774	-
DISTRIBUTION PLANT										
20 DISTRIBUTION KENTUCKY	KYDIST	30,548,382	30,450,891	-	97,491		97,491	80,552	16,939	-
21 DISTRIBUTION VIRGINIA	VADIST	1,759,567	-	1,759,567	-	-	-		-	-
22 TENNESSEE DISTRIBUTION	TNDIST	4,427		-	4,427	4,427	-	-	-	-
23 TOTAL DISTRIBUTION PLANT		32,312,376	30,450,891	1,759,567	101,918	4,427	97,491	80,552	16,939	-
24 GENERAL PLANT	GENPLT	5,159,491	4,599,109	281,287	279,095	292	278,802	88,554	190,248	0
25 INTANGIBLE PLANT-SOFTWARE	PLT303	5,189,948	4,530,985	313,726	345,236	252	344,984	107,463	237,521	0
26 INTANGIBLE PLANT-FRANCHISES	PLT302	3,107	3,107		-					-
27 TOTAL DEPREC & AMORT EXP		124,356,219	108,757,794	7,371,432	8,226,993	5,568	8,221,425	2,561,576	5,659,849	0

KENTUCKY UTILITIES COMPANY
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		ALLOC	TOTAL KENTUCKY UTILITIES (1)-1	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)	PARIS (9)
	REGULATORY CREDITS AND ACCRETION										
	REGULATORY CREDITS										
	PRODUCTION PLANT										
1	STEAM PRODUCTION PLANT	STMSYS	(2,184,451)	(1,890,356)	(104,528)	(189,567)	(16)	(189,551)	(57,749)	(131,802)	
2	*HYDRAULIC PRODUCTION PLANT*	HYDSYS	-	-	-	-	-	-	-		
3	OTHER PRODUCTION PLANT	OTHSYS		-	-	-	-	-			
4	TOTAL PRODUCTION PLANT		(2,184,451)	(1,890,356)	(104,528)	(189,567)	(16)	(189,551)	(57,749)	(131,802)	
	TRANSMISSION PLANT										
5	KENTUCKY SYSTEM PROPERTY	KYTRPLT	(4,587)	(3,969)	(219)	(398)	(0)	(398)	(121)	(277)	-
6	VIRGINIA PROPERTY	TRPLTVA	-	-	-	-	-				-
7	TOTAL TRANSMISSION PLANT		(4,587)	(3,969)	(219)	(398)	(0)	(398)	(121)	(277)	-
	DISTRIBUTION PLANT										
8	KENTUCKY DISTRIBUTION PROPERTY	KYDIST	(7,383)	(7,359)	-	(24)		(24)	(19)	(4)	-
9	VIRGINIA DISTRIBUTION PROPERTY	VADIST	-	-	-	-		-	-	-	-
10	TOTAL DISTRIBUTION PLANT		(7,383)	(7,359)	-	(24)	-	(24)	(19)	(4)	
11	TOTAL REGULATORY CREDITS		(2,196,420)	(1,901,684)	(104,747)	(189,988)	(16)	(189,972)	(57,889)	(132,083)	
	ACCRETION										
	PRODUCTION PLANT										
12	STEAM PRODUCTION PLANT	STMSYS	1,889,737	1,635,320	90,426	163,992	14	163,978	49,958	114,020	-
13	HYDRAULIC PRODUCTION PLANT	HYDSYS	-	-	-	-	-		-	-	-
14	OTHER PRODUCTION PLANT	OTHSYS	-	-	-	-	-			-	-
15	TOTAL PRODUCTION PLANT		1,889,737	1,635,320	90,426	163,992	14	163,978	49,958	114,020	-
	TRANSMISSION PLANT										
16	KENTUCKY SYSTEM PROPERTY	KYTRPLT	4,407	3,814	211	382	0	382	116	266	-
17	VIRGINIA PROPERTY	TRPLTVA	-			-	-	-	-	-	-
18	TOTAL TRANSMISSION PLANT		4,407	3,814	211	382	0	382	116	266	
	DISTRIBUTION PLANT										
19	KENTUCKY SYSTEM PROPERTY	KYDIST	7,200	7,177	-	23	-	23	19	4	
20	VIRGINIA PROPERTY	DPLTXVA	-	-	-	-	-	-			
21	TOTAL DISTRIBUTION PLANT		7,200	7,177	-	23	-	23	19	4	
22	TOTAL ACCRETION EXPENSE		1,901,344	1,646,311	90,636	164,397	14	164,383	50,093	114,290	

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OTHER TAXES & OTHER EXPENSES										
TAXES OTHER THAN INCOME TAX										
1 PROPERTY TAXES	NETPLANT	11,388,302	10,026,011	629,945	732,347	59	732,288	228,637	503,651	0
2 PSC ASSESSMENT-KY REVENUE	REVKU	1,769,547	1,769,547	-	-	-	-	-	-	-
3 VA GROSS RECEIPTS TAX	REVVA	-	-		-	-		-		
4 UNEMPLOYMENT	LABOR	248,757	221,739	13,562	13,456	14	13,442	4,270	9,173	0
5 FICA	LABOR	5,631,081	5,019,479	306,997	304,605	319	304,286	96,648	207,637	0
6 MISCELLANEOUS	PLANT	(43,852)	(38,284)	(2,651)	(2,917)	(2)	(2,915)	(908)	(2,007)	(0)
7 TOTAL OTHER TAXES		18,993,835	16,998,492	947,853	1,047,490	390	1,047,101	328,647	718,454	0
8 GAIN DISPOSITION OF ALLOWANCES	DEMPROD	(583,107)	(504,602)	(27,902)	(50,602)	(4)	(50,598)	(15,415)	(35,183)	-
203(E) EXCESS										
9 PRODUCTION PLANT	PRODSYS	(927,249)	(802,413)	(44,370)	(80,467)	(7)	(80,460)	(24,513)	(55,947)	-
TRANSMISSION PLANT										
10 KENTUCKY SYSTEM PROPERTY	KYTRPLT	(150,088)	(129,882)	(7,182)	(13,025)	(1)	(13,024)	(3,968)	(9,056)	-
11 VIRGINIA PROPERTY	TRPLTVA	(15,338)	(2,615)	(12,461)	(262)	(0)	(262)	(80)	(182)	
12 TOTAL TRANSMISSION PLANT		(165,426)	(132,496)	(19,643)	(13,287)	(1)	(13,286)	(4,048)	(9,238)	
13 DISTRIBUTION - VA	DIR203E	(21,691)	-	(21,691)	-	-	-	-	-	
14 DISTRIBUTION PLT KY,FERC & TN	DPLTXVA	(453,327)	(451,808)	-	(1,519)	(73)	(1,447)	(1,195)	(251)	-
15 GENERAL	GENPLT	(41,020)	(36,565)	(2,236)	(2,219)	(2)	(2,217)	(704)	(1,513)	(0)
16 TOTAL 203(E) EXCESS		(1,608,713)	(1,423,281)	(87,940)	(97,492)	(83)	(97,409)	(30,460)	(66,949)	(0)
INVESTMENT TAX CREDIT ADJ										
17 *PRODUCTION*	PRODPLT	-	-	-	-	-	-		-	
18 TRANSMISSION	TRANPLTX	-	-	-	-	-	-	-	-	-
19 TRANSMISSION VA	TRPLTVA	-	-	-	-	-	-	-	-	-
20 DISTRIBUTION - DIRECT	DIRITCADJ	-	-	-	-	-	-	-	-	
21 DISTRIBUTION PLT KY,FERC & TN	DPLTXVA	-	-	-	-	-	-	-	-	
22 GENERAL	GENPLT	-	-	-	-	-	-	-	-	-
23 TOTAL INVEST TAX CREDIT ADJ			-	-	-	-	-	-	-	
24 TOTAL EXP OTHER THAN INC TAX		1,045,819,986	913,740,923	51,058,927	81,020,136	17,906	81,002,231	25,634,549	55,367,682	0

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	ALLOC	TOTAL KENTUCKY UTILITIES (1)-1	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)	PARIS (9)
INCOME TAXES										
1 OPERATING INC BEFORE INC TAXES		260,213,941	240,415,118	6,598,079	13,200,744	(14,945)	13,215,689	4,087,726	9,127,963	(0)
DEVELOPMENT OF FED INC TAX										
ADDITIONS TO INCOME										
2										
3										
4 TOTAL ADDITIONS		-		-	-		-	-		-
DEDUCTIONS FROM INCOME										
INTEREST EXPENSE										
5 LONG TERM DEBT OTHER	RATEBASE	62,708,668	55,159,261	3,092,222	4,457,185	146	4,457,039	1,383,285	3,073,754	(0)
6 INT ON CUSTOMER DEPOSITS	CUSTDEPI	1,111,987	1,077,634	34,354	-		-	-	-	
7 AFUDC-INTEREST POST FERC	AFUDC	(1,379,941)	-	-	(1,379,941)		(1,379,941)	(420,415)	(959,526)	-
8 SEC. 199 MANUFACTURING DEDUCTION	STMSYS	9,607,401	8,313,947	459,722	833,731	72	833,660	253,984	579,676	
9 TOTAL DEDUCTIONS		72,048,115	64,550,842	3,586,298	3,910,975	217	3,910,758	1,216,854	2,693,904	(0)
PLUS: ABOVE THE LINE DIFF:										
10 OTHER	RATEBASE	360,070	316,722	17,755	25,593	1	25,592	7,943	17,649	(0)
11 DEPREC-EQUITY AFUDC	DEMFERCT	1,200,000	-	426,530	773,470	-	773,470	235,646	537,823	-
12 TOTAL PERMANENT DIFFERENCES		1,560,070	316,722	444,286	799,062	1	799,062	243,589	555,472	(0)
13 TAXABLE INCOME		189,725,896	176,180,998	3,456,067	10,088,831	(15,162)	10,103,993	3,114,461	6,989,532	(0)
14 STATE TAX		11,383,478	10,570,860	207,364	605,254	(986)	606,240	186,868	419,372	(0)
15 STATE TAX TRUE-UP	RATEBASE	(321,629)	(282,908)	(15,860)	(22,861)	(1)	(22,860)	(7,095)	(15,765)	0
16 STATE TAX TOTAL		11,061,849	10,287,952	191,504	582,393	(987)	583,380	179,773	403,607	(0)
17 LESS PREFERRED DIVIDEND	RATEBASE	-		-	-		-		-	-
18 FEDERAL TAXABLE INCOME		178,664,047	165,893,046	3,264,563	9,506,438	(14,175)	9,520,613	2,934,688	6,585,925	(0)
19 FEDERAL TAXES @ 35%		62,532,417	58,062,566	1,142,597	3,327,254	(4,961)	3,332,215	1,027,141	2,305,074	(0)
20 EXCESS DEFERRED TAXES	RATEBASE	(2,104,000)	(1,850,702)	(103,750)	(149,547)	(5)	(149,542)	(46,412)	(103,131)	0
21 203(E) EXCESS		(1,608,713)	(1,423,281)	(87,940)	(97,492)	(83)	(97,409)	(30,460)	(66,949)	(0)
22 INVESTMENT TAX CREDIT ADJ		-		-	-					
23 FEDERAL TAX TRUE-UP	RATEBASE	1,360,779	1,196,957	67,101	96,721	5	96,718	30,017	66,701	-
24 FEDERAL TAX TOTAL		60,180,483	55,985,539	1,018,008	3,176,936	(5,046)	3,181,982	980,286	2,201,696	(0)
25 RETURN		188,971,609	174,141,627	5,388,567	9,441,415	(8,913)	9,450,328	2,927,667	6,522,661	(0)
26 RATE OF RETURN		0	0	0	0	(1)	0	0	0	9
STATE TAX RATE		0	0	0	0	0	0	0	0	0
FEDERAL TAX RATE - CURRENT		0	0	0	0	0		0	0	0
1 - EFFECTIVE TAX RATE		1	1	1	1	1	1	1	1	1
EFFECTIVE TAX RATE		0	0	0	0	0	0	0	0	0
FACTOR FOR TAXABLE BASIS		2	2	2	2	2	1	2	2	2

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DEVELOPMENT OF REVENUE REQUIREMENTS	ALLOC	TOTAL KENTUCKY UTILITIES (1)-1	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)	PARIS (9)
PRESENT RATES										
1 RATE BASE		2,994,552,085	2,634,042,250	147,664,107	212,845,727	6,950	212,838,777	66,056,555	146,782,223	
2 NET OPER INC (PRESENT RATES)		188,971,609	174,141,627	5,388,567	9,441,415	(8,913)	9,450,328	2,927,667	6,522,661	(0)
3 RATE OF RETURN (PRES RATES)		0	0	0	0	(1)	0	0	0	(0)
4 RELATIVE RATE OF RETURN		1	1	1	1	(20)	1	1	1	9
5 SALES REVENUE (PRE RATES)		1,244,702,734	1,100,598,589	54,974,817	89,129,328	2,414	89,126,914	28,107,483	61,019,431	135
CLAIMED RATE OF RETURN										
6 CLAIMED RATE OF RETURN		0	0	0	0	0	0	0	0	0
7 RETURN REQ FOR CLAIMED ROR		299,455,208	263,404,225	14,766,411	21,284,573	695	21,263,878	6,605,655	14,678,222	(0)
8 SALES REVENUE REQ CLAIMED ROR		1,425,327,040	1,246,691,221	70,323,170	108,512,649	18,223	108,494,426	34,127,104	74,367,322	0
9 REVENUE DEFICIENCY SALES REV		180,824,306	146,092,632	15,348,353	19,383,321	15,809	19,367,512	6,019,621	13,347,891	0
10 PERCENT INCREASE REQUIRED		0	0	0	0	7	0	0	0	
11 ANNUAL BOOKED KWH SALES		16,476,965,319	14,005,808,602	795,303,005	1,675,853,712	114,290	1,675,739,422	526,560,080	1,111,118,832	38,060,510
12 SALES REV REQUIRED MILLS/KWH		87	89	88	224	159	65	65	67	0
13 REVENUE DEFICIENCY MILLS/KWH		11	10	19	150	138	12	11	12	0
PROPOSED REVENUES										
14 PROPOSED SALES REVENUES		588,604,296	501,250,147	42,341,280	45,012,868	23,822	44,989,046	14,996,349	14,996,349	14,996,349
15 REVENUE DEFICIENCY SALES REV		(656,098,438)	(599,348,442)	(12,633,537)	(44,316,460)	21,408	(44,137,868)	(13,111,134)	(46,023,082)	14,996,349
16 PERCENT INCREASE PROPOSED		(1)	(1)	(0)	(0)	9	(0)	(0)	(1)	
17 PROPOSED RATE OF RETURN		(0)	(0)	(0)	(0)	3	(0)	(0)	(0)	
18 RETURN REQ FOR PROPOSED REV		(211,904,606)	(192,060,271)	(2,330,524)	(17,513,812)	4,098	(17,517,910)	(5,083,236)	(21,597,443)	9,162,769
19 ANNUAL BOOKED KWH SALES		16,476,965,319	14,005,808,602	795,303,005	1,675,853,712	114,290	1,675,739,422	526,560,080	1,111,118,832	38,060,510
20 SALES REV REQUIRED MILLS/KWH		36	36	53	27	208	27	28	13	394
21 REVENUE DEFICIENCY MILLS/KWH		(40)	(43)	(16)	(26)	187	(26)	(25)	(43)	394
WORKING SECTION										
11 MONTHLY AVERAGE CUSTOMERS		527,408	494,863	32,516	29	9	20	12	7	1
12 REVENUE REQUIRED - $/MO/CUST		225	210	180	311,818	169	452,060	236,994		0
13 REV DEFIC PER BILLING UNIT		29	25	39		146				6
14 ANNUAL BILLING DEMANDS		28,388,088	24,042,091	933,841	3,412,156	0	3,412,156	1,091,062	2,236,942	84,152
15 SALES REV REQUIRED $/KW		50	52	75	32		32	31	33	0
16 REVENUE DEFICIENCY $/KW		6	6	16	6		6	6	6	0
SALES TO ULTIMATE CONSUMERS		1,244,702,734	1,100,598,589	54,974,817	89,129,328	2,414	89,126,914	28,107,483	61,019,431	
ANNUALIZATION							#DIV/0!			#DIV/0!

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	ALLOC	TOTAL KENTUCKY UTILITIES (1)-1	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)	PARIS (9)
ANNUALIZATION ADJUSTMENTS										
RATE BASE										
DEPRECIATION RESERVE										
1 PRODUCTION	PRODPLT		-	-	-	-	-			-
2 TRANSMISSION	TRANPLT		-	-	-	-	-	-	-	
3 DISTRIBUTION	DISTPLT	-	-	-	-	-	-	-	-	-
4 GENERAL	GENPLT	-	-	-	-	-	-	-	-	-
5 TOTAL ADJ DEPREC RESERVE		-	-	-				-	-	
6 WORKING CASH - CALC BY JURIS		-		-				-	-	
7 TOTAL RATE BASE ADJUSTMENT		-	-	-				-	-	
REVENUE:										
8 ANNUALIZATION			-	-	-		-			-
INTERSYSTEM SALES										
9 DEMAND	DEMPROD	-		-	-	-	-			-
10 ENERGY	ENERGY	-	-	-	-	-	-	-	-	-
11 TOTAL INTERSYSTEM SALES			-	-	-	-	-	-		-
12 CUSTOMER ANNUALIZATION	CUSTANN	-	-	-	-	-	-	-	-	-
13 TOTAL REVENUE ADJUSTMENTS		-		-		-		-	-	-
EXPENSES:										
OPER & MAINT EXPENSES										
14 LABOR & LABOR RELATED	LABOR		-			-	-	-		
15 PROPERTY TAXES	NETPLANT		-		-	-	-			
16 INSTITUTIONAL ADVERTISING	EXP930A		-		-	-	-	-		
17 TRANSMISSION RENTAL EXPENSE	TRANPLT	-	-		-	-	-	-		
18 PSC ASSESSMENT	REVKU	-	-	-	-	-	-		-	-
19 PAYROLL TAXES	LABOR		-		-	-	-		-	

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ANNUALIZATION ADJ CONT										
CUSTOMER ANNUALIZATION										
1 PRODUCTION	CUSTANN									
2 TRANSMISSION	CUSTANN									
3 DISTRIBUTION	CUSTANN									
4 CUSTOMER ACCOUNTS	CUSTANN									
5 SALES	CUSTANN									
6 ADMINISTRATIVE & GENERAL	CUSTANN									
7 TOTAL CUSTOMER ANNUALIZATN										
8 TOTAL OPER & MAINT EXPENSES										
DEPRECIATION EXPENSE:										
9 PRODUCTION	PRODPLT									
10 TRANSMISSION	TRANPLT									
11 DISTRIBUTION	DISTPLT									
12 GENERAL	GENPLT									
13 TOTAL DEPRECIATION										
14 TOTAL EXPENSE ADJUSTMENT										
INTEREST ADJUSTMENT										
15 LONG TERM INTEREST	RATEBASE									
16 SHORT TERM INTEREST	RATEBASE									
17 TOTAL INTEREST ADJUSTMENT										
INCOME TAXES:										
18 PRODUCTION	PRODPLT									
19 TRANSMISSION	TRANPLT									
20 TOTAL INCOME TAXES										
21 STATE INC TAX DEPRECIATION	PLANT									
22 REDUCT INC TX-YEAR END INT										
23 INCOME TAX DUE TO ADJUSTMENT										
24 TOTAL INCOME TAX ADJUSTMENT										

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	LABOR ALLOCATOR	ALLOC	TOTAL KENTUCKY UTILITIES (1)-1	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)	PARIS (9)
	LABOR EXPENSE										
	PRODUCTION LABOR										
	ENERGY RELATED										
1	FERC 501	ENERGY	2,000,399	1,737,173	85,799	177,427	14	177,413	56,388	121,025	-
2	FERC 510	ENERGY	3,691,395	3,205,656	158,328	327,411	26	327,385	104,054	223,331	
3	FERC 512	ENERGY	4,016,163	3,487,689	172,257	356,216	28	356,188	113,208	242,980	
4	FERC 513	ENERGY	1,389,576	1,206,726	59,600	123,249	10	123,240	39,170	84,070	
5	FERC 547	ENERGY	-	-	-			-	-	-	-
6	TOTAL ENERGY LABOR		11,097,532	9,637,245	475,985	984,303	77	984,226	312,819	671,407	-
	DEMAND RELATED										
7	FERC 500	PRODPLT	2,438,259	2,086,714	122,430	229,115	18	229,097	69,797	159,300	
8	FERC 502	PRODPLT	5,949,255	5,091,499	298,725	559,032	44	558,988	170,302	388,686	-
9	FERC 505	PRODPLT	4,012,508	3,433,990	201,477	377,042	30	377,012	114,861	262,151	-
10	FERC 506	PRODPLT	260,096	222,596	13,060	24,440	2	24,438	7,445	16,993	-
11	FERC 509	PRODPLT	-	-	-	-	-	-	-	-	
12	FERC 511	PRODPLT	920,052	787,400	46,198	86,454	7	86,447	26,337	60,110	-
13	FERC 514	PRODPLT	121,443	103,934	6,098	11,412	1	11,411	3,476	7,934	-
14	FERC 535	PRODPLT	6,460	5,529	324	607	0	607	185	422	-
15	FERC 538	PRODPLT	-	-	-			-	-	-	-
16	FERC 539	PRODPLT	2,643	2,262	133	248	0	248	76	173	-
17	FERC 541	PRODPLT	71,519	61,207	3,591	6,720	1	6,720	2,047	4,673	-
18	FERC 542	PRODPLT	34,658	29,661	1,740	3,257	0	3,256	992	2,264	-
19	FERC 544	PRODPLT	68,515	58,637	3,440	6,438	1	6,438	1,961	4,476	-
20	FERC 545	PRODPLT	3,001	2,568	151	282	0	282	86	196	-
21	FERC 546	PRODPLT	80,274	68,700	4,031	7,543	1	7,542	2,298	5,245	-
22	FERC 548	PRODPLT	368,833	315,655	18,520	34,658	3	34,655	10,558	24,097	
23	FERC 549	PRODPLT	0	0	0	0	0	0	0	0	
24	FERC 550	PRODPLT	-		-	-	-	-			
25	FERC 551	PRODPLT	27,468	23,508	1,379	2,581	0	2,581	786	1,795	
26	FERC 552	PRODPLT	80,316	68,736	4,033	7,547	1	7,546	2,299	5,247	
27	FERC 553	PRODPLT	350,193	299,702	17,584	32,906	3	32,904	10,025	22,879	
28	FERC 554	PRODPLT	75,397	64,527	3,786	7,085	1	7,084	2,158	4,926	
29	FERC 555	PRODPLT	-	-	-	-		-	-	-	
30	FERC 556	PRODPLT	1,099,166	940,689	55,191	103,285	8	103,277	31,464	71,812	-
31	FERC 557	PRODPLT	-	-	-				-	-	-
32	TOTAL DEMAND		15,970,057	13,667,514	801,891	1,500,653	118	1,500,535	457,155	1,043,379	-
33	TOTAL PRODUCTION		27,067,590	23,304,759	1,277,875	2,484,955	195	2,484,761	769,975	1,714,786	-

KENTUCKY UTILITIES COMPANY
Electric Cost of Service Study
12 months Ended April 30, 2008

Jurisdictional Separation Study

		ALLOC	TOTAL KENTUCKY UTILITIES (1)-1	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)	PARIS (9)
	TRANSMISSION LABOR										
1	FERC 560	TRANPLT	719,552	576,280	82,048	61,224	5	61,219	18,651	42,568	-
2	FERC 561	TRANPLT	794,340	636,176	90,576	67,588	5	67,582	20,590	46,993	-
3	FERC 562	TRANPLT	181,342	145,235	20,678	15,430	1	15,429	4,700	10,728	-
4	FERC 563	TRANPLT	32,471	26,006	3,703	2,763	0	2,763	842	1,921	-
5	FERC 565	TRANPLT	-	-	-	-	-	-	-	-	
6	FERC 566	TRANPLT	203,653	163,103	23,222	17,328	1	17,327	5,279	12,048	
7	FERC 567	TRANPLT		-	-	-	-	-	-	-	
8	FERC 569	TRANPLT	-	-	-	-	-	-	-	-	
9	FERC 570	TRANPLT	413,419	331,101	47,141	35,176	2	35,174	10,716	24,458	
10	FERC 571	TRANPLT	92,432	74,028	10,540	7,865	1	7,864	2,396	5,468	
11	FERC 572	TRANPLT		-	-	-	-	-	-	-	
12	FERC 573	TRANPLT	55,251	44,250	6,300	4,701	0	4,701	1,432	3,269	
13	TOTAL TRANSMISSION LABOR	TRANPLT	2,492,461	1,996,178	284,207	212,075	17	212,058	64,606	147,452	
	DISTRIBUTION LABOR										
1	FERC 580	DISTPLT	847,292	797,280	47,332	2,681	128	2,553	2,109	444	-
2	FERC 581	DISTPLT	506,633	476,728	28,302	1,603	77	1,526	1,261	265	-
3	FERC 582	DISTPLT	497,232	467,882	27,776	1,573	75	1,498	1,238	260	-
4	FERC 583	DISTPLT	1,792,871	1,687,045	100,154	5,672	271	5,401	4,463	938	-
5	FERC 584	DISTPLT	43,570	40,998	2,434	138	7	131	108	23	-
6	FERC 585	DISTPLT	6,441	6,061	360	20	1	19	16	3	-
7	FERC 586	DISTPLT	2,615,027	2,458,791	145,970	8,267	395	7,872	6,504	1,368	-
8	FERC 587	DISTPLT	2,803	2,638	157	9	0	8	7	1	-
9	FERC 588	DISTPLT	2,009,682	1,891,059	112,265	6,358	304	6,054	5,002	1,052	-
10	FERC 589	DISTPLT	-	-	-	-	-	-	-	-	-
11	FERC 590	DISTPLT	5,016	4,720	280	16	1	15	12	3	
12	FERC 591	DISTPLT	370	348	21	1	0	1	1	0	
13	FERC 592	DISTPLT	330,290	310,795	18,451	1,045	50	995	822	173	
14	FERC 593	DISTPLT	4,971,619	4,678,164	277,726	15,729	751	14,978	12,375	2,602	
15	FERC 594	DISTPLT	111,599	105,012	6,234	353	17	336	278	58	
16	FERC 595	DISTPLT	44,805	42,160	2,503	142	7	135	112	23	
17	FERC 596	DISTPLT	38,599	36,321	2,156	122	6	116	96	20	
18	FERC 597	DISTPLT	-	-	-	-	-	-		-	
19	FERC 598	DISTPLT	60	56	3	0	0	0	0	0	
20	TOTAL DISTRIBUTION LABOR	DISTPLT	13,821,911	13,006,059	772,123	43,729	2,089	41,640	34,405	7,235	
21	TOT PROD, TRNS & DISTR LABOR		43,381,961	38,306,996	2,334,205	2,740,760	2,301	2,738,459	868,986	1,869,473	-

KENTUCKY UTILITIES COMPANY
Electric Cost of Service Study
12 months Ended April 30, 2008

Jurisdictional Separation Study

		ALLOC	TOTAL KENTUCKY UTILITIES (1)-1	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)	PARIS (9)
	CUSTOMER ACCOUNTING										
1	FERC 901	EXP9025	1,413,255	1,329,439	83,133	683	113	569	343	227	-
2	FERC 902	EXP9025	514,999	484,456	30,294	249	41	208	125	83	-
3	FERC 903	EXP9025	5,053,160	4,753,471	297,247	2,442	406	2,036	1,225	811	-
4	FERC 904	EXP9025	-	-	-	-			-	-	-
5	FERC 905	EXP9025	118,777	111,733	6,987	57	10	48	29	19	-
6	TOTAL CUSTOMER ACCOUNTING LABOR		7,100,191	6,679,098	417,662	3,431	570	2,861	1,721	1,140	
	CUSTOMER SERVICE & SALES EXP										
7	FERC 907	EXP9080	114,027	107,651	6,370	6	2	4	2	2	
8	FERC 908	EXP9080	113,248	106,916	6,327	6	2	4	2	2	
9	FERC 909	EXP9080	-	-	-		-	-	-	-	
10	FERC 910	EXP9080	21,314	20,122	1,191	1	0	1	0	0	
11	FERC 912	EXP9080	-	-	-		-	-	-	-	-
12	FERC 913	EXP9080		-	-			-		-	
13	FERC 916	EXP9080		-	-		-	-		-	-
14	TOTAL CUSTOMER SERVICE AND SALES LABOR		248,589	234,689	13,887	12	4	8	5	5	-
15	TOTAL PROD, TRAN, DIST, CUSTOMER LABOR		50,730,740	45,220,783	2,765,755	2,744,202	2,874	2,741,328	870,712	1,870,616	
	ADMIN & GENERAL LABOR										
16	FERC 920	PTDCUSTLABOR	12,114,983	10,799,153	660,488	655,342	686	654,655	207,934	446,721	-
17	FERC 921	PTDCUSTLABOR	-	-	-	-		-	-	-	-
18	FERC 922	PTDCUSTLABOR	(1,047,530)	(933,756)	(57,110)	(56,665)	(59)	(56,605)	(17,979)	(38,626)	-
19	FERC 923	PTDCUSTLABOR	-	-			-	-	-	-	
20	FERC 924	PTDCUSTLABOR	-	-	-		-	-	-	-	
21	FERC 925	PTDCUSTLABOR	88,828	79,180	4,843	4,805	5	4,800	1,525	3,275	
22	FERC 926	PTDCUSTLABOR	-	-	-	-	-	-		-	
23	FERC 927	PTDCUSTLABOR	-	-	-		-	-		-	-
24	FERC 929	PTDCUSTLABOR		-	-	-	-	-		-	-
25	FERC 930	PTDCUSTLABOR	-	-	-		-	-		-	
26	FERC 931	PTDCUSTLABOR	-	-	-	-	-	-		-	
27	FERC 935	PTDCUSTLABOR			-	-	-	-		-	-
28	TOTAL ADMIN & GENERAL LABOR		11,156,281	9,944,577	608,222	603,482	632	602,850	191,480	411,370	-
29	TOTAL LABOR EXPENSES		61,887,021	55,165,360	3,373,976	3,347,684	3,507	3,344,178	1,062,192	2,281,986	-

Seelye Exhibit 17

LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES
Assignment of Production and Transmission Demand-Related Costs
Based on the 12 Months Ended April 30, 2008

Minimum System Demand	2,417
Winter System Peak Demand	6,357
Summer System Peak Demand	7,132

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

Non-Time-Differentiated Capacity Costs

1. Minimum System Demand	2,417	
2. Maximum System Demand	7,132	
3. Non-Time-Differentiated Capacity Factor (Line 1/Line 2)	0.3389	
4. Non-Time-Differentiated Cost (Line 3)		33.89%

Winter Peak Period Costs

5. Maximum Winter System Demand	6,357	
6. Intermediate Peak Period Capacity Factor (Line 5/Line2 - Line 3)	0.5524	
7. Winter Peak Period Hours	946	
8. *Summer Peak Period Hours*	2,464	
9. Total Summer and Winter Peak Period Hours (Line 7 + Line 8)	3,410	
10. Winter Peak Period Costs (Line 7/Line 9 x Line 6)		15.32%

Summer Peak Period Costs

11. Peak Capacity Factor (1.0000 - Line 3 - Line 6)	0.1087	
12. Summer Peak Period Costs (Line 11 + Line 8/Line 9 x Line 6)		50.78%

Seelye Exhibit 18

KENTUCKY UTILITIES
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
April 30, 2008

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Plant in Service									
Intangible Plant									
301.00 ORGANIZATION	P301	PT&D	$ 38,811	7,378	8,782	5,812	-	-	-
302.00 FRANCHISE AND CONSENTS	P301	PT&D	$ 83,453	15,865	18,884	12,496	-	-	-
303.00 SOFTWARE	P302	PT&D	$ 22,294,019	4,238,148	5,044,633	3,338,267	-	-	-
Total Intangible Plant	PINT		$ 22,416,283	$ 4,261,391	$ 5,072,299	$ 3,356,575	$ -	$ -	$ -
Steam Production Plant									
Total Steam Production Plant	PSTPR	F017	$ 1,434,800,591	481,806,038	573,489,796	379,504,756	-	-	-
Hydraulic Production Plant									
Total Hydraulic Production Plant	PHDPR	F017	$ 9,546,697	3,205,781	3,815,815	2,525,101	-	-	-
Other Production Plant									
Total Other Production Plant	POTPR	F017	$ 428,799,376	143,990,830	171,391,111	113,417,435	-	-	-
Total Production Plant	PPRTL		$ 1,873,146,664	$ 629,002,650	$ 748,696,722	$ 495,447,293	$ -	$ -	$ -
Transmission									
KENTUCKY SYSTEM PROPERTY	P350	F011	$ 410,409,382	-	-	-	-	-	-
VIRGINIA PROPERTY - 500 KV LINE	P352	F011	$ 7,475,857	-	-	-	-	-	-
Total Transmission Plant	PTRAN		$ 417,885,239	$ -	$ -	$ -	$ -	$ -	$ -
Distribution									
TOTAL ACCTS 360-362	P362	F001	$ 102,616,477	-	-	-	-	-	-
364 & 365-OVERHEAD LINES	P365	F003	$ 383,731,335	-	-	-	-	-	-
366 & 367-UNDERGROUND LINES	P367	F004	$ 86,588,726	-	-	-	-	-	-
368-TRANSFORMERS - POWER POOL	P368	F005	$ 5,372,853	-	-	-	-	-	-
368-TRANSFORMERS - ALL OTHER	P368a	F005	$ 230,038,518	-	-	-	-	-	-
369-SERVICES	P369	F006	$ 78,030,101	-	-	-	-	-	-
370-METERS	P370	F007	$ 61,476,425	-	-	-	-	-	-
371-CUSTOMER INSTALLATION	P371	F008	$ 17,415,370	-	-	-	-	-	-
373-STREET LIGHTING	P373	F008	$ 52,453,968	-	-	-	-	-	-
Total Distribution Plant	PDIST		$ 1,017,723,773	$ -	$ -	$ -	$ -	$ -	$ -
Total Prod, Trans, and Dist Plant	PT&D		$ 3,308,755,676	$ 629,002,650	$ 748,696,722	$ 495,447,293	$ -	$ -	$ -

KENTUCKY UTILITIES
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
April 30, 2008

Description	Name	Functional Vector	Transmission Demand Base	Transmission Demand Inter.	Transmission Demand Peak	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer
Plant in Service										
Intangible Plant										
301.00 ORGANIZATION	P301	PT&D	1,646	1,959	1,297	-	1,204	-	948	3,548
302.00 FRANCHISE AND CONSENTS	P301	PT&D	3,539	4,213	2,788	-	2,588	-	2,038	7,628
303.00 SOFTWARE	P302	PT&D	945,500	1,125,421	744,743	-	691,418	-	544,345	2,037,810
Total Intangible Plant	PINT		$ 950,685	$ 1,131,593	$ 748,827	$ -	$ 695,210	$ -	$ 547,330	$ 2,048,986
Steam Production Plant										
Total Steam Production Plant	PSTPR	F017	-	-	-	-	-	-	-	-
Hydraulic Production Plant										
Total Hydraulic Production Plant	PHDPR	F017	-	-	-	-	-	-	-	-
Other Production Plant										
Total Other Production Plant	POTPR	F017	-	-	-	-	-	-	-	-
Total Production Plant	PPRTL		$ -	$ -	$ -	$ -		$ -	$ -	
Transmission										
KENTUCKY SYSTEM PROPERTY	P350	F011	137,815,470	164,040,630	108,553,281	-	-	-	-	-
VIRGINIA PROPERTY - 500 KV LINE	P352	F011	2,510,393	2,988,100	1,977,364	-	-	-	-	-
Total Transmission Plant	PTRAN		$ 140,325,863	$ 167,028,730	$ 110,530,646	$ -	$ -	$ -	$ -	$ -
Distribution										
TOTAL ACCTS 360-362	P362	F001	-	-	-	-	102,616,477	-	-	-
364 & 365-OVERHEAD LINES	P365	F003	-	-	-	-	-	-	65,915,008	246,759,476
366 & 367-UNDERGROUND LINES	P367	F004	-	-	-	-	-	-	14,873,679	55,681,115
368-TRANSFORMERS - POWER POOL	P368	F005	-	-	-	-	-	-	-	-
368-TRANSFORMERS - ALL OTHER	P368a	F005	-	-	-	-	-	-	-	-
369-SERVICES	P369	F006	-	-	-	-	-	-	-	-
370-METERS	P370	F007	-	-	-	-	-	-	-	-
371-CUSTOMER INSTALLATION	P371	F008	-	-	-	-	-	-	-	-
373-STREET LIGHTING	P373	F008	-	-	-	-	-	-	-	-
Total Distribution Plant	PDIST		$ -	$ -	$ -	$ -	$ 102,616,477	$ -	$ 80,788,687	$ 302,440,591
Total Prod, Trans, and Dist Plant	PT&D		$ 140,325,863	$ 167,028,730	$ 110,530,646	$ -	$ 102,616,477	$ -	$ 80,788,687	$ 302,440,591

KENTUCKY UTILITIES
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
April 30, 2008

Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Plant in Service									
Intangible Plant									
301.00 ORGANIZATION	P301	PT&D	215	806	1,439	1,322	915	721	820
302.00 FRANCHISE AND CONSENTS	P301	PT&D	463	1,734	3,095	2,843	1,968	1,551	1,762
303.00 SOFTWARE	P302	PT&D	123,705	463,103	826,715	759,460	525,758	414,221	470,772
Total Intangible Plant	PINT		$ 124,384	$ 465,642	$ 831,249	$ 763,625	$ 528,641	$ 416,493	$ 473,353
Steam Production Plant									
Total Steam Production Plant	PSTPR	F017	-	-	-	-	-	-	-
Hydraulic Production Plant									
Total Hydraulic Production Plant	PHDPR	F017	-	-	-	-	-	-	-
Other Production Plant									
Total Other Production Plant	POTPR	F017	-	-	-	-	-	-	-
Total Production Plant	PPRTL				$ -	$ -			$ -
Transmission									
KENTUCKY SYSTEM PROPERTY	P350	F011	-	-	-	-	-	-	-
VIRGINIA PROPERTY - 500 KV LINE	P352	F011	-	-	-	-	-	-	-
Total Transmission Plant	PTRAN		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution									
TOTAL ACCTS 360-362	P362	F001	-	-	-	-	-	-	-
364 & 365-OVERHEAD LINES	P365	F003	14,979,517	56,077,333	-	-	-	-	-
366 & 367-UNDERGROUND LINES	P367	F004	3,380,118	12,653,814	-	-	-	-	-
368-TRANSFORMERS - POWER POOL	P368	F005	-	-	2,800,333	2,572,520	-	-	-
368-TRANSFORMERS - ALL OTHER	P368a	F005	-	-	119,896,161	110,142,357	-	-	-
369-SERVICES	P369	F006	-	-	-	-	78,030,101	-	-
370-METERS	P370	F007	-	-	-	-	-	61,476,425	-
371-CUSTOMER INSTALLATION	P371	F008	-	-	-	-	-	-	17,415,370
373-STREET LIGHTING	P373	F008	-	-	-	-	-	-	52,453,968
Total Distribution Plant	PDIST		$ 18,359,636	$ 68,731,147	$ 122,696,494	$ 112,714,877	$ 78,030,101	$ 61,476,425	$ 69,869,338
Total Prod, Trans, and Dist Plant	PT&D		$ 18,359,636	$ 68,731,147	$ 122,696,494	$ 112,714,877	$ 78,030,101	$ 61,476,425	$ 69,869,338

KENTUCKY UTILITIES
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
April 30, 2008

Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Plant in Service					
Intangible Plant					
301.00 ORGANIZATION	P301	PT&D	-	-	-
302.00 FRANCHISE AND CONSENTS	P301	PT&D	-	-	-
303.00 SOFTWARE	P302	PT&D	-	-	-
Total Intangible Plant	PINT		$ -	$ -	$ -
Steam Production Plant					
Total Steam Production Plant	PSTPR	F017	-	-	-
Hydraulic Production Plant					
Total Hydraulic Production Plant	PHDPR	F017	-	-	-
Other Production Plant					
Total Other Production Plant	POTPR	F017	-	-	-
Total Production Plant	PPRTL		$ -	$ -	$ -
Transmission					
KENTUCKY SYSTEM PROPERTY	P350	F011	-	-	-
VIRGINIA PROPERTY - 500 KV LINE	P352	F011	-	-	-
Total Transmission Plant	PTRAN		$ -	$ -	$ -
Distribution					
TOTAL ACCTS 360-362	P362	F001	-	-	-
364 & 365-OVERHEAD LINES	P365	F003	-	-	-
366 & 367-UNDERGROUND LINES	P367	F004	-	-	-
368-TRANSFORMERS - POWER POOL	P368	F005	-	-	-
368-TRANSFORMERS - ALL OTHER	P368a	F005	-	-	-
369-SERVICES	P369	F006	-	-	-
370-METERS	P370	F007	-	-	-
371-CUSTOMER INSTALLATION	P371	F008	-	-	-
373-STREET LIGHTING	P373	F008	-	-	-
Total Distribution Plant	PDIST		$ -	$ -	$ -
Total Prod, Trans, and Dist Plant	PT&D		$ -	$ -	$ -

KENTUCKY UTILITIES
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
April 30, 2008

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Plant in Service (Continued)									
General Plant									
Total General Plant	PGP	PT&D	$ 88,658,922	16,854,281	20,061,513	13,275,632	-	-	-
TOTAL COMMON PLANT	PCOM	PT&D	$ -	-	-	-	-	-	-
106.00 COMPLETED CONSTR NOT CLASSIFIED	P106	PT&D	$ -	-	-	-	-	-	-
105.00 PLANT HELD FOR FUTURE USE	P105	PDIST	$ -	-	-	-	-	-	-
OTHER		PDIST	$ -	-	-	-	-	-	-
Total Plant in Service	TPIS		$ 3,419,830,881	$ 650,118,321	$ 773,830,533	$ 512,079,500	$ -	$ -	$ -
Construction Work in Progress (CWIP)									
CWIP Production	CWIP1	F017	$ 850,877,946	285,724,814	340,095,915	225,057,217	-	-	-
CWIP Transmission	CWIP2	F011	59,963,820	-	-	-	-	-	-
CWIP Distribution Plant	CWIP3	PDIST	137,343,542	-	-	-	-	-	-
CWIP General Plant	CWIP4	PT&D	27,677,464	5,261,555	6,262,785	4,144,375	-	-	-
RWIP	CWIP5	F004	-	-	-	-	-	-	-
Total Construction Work in Progress	TCWIP		$ 1,075,862,772	$ 290,986,369	$ 346,358,701	$ 229,201,592	$ -	$ -	$ -
Total Utility Plant			$ 4,495,693,653	$ 941,104,690	$ 1,120,189,234	$ 741,281,092	$ -	$ -	$ -

KENTUCKY UTILITIES
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
April 30, 2008

Description	Name	Functional Vector	Transmission Demand Base	Transmission Demand Inter.	Transmission Demand Peak	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer
Plant in Service (Continued)										
General Plant										
Total General Plant	PGP	PT&D	3,760,066	4,475,576	2,961,696	-	2,749,634	-	2,164,753	8,103,970
TOTAL COMMON PLANT	PCOM	PT&D	-	-	-	-	-	-	-	-
106.00 COMPLETED CONSTR NOT CLASSIFIED	P106	PT&D	-	-	-	-	-	-	-	-
105.00 PLANT HELD FOR FUTURE USE	P105	PDIST	-	-	-	-	-	-	-	-
OTHER		PDIST	-	-	-	-	-	-	-	-
Total Plant in Service	TPIS		$ 145,036,614	$ 172,635,898	$ 114,241,169	$ -	$ 106,061,321	$ -	$ 83,500,770	$ 312,593,547
Construction Work in Progress (CWIP)										
CWIP Production	CWIP1	F017	-	-	-	-	-	-	-	-
CWIP Transmission	CWIP2	F011	20,135,851	23,967,539	15,860,430	-	-	-	-	-
CWIP Distribution Plant	CWIP3	PDIST	-	-	-	-	13,848,267	-	10,902,570	40,814,869
CWIP General Plant	CWIP4	PT&D	1,173,814	1,397,181	924,580	-	858,378	-	675,791	2,529,890
RWIP	CWIP5	F004	-	-	-	-	-	-	-	-
Total Construction Work in Progress	TCWIP		$ 21,309,665	$ 25,364,720	$ 16,785,010	$ -	$ 14,706,645	$ -	$ 11,578,360	$ 43,344,759
Total Utility Plant			$ 166,346,279	$ 198,000,619	$ 131,026,179	$ -	$ 120,767,966	$ -	$ 95,079,130	$ 355,938,306

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Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Plant in Service (Continued)									
General Plant									
Total General Plant	PGP	PT&D	491,951	1,841,668	3,287,683	3,020,223	2,090,836	1,647,276	1,872,166
TOTAL COMMON PLANT	PCOM	PT&D	-	-	-	-	-	-	-
106.00 COMPLETED CONSTR NOT CLASSIFIED	P106	PT&D	-	-	-	-	-	-	-
105.00 PLANT HELD FOR FUTURE USE	P105	PDIST	-	-	-	-	-	-	-
OTHER		PDIST	-	-	-	-	-	-	-
Total Plant in Service	TPIS		$ 18,975,970	$ 71,038,457	$ 126,815,425	$ 116,498,725	$ 80,649,578	$ 63,540,194	$ 72,214,857
Construction Work in Progress (CWIP)									
CWIP Production	CWIP1	F017	-	-	-	-	-	-	-
CWIP Transmission	CWIP2	F011	-	-	-	-	-	-	-
CWIP Distribution Plant	CWIP3	PDIST	2,477,664	9,275,384	16,558,099	15,211,063	10,530,294	8,296,347	9,428,985
CWIP General Plant	CWIP4	PT&D	153,577	574,930	1,026,346	942,851	652,715	514,245	584,451
RWIP	CWIP5	F004	-	-	-	-	-	-	-
Total Construction Work in Progress	TCWIP		$ 2,631,241	$ 9,850,315	$ 17,584,445	$ 16,153,913	$ 11,183,009	$ 8,810,592	$ 10,013,436
Total Utility Plant			$ 21,607,211	$ 80,888,772	$ 144,399,870	$ 132,652,638	$ 91,832,587	$ 72,350,786	$ 82,228,294

KENTUCKY UTILITIES
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
April 30, 2008

Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Plant in Service (Continued)					
General Plant					
Total General Plant	PGP	PT&D	-	-	-
TOTAL COMMON PLANT	PCOM	PT&D	-	-	-
106.00 COMPLETED CONSTR NOT CLASSIFIED	P106	PT&D	-	-	-
105.00 PLANT HELD FOR FUTURE USE	P105	PDIST	-	-	-
OTHER		PDIST	-	-	-
Total Plant in Service	TPIS		$ -	$ -	$ -
Construction Work in Progress (CWIP)					
CWIP Production	CWIP1	F017	-	-	-
CWIP Transmission	CWIP2	F011	-	-	-
CWIP Distribution Plant	CWIP3	PDIST	-	-	-
CWIP General Plant	CWIP4	PT&D	-	-	-
RWIP	CWIP5	F004	-	-	-
Total Construction Work in Progress	TCWIP		$ -	$ -	$ -
Total Utility Plant			$ -	$ -	$ -

KENTUCKY UTILITIES
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12 Months Ended
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Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Rate Base									
Utility Plant									
Plant in Service			$ 3,419,830,881	$ 650,118,321	$ 773,830,533	$ 512,079,500	$ -	$ -	$ -
Construction Work in Progress (CWIP)			1,075,862,772	290,986,368.89	346,358,700.55	229,201,591.93	-	-	-
Total Utility Plant	TUP		$ 4,495,693,653	$ 941,104,690	$ 1,120,189,234	$ 741,281,092	$ -	$ -	$ -
Less: Acummulated Provision for Depreciation									
Steam Production	ADEPREPA	F017	$ 801,561,442	269,164,332	320,384,109	212,013,002	-	-	-
Hydraulic Production	RWIP	F017	7,152,933	2,401,955	2,859,027	1,891,951	-	-	-
Other Production		F017	105,179,005	35,319,110	42,040,048	27,819,847	-	-	-
Transmission - Kentucky System Property	ADEPRTP	PTRAN	254,442,507	-	-	-	-	-	-
Transmission - Virginia Property	ADEPRDI	PTRAN	4,333,686	-	-	-	-	-	-
Distribution	ADEPRD11	PDIST	474,165,401	-	-	-	-	-	-
General Plant	ADEPRD12	PT&D	44,717,082	8,500,828	10,118,466	6,695,858	-	-	-
Intangible Plant	ADEPRGP	PT&D	16,103,542	3,061,323	3,643,868	2,411,316	-	-	-
Total Accumulated Depreciation	TADEPR		$ 1,707,655,598	$ 318,447,548	$ 379,045,518	$ 250,831,973	$ -	$ -	$ -
Net Utility Plant	NTPLANT		$ 2,788,038,055	$ 622,657,142	$ 741,143,715	$ 490,449,119	$ -	$ -	$ -
Working Capital									
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	$ 78,937,746	2,252,918	2,681,630	1,774,559	58,273,194	-	-
Materials and Supplies	M&S	TPIS	74,430,157	14,149,357	16,841,864	11,145,042	-	-	-
Prepayments	PREPAY	TPIS	1,461,220	277,781	330,641	218,800	-	-	-
Total Working Capital	TWC		$ 154,829,123	$ 16,680,057	$ 19,854,136	$ 13,138,401	$ 58,273,194	$ -	$ -
Emission Allowance	EMALL	PROFIX	193,051	64,827	77,163	51,062	-	-	-
Deferred Debits									
Service Pension Cost	PENSCOST	TLB	$ -	-	-	-	-	-	-
Accumulated Deferred Income Tax									
Total Production Plant	ADITPP	F017	143,326,414	48,129,010	57,287,568	37,909,837	-	-	-
Total Transmission Plant	ADITTP	F011	24,426,563	-	-	-	-	-	-
Total Distribution Plant	ADITDP	PDIST	82,470,281	-	-	-	-	-	-
Total General Plant	ADITGP	PT&D	6,674,350	1,268,811	1,510,255	999,406	-	-	-
Total Accumulated Deferred Income Tax	ADITT		256,897,609	49,397,820	58,797,823	38,909,242	-	-	-
Accumulated Deferred Investment Tax Credits									
Production	ADITCP	F017	48,588,068	16,315,873	19,420,651	12,851,544	-	-	-
Transmission	ADITCT	F011	74,169	-	-	-	-	-	-
Transmission VA	ADITCTVA	F011	3,355	-	-	-	-	-	-
Distribution VA	ADITCDVA	PDIST	-	-	-	-	-	-	-
Distribution Plant KY,FERC & TN	ADITCDKY	PDIST	101,221	-	-	-	-	-	-
General	ADITCG	PT&D	16,235	3,086	3,674	2,431	-	-	-
Total Accum. Deferred Investment Tax Credits	ADITCTL		48,783,047	16,318,960	19,424,324	12,853,975	-	-	-
Total Deferred Debits			$ 305,680,656	$ 65,716,780	$ 78,222,147	$ 51,763,217	$ -	$ -	$ -
Less: Customer Advances	CSTDEP	F027	$ 2,405,862	-	-	-	-	-	-
Net Rate Base	RB		$ 2,634,973,711	$ 573,685,245	$ 682,852,867	$ 451,875,365	$ 58,273,194	$ -	$ -

KENTUCKY UTILITIES
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Description	Name	*Functional* Vector	*Transmission Demand* Base	Inter.	Peak	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Demand	Customer
Rate Base										
Utility Plant										
Plant in Service			$ 145,036,614	$ 172,635,898	$ 114,241,169	$ -	$ 106,061,321	$ -	$ 83,500,770	$ 312,593,547
Construction Work in Progress (CWIP)			21,309,664.87	25,364,720.22	16,785,010.00	-	14,706,645.16	-	11,578,360.36	43,344,758.75
Total Utility Plant	TUP		$ 166,346,279	$ 198,000,619	$ 131,026,179	$ -	$ 120,767,966	$ -	$ 95,079,130	$ 355,938,306
Less: Acummulated Provision for Depreciation										
Steam Production	ADEPREPA	F017	-	-	-	-	-	-	-	-
Hydraulic Production	RWIP	F017	-	-	-	-	-	-	-	-
Other Production		F017	-	-	-	-	-	-	-	-
Transmission - Kentucky System Property	ADEPRTP	PTRAN	85,441,794	101,700,670	67,300,043	-	-	-	-	-
Transmission - Virginia Property	ADEPRD1	PTRAN	1,455,252	1,732,174	1,146,260	-	-	-	-	-
Distribution	ADEPRD11	PDIST	-	-	-	-	47,809,813	-	37,640,076	140,909,418
General Plant	ADEPRD12	PT&D	1,896,472	2,257,355	1,493,797	-	1,386,838	-	1,091,841	4,087,416
Intangible Plant	ADEPRGP	PT&D	682,959	812,920	537,947	-	499,429	-	393,194	1,471,963
Total Accumulated Depreciation	TADEPR		$ 89,476,476	$ 106,503,120	$ 70,478,047	$ -	$ 49,696,080	$ -	$ 39,125,111	$ 146,468,796
Net Utility Plant	NTPLANT		$ 76,869,802	$ 91,497,499	$ 60,548,132	$ -	$ 71,071,886	$ -	$ 55,954,019	$ 209,469,510
Working Capital										
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	828,069	985,643	652,246	-	619,601	-	758,337	2,838,911
Materials and Supplies	M&S	TPIS	3,156,617	3,757,296	2,486,377	-	2,308,348	-	1,817,334	6,803,374
Prepayments	PREPAY	TPIS	61,971	73,764	48,813	-	45,318	-	35,678	133,564
Total Working Capital	TWC		$ 4,046,657	$ 4,816,703	$ 3,187,435	$ -	$ 2,973,267	$ -	$ 2,611,349	$ 9,775,849
Emission Allowance	EMALL	PROFIX	-	-	-	-	-	-	-	-
Deferred Debits										
Service Pension Cost	PENSCOST	TLB	-	-	-	-	-	-	-	-
Accumulated Deferred Income Tax										
Total Production Plant	ADITPP	F017	-	-	-	-	-	-	-	-
Total Transmission Plant	ADITTP	F011	8,202,440	9,763,297	6,460,826	-	-	-	-	-
Total Distribution Plant	ADITDP	PDIST	-	-	-	-	8,315,429	-	6,546,635	24,507,986
Total General Plant	ADITGP	PT&D	283,062	336,927	222,960	-	206,996	-	162,965	610,077
Total Accumulated Deferred Income Tax	ADITT		8,485,502	10,100,224	6,683,786	-	8,522,425	-	6,709,600	25,118,063
Accumulated Deferred Investment Tax Credits										
Production	ADITCP	F017	-	-	-	-	-	-	-	-
Transmission	ADITCT	F011	24,906	29,645	19,618	-	-	-	-	-
Transmission VA	ADITCTVA	F011	1,126	1,341	887	-	-	-	-	-
Distribution VA	ADITCDVA	PDIST	-	-	-	-	-	-	-	-
Distribution Plant KY,FERC & TN	ADITCDKY	PDIST	-	-	-	-	10,206	-	8,035	30,080
General	ADITCG	PT&D	689	820	542	-	504	-	396	1,484
Total Accum. Deferred Investment Tax Credits	ADITCTL		26,721	31,806	21,047	-	10,710	-	8,431	31,564
Total Deferred Debits			$ 8,512,223	$ 10,132,030	$ 6,704,833	$ -	$ 8,533,134	$ -	$ 6,718,031	$ 25,149,627
Less: Customer Advances	CSTDEP	F027	-	-	-	-	-	-	413,264	1,547,096
Net Rate Base	RB		$ 72,404,237	$ 86,182,172	$ 57,030,734	$ -	$ 65,512,019	$ -	$ 51,434,073	$ 192,548,635

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Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Rate Base									
Utility Plant									
Plant in Service			$ 18,975,970	$ 71,038,457	$ 126,815,425	$ 116,498,725	$ 80,649,578	$ 63,540,194	$ 72,214,857
Construction Work in Progress (CWIP)			2,631,240.68	9,850,314.63	17,584,444.96	16,153,913.49	11,183,009.20	8,810,592.49	10,013,436.30
Total Utility Plant	TUP		$ 21,607,211	$ 80,888,772	$ 144,399,870	$ 132,652,638	$ 91,832,587	$ 72,350,786	$ 82,228,294
Less: Acummulated Provision for Depreciation									
Steam Production	ADEPREPA	F017	-	-	-	-	-	-	-
Hydraulic Production	RWIP	F017	-	-	-	-	-	-	-
Other Production		F017	-	-	-	-	-	-	-
Transmission - Kentucky System Property	ADEPRTP	PTRAN	-	-	-	-	-	-	-
Transmission - Virginia Property	ADEPRDI	PTRAN	-	-	-	-	-	-	-
Distribution	ADEPRD11	PDIST	8,553,897	32,022,375	57,165,248	52,514,736	36,354,830	28,642,343	32,552,667
General Plant	ADEPRD12	PT&D	248,126	928,886	1,658,215	1,523,316	1,054,559	830,840	944,268
Intangible Plant	ADEPRGP	PT&D	89,355	334,511	597,157	548,577	379,768	299,203	340,050
Total Accumulated Depreciation	TADEPR		$ 8,891,378	$ 33,285,771	$ 59,420,621	$ 54,586,629	$ 37,789,157	$ 29,772,386	$ 33,836,985
Net Utility Plant	NTPLANT		$ 12,715,833	$ 47,603,001	$ 84,979,249	$ 78,066,009	$ 54,043,430	$ 42,578,400	$ 48,391,308
Working Capital									
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	172,336	645,157	353,709	324,934	220,372	990,803	196,701
Materials and Supplies	M&S	TPIS	412,998	1,546,101	2,760,046	2,535,511	1,755,280	1,382,907	1,571,704
Prepayments	PREPAY	TPIS	8,108	30,353	54,185	49,777	34,460	27,149	30,856
Total Working Capital	TWC		$ 593,442	$ 2,221,611	$ 3,167,941	$ 2,910,222	$ 2,010,112	$ 2,400,859	$ 1,799,261
Emission Allowance	EMALL	PROFIX	-	-	-	-	-	-	-
Deferred Debits									
Service Pension Cost	PENSCOST	TLB	-	-	-	-	-	-	-
Accumulated Deferred Income Tax									
Total Production Plant	ADITPP	F017	-	-	-	-	-	-	-
Total Transmission Plant	ADITTP	F011	-	-	-	-	-	-	-
Total Distribution Plant	ADITDP	PDIST	1,487,756	5,569,563	9,942,594	9,133,743	6,323,095	4,981,684	5,661,796
Total General Plant	ADITGP	PT&D	37,035	138,643	247,501	227,366	157,401	124,009	140,939
Total Accumulated Deferred Income Tax	ADITT		*1,524,790*	*5,708,206*	*10,190,095*	*9,361,109*	*6,480,496*	*5,105,693*	*5,802,734*
Accumulated Deferred Investment Tax Credits									
Production	ADITCP	F017	-	-	-	-	-	-	-
Transmission	ADITCT	F011	-	-	-	-	-	-	-
Transmission VA	ADITCTVA	F011	-	-	-	-	-	-	-
Distribution VA	ADITCDVA	PDIST	-	-	-	-	-	-	-
Distribution Plant KY,FERC & TN	ADITCDKY	PDIST	1,826	6,836	12,203	11,210	7,761	6,114	6,949
General	ADITCG	PT&D	90	337	602	553	383	302	343
Total Accum. Deferred Investment Tax Credits	ADITCTL		1,916	7,173	12,805	11,763	8,144	6,416	7,292
Total Deferred Debits			$ 1,526,706	$ 5,715,379	$ 10,202,900	$ 9,372,873	$ 6,488,639	$ 5,112,109	$ 5,810,026
Less: Customer Advances	CSTDEP	F027	93,916	351,585	-	-	-	-	-
Net Rate Base	RB		$ 11,688,652	$ 43,757,647	$ 77,944,290	$ 71,603,359	$ 49,564,903	$ 39,867,151	$ 44,380,543

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Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Rate Base					
Utility Plant					
Plant in Service			$ -	$ -	$ -
Construction Work in Progress (CWIP)			-	-	-
Total Utility Plant	TUP		$ -	$ -	$ -
Less: Acummulated Provision for Depreciation					
Steam Production	ADEPREPA	F017	-	-	-
Hydraulic Production	RWIP	F017	-	-	-
Other Production		F017	-	-	-
Transmission - Kentucky System Property	ADEPRTP	PTRAN	-	-	-
Transmission - Virginia Property	ADEPRD1	PTRAN	-	-	-
Distribution	ADEPRD11	PDIST	-	-	-
General Plant	ADEPRD12	PT&D	-	-	-
Intangible Plant	ADEPRGP	PT&D	-	-	-
Total Accumulated Depreciation	TADEPR		$ -	$ -	$ -
Net Utility Plant	NTPLANT		$ -	$ -	$ -
Working Capital					
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	3,553,632	814,994	-
Materials and Supplies	M&S	TPIS	-	-	-
Prepayments	PREPAY	TPIS	-	-	-
Total Working Capital	TWC		$ 3,553,632	$ 814,994	$ -
Emission Allowance	EMALL	PROFIX	-	-	-
Deferred Debits					
Service Pension Cost	PENSCOST	TLB	-	-	-
Accumulated Deferred Income Tax					
Total Production Plant	ADITPP	F017	-	-	-
Total Transmission Plant	ADITTP	F011	-	-	-
Total Distribution Plant	ADITDP	PDIST	-	-	-
Total General Plant	ADITGP	PT&D	-	-	-
Total Accumulated Deferred Income Tax	ADITT		-	-	-
Accumulated Deferred Investment Tax Credits					
Production	ADITCP	F017	-	-	-
Transmission	ADITCT	F011	-	-	-
Transmission VA	ADITCTVA	F011	-	-	-
Distribution VA	ADITCDVA	PDIST	-	-	-
Distribution Plant KY,FERC & TN	ADITCDKY	PDIST	-	-	-
General	ADITCG	PT&D	-	-	-
Total Accum. Deferred Investment Tax Credits	ADITCTL		-	-	-
Total Deferred Debits			$ -	$ -	$ -
Less: Customer Advances	CSTDEP	F027	-	-	-
Net Rate Base	RB		$ 3,553,632	$ 814,994	$ -

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Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Operation and Maintenance Expenses									
Steam Power Generation Operation Expenses									
500 OPERATION SUPERVISION & ENGINEERING	OM500	LBSUB1	$ 3,348,315	938,082	1,116,592	738,900	554,741	-	-
501 FUEL	OM501	Energy	$ 359,943,470	-	-	-	359,943,470	-	-
502 STEAM EXPENSES	OM502		$ 9,025,021	1,709,725	2,035,072	1,346,701	3,933,522	-	-
505 ELECTRIC EXPENSES	OM505		$ 4,886,361	1,153,134	1,372,566	908,290	1,452,371	-	-
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	$ 6,423,607	2,157,047	2,567,516	1,699,044	-	-	-
507 RENTS	OM507	PROFIX	$ 1,911,917	642,022	764,193	505,702	-	-	-
Total Steam Power Operation Expenses			$ 385,538,691	$ 6,600,010	$ 7,855,938	$ 5,198,638	$ 365,884,104	$ -	$ -
Steam Power Generation Maintenance Expenses									
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	LBSUB2	$ 4,677,355	221,409	263,541	174,397	4,018,007	-	-
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	$ 4,477,790	1,503,642	1,789,773	1,184,376	-	-	-
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	$ 24,647,620	-	-	-	24,647,620	-	-
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	$ 9,390,527	-	-	-	9,390,527	-	-
514 MAINTENANCE OF MISC STEAM PLANT	OM514	Energy	$ 991,695	-	-	-	991,695	-	-
Total Steam Power Generation Maintenance Expense			$ 44,184,987	$ 1,725,051	$ 2,053,314	$ 1,358,773	$ 39,047,849	$ -	$ -
Total Steam Power Generation Expense			$ 429,723,678	$ 8,325,061	$ 9,909,252	$ 6,557,411	$ 404,931,953	$ -	$ -
Hydraulic Power Generation Operation Expenses									
535 OPERATION SUPERVISION & ENGINEERING	OM535	LBSUB3	$ 7,220	2,424	2,886	1,910	-	-	-
536 WATER FOR POWER	OM536	PROFIX	$ -	-	-	-	-	-	-
537 HYDRAULIC EXPENSES	OM537	PROFIX	$ -	-	-	-	-	-	-
538 ELECTRIC EXPENSES	OM538		$ -	-	-	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	OM539	PROFIX	$ 36,018	12,095	14,397	9,527	-	-	-
540 RENTS		PROFIX	$ -	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses			$ 43,238	$ 14,519	$ 17,282	$ 11,436	$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses									
541 MAINTENANCE SUPERVISION & ENGINEERING	OM541	LBSUB4	$ 104,232	11,425	13,600	8,999	70,208	-	-
542 MAINTENANCE OF STRUCTURES	OM542	PROFIX	$ 135,839	45,615	54,295	35,929	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	OM543	PROFIX	$ -	-	-	-	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	OM544	Energy	$ 136,478	-	-	-	136,478	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	OM545	Energy	$ 5,457	-	-	-	5,457	-	-
Total Hydraulic Power Generation Maint. Expense			$ 382,006	$ 57,040	$ 67,894	$ 44,929	$ 212,143	$ -	$ -
Total Hydraulic Power Generation Expense			$ 425,244	$ 71,559	$ 85,176	$ 56,365	$ 212,143	$ -	$ -
Other Power Generation Operation Expense									
546 OPERATION SUPERVISION & ENGINEERING	OM546	LBSUB5	$ 99,030	33,254	39,582	26,193	-	-	-
547 FUEL	OM547	Energy	$ 50,197,106	-	-	-	50,197,106	-	-
548 GENERATION EXPENSE	OM548	PROFIX	$ 1,459,910	490,238	583,526	386,146	-	-	-
549 MISC OTHER POWER GENERATION	OM549	PROFIX	$ 114,052	38,299	45,587	30,167	-	-	-
550 RENTS	OM550	PROFIX	$ -	-	-	-	-	-	-
Total Other Power Generation Expenses			$ 51,870,098	$ 561,791	$ 668,695	$ 442,506	$ 50,197,106	$ -	$ -

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

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

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

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Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Other Power Generation Maintenance Expense									
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	$ 33,775	11,341	13,500	8,933	-	-	-
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	$ 143,980	48,348	57,549	38,083	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	$ 2,313,971	777,032	924,894	612,045	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	$ 247,222	83,017	98,815	65,390	-	-	-
Total Other Power Generation Maintenance Expense			$ 2,738,948	$ 919,739	$ 1,094,758	$ 724,452	$ -	$ -	$ -
Total Other Power Generation Expense			$ 54,609,046	$ 1,481,529	$ 1,763,452	$ 1,166,958	$ 50,197,106	$ -	$ -
Total Station Expense			$ 484,757,968	$ 9,878,150	$ 11,757,881	$ 7,780,734	$ 455,341,203	$ -	$ -
Other Power Supply Expenses									
555 PURCHASED POWER	OM555	OMPP	$ 157,242,642	5,047,496	6,007,994	3,975,768	142,211,384	-	-
555 PURCHASED POWER OPTIONS	OMO555	OMPP	$ -	-	-	-	-	-	-
555 BROKERAGE FEES	OMB555	OMPP	$ -	-	-	-	-	-	-
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	$ -	-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	$ 1,341,969	450,633	536,385	354,951	-	-	-
557 OTHER EXPENSES	OM557	PROFIX	$ 1,040,935	349,546	416,062	275,327	-	-	-
Total Other Power Supply Expenses	TPP		$ 159,625,547	$ 5,847,676	$ 6,960,441	$ 4,606,046	$ 142,211,384	$ -	$ -
Total Electric Power Generation Expenses			$ 644,383,515	$ 15,725,826	$ 18,718,322	$ 12,386,781	$ 597,552,587	$ -	$ -
Transmission Expenses									
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	$ 888,516	-	-	-	-	-	-
561 LOAD DISPATCHING	OM561	LBTRAN	$ 842,754	-	-	-	-	-	-
562 STATION EXPENSES	OM562	LBTRAN	$ 361,025	-	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	OM563	LBTRAN	$ 335,766	-	-	-	-	-	-
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	LBTRAN	$ 4,617,906	-	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	$ 4,624,059	-	-	-	-	-	-
567 RENTS	OM567	PTRAN	$ 88,823	-	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	-	-	-	-	-	-	-
569 STRUCTURES	OM569	LBTRAN	-	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	OM570	LBTRAN	915,531	-	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	OM571	LBTRAN	3,300,624	-	-	-	-	-	-
572 UNDERGROUND LINES	OM572	LBTRAN	-	-	-	-	-	-	-
573 MISC PLANT	OM573	PTRAN	175,179	-	-	-	-	-	-
575 MISO DAY 1&2 EXPENSE	OM575	PTRAN	10,185	-	-	-	-	-	-
Total Transmission Expenses			$ 16,160,369	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Operation Expense									
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	$ 1,284,074	-	-	-	-	-	-
581 LOAD DISPATCHING	OM581	P362	$ 610,159	-	-	-	-	-	-
582 STATION EXPENSES	OM582	P362	$ 1,001,284	-	-	-	-	-	-
583 OVERHEAD LINE EXPENSES	OM583	P365	$ 3,030,139	-	-	-	-	-	-
584 UNDERGROUND LINE EXPENSES	OM584	P367	$ 72,494	-	-	-	-	-	-
585 STREET LIGHTING EXPENSE	OM585	P373	$ 10,832	-	-	-	-	-	-
586 METER EXPENSES	OM586	P370	$ 6,096,249	-	-	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	F012	-	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	P371	(73,416)	-	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	4,379,334	-	-	-	-	-	-
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	-	-	-	-	-	-	-
589 RENTS	OM589	PDIST	12,654	-	-	-	-	-	-
Total Distribution Operation Expense	OMDO		$ 16,423,804	$ -	$ -	$ -	$ -	$ -	$ -

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Description	Name	Functional Vector	Transmission Demand Base	Transmission Demand Inter.	Transmission Demand Peak	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer
Other Power Generation Maintenance Expense										
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	-	-	-	-	-	-	-	-
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	-	-	-	-	-	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	-	-	-	-	-	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	-	-	-	-	-	-	-	-
Total Other Power Generation Maintenance Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Other Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Station Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Power Supply Expenses										
555 PURCHASED POWER	OM555	OMPP	-	-	-	-	-	-	-	-
555 PURCHASED POWER OPTIONS	OMO555	OMPP	-	-	-	-	-	-	-	-
555 BROKERAGE FEES	OMB555	OMPP	-	-	-	-	-	-	-	-
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	-	-	-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	-	-	-	-	-	-	-	-
557 OTHER EXPENSES	OM557	PROFIX	-	-	-	-	-	-	-	-
Total Other Power Supply Expenses	TPP		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Electric Power Generation Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Expenses										
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	298,364	355,140	235,012	-	-	-	-	-
561 LOAD DISPATCHING	OM561	LBTRAN	282,997	336,849	222,908	-	-	-	-	-
562 STATION EXPENSES	OM562	LBTRAN	121,232	144,302	95,491	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	OM563	LBTRAN	112,750	134,206	88,810	-	-	-	-	-
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	LBTRAN	1,550,693	1,845,777	1,221,436	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	1,552,759	1,848,237	1,223,064	-	-	-	-	-
567 RENTS	OM567	PTRAN	29,827	35,503	23,494	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	-	-	-	-	-	-	-	-
569 STRUCTURES	OM569	LBTRAN	-	-	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	OM570	LBTRAN	307,435	365,938	242,158	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	OM571	LBTRAN	1,108,350	1,319,259	873,015	-	-	-	-	-
572 UNDERGROUND LINES	OM572	LBTRAN	-	-	-	-	-	-	-	-
573 MISC PLANT	OM573	PTRAN	58,825	70,019	46,335	-	-	-	-	-
575 MISO DAY 1&2 EXPENSE	OM575	PTRAN	3,420	4,071	2,694	-	-	-	-	-
Total Transmission Expenses			$ 5,426,652	$ 6,459,299	$ 4,274,418	$ -	$ -	$ -	$ -	$ -
Distribution Operation Expense										
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	-	-	-	-	207,332	-	81,624	305,568
581 LOAD DISPATCHING	OM581	P362	-	-	-	-	610,159	-	-	-
582 STATION EXPENSES	OM582	P362	-	-	-	-	1,001,284	-	-	-
583 OVERHEAD LINE EXPENSES	OM583	P365	-	-	-	-	-	-	520,499	1,948,539
584 UNDERGROUND LINE EXPENSES	OM584	P367	-	-	-	-	-	-	12,453	46,618
585 STREET LIGHTING EXPENSE	OM585	P373	-	-	-	-	-	-	-	-
586 METER EXPENSES	OM586	P370	-	-	-	-	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	F012	-	-	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	P371	-	-	-	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	-	-	-	-	441,566	-	347,639	1,301,422
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	-	-	-	-	-	-	-	-
589 RENTS	OM589	PDIST	-	-	-	-	1,276	-	1,004	3,760
Total Distribution Operation Expense	OMDO		$ -	$ -	$ -	$ -	$ 2,261,616	$ -	$ 963,219	$ 3,605,907

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Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Other Power Generation Maintenance Expense									
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	-	-	-	-	-	-	-
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	-	-	-	-	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	-	-	-	-	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	-	-	-	-	-	-	-
Total Other Power Generation Maintenance Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Other Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Station Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Power Supply Expenses									
555 PURCHASED POWER	OM555	OMPP	-	-	-	-	-	-	-
555 PURCHASED POWER OPTIONS	OMO555	OMPP	-	-	-	-	-	-	-
555 BROKERAGE FEES	OMB555	OMPP	-	-	-	-	-	-	-
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	-	-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	-	-	-	-	-	-	-
557 OTHER EXPENSES	OM557	PROFIX	-	-	-	-	-	-	-
Total Other Power Supply Expenses	TPP		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Electric Power Generation Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Expenses									
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	-	-	-	-	-	-	-
561 LOAD DISPATCHING	OM561	LBTRAN	-	-	-	-	-	-	-
562 STATION EXPENSES	OM562	LBTRAN	-	-	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	OM563	LBTRAN	-	-	-	-	-	-	-
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	LBTRAN	-	-	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	-	-	-	-	-	-	-
567 RENTS	OM567	PTRAN	-	-	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	-	-	-	-	-	-	-
569 STRUCTURES	OM569	LBTRAN	-	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	OM570	LBTRAN	-	-	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	OM571	LBTRAN	-	-	-	-	-	-	-
572 UNDERGROUND LINES	OM572	LBTRAN	-	-	-	-	-	-	-
573 MISC PLANT	OM573	PTRAN	-	-	-	-	-	-	-
575 MISO DAY 1&2 EXPENSE	OM575	PTRAN	-	-	-	-	-	-	-
Total Transmission Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Operation Expense									
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	18,549	69,442	41,636	38,249	26,479	469,898	25,298
581 LOAD DISPATCHING	OM581	P362	-	-	-	-	-	-	-
582 STATION EXPENSES	OM582	P362	-	-	-	-	-	-	-
583 OVERHEAD LINE EXPENSES	OM583	P365	118,286	442,815	-	-	-	-	-
584 UNDERGROUND LINE EXPENSES	OM584	P367	2,830	10,594	-	-	-	-	-
585 STREET LIGHTING EXPENSE	OM585	P373	-	-	-	-	-	-	10,832
586 METER EXPENSES	OM586	P370	-	-	-	-	-	6,096,249	-
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	F012	-	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	P371	-	-	-	-	-	-	(73,416)
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	79,003	295,755	527,971	485,020	335,769	264,537	300,652
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	-	-	-	-	-	-	-
589 RENTS	OM589	PDIST	228	855	1,526	1,401	970	764	869
Total Distribution Operation Expense	OMDO		$ 218,896	$ 819,461	$ 571,133	$ 524,670	$ 363,218	$ 6,831,448	$ 264,236

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Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Other Power Generation Maintenance Expense					
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	-	-	-
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	-	-	-
Total Other Power Generation Maintenance Expense			$ -	$ -	$ -
Total Other Power Generation Expense			$ -	$ -	$ -
Total Station Expense			$ -	$ -	$ -
Other Power Supply Expenses					
555 PURCHASED POWER	OM555	OMPP	-	-	-
555 PURCHASED POWER OPTIONS	OMO555	OMPP	-	-	-
555 BROKERAGE FEES	OMB555	OMPP	-	-	-
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	-	-	-
557 OTHER EXPENSES	OM557	PROFIX	-	-	-
Total Other Power Supply Expenses	TPP		$ -	$ -	$ -
Total Electric Power Generation Expenses			$ -	$ -	$ -
Transmission Expenses					
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	-	-	-
561 LOAD DISPATCHING	OM561	LBTRAN	-	-	-
562 STATION EXPENSES	OM562	LBTRAN	-	-	-
563 OVERHEAD LINE EXPENSES	OM563	LBTRAN	-	-	-
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	LBTRAN	-	-	-
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	-	-	-
567 RENTS	OM567	PTRAN	-	-	-
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	-	-	-
569 STRUCTURES	OM569	LBTRAN	-	-	-
570 MAINT OF STATION EQUIPMENT	OM570	LBTRAN	-	-	-
571 MAINT OF OVERHEAD LINES	OM571	LBTRAN	-	-	-
572 UNDERGROUND LINES	OM572	LBTRAN	-	-	-
573 MISC PLANT	OM573	PTRAN	-	-	-
575 MISO DAY 1&2 EXPENSE	OM575	PTRAN	-	-	-
Total Transmission Expenses			$ -	$ -	$ -
Distribution Operation Expense					
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	-	-	-
581 LOAD DISPATCHING	OM581	P362	-	-	-
582 STATION EXPENSES	OM582	P362	-	-	-
583 OVERHEAD LINE EXPENSES	OM583	P365	-	-	-
584 UNDERGROUND LINE EXPENSES	OM584	P367	-	-	-
585 STREET LIGHTING EXPENSE	OM585	P373	-	-	-
586 METER EXPENSES	OM586	P370	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	F012	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	P371	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	-	-	-
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	-	-	-
589 RENTS	OM589	PDIST	-	-	-
Total Distribution Operation Expense	OMDO		$ -	$ -	$ -

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Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Operation and Maintenance Expenses (Continued)									
Distribution Maintenance Expense									
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	$ 6,387	-	-	-	-	-	-
591 STRUCTURES	OM591	P362	$ 628	-	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	OM592	P362	$ 856,534	-	-	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	OM593	P365	$ 20,706,877	-	-	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	OM594	P367	$ 590,308	-	-	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	OM595	P368	$ 110,444	-	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	P373	$ 55,955	-	-	-	-	-	-
597 MAINTENANCE OF METERS	OM597	P370	$ -	-	-	-	-	-	-
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	$ 7,695	-	-	-	-	-	-
Total Distribution Maintenance Expense	OMDM		$ 22,334,828	$ -	$ -	$ -	$ -	$ -	$ -
Total Distribution Operation and Maintenance Expenses			38,758,632	-	-	-	-	-	-
Transmission and Distribution Expenses			54,919,001	-	-	-	-	-	-
Production, Transmission and Distribution Expenses	OMSUB		$ 699,302,516	$ 15,725,826	$ 18,718,322	$ 12,386,781	$ 597,552,587	$ -	$ -
Customer Accounts Expense									
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	$ 1,853,549	-	-	-	-	-	-
902 METER READING EXPENSES	OM902	F025	$ 4,126,623	-	-	-	-	-	-
903 RECORDS AND COLLECTION	OM903	F025	$ 11,300,549	-	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	$ 3,133,404	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	OM903	F025	$ 227,523	-	-	-	-	-	-
Total Customer Accounts Expense	OMCA		$ 20,641,648	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expense									
907 SUPERVISION	OM907	F026	$ 217,872	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	F026	$ 4,733,193	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	F026	-	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	F026	449,354	-	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	F026	-	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	F026	785,960	-	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	OM911	F026	-	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	OM912	F026	-	-	-	-	-	-	-
913 ADVERTISING EXPENSES	OM913	F026	66,555	-	-	-	-	-	-
915 MDSE-JOBBING-CONTRACT	OM915	F026	-	-	-	-	-	-	-
916 MISC SALES EXPENSE	OM916	F026	-	-	-	-	-	-	-
Total Customer Service Expense	OMCS		$ 6,252,934	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		726,197,098	15,725,826	18,718,322	12,386,781	597,552,587	-	-

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Description	Name	Functional Vector	Transmission Demand Base	Transmission Demand Inter.	Transmission Demand Peak	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer
Operation and Maintenance Expenses (Continued)										
Distribution Maintenance Expense										
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	-	-	-	-	384	-	1,015	3,798
591 STRUCTURES	OM591	P362	-	-	-	-	628	-	-	-
592 MAINTENANCE OF STATION EQUIPME	OM592	P362	-	-	-	-	856,534	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	OM593	P365	-	-	-	-	-	-	3,556,900	13,315,614
594 MAINTENANCE OF UNDERGROUND LIN	OM594	P367	-	-	-	-	-	-	101,400	379,599
595 MAINTENANCE OF LINE TRANSFORME	OM595	P368	-	-	-	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	P373	-	-	-	-	-	-	-	-
597 MAINTENANCE OF METERS	OM597	P370	-	-	-	-	-	-	-	-
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	-	-	-	-	776	-	611	2,287
Total Distribution Maintenance Expense	OMDM		$ -	$ -	$ -	$ -	$ 858,322	$ -	$ 3,659,925	$ 13,701,298
Total Distribution Operation and Maintenance Expenses			-	-	-	-	3,119,938	-	4,623,144	17,307,205
Transmission and Distribution Expenses			5,426,652	6,459,299	4,274,418	-	3,119,938	-	4,623,144	17,307,205
Production, Transmission and Distribution Expenses	OMSUB		$ 5,426,652	$ 6,459,299	$ 4,274,418	$ -	$ 3,119,938	$ -	$ 4,623,144	$ 17,307,205
Customer Accounts Expense										
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	-	-	-	-	-	-	-	-
902 METER READING EXPENSES	OM902	F025	-	-	-	-	-	-	-	-
903 RECORDS AND COLLECTION	OM903	F025	-	-	-	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	-	-	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	OM903	F025	-	-	-	-	-	-	-	-
Total Customer Accounts Expense	OMCA		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expense										
907 SUPERVISION	OM907	F026	-	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	F026	-	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	F026	-	-	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	F026	-	-	-	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	F026	-	-	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	F026	-	-	-	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	OM911	F026	-	-	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	OM912	F026	-	-	-	-	-	-	-	-
913 ADVERTISING EXPENSES	OM913	F026	-	-	-	-	-	-	-	-
915 MDSE-JOBBING-CONTRACT	OM915	F026	-	-	-	-	-	-	-	-
916 MISC SALES EXPENSE	OM916	F026	-	-	-	-	-	-	-	-
Total Customer Service Expense	OMCS		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		5,426,652	6,459,299	4,274,418	-	3,119,938	-	4,623,144	17,307,205

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Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Operation and Maintenance Expenses (Continued)									
Distribution Maintenance Expense									
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	231	863	27	25	0	0	45
591 STRUCTURES	OM591	P362	-	-	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	OM592	P362	-	-	-	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	OM593	P365	808,323	3,026,040	-	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	OM594	P367	23,044	86,266	-	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	*OM595*	*P368*	-	-	57,563	52,880	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	P373	-	-	-	-	-	-	55,955
597 MAINTENANCE OF METERS	OM597	P370	-	-	-	-	-	-	-
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	139	520	928	852	590	465	528
Total Distribution Maintenance Expense	OMDM		$ 831,736	$ 3,113,689	$ 58,518	$ 53,758	$ 590	$ 465	$ 56,529
Total Distribution Operation and Maintenance Expenses			1,050,633	3,933,149	629,651	578,427	363,808	6,831,913	320,764
Transmission and Distribution Expenses			1,050,633	3,933,149	629,651	578,427	363,808	6,831,913	320,764
Production, Transmission and Distribution Expenses	OMSUB		$ 1,050,633	$ 3,933,149	$ 629,651	$ 578,427	$ 363,808	$ 6,831,913	$ 320,764
Customer Accounts Expense									
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	-	-	-	-	-	-	-
902 METER READING EXPENSES	OM902	F025	-	-	-	-	-	-	-
903 RECORDS AND COLLECTION	OM903	F025	-	-	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	-	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	OM903	F025	-	-	-	-	-	-	-
Total Customer Accounts Expense	OMCA		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expense									
907 SUPERVISION	OM907	F026	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	F026	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	F026	-	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	F026	-	-	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	F026	-	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	F026	-	-	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	OM911	F026	-	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	OM912	F026	-	-	-	-	-	-	-
913 ADVERTISING EXPENSES	OM913	F026	-	-	-	-	-	-	-
915 MDSE-JOBBING-CONTRACT	OM915	F026	-	-	-	-	-	-	-
916 MISC SALES EXPENSE	OM916	F026	-	-	-	-	-	-	-
Total Customer Service Expense	OMCS		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		1,050,633	3,933,149	629,651	578,427	363,808	6,831,913	320,764

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Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Operation and Maintenance Expenses (Continued)					
Distribution Maintenance Expense					
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	-	-	-
591 STRUCTURES	OM591	P362	-	-	-
592 MAINTENANCE OF STATION EQUIPME	OM592	P362	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	OM593	P365	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	OM594	P367	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	OM595	P368	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	P373	-	-	-
597 MAINTENANCE OF METERS	OM597	P370	-	-	-
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	-	-	-
Total Distribution Maintenance Expense	OMDM		$ -	$ -	$ -
Total Distribution Operation and Maintenance Expenses			-	-	-
Transmission and Distribution Expenses			-	-	-
Production, Transmission and Distribution Expenses	OMSUB		$ -	$ -	$ -
Customer Accounts Expense					
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	1,853,549	-	-
902 METER READING EXPENSES	OM902	F025	4,126,623	-	-
903 RECORDS AND COLLECTION	OM903	F025	11,300,549	-	-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	3,133,404	-	-
905 MISC CUST ACCOUNTS	OM903	F025	227,523	-	-
Total Customer Accounts Expense	OMCA		$ 20,641,648	$ -	$ -
Customer Service Expense					
907 SUPERVISION	OM907	F026	-	217,872	-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	F026	-	4,733,193	-
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	F026	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	F026	-	449,354	-
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	F026	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	F026	-	785,960	-
911 DEMONSTRATION AND SELLING EXP	OM911	F026	-	-	-
912 DEMONSTRATION AND SELLING EXP	OM912	F026	-	-	-
913 ADVERTISING EXPENSES	OM913	F026	-	66,555	-
915 MDSE-JOBBING-CONTRACT	OM915	F026	-	-	-
916 MISC SALES EXPENSE	OM916	F026	-	-	-
Total Customer Service Expense	OMCS		$ -	$ 6,252,934	$ -
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		20,641,648	6,252,934	-

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Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Operation and Maintenance Expenses (Continued)									
Administrative and General Expense									
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB7	$ 14,199,205	1,430,542	1,702,762	1,126,797	3,057,532	-	-
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB7	$ 6,808,062	685,899	816,420	540,263	1,465,988	-	-
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB7	$ (1,409,208)	(141,975)	(168,992)	(111,830)	(303,446)	-	-
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB7	$ 9,557,040	962,853	1,146,076	758,411	2,057,929	-	-
924 PROPERTY INSURANCE	OM924	TUP	2,804,917	587,166	698,899	462,494	-	-	-
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB7	1,723,528	173,642	206,685	136,773	371,129	-	-
926 EMPLOYEE BENEFITS	OM926	LBSUB7	20,838,595	2,099,447	2,498,955	1,653,674	4,487,199	-	-
928 REGULATORY COMMISSION FEES	OM928	TUP	529,026	110,744	131,817	87,230	-	-	-
929 DUPLICATE CHARGES	OM929	LBSUB7	(2,928)	(295)	(351)	(232)	(631)	-	-
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB7	1,240,888	125,017	148,807	98,472	267,202	-	-
931 RENTS AND LEASES	OM931	PGP	1,396,179	265,417	315,924	209,061	-	-	-
932 MAINTENANCE OF GENERAL PLANT	OM932	PGP	-	-	-	-	-	-	-
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	5,618,834	1,068,154	1,271,415	841,354	-	-	-
Total Administrative and General Expense	OMAG		$ 63,304,138	$ 7,366,611	$ 8,768,417	$ 5,802,467	$ 11,402,902	$ -	$ -
Total Operation and Maintenance Expenses	TOM		$ 789,501,236	$ 23,092,436	$ 27,486,739	$ 18,189,248	$ 608,955,489	$ -	$ -
Operation and Maintenance Expenses Less Purchase Power	OMLPP		$ 632,258,594	$ 18,044,940	$ 21,478,745	$ 14,213,480	$ 466,744,105	$ -	$ -

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Description	Name	Functional Vector	Transmission Demand Base	Transmission Demand Inter.	Transmission Demand Peak	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer
Operation and Maintenance Expenses (Continued)										
Administrative and General Expense										
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB7	210.478	250,530	165.787	-	411,774	-	324,185	1,213,617
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB7	100,917	120,121	79,490	-	197,432	-	155,436	581,890
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB7	(20,889)	(24,864)	(16,454)	-	(40,867)	-	(32,174)	(120,446)
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB7	141,666	168,624	111,586	-	277,152	-	218,198	816,848
924 PROPERTY INSURANCE	OM924	TUP	103,785	123,535	81,749	-	75,349	-	59,321	222,074
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB7	25,548	30,410	20,124	-	49,982	-	39,350	147,311
926 EMPLOYEE BENEFITS	OM926	LBSUB7	308,895	367,675	243,307	-	604,315	-	475,770	1,781,091
928 REGULATORY COMMISSION FEES	OM928	TUP	19,575	23,300	15,418	-	14,211	-	11,188	41,885
929 DUPLICATE CHARGES	OM929	LBSUB7	(43)	(52)	(34)	-	(85)	-	(67)	(250)
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB7	18,394	21,894	14,488	-	35,985	-	28,331	106,060
931 RENTS AND LEASES	OM931	PGP	59,213	70,480	46,640	-	43,301	-	34,090	127,619
932 MAINTENANCE OF GENERAL PLANT	OM932	PGP	-	-	-	-	-	-	-	-
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	238,297	283,643	187,700	-	174,260	-	137,193	513,596
Total Administrative and General Expense	OMAG		$ 1,205,835	$ 1,435,296	$ 949,802	$ -	$ 1,842,810	$ -	$ 1,450,821	$ 5,431,296
Total Operation and Maintenance Expenses	TOM		$ 6,632,487	$ 7,894,595	$ 5,224,219	$ -	$ 4,962,747	$ -	$ 6,073,965	$ 22,738,501
Operation and Maintenance Expenses Less Purchase Power	OMLPP		$ 6,632,487	$ 7,894,595	$ 5,224,219	$ -	$ 4,962,747	$ -	$ 6,073,965	$ 22,738,501

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Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Operation and Maintenance Expenses (Continued)									
Administrative and General Expense									
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB7	73,673	275,801	492,350	452,296	313,115	246,689	280,368
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB7	35,324	132,238	236,066	216,861	150,129	118,280	134,427
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB7	(7,312)	(27,372)	(48,864)	(44,888)	(31,075)	(24,483)	(27,825)
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB7	49,587	185,633	331,385	304,426	210,748	166,039	188,707
924 PROPERTY INSURANCE	OM924	TUP	13,481	50,467	90,093	82,764	57,295	45,141	51,303
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB7	8,943	33,477	59,762	54,901	38,007	29,944	34,032
926 EMPLOYEE BENEFITS	OM926	LBSUB7	108,121	404,762	722,567	663,785	459,524	362,038	411,465
928 REGULATORY COMMISSION FEES	OM928	TUP	2,543	9,519	16,992	15,610	10,806	8,514	9,676
929 DUPLICATE CHARGES	OM929	LBSUB7	(15)	(57)	(102)	(93)	(65)	(51)	(58)
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB7	6,438	24,103	43,027	39,527	27,364	21,559	24,502
931 RENTS AND LEASES	OM931	PGP	7,747	29,002	51,774	47,562	32,926	25,941	29,482
932 MAINTENANCE OF GENERAL PLANT	OM932	PGP	-	-	-	-	-	-	-
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	31,178	116,717	208,360	191,409	132,508	104,397	118,650
Total Administrative and General Expense	OMAG		$ 329,706	$ 1,234,289	$ 2,203,411	$ 2,024,159	$ 1,401,282	$ 1,104,007	$ 1,254,729
Total Operation and Maintenance Expenses	TOM		$ 1,380,339	$ 5,167,439	$ 2,833,062	$ 2,602,586	$ 1,765,090	$ 7,935,921	$ 1,575,493
Operation and Maintenance Expenses Less Purchase Power	OMLPP		$ 1,380,339	$ 5,167,439	$ 2,833,062	$ 2,602,586	$ 1,765,090	$ 7,935,921	$ 1,575,493

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Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Operation and Maintenance Expenses (Continued)					
Administrative and General Expense					
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB7	2,097,219	73,692	-
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB7	1,005,549	35,333	-
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB7	(208,140)	(7,314)	-
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB7	1,411,572	49,600	-
924 PROPERTY INSURANCE	OM924	TUP	-	-	-
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB7	254,565	8,945	-
926 EMPLOYEE BENEFITS	OM926	LBSUB7	3,077,855	108,149	-
928 REGULATORY COMMISSION FEES	OM928	TUP	-	-	-
929 DUPLICATE CHARGES	OM929	LBSUB7	(432)	(15)	-
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB7	183,279	6,440	-
931 RENTS AND LEASES	OM931	PGP	-	-	-
932 MAINTENANCE OF GENERAL PLANT	OM932	PGP	-	-	-
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	-	-	-
Total Administrative and General Expense	OMAG		$ 7,821,467	$ 274,830	$ -
Total Operation and Maintenance Expenses	TOM		$ 28,463,115	$ 6,527,764	$ -
Operation and Maintenance Expenses Less Purchase Power	OMLPP		$ 28,463,115	$ 6,527,764	$ -

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Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Labor Expenses									
Steam Power Generation Operation Expenses									
500 OPERATION SUPERVISION & ENGINEERING	LB500	F019	$ 2,086,714	584,625	695,875	460,492	345,722	-	-
501 FUEL	LB501	Energy	$ 1,737,173	-	-	-	1,737,173	-	-
502 STEAM EXPENSES	LB502	PROFIX	$ 5,091,499	1,709,725	2,035,072	1,346,701	-	-	-
505 ELECTRIC EXPENSES	LB505	PROFIX	$ 3,433,990	1,153,134	1,372,566	908,290	-	-	-
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	$ 222,596	74,748	88,971	58,877	-	-	-
507 RENTS	LB507	PROFIX	$ -	-	-	-	-	-	-
Total Steam Power Operation Expenses	LBSUB1		$ 12,571,972	$ 3,522,232	$ 4,192,484	$ 2,774,361	$ 2,082,895	$ -	$ -
Steam Power Generation Maintenance Expenses									
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	F020	$ 3,205,656	151,744	180,620	119,524	2,753,768	-	-
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	$ 787,400	264,409	314,724	208,267	-	-	-
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	$ 3,487,689	-	-	-	3,487,689	-	-
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	$ 1,206,726	-	-	-	1,206,726	-	-
514 MAINTENANCE OF MISC STEAM PLANT	LB514	Energy	$ 103,934	-	-	-	103,934	-	-
Total Steam Power Generation Maintenance Expense	LBSUB2		$ 8,791,406	$ 416,153	$ 495,344	$ 327,792	$ 7,552,117	$ -	$ -
Total Steam Power Generation Expense			$ 21,363,377	$ 3,938,385	$ 4,687,827	$ 3,102,152	$ 9,635,012	$ -	$ -
Hydraulic Power Generation Operation Expenses									
535 OPERATION SUPERVISION & ENGINEERING	LB535	F021	$ 5,529	1,857	2,210	1,462	-	-	-
536 WATER FOR POWER	LB536	PROFIX	$ -	-	-	-	-	-	-
537 HYDRAULIC EXPENSES	LB537	PROFIX	$ -	-	-	-	-	-	-
538 ELECTRIC EXPENSES	LB538	PROFIX	$ -	-	-	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	LB539	PROFIX	$ 2,262	760	904	598	-	-	-
540 RENTS	LB540	PROFIX	$ -	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses	LBSUB3		$ 7,791	$ 2,616	$ 3,114	$ 2,061	$ -	$ -	-
Hydraulic Power Generation Maintenance Expenses									
541 MAINTENANCE SUPERVISION & ENGINEERING	LB541	F022	$ 61,207	6,709	7,986	5,285	41,227	-	-
542 MAINTENANCE OF STRUCTURES	LB542	PROFIX	$ 29,661	9,960	11,856	7,845	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	LB543	PROFIX	$ -	-	-	-	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	LB544	Energy	$ 58,637	-	-	-	58,637	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	LB545	Energy	$ 2,568	-	-	-	2,568	-	-
Total Hydraulic Power Generation Maint. Expense	LBSUB4		$ 152,074	$ 16,670	$ 19,842	$ 13,130	$ 102,432	$ -	$ -
Total Hydraulic Power Generation Expense			$ 159,865	$ 19,286	$ 22,956	$ 15,191	$ 102,432	$ -	$ -
Other Power Generation Operation Expense									
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	$ 68,700	23,070	27,460	18,171	-	-	-
547 FUEL	LB547	Energy	$ -	-	-	-	-	-	-
548 GENERATION EXPENSE	LB548	PROFIX	$ 315,655	105,997	126,167	83,491	-	-	-
549 MISC OTHER POWER GENERATION	LB549	PROFIX	$ 0	0	0	0	-	-	-
550 RENTS	LB550	PROFIX	$ -	-	-	-	-	-	-
Total Other Power Generation Expenses	LBSUB5		$ 384,355	$ 129,066	$ 153,627	$ 101,662	$ -	$ -	-

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Description	Name	Functional Vector	Transmission Demand Base	Transmission Demand Inter.	Transmission Demand Peak	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer
Labor Expenses										
Steam Power Generation Operation Expenses										
500 OPERATION SUPERVISION & ENGINEERING	LB500	F019	-	-	-	-	-	-	-	-
501 FUEL	LB501	Energy	-	-	-	-	-	-	-	-
502 STEAM EXPENSES	LB502	PROFIX	-	-	-	-	-	-	-	-
505 ELECTRIC EXPENSES	LB505	PROFIX	-	-	-	-	-	-	-	-
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	-	-	-	-	-	-	-	-
507 RENTS	LB507	PROFIX	-	-	-	-	-	-	-	-
Total Steam Power Operation Expenses	LBSUB1		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Steam Power Generation Maintenance Expenses										
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	F020	-	-	-	-	-	-	-	-
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	-	-	-	-	-	-	-	-
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	-	-	-	-	-	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	-	-	-	-	-	-	-	-
514 MAINTENANCE OF MISC STEAM PLANT	LB514	Energy	-	-	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense	LBSUB2		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Steam Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Operation Expenses										
535 OPERATION SUPERVISION & ENGINEERING	LB535	F021	-	-	-	-	-	-	-	-
536 WATER FOR POWER	LB536	PROFIX	-	-	-	-	-	-	-	-
537 HYDRAULIC EXPENSES	LB537	PROFIX	-	-	-	-	-	-	-	-
538 ELECTRIC EXPENSES	LB538	PROFIX	-	-	-	-	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	LB539	PROFIX	-	-	-	-	-	-	-	-
540 RENTS	LB540	PROFIX	-	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses	LBSUB3		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses										
541 MAINTENANCE SUPERVISION & ENGINEERING	LB541	F022	-	-	-	-	-	-	-	-
542 MAINTENANCE OF STRUCTURES	LB542	PROFIX	-	-	-	-	-	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	LB543	PROFIX	-	-	-	-	-	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	LB544	Energy	-	-	-	-	-	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	LB545	Energy	-	-	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense	LBSUB4		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Power Generation Operation Expense										
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	-	-	-	-	-	-	-	-
547 FUEL	LB547	Energy	-	-	-	-	-	-	-	-
548 GENERATION EXPENSE	LB548	PROFIX	-	-	-	-	-	-	-	-
549 MISC OTHER POWER GENERATION	LB549	PROFIX	-	-	-	-	-	-	-	-
550 RENTS	LB550	PROFIX	-	-	-	-	-	-	-	-
Total Other Power Generation Expenses	LBSUB5		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Labor Expenses									
Steam Power Generation Operation Expenses									
500 OPERATION SUPERVISION & ENGINEERING	LB500	F019	-	-	-	-	-	-	-
501 FUEL	LB501	Energy	-	-	-	-	-	-	-
502 STEAM EXPENSES	LB502	PROFIX	-	-	-	-	-	-	-
505 ELECTRIC EXPENSES	LB505	PROFIX	-	-	-	-	-	-	-
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	-	-	-	-	-	-	-
507 RENTS	LB507	PROFIX	-	-	-	-	-	-	-
Total Steam Power Operation Expenses	LBSUB1		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Steam Power Generation Maintenance Expenses									
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	F020	-	-	-	-	-	-	-
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	-	-	-	-	-	-	-
512 MAINTENANCE OF BOILER PLANT	*LB512*	*Energy*	-	-	-	-	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	-	-	-	-	-	-	-
514 MAINTENANCE OF MISC STEAM PLANT	LB514	Energy	-	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense	LBSUB2		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Steam Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Operation Expenses									
535 OPERATION SUPERVISION & ENGINEERING	LB535	F021	-	-	-	-	-	-	-
536 WATER FOR POWER	LB536	PROFIX	-	-	-	-	-	-	-
537 HYDRAULIC EXPENSES	LB537	PROFIX	-	-	-	-	-	-	-
538 ELECTRIC EXPENSES	LB538	PROFIX	-	-	-	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	LB539	PROFIX	-	-	-	-	-	-	-
540 RENTS	LB540	PROFIX	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses	LBSUB3		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses									
541 MAINTENANCE SUPERVISION & ENGINEERING	LB541	F022	-	-	-	-	-	-	-
542 MAINTENANCE OF STRUCTURES	LB542	PROFIX	-	-	-	-	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	LB543	PROFIX	-	-	-	-	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	LB544	Energy	-	-	-	-	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	LB545	Energy	-	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense	LBSUB4		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Power Generation Operation Expense									
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	-	-	-	-	-	-	-
547 FUEL	LB547	Energy	-	-	-	-	-	-	-
548 GENERATION EXPENSE	LB548	PROFIX	-	-	-	-	-	-	-
549 MISC OTHER POWER GENERATION	LB549	PROFIX	-	-	-	-	-	-	-
550 RENTS	LB550	PROFIX	-	-	-	-	-	-	-
Total Other Power Generation Expenses	LBSUB5		$ -	$ -	$ -	$ -	$ -	$ -	$ -

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Description	Name	Functional Vector	Customer Accounts Expense	Customer *Service & Info.*	*Sales Expense*
Labor Expenses					
Steam Power Generation Operation Expenses					
500 OPERATION SUPERVISION & ENGINEERING	LB500	F019	-	-	-
501 FUEL	LB501	Energy	-	-	-
502 STEAM EXPENSES	LB502	PROFIX	-	-	-
505 ELECTRIC EXPENSES	LB505	PROFIX	-	-	-
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	-	-	-
507 RENTS	LB507	PROFIX	-	-	-
Total Steam Power Operation Expenses	LBSUB1		$ -	$ -	$ -
Steam Power Generation Maintenance Expenses					
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	F020	-	-	-
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	-	-	-
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	-	-	-
514 MAINTENANCE OF MISC STEAM PLANT	LB514	Energy	-	-	-
Total Steam Power Generation Maintenance Expense	LBSUB2		$ -	$ -	$ -
Total Steam Power Generation Expense			$ -	$ -	$ -
Hydraulic Power Generation Operation Expenses					
535 OPERATION SUPERVISION & ENGINEERING	LB535	F021	-	-	-
536 WATER FOR POWER	LB536	PROFIX	-	-	-
537 HYDRAULIC EXPENSES	LB537	PROFIX	-	-	-
538 ELECTRIC EXPENSES	LB538	PROFIX	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	LB539	PROFIX	-	-	-
540 RENTS	LB540	PROFIX	-	-	-
Total Hydraulic Power Operation Expenses	LBSUB3		$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses					
541 MAINTENANCE SUPERVISION & ENGINEERING	LB541	F022	-	-	-
542 MAINTENANCE OF STRUCTURES	LB542	PROFIX	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	LB543	PROFIX	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	LB544	Energy	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	LB545	Energy	-	-	-
Total Hydraulic Power Generation Maint. Expense	LBSUB4		$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ -	$ -	$ -
Other Power Generation Operation Expense					
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	-	-	-
547 FUEL	LB547	Energy	-	-	-
548 GENERATION EXPENSE	LB548	PROFIX	-	-	-
549 MISC OTHER POWER GENERATION	LB549	PROFIX	-	-	-
550 RENTS	LB550	PROFIX	-	-	-
Total Other Power Generation Expenses	LBSUB5		$ -	$ -	$ -

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Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Other Power Generation Maintenance Expense									
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	$ 23,508	7,894	9,396	6,218	-	-	-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	$ 68,736	23,082	27,474	18,181	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	$ 299,702	100,640	119,791	79,271	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	$ 64,527	21,668	25,791	17,067	-	-	-
Total Other Power Generation Maintenance Expense	LBSUB6		$ 456,473	$ 153,284	$ 182,452	$ 120,737	$ -	$ -	$ -
Total Other Power Generation Expense			$ 840,828	$ 282,350	$ 336,079	$ 222,399	$ -	$ -	$ -
Total Production Expense	LPREX		$ 22,364,070	$ 4,240,021	$ 5,046,862	$ 3,339,742	$ 9,737,445	$ -	$ -
Purchased Power									
555 PURCHASED POWER	LB555	OMPP	$ -	-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	$ 940,689	315,883	375,994	248,812	-	-	-
557 OTHER EXPENSES	LB557	PROFIX	$ -	-	-	-	-	-	-
Total Purchased Power Labor	LBPP		$ 940,689	$ 315,883	$ 375,994	$ 248,812	$ -	$ -	$ -
Transmission Labor Expenses									
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	$ 576,280	-	-	-	-	-	-
561 LOAD DISPATCHING	LB561	PTRAN	$ 636,176	-	-	-	-	-	-
562 STATION EXPENSES	LB562	PTRAN	$ 145,235	-	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	$ 26,006	-	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	163,103	-	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	-	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	331,101	-	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	74,028	-	-	-	-	-	-
572 UNDERGROUND LINES	LB572	PTRAN	-	-	-	-	-	-	-
573 MISC PLANT	LB573	PTRAN	44,250	-	-	-	-	-	-
Total Transmission Labor Expenses	LBTRAN		$ 1,996,178	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Operation Labor Expense									
580 OPERATION SUPERVISION AND ENGI	LB580	F023	$ 797,280	-	-	-	-	-	-
581 LOAD DISPATCHING	LB581	P362	$ 476,728	-	-	-	-	-	-
582 STATION EXPENSES	LB582	P362	$ 467,882	-	-	-	-	-	-
583 OVERHEAD LINE EXPENSES	LB583	P365	$ 1,687,045	-	-	-	-	-	-
584 UNDERGROUND LINE EXPENSES	LB584	P367	$ 40,998	-	-	-	-	-	-
585 STREET LIGHTING EXPENSE	LB585	P371	$ 6,061	-	-	-	-	-	-
586 METER EXPENSES	LB586	P370	$ 2,458,791	-	-	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	F012	-	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	P371	2,638	-	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	1,891,059	-	-	-	-	-	-
589 RENTS	LB589	PDIST	-	-	-	-	-	-	-
Total Distribution Operation Labor Expense	LBDO		$ 7,828,482	$ -	$ -	$ -	$ -	$ -	$ -

KENTUCKY UTILITIES
Cost of Service Study
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Description	Name	Functional Vector	Transmission Demand Base	Transmission Demand Inter.	Transmission Demand Peak	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer
Other Power Generation Maintenance Expense										
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	-	-	-	-	-	-	-	-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	-	-	-	-	-	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	-	-	-	-	-	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	-	-	-	-	-	-	-	-
Total Other Power Generation Maintenance Expense	LBSUB6		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Other Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Production Expense	LPREX		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power										
555 PURCHASED POWER	LB555	OMPP	-	-	-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	-	-	-	-	-	-	-	-
557 OTHER EXPENSES	LB557	PROFIX	-	-	-	-	-	-	-	-
Total Purchased Power Labor	LBPP		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Labor Expenses										
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	193,515	230,339	152,426	-	-	-	-	-
561 LOAD DISPATCHING	LB561	PTRAN	213,628	254,280	168,269	-	-	-	-	-
562 STATION EXPENSES	LB562	PTRAN	48,770	58,050	38,415	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	8,733	10,395	6,879	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	54,770	65,192	43,141	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	-	-	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	111,184	132,341	87,576	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	24,858	29,589	19,580	-	-	-	-	-
572 UNDERGROUND LINES	LB572	PTRAN	-	-	-	-	-	-	-	-
573 MISC PLANT	LB573	PTRAN	14,859	17,687	11,704	-	-	-	-	-
Total Transmission Labor Expenses	LBTRAN		$ 670,317	$ 797,872	$ 527,989	$ -	$ -	$ -	$ -	$ -
Distribution Operation Labor Expense										
580 OPERATION SUPERVISION AND ENGI	LB580	F023	-	-	-	-	128,732	-	50,680	189,726
581 LOAD DISPATCHING	LB581	P362	-	-	-	-	476,728	-	-	-
582 STATION EXPENSES	LB582	P362	-	-	-	-	467,882	-	-	-
583 OVERHEAD LINE EXPENSES	LB583	P365	-	-	-	-	-	-	289,790	1,084,859
584 UNDERGROUND LINE EXPENSES	LB584	P367	-	-	-	-	-	-	7,042	26,364
585 STREET LIGHTING EXPENSE	LB585	P371	-	-	-	-	-	-	-	-
586 METER EXPENSES	LB586	P370	-	-	-	-	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	F012	-	-	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	P371	-	-	-	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	-	-	-	-	190,674	-	150,116	561,973
589 RENTS	LB589	PDIST	-	-	-	-	-	-	-	-
Total Distribution Operation Labor Expense	LBDO		$ -	$ -	$ -	$ -	$ 1,264,017	$ -	$ 497,628	$ 1,862,922

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Cost of Service Study
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Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Other Power Generation Maintenance Expense									
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	-	-	-	-	-	-	-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	-	-	-	-	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	-	-	-	-	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	-	-	-	-	-	-	-
Total Other Power Generation Maintenance Expense	LBSUB6		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Other Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Production Expense	LPREX		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power									
555 PURCHASED POWER	LB555	OMPP	-	-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	-	-	-	-	-	-	-
557 OTHER EXPENSES	LB557	PROFIX	-	-	-	-	-	-	-
Total Purchased Power Labor	LBPP		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Labor Expenses									
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	-	-	-	-	-	-	-
561 LOAD DISPATCHING	LB561	PTRAN	-	-	-	-	-	-	-
562 STATION EXPENSES	LB562	PTRAN	-	-	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	-	-	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	-	-	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	-	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	-	-	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	-	-	-	-	-	-	-
572 UNDERGROUND LINES	LB572	PTRAN	-	-	-	-	-	-	-
573 MISC PLANT	LB573	PTRAN	-	-	-	-	-	-	-
Total Transmission Labor Expenses	LBTRAN		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Operation Labor Expense									
580 OPERATION SUPERVISION AND ENGI	LB580	F023	11,517	43,116	25,852	23,749	16,441	291,759	15,708
581 LOAD DISPATCHING	LB581	P362	-	-	-	-	-	-	-
582 STATION EXPENSES	LB582	P362	-	-	-	-	-	-	-
583 OVERHEAD LINE EXPENSES	LB583	P365	65,856	246,540	-	-	-	-	-
584 UNDERGROUND LINE EXPENSES	LB584	P367	1,600	5,991	-	-	-	-	-
585 STREET LIGHTING EXPENSE	LB585	P371	-	-	-	-	-	-	6,061
586 METER EXPENSES	LB586	P370	-	-	-	-	-	2,458,791	-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	F012	-	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	P371	-	-	-	-	-	-	2,638
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	34,115	127,711	227,985	209,438	144,990	114,231	129,826
589 RENTS	LB589	PDIST	-	-	-	-	-	-	-
Total Distribution Operation Labor Expense	LBDO		$ 113,089	$ 423,358	$ 253,837	$ 233,187	$ 161,430	$ 2,864,781	$ 154,232

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Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Other Power Generation Maintenance Expense					
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	-	-	-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	-	-	-
Total Other Power Generation Maintenance Expense	LBSUB6		$ -	$ -	$ -
Total Other Power Generation Expense			$ -	$ -	$ -
Total Production Expense	LPREX		$ -	$ -	$ -
Purchased Power					
555 PURCHASED POWER	LB555	OMPP	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	-	-	-
557 OTHER EXPENSES	LB557	PROFIX	-	-	-
Total Purchased Power Labor	LBPP		$ -	$ -	$ -
Transmission Labor Expenses					
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	-	-	-
561 LOAD DISPATCHING	LB561	PTRAN	-	-	-
562 STATION EXPENSES	LB562	PTRAN	-	-	-
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	-	-	-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	-	-	-
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	-	-	-
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	-	-	-
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	-	-	-
572 UNDERGROUND LINES	LB572	PTRAN	-	-	-
573 MISC PLANT	LB573	PTRAN	-	-	-
Total Transmission Labor Expenses	LBTRAN		$ -	$ -	$ -
Distribution Operation Labor Expense					
580 OPERATION SUPERVISION AND ENGI	LB580	F023	-	-	-
581 LOAD DISPATCHING	LB581	P362	-	-	-
582 STATION EXPENSES	LB582	P362	-	-	-
583 OVERHEAD LINE EXPENSES	LB583	P365	-	-	-
584 UNDERGROUND LINE EXPENSES	LB584	P367	-	-	-
585 STREET LIGHTING EXPENSE	LB585	P371	-	-	-
586 METER EXPENSES	LB586	P370	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	F012	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	P371	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	-	-	-
589 RENTS	LB589	PDIST	-	-	-
Total Distribution Operation Labor Expense	LBDO		$ -	$ -	$ -

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12 Months Ended
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Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Labor Expenses (Continued)									
Distribution Maintenance Labor Expense									
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	$ 4,720	-	-	-	-	-	-
591 MAINTENANCE OF STRUCTURES	LB591	P362	$ 348	-	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	LB592	P362	$ 310,795	-	-	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	LB593	P365	$ 4,678,164	-	-	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	LB594	P367	$ 105,012	-	-	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	LB595	P368	$ 42,160	-	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	P373	$ 36,321	-	-	-	-	-	-
597 MAINTENANCE OF METERS	LB597	P370	$ -	-	-	-	-	-	-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	$ 56	-	-	-	-	-	-
Total Distribution Maintenance Labor Expense	LBDM		$ 5,177,577	$ -	$ -	$ -	$ -	$ -	$ -
Total Distribution Operation and Maintenance Labor Expenses		PDIST	13,006,059	-	-	-	-	-	-
Transmission and Distribution Labor Expenses			15,002,237	-	-	-	-	-	-
Production, Transmission and Distribution Labor Expenses	LBSUB		$ 38,306,996	$ 4,555,904	$ 5,422,855	$ 3,588,555	$ 9,737,445	$ -	$ -
Customer Accounts Expense									
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	$ 1,329,439	-	-	-	-	-	-
902 METER READING EXPENSES	LB902	F025	$ 484,456	-	-	-	-	-	-
903 RECORDS AND COLLECTION	LB903	F025	$ 4,753,471	-	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	$ -	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	LB903	F025	$ 111,733	-	-	-	-	-	-
Total Customer Accounts Labor Expense	LBCA		$ 6,679,098	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expense									
907 SUPERVISION	LB907	F026	$ 107,651	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	F026	$ 106,916	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	F026	-	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	F026	-	-	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	F026	-	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	F026	20,122	-	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	LB911	F026	-	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	LB912	F026	-	-	-	-	-	-	-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	F026	-	-	-	-	-	-	-
915 MDSE-JOBBING-CONTRACT	LB915	F026	-	-	-	-	-	-	-
916 MISC SALES EXPENSE	LB916	F026	-	-	-	-	-	-	-
Total Customer Service Labor Expense	LBCS		$ 234,689	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total Labor Exp	LBSUB7		45,220,783	4,555,904	5,422,855	3,588,555	9,737,445	-	-

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Description	Name	Functional Vector	Transmission Demand Base	Transmission Demand Inter.	Transmission Demand Peak	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer
Labor Expenses (Continued)										
Distribution Maintenance Labor Expense										
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	-	-	-	-	284	-	750	2,807
591 MAINTENANCE OF STRUCTURES	LB591	P362	-	-	-	-	348	-	-	-
592 MAINTENANCE OF STATION EQUIPME	LB592	P362	-	-	-	-	310,795	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	LB593	P365	-	-	-	-	-	-	803,586	3,008,306
594 MAINTENANCE OF UNDERGROUND LIN	LB594	P367	-	-	-	-	-	-	18,038	67,528
595 MAINTENANCE OF LINE TRANSFORME	LB595	P368	-	-	-	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	P373	-	-	-	-	-	-	-	-
597 MAINTENANCE OF METERS	LB597	P370	-	-	-	-	-	-	-	-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	-	-	-	-	6	-	4	17
Total Distribution Maintenance Labor Expense	LBDM		$ -	$ -	$ -	$ -	$ 311,432	$ -	$ 822,379	$ 3,078,658
Total Distribution Operation and Maintenance Labor Expenses		PDIST	-	-	-	-	1,311,393	-	1,032,444	3,865,057
Transmission and Distribution Labor Expenses			670,317	797,872	527,989	-	1,311,393	-	1,032,444	3,865,057
Production, Transmission and Distribution Labor Expenses	LBSUB		$ 670,317	$ 797,872	$ 527,989	$ -	$ 1,311,393	$ -	$ 1,032,444	$ 3,865,057
Customer Accounts Expense										
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	-	-	-	-	-	-	-	-
902 METER READING EXPENSES	LB902	F025	-	-	-	-	-	-	-	-
903 RECORDS AND COLLECTION	LB903	F025	-	-	-	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	-	-	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	LB903	F025	-	-	-	-	-	-	-	-
Total Customer Accounts Labor Expense	LBCA		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expense										
907 SUPERVISION	LB907	F026	-	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	F026	-	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	F026	-	-	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	F026	-	-	-	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	F026	-	-	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	F026	-	-	-	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	LB911	F026	-	-	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	LB912	F026	-	-	-	-	-	-	-	-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	F026	-	-	-	-	-	-	-	-
915 MDSE-JOBBING-CONTRACT	LB915	F026	-	-	-	-	-	-	-	-
916 MISC SALES EXPENSE	LB916	F026	-	-	-	-	-	-	-	-
Total Customer Service Labor Expense	LBCS		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total Labor Exp	LBSUB7		670,317	797,872	527,989	-	1,311,393	-	1,032,444	3,865,057

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Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Labor Expenses (Continued)									
Distribution Maintenance Labor Expense									
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	170	638	20	18	0	0	33
591 MAINTENANCE OF STRUCTURES	LB591	P362	-	-	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	LB592	P362	-	-	-	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	LB593	P365	182,619	683,653	-	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	LB594	P367	4,099	15,346	-	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	LB595	P368	-	-	21,974	20,186	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	P373	-	-	-	-	-	-	36,321
597 MAINTENANCE OF METERS	LB597	P370	-	-	-	-	-	-	-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	1	4	7	6	4	3	4
Total Distribution Maintenance Labor Expense	LBDM		$ 186,890	$ 699,641	$ 22,001	$ 20,211	$ 4	$ 3	$ 36,358
Total Distribution Operation and Maintenance Labor Expenses		PDIST	234,628	878,354	1,568,007	1,440,446	997,190	785,641	892,899
Transmission and Distribution Labor Expenses			234,628	878,354	1,568,007	1,440,446	997,190	785,641	892,899
Production, Transmission and Distribution Labor Expenses	LBSUB		$ 234,628	$ 878,354	$ 1,568,007	$ 1,440,446	$ 997,190	$ 785,641	$ 892,899
Customer Accounts Expense									
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	-	-	-	-	-	-	-
902 METER READING EXPENSES	LB902	F025	-	-	-	-	-	-	-
903 RECORDS AND COLLECTION	LB903	F025	-	-	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	-	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	LB903	F025	-	-	-	-	-	-	-
Total Customer Accounts Labor Expense	LBCA		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expense									
907 SUPERVISION	LB907	F026	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	F026	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	F026	-	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	F026	-	-	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	F026	-	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	F026	-	-	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	LB911	F026	-	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	LB912	F026	-	-	-	-	-	-	-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	F026	-	-	-	-	-	-	-
915 MDSE-JOBBING-CONTRACT	LB915	F026	-	-	-	-	-	-	-
916 MISC SALES EXPENSE	LB916	F026	-	-	-	-	-	-	-
Total Customer Service Labor Expense	LBCS		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total Labor Exp	LBSUB7		234,628	878,354	1,568,007	1,440,446	997,190	785,641	892,899

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Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Labor Expenses (Continued)					
Distribution Maintenance Labor Expense					
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	-	-	-
591 MAINTENANCE OF STRUCTURES	LB591	P362	-	-	-
592 MAINTENANCE OF STATION EQUIPME	LB592	P362	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	LB593	P365	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	LB594	P367	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	LB595	P368	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	P373	-	-	-
597 MAINTENANCE OF METERS	LB597	P370	-	-	-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	-	-	-
Total Distribution Maintenance Labor Expense	LBDM		$ -	$ -	$ -
Total Distribution Operation and Maintenance Labor Expenses		PDIST	-	-	-
Transmission and Distribution Labor Expenses			-	-	-
Production, Transmission and Distribution Labor Expenses	LBSUB		$ -	$ -	$ -
Customer Accounts Expense					
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	1,329,439	-	-
902 METER READING EXPENSES	LB902	F025	484,456	-	-
903 RECORDS AND COLLECTION	LB903	F025	4,753,471	-	-
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	-	-	-
905 MISC CUST ACCOUNTS	LB903	F025	111,733	-	-
Total Customer Accounts Labor Expense	LBCA		$ 6,679,098	$ -	$ -
Customer Service Expense					
907 SUPERVISION	LB907	F026	-	107,651	-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	F026	-	106,916	-
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	F026	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	F026	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	F026	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	F026	-	20,122	-
911 DEMONSTRATION AND SELLING EXP	LB911	F026	-	-	-
912 DEMONSTRATION AND SELLING EXP	LB912	F026	-	-	-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	F026	-	-	-
915 MDSE-JOBBING-CONTRACT	LB915	F026	-	-	-
916 MISC SALES EXPENSE	LB916	F026	-	-	-
Total Customer Service Labor Expense	LBCS		$ -	$ 234,689	$ -
Sub-Total Labor Exp	LBSUB7		6,679,098	234,689	-

KENTUCKY UTILITIES
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
April 30, 2008

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Labor Expenses (Continued)									
Administrative and General Expense									
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB7	$ 10,799,153	1,087,993	1,295,029	856,981	2,325,394	-	-
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB7	$ -	-	-	-	-	-	-
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB7	$ (933,756)	(94,074)	(111,976)	(74,099)	(201,067)	-	-
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB7	$ -	-	-	-	-	-	-
924 PROPERTY INSURANCE	LB924	TUP	$ -	-	-	-	-	-	-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB7	$ 79,180	7,977	9,495	6,283	17,050	-	-
926 EMPLOYEE BENEFITS	LB926	LBSUB7	$ -	-	-	-	-	-	-
928 REGULATORY COMMISSION FEES	LB928	TUP	-	-	-	-	-	-	-
929 DUPLICATE CHARGES-CR	LB929	LBSUB7	-	-	-	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB7	-	-	-	-	-	-	-
931 RENTS AND LEASES	LB931	PGP	-	-	-	-	-	-	-
932 MAINTENANCE OF GENERAL PLANT	LB932	PGP	-	-	-	-	-	-	-
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	-	-	-	-	-	-	-
Total Administrative and General Expense	LBAG		$ 9,944,577	$ 1,001,896	$ 1,192,549	$ 789,165	$ 2,141,378	$ -	$ -
Total Operation and Maintenance Expenses	TLB		$ 55,165,360	$ 5,557,800	$ 6,615,405	$ 4,377,720	$ 11,878,822	$ -	$ -
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$ 55,165,360	$ 5,557,800	$ 6,615,405	$ 4,377,720	$ 11,878,822	$ -	$ -

KENTUCKY UTILITIES
Cost of Service Study
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Description	Name	Functional Vector	Transmission Demand Base	Transmission Demand Inter.	Transmission Demand Peak	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer
Labor Expenses (Continued)										
Administrative and General Expense										
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB7	160,078	190,540	126,089	-	313,173	-	246,557	923,012
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB7	-	-	-	-	-	-	-	-
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB7	(13,841)	(16,475)	(10,902)	-	(27,079)	-	(21,319)	(79,809)
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB7	-	-	-	-	-	-	-	-
924 PROPERTY INSURANCE	LB924	TUP	-	-	-	-	-	-	-	-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB7	1,174	1,397	924	-	2,296	-	1,808	6,768
926 EMPLOYEE BENEFITS	LB926	LBSUB7	-	-	-	-	-	-	-	-
928 REGULATORY COMMISSION FEES	LB928	TUP	-	-	-	-	-	-	-	-
929 DUPLICATE CHARGES-CR	LB929	LBSUB7	-	-	-	-	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB7	-	-	-	-	-	-	-	-
931 RENTS AND LEASES	LB931	PGP	-	-	-	-	-	-	-	-
932 MAINTENANCE OF GENERAL PLANT	LB932	PGP	-	-	-	-	-	-	-	-
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	-	-	-	-	-	-	-	-
Total Administrative and General Expense	LBAG		$ 147,410	$ 175,461	$ 116,111	$ -	$ 288,391	$ -	$ 227,046	$ 849,971
Total Operation and Maintenance Expenses	TLB		$ 817,727	$ 973,334	$ 644,100	$ -	$ 1,599,784	$ -	$ 1,259,490	$ 4,715,028
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$ 817,727	$ 973,334	$ 644,100	$ -	$ 1,599,784	$ -	$ 1,259,490	$ 4,715,028

KENTUCKY UTILITIES
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Functional Assignment and Classification

12 Months Ended
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Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Labor Expenses (Continued)									
Administrative and General Expense									
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB7	56,031	209,759	374,455	343,992	238,138	187,619	213,233
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB7	-	-	-	-	-	-	-
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB7	(4,845)	(18,137)	(32,377)	(29,744)	(20,591)	(16,223)	(18,437)
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB7	-	-	-	-	-	-	-
924 PROPERTY INSURANCE	LB924	TUP	-	-	-	-	-	-	-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB7	411	1,538	2,746	2,522	1,746	1,376	1,563
926 EMPLOYEE BENEFITS	LB926	LBSUB7	-	-	-	-	-	-	-
928 REGULATORY COMMISSION FEES	LB928	TUP	-	-	-	-	-	-	-
929 DUPLICATE CHARGES-CR	LB929	LBSUB7	-	-	-	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB7	-	-	-	-	-	-	-
931 RENTS AND LEASES	LB931	PGP	-	-	-	-	-	-	-
932 MAINTENANCE OF GENERAL PLANT	LB932	PGP	-	-	-	-	-	-	-
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	-	-	-	-	-	-	-
Total Administrative and General Expense	LBAG		$ 51,597	$ 193,160	$ 344,823	$ 316,771	$ 219,294	$ 172,772	$ 196,359
Total Operation and Maintenance Expenses	TLB		$ 286,225	$ 1,071,514	$ 1,912,830	$ 1,757,217	$ 1,216,484	$ 958,413	$ 1,089,258
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$ 286,225	$ 1,071,514	$ 1,912,830	$ 1,757,217	$ 1,216,484	$ 958,413	$ 1,089,258

KENTUCKY UTILITIES
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
April 30, 2008

Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Labor Expenses (Continued)					
Administrative and General Expense					
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB7	1,595,032	56,046	-
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB7	-	-	-
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB7	(137,916)	(4,846)	-
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB7	-	-	-
924 PROPERTY INSURANCE	LB924	TUP	-	-	-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB7	11,695	411	-
926 EMPLOYEE BENEFITS	LB926	LBSUB7	-	-	-
928 REGULATORY COMMISSION FEES	LB928	TUP	-	-	-
929 DUPLICATE CHARGES-CR	LB929	LBSUB7	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB7	-	-	-
931 RENTS AND LEASES	LB931	PGP	-	-	-
932 MAINTENANCE OF GENERAL PLANT	LB932	PGP	-	-	-
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	-	-	-
Total Administrative and General Expense	LBAG		$ 1,468,811	$ 51,611	$ -
Total Operation and Maintenance Expenses	TLB		$ 8,147,910	$ 286,300	$ -
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$ 8,147,910	$ 286,300	$ -

KENTUCKY UTILITIES
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
April 30, 2008

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Other Expenses									
Depreciation Expenses									
Steam Production	DEPRTP	PPRTL	$ 41,922,608	14,077,612	16,756,467	11,088,530	-	-	-
Hydraulic Production	DEPRDP1	PPRTL	150,640	50,585	60,211	39,844	-	-	-
Other Production	DEPRDP2	PPRTL	14,711,364	4,940,076	5,880,132	3,891,156	-	-	-
Transmission - Kentucky System Property	DEPRDP3	PTRAN	12,173,047	-	-	-	-	-	-
Transmission - Virginia Property	DEPRDP4	PTRAN	216,042	-	-	-	-	-	-
Distribution	DEPRDP5	PDIST	30,450,891	-	-	-	-	-	-
General Plant	DEPRDP6	PGP	4,599,109	874,302	1,040,675	688,663	-	-	-
Intangible Plant	DEPRAADJ	PINT	5,512,422	1,047,925	1,247,337	825,420	-	-	-
Total Depreciation Expense	TDEPR		$ 109,736,123	20,990,500	24,984,821	16,533,613	-	-	-
Regulatory Credits and Accretion Expenses									
Production Plant	ACRTPP	PPRTL	$ (255,036)	(85,641)	(101,938)	(67,457)	-	-	-
Transmission Plant	ACRTTP	PTRAN	(156)	-	-	-	-	-	-
Distribution Plant		PDIST	(182)	-	-	-	-	-	-
Total Regulatory Credits and Accretion Expenses	TACRT		$ (255,373)	$ (85,641)	$ (101,938)	$ (67,457)	$ -	$ -	$ -
Property Taxes	PTAX	TUP	$ 10,473,065	2,192,376	2,609,567	1,726,871	-	-	-
Other Taxes	OTAX	TUP	$ 6,763,965	1,415,933	1,685,373	1,115,289	-	-	-
Gain Disposition of Allowances	GAIN	F013	$ (504,602)	-	-	-	(504,602)	-	-
Interest	INTLTD	TUP	$ 56,236,895	11,772,334	14,012,513	9,272,728	-	-	-
Other Expenses	OT	TUP	$ -	-	-	-	-	-	-
Total Other Expenses	TOE		$ 182,450,072	$ 36,285,501	$ 43,190,336	$ 28,581,045	$ (504,602)	$ -	$ -
Total Cost of Service (O&M + Other Expenses)			$ 971,951,308	$ 59,377,937	$ 70,677,074	$ 46,770,293	$ 608,450,887	$ -	$ -
Non-Operating Items									
Non-Operating Margins - Interest			-						
AFUDC			-						
Income (Loss) from Equity Investments			-						
Non-Operating Margins - Other			-						
Generation and Transmission Capital Credits			-						
Other Capital Credits and Patronage Dividends			-						
Extraordinary Items			-						
Long Term Debt Service Requirements			-						

KENTUCKY UTILITIES
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Functional Assignment and Classification

12 Months Ended
April 30, 2008

Description	Name	Functional Vector	Transmission Demand Base	Transmission Demand Inter.	Transmission Demand Peak	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer
Other Expenses										
Depreciation Expenses										
Steam Production	DEPRTP	PPRTL	-	-	-	-	-	-	-	-
Hydraulic Production	DEPRDP1	PPRTL	-	-	-	-	-	-	-	-
Other Production	DEPRDP2	PPRTL	-	-	-	-	-	-	-	-
Transmission - Kentucky System Property	DEPRDP3	PTRAN	4,087,709	4,865,567	3,219,771	-	-	-	-	-
Transmission - Virginia Property	DEPRDP4	PTRAN	72,547	86,352	57,143	-	-	-	-	-
Distribution	DEPRDP5	PDIST	-	-	-	-	3,070,345	-	2,417,245	9,049,199
General Plant	DEPRDP6	PGP	195,050	232,167	153,636	-	142,635	-	112,295	420,387
Intangible Plant	DEPRAADJ	PINT	233,784	278,272	184,145	-	170,960	-	134,595	503,869
Total Depreciation Expense	TDEPR		4,589,091	5,462,357	3,614,695	-	3,383,940	-	2,664,134	9,973,455
Regulatory Credits and Accretion Expenses										
Production Plant	ACRTPP	PPRTL	-	-	-	-	-	-	-	-
Transmission Plant	ACRTTP	PTRAN	(52)	(62)	(41)	-	(18)	-	(14)	(54)
Distribution Plant		PDIST	-	-	-					
Total Regulatory Credits and Accretion Expenses	TACRT		$ (52)	$ (62)	$ (41)	$ -	$ (18)	$ -	$ (14)	$ (54)
Property Taxes	PTAX	TUP	387,516	461,258	305,236	-	281,338	-	221,494	829,186
Other Taxes	OTAX	TUP	250,275	297,900	197,135	-	181,701	-	143,051	535,525
Gain Disposition of Allowances	GAIN	F013	-	-	-	-	-	-	-	-
Interest	INTLTD	TUP	2,080,835	2,476,801	1,639,014	-	1,510,694	-	1,189,350	4,452,453
Other Expenses	OT	TUP	-	-	-	-	-	-	-	-
Total Other Expenses	TOE		$ 7,307,666	$ 8,698,255	$ 5,756,038	$ -	$ 5,357,654	$ -	$ 4,218,015	$ 15,790,565
Total Cost of Service (O&M + Other Expenses)			$ 13,940,153	$ 16,592,850	$ 10,980,257	$ -	$ 10,320,401	$ -	$ 10,291,980	$ 38,529,066

Non-Operating Items
Non-Operating Margins - Interest
AFUDC
Income (Loss) from Equity Investments
Non-Operating Margins - Other
Generation and Transmission Capital Credits
Other Capital Credits and Patronage Dividends
Extraordinary Items

Long Term Debt Service Requirements

KENTUCKY UTILITIES
Cost of Service Study
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12 Months Ended
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Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Other Expenses									
Depreciation Expenses									
Steam Production	DEPRTP	PPRTL	-	-	-	-	-	-	-
Hydraulic Production	DEPRDP1	PPRTL	-	-	-	-	-	-	-
Other Production	DEPRDP2	PPRTL	-	-	-	-	-	-	-
Transmission - Kentucky System Property	DEPRDP3	PTRAN	-	-	-	-	-	-	-
Transmission - Virginia Property	DEPRDP4	PTRAN	-	-	-	-	-	-	-
Distribution	DEPRDP5	PDIST	549,331	2,056,476	3,671,151	3,372,495	2,334,706	1,839,411	2,090,531
General Plant	DEPRDP6	PGP	25,520	95,535	170,546	156,672	108,460	85,451	97,117
Intangible Plant	DEPRAADJ	PINT	30,587	*114,507*	*204,414*	*187,784*	*129,999*	*102,420*	*116,403*
Total Depreciation Expense	TDEPR		605,438	2,266,518	4,046,110	3,716,951	2,573,166	2,027,282	2,304,052
Regulatory Credits and Accretion Expenses									
Production Plant	ACRTPP	PPRTL	-	-	-	-	-	-	-
Transmission Plant	ACRTTP	PTRAN	-	-	-	-	-	-	-
Distribution Plant		PDIST	(3)	(12)	(22)	(20)	(14)	(11)	(12)
Total Regulatory Credits and Accretion Expenses	TACRT		$ (3)	$ (12)	$ (22)	$ (20)	$ (14)	$ (11)	$ (12)
Property Taxes	PTAX	TUP	50,336	188,437	336,391	309,025	213,931	168,547	191,557
Other Taxes	OTAX	TUP	32,509	*121,701*	*217,256*	*199,582*	*138,166*	108,855	123,716
Gain Disposition of Allowances	GAIN	F013	-	-	-	-	-	-	-
Interest	INTLTD	TUP	270,286	1,011,842	1,806,306	1,659,360	1,148,739	905,040	1,028,599
Other Expenses	OT	TUP	-	-	-	-	-	-	-
Total Other Expenses	TOE		$ 958,565	$ 3,588,485	$ 6,406,041	$ 5,884,896	$ 4,073,988	$ 3,209,713	$ 3,647,911
Total Cost of Service (O&M + Other Expenses)			$ 2,338,904	$ 8,755,924	$ 9,239,103	$ 8,487,483	$ 5,839,078	$ 11,145,634	$ 5,223,404

Non-Operating Items
Non-Operating Margins - Interest
AFUDC
Income (Loss) from Equity Investments
Non-Operating Margins - Other
Generation and Transmission Capital Credits
Other Capital Credits and Patronage Dividends
Extraordinary Items

Long Term Debt Service Requirements

KENTUCKY UTILITIES
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
April 30, 2008

Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Other Expenses					
Depreciation Expenses					
Steam Production	DEPRTP	PPRTL	-	-	-
Hydraulic Production	DEPRDP1	PPRTL	-	-	-
Other Production	DEPRDP2	PPRTL	-	-	-
Transmission - Kentucky System Property	DEPRDP3	PTRAN	-	-	-
Transmission - Virginia Property	DEPRDP4	PTRAN	-	-	-
Distribution	DEPRDP5	PDIST	-	-	-
General Plant	DEPRDP6	PGP	-	-	-
Intangible Plant	DEPRAADJ	PINT	-	-	-
Total Depreciation Expense	TDEPR		-	-	-
Regulatory Credits and Accretion Expenses					
Production Plant	ACRTPP	PPRTL	-	-	-
Transmission Plant	ACRTTP	PTRAN	-	-	-
Distribution Plant		PDIST	-	-	-
Total Regulatory Credits and Accretion Expenses	TACRT		$ -	$ -	$ -
Property Taxes	PTAX	TUP	-	-	-
Other Taxes	OTAX	TUP	-	-	-
Gain Disposition of Allowances	GAIN	F013	-	-	-
Interest	INTLTD	TUP	-	-	-
Other Expenses	OT	TUP	-	-	-
Total Other Expenses	TOE		$ -	$ -	$ -
Total Cost of Service (O&M + Other Expenses)			$ 28,463,115	$ 6,527,764	$ -

Non-Operating Items
Non-Operating Margins - Interest
AFUDC
Income (Loss) from Equity Investments
Non-Operating Margins - Other
Generation and Transmission Capital Credits
Other Capital Credits and Patronage Dividends
Extraordinary Items

Long Term Debt Service Requirements

KENTUCKY UTILITIES
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
April 30, 2008

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Functional Vectors									
Station Equipment	F001		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Poles, Towers and Fixtures	F002		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Overhead Conductors and Devices	F003		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Underground Conductors and Devices	F004		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Line Transformers	F005		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Services	F006		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Meters	F007		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Street Lighting	F008		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Meter Reading	F009		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Billing	F010		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Transmission	F011		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Load Management	F012		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Production Plant	F017		1.000000	0.335800	0.399700	0.264500	0.000000	0.000000	0.000000
Provar	PROVAR		1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
Fuel	F018		1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
Steam Generation Operation Labor	F019		10,485,257	2,937,606.64	3,496,609	2,313,868	1,737,173	-	-
PROFIX	PROFIX		1.000000	0.335800	0.399700	0.264500	0.000000	0.000000	0.000000
Steam Generation Maintenance Labor	F020		5,585,749	264,409	314,724	208,267	4,798,349	-	-
Hydraulic Generation Operation Labor	F021		2,262	760	904	598	-	-	-
Hydraulic Generation Maintenance Labor	F022		90,866	9,960	11,856	7,845	61,205	-	-
Distribution Operation Labor	F023		7,031,202	-	-	-	-	-	-
Distribution Maintenance Labor	F024		5,172,508	-	-	-	-	-	-
Customer Accounts Expense	F025		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Service Expense	F026		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Advances	F027		470,320,061	-	-	-	-	-	-
Purchase Power Demand		F017	15,031,258	5,047,496	6,007,994	3,975,768	-	-	-
Purchase Power Energy		F018	142,211,384	-	-	-	142,211,384	-	-
Purchased Power Expenses	OMPP	F017	157,242,642	5,047,496	6,007,994	3,975,768	142,211,384	-	-
Gain Disposition of Allowances	F013		1.00000	-	-	-	1.000000	-	-
Intallations on Customer Premises - Accum Depr	F014		1.00000	-	-	-	-	-	-
Generators -Energy	F015		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
	Energy		1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
Internally Generated Functional Vectors									
Total Prod, Trans, and Dist Plant		PT&D	1.000000	0.190102	0.226277	0.149738	-	-	-
Total Distribution Plant		PDIST	1.000000	-	-	-	-	-	-
Total Transmission Plant		PTRAN	1.000000	-	-	-	-	-	-
Operation and Maintenance Expenses Less Purchase Power		OMLPP	1.000000	0.028540	0.033971	0.022480	0.738217	-	-
Total Plant in Service		TPIS	1.000000	0.190102	0.226277	0.149738	-	-	-
Total Operation and Maintenance Expenses (Labor)		TLB	1.000000	0.100748	0.119920	0.079356	0.215331	-	-
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	1.000000	0.021655	0.025776	0.017057	0.822852	-	-
Total Steam Power Operation Expenses (Labor)		LBSUB1	1.000000	0.280165	0.333479	0.220678	0.165678	-	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	1.000000	0.047336	0.056344	0.037285	0.859034	-	-
Total Hydraulic Power Operation Expenses (Labor)		LBSUB3	1.000000	0.335800	0.399700	0.264500	-	-	-
Total Hydraulic Power Generation Maint. Expense (Labor)		LBSUB4	1.000000	0.109615	0.130474	0.086340	0.673571	-	-
Total Other Power Generation Expenses (Labor)		LBSUB5	1.000000	0.335800	0.399700	0.264500	-	-	-
Total Transmission Labor Expenses		LBTRAN	1.000000	-	-	-	-	-	-
Total Distribution Operation Labor Expense		LBDO	1.000000	-	-	-	-	-	-
Total Distribution Maintenance Labor Expense		LBDM	1.000000	-	-	-	-	-	-
Sub-Total Labor Exp		LBSUB7	1.000000	0.100748	0.119920	0.079356	0.215331	-	-
Total General Plant		PGP	1.000000	0.190102	0.226277	0.149738	-	-	-
Total Production Plant		PPRTL	1.000000	0.335800	0.399700	0.264500	-	-	-
Total Intangible Plant		PINT	1.000000	0.190102	0.226277	0.149738	-	-	-

KENTUCKY UTILITIES
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Functional Assignment and Classification

12 Months Ended
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Description	Name	Functional Vector	Transmission Demand Base	Transmission Demand Inter.	Transmission Demand Peak	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer
Functional Vectors										
Station Equipment	F001		0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
Poles, Towers and Fixtures	F002		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.171774	0.643053
Overhead Conductors and Devices	F003		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.171774	0.643053
Underground Conductors and Devices	F004		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.171774	0.643053
Line Transformers	F005		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Services	F006		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Meters	F007		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Street Lighting	F008		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Meter Reading	F009		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Billing	F010		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Transmission	F011		0.335800	0.399700	0.264500	0.000000	0.000000	0.000000	0.000000	0.000000
Load Management	F012		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Production Plant	F017		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Provar	PROVAR		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Fuel	F018		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Steam Generation Operation Labor	F019		-	-	-	-	-	-	-	-
PROFIX	PROFIX		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Steam Generation Maintenance Labor	F020		-	-	-	-	-	-	-	-
Hydraulic Generation Operation Labor	F021		-	-	-	-	-	-	-	-
Hydraulic Generation Maintenance Labor	F022		-	-	-	-	-	-	-	-
Distribution Operation Labor	F023		-	-	-	-	1,135,285	-	446,948	1,673,195
Distribution Maintenance Labor	F024		-	-	-	-	310,800	-	821,629	3,075,851
Customer Accounts Expense	F025		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Service Expense	F026		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Advances	F027		-	-	-	-	-	-	80,788,687	302,440,591
Purchase Power Demand		F017	-	-	-	-	-	-	-	-
Purchase Power Energy		F018	-	-	-	-	-	-	-	-
Purchased Power Expenses	OMPP	F017	-	-	-	-	-	-	-	-
Gain Disposition of Allowances	F013		-	-	-	-	-	-	-	-
Intallations on Customer Premises - Accum Depr	F014		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Generators -Energy	F015		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
	Energy									
Internally Generated Functional Vectors										
Total Prod, Trans, and Dist Plant		PT&D	0.042410	0.050481	0.033406	-	0.031014	-	0.024417	0.091406
Total Distribution Plant		PDIST	-	-	-	-	0.100829	-	0.079382	0.297174
Total Transmission Plant		PTRAN	0.335800	0.399700	0.264500	-	-	-	-	-
Operation and Maintenance Expenses Less Purchase Power		OMLPP	0.010490	0.012486	0.008263	-	0.007849	-	0.009607	0.035964
Total Plant in Service		TPIS	0.042410	0.050481	0.033406	-	0.031014	-	0.024417	0.091406
Total Operation and Maintenance Expenses (Labor)		TLB	0.014823	0.017644	0.011676	-	0.029000	-	0.022831	0.085471
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	0.007473	0.008895	0.005886	-	0.004296	-	0.006366	0.023833
Total Steam Power Operation Expenses (Labor)		LBSUB1	-	-	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	-	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses (Labor)		LBSUB3	-	-	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense (Labor)		LBSUB4	-	-	-	-	-	-	-	-
Total Other Power Generation Expenses (Labor)		LBSUB5	-	-	-	-	-	-	-	-
Total Transmission Labor Expenses		LBTRAN	0.3358000	0.3997000	0.2645000	-	-	-	-	-
Total Distribution Operation Labor Expense		LBDO	-	-	-	-	0.161464	-	0.063566	0.237967
Total Distribution Maintenance Labor Expense		LBDM	-	-	-	-	0.060150	-	0.158835	0.594614
Sub-Total Labor Exp		LBSUB7	0.014823	0.017644	0.011676	-	0.029000	-	0.022831	0.085471
Total General Plant		PGP	0.042410	0.050481	0.033406	-	0.031014	-	0.024417	0.091406
Total Production Plant		PPRTL	-	-	-	-	-	-	-	-
Total Intangible Plant		PINT	0.042410	0.050481	0.033406	-	0.031014	-	0.024417	0.091406

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Functional Assignment and Classification

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Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Functional Vectors									
Station Equipment	F001		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Poles, Towers and Fixtures	F002		0.039036	0.146137	0.000000	0.000000	0.000000	0.000000	0.000000
Overhead Conductors and Devices	F003		0.039036	0.146137	0.000000	0.000000	0.000000	0.000000	0.000000
Underground Conductors and Devices	F004		0.039036	0.146137	0.000000	0.000000	0.000000	0.000000	0.000000
Line Transformers	F005		0.000000	0.000000	0.521200	0.478800	0.000000	0.000000	0.000000
Services	F006		0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
Meters	F007		0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
Street Lighting	F008		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
Meter Reading	F009		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Billing	F010		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Transmission	F011		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Load Management	F012		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Production Plant	F017		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Provar	PROVAR		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Fuel	F018		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Steam Generation Operation Labor	F019		-	-	-	-	-	-	-
PROFIX	PROFIX		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Steam Generation Maintenance Labor	F020		-	-	-	-	-	-	-
Hydraulic Generation Operation Labor	F021		-	-	-	-	-	-	-
Hydraulic Generation Maintenance Labor	F022		-	-	-	-	-	-	-
Distribution Operation Labor	F023		101,571	380,242	227,985	209,438	144,990	2,573,022	138,525
Distribution Maintenance Labor	F024		186,719	699,003	21,981	20,192	4	3	36,325
Customer Accounts Expense	F025		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Service Expense	F026		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Advances	F027		18,359,636	68,731,147	-	-	-	-	-
Purchase Power Demand		F017	-	-	-	-	-	-	-
Purchase Power Energy		F018	-	-	-	-	-	-	-
Purchased Power Expenses	OMPP	F017	-	-	-	-	-	-	-
Gain Disposition of Allowances	F013		-	-	-	-	-	-	-
Intallations on Customer Premises - Accum Depr	F014		-	-	-	-	-	-	-
Generators -Energy	F015		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
	Energy		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Internally Generated Functional Vectors									
Total Prod, Trans, and Dist Plant		PT&D	0.005549	0.020773	0.037082	0.034066	0.023583	0.018580	0.021116
Total Distribution Plant		PDIST	0.018040	0.067534	0.120560	0.110752	0.076671	0.060406	0.068653
Total Transmission Plant		PTRAN	-	-	-	-	-	-	-
Operation and Maintenance Expenses Less Purchase Power		OMLPP	0.002183	0.008173	0.004481	0.004116	0.002792	0.012552	0.002492
Total Plant in Service		TPIS	0.005549	0.020773	0.037082	0.034066	0.023583	0.018580	0.021116
Total Operation and Maintenance Expenses (Labor)		TLB	0.005188	0.019424	0.034674	0.031854	0.022052	0.017373	0.019745
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	0.001447	0.005416	0.000867	0.000797	0.000501	0.009408	0.000442
Total Steam Power Operation Expenses (Labor)		LBSUB1	-	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses (Labor)		LBSUB3	-	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense (Labor)		LBSUB4	-	-	-	-	-	-	-
Total Other Power Generation Expenses (Labor)		LBSUB5	-	-	-	-	-	-	-
Total Transmission Labor Expenses		LBTRAN	-	-	-	-	-	-	-
Total Distribution Operation Labor Expense		LBDO	0.014446	0.054079	0.032425	0.029787	0.020621	0.365943	0.019701
Total Distribution Maintenance Labor Expense		LBDM	0.036096	0.135129	0.004249	0.003904	0.000001	0.000001	0.007022
Sub-Total Labor Exp		LBSUB7	0.005188	0.019424	0.034674	0.031854	0.022052	0.017373	0.019745
Total General Plant		PGP	0.005549	0.020773	0.037082	0.034066	0.023583	0.018580	0.021116
Total Production Plant		PPRTL	-	-	-	-	-	-	-
Total Intangible Plant		PINT	0.005549	0.020773	0.037082	0.034066	0.023583	0.018580	0.021116

KENTUCKY UTILITIES
Cost of Service Study
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Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Functional Vectors					
Station Equipment	F001		0.000000	0.000000	0.000000
Poles, Towers and Fixtures	F002		0.000000	0.000000	0.000000
Overhead Conductors and Devices	F003		0.000000	0.000000	0.000000
Underground Conductors and Devices	F004		0.000000	0.000000	0.000000
Line Transformers	F005		0.000000	0.000000	0.000000
Services	F006		0.000000	0.000000	0.000000
Meters	F007		0.000000	0.000000	0.000000
Street Lighting	F008		0.000000	0.000000	0.000000
Meter Reading	F009		0.000000	1.000000	0.000000
Billing	F010		0.000000	1.000000	0.000000
Transmission	F011		0.000000	0.000000	0.000000
Load Management	F012		0.000000	0.000000	1.000000
Production Plant	F017		0.000000	0.000000	0.000000
Provar	PROVAR		0.000000	0.000000	0.000000
Fuel	F018		0.000000	0.000000	0.000000
Steam Generation Operation Labor	F019		-	-	-
PROFIX	PROFIX		0.000000	0.000000	0.000000
Steam Generation Maintenance Labor	F020		-	-	-
Hydraulic Generation Operation Labor	F021		-	-	-
Hydraulic Generation Maintenance Labor	F022		-	-	-
Distribution Operation Labor	F023		-	-	-
Distribution Maintenance Labor	F024		-	-	-
Customer Accounts Expense	F025		1.000000	0.000000	0.000000
Customer Service Expense	F026		0.000000	1.000000	0.000000
Customer Advances	F027		-	-	-
Purchase Power Demand		F017	-	-	-
Purchase Power Energy		F018	-	-	-
Purchased Power Expenses	OMPP	F017	-	-	-
Gain Disposition of Allowances	F013		-	-	-
Intallations on Customer Premises - Accum Depr	F014		1.00000	-	-
Generators -Energy	F015		0.000000	0.000000	0.000000
	Energy		0.000000	0.000000	0.000000
Internally Generated Functional Vectors					
Total Prod, Trans, and Dist Plant		PT&D	-	-	-
Total Distribution Plant		PDIST	-	-	-
Total Transmission Plant		PTRAN	-	-	-
Operation and Maintenance Expenses Less Purchase Power		OMLPP	0.045018	0.010325	-
Total Plant in Service		TPIS	-	-	-
Total Operation and Maintenance Expenses (Labor)		TLB	0.147700	0.005190	-
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	0.028424	0.008611	-
Total Steam Power Operation Expenses (Labor)		LBSUB1	-	-	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	-	-	-
Total Hydraulic Power Operation Expenses (Labor)		LBSUB3	-	-	-
Total Hydraulic Power Generation Maint. Expense (Labor)		LBSUB4	-	-	-
Total Other Power Generation Expenses (Labor)		LBSUB5	-	-	-
Total Transmission Labor Expenses		LBTRAN	-	-	-
Total Distribution Operation Labor Expense		LBDO	-	-	-
Total Distribution Maintenance Labor Expense		LBDM	-	-	-
Sub-Total Labor Exp		LBSUB7	0.147700	0.005190	-
Total General Plant		PGP	-	-	-
Total Production Plant		PPRTL	-	-	-
Total Intangible Plant		PINT	-	-	-

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KENTUCKY UTILITIES
Cost of Service Study
Class Allocation
12 Months Ended
April 30, 2008

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Secondary GSS	General Service Primary GSP
Plant in Service							
Power Production Plant							
Production Demand - Base	TPIS	PLPPDB	BDEM	$ 650,118,321	$ 227,781,909	$ 63,786,807	$ 1,484,219
Production Demand - Inter.	TPIS	PLPPDI	PPWDA	$ 773,830,533	$ 408,204,208	$ 59,825,111	$ 5,116,238
Production Demand - Peak	TPIS	PLPPDP	PPSDA	$ 512,079,500	$ 213,124,832	$ 56,678,203	$ 3,125,295
Production Energy - Base	TPIS	PLPPEB	E01	$ -	$ -	$ -	$ -
Production Energy - Inter.	TPIS	PLPPEI	E01	$ -	$ -	$ -	$ -
Production Energy - Peak	TPIS	PLPPEP	E01	$ -	$ -	$ -	$ -
Total Power Production Plant		PLPPT		$ 1,936,028,354	$ 849,110,949	$ 180,290,120	$ 9,725,752
Transmission Plant							
Transmission Demand - Base	TPIS	PLTRB	BDEM	$ 145,036,614	$ 50,816,468	$ 14,230,367	$ 331,118
Transmission Demand - Inter.	TPIS	PLTRI	PPWDA	$ 172,635,898	$ 91,067,355	$ 13,346,542	$ 1,141,395
Transmission Demand - Peak	TPIS	PLTRP	PPSDA	$ 114,241,169	$ 47,546,582	$ 12,644,490	$ 697,230
Total Transmission Plant		PLTRT		$ 431,913,681	$ 189,430,405	$ 40,221,399	$ 2,169,744
Distribution Poles							
Specific	TPIS	PLDPS	NCPP	$ -	$ -	$ -	$ -
Distribution Substation							
General	TPIS	PLDSG	NCPP	$ 106,061,321	$ 54,024,499	$ 11,128,695	$ 623,122
Distribution Primary & Secondary Lines							
Primary Specific	TPIS	PLDPLS	NCPP	$ -	$ -	$ -	$ -
Primary Demand	TPIS	PLDPLD	NCPP	$ 83,500,770	$ 42,532,821	$ 8,761,484	$ 490,576
Primary Customer	TPIS	PLDPLC	YECust08	$ 312,593,547	$ 246,428,442	$ 46,838,399	$ 42,814
Secondary Demand	TPIS	PLDSLD	SICD	$ 18,975,970	$ 11,544,684	$ 5,820,703	$ -
Secondary Customer	TPIS	PLDSLC	YECust07	$ 71,038,457	$ 56,057,662	$ 10,654,822	$ -
Total Distribution Primary & Secondary Lines		PLDLT		$ 486,108,745	$ 356,563,609	$ 72,075,407	$ 533,390
Distribution Line Transformers							
Demand	TPIS	PLDLTD	SICD	$ 126,815,425	$ 77,152,522	$ 38,899,457	$ -
Customer	TPIS	PLDLTC	YECust07	$ 116,498,725	$ 91,931,136	$ 17,473,256	$ -
Total Line Transformers		PLDLTT		$ 243,314,150	$ 169,083,658	$ 56,372,713	$ -
Distribution Services							
Customer	TPIS	PLDSC	C02	$ 80,649,578	$ 47,420,097	$ 8,944,381	$ -
Distribution Meters							
Customer	TPIS	PLDMC	C03	$ 63,540,194	$ 39,554,107	$ 17,450,824	$ 42,237
Distribution Street & Customer Lighting							
Customer	TPIS	PLDSCL	YECust04	$ 72,214,857	$ -	$ -	$ -
Customer Accounts Expense							
Customer	*TPIS*	*PLCAE*	*YECust05*	$ -	$ -	$ -	$ -
Customer Service & Info.							
Customer	TPIS	PLCSI	YECust06	$ -	$ -	$ -	$ -
Sales Expense							
Customer	TPIS	PLSEC	YECust06	$ -	$ -	$ -	$ -
Total		PLT		$ 3,419,830,881	$ 1,705,187,324	$ 386,483,519	$ 13,094,243

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation
12 Months Ended
April 30, 2008

Description	Ref	Name	Allocation Vector	All Electric School AES	Combined Light & Power LPS	Combined Light & Power LPP	Combined Light & Power LPT	Small Time-of-Day Secondary STODS	Small Time-of-Day Primary STODP	Large Comm/Ind TOD Primary LCIP	Large Comm/Ind TOD Transmission LCIT
Plant in Service											
Power Production Plant											
Production Demand - Base	TPIS	PLPPDB	BDEM	$ 4,624,897	$ 133,104,865	$ 55,160,918	$ 882,361	$ 8,638,096	$ 538,044	$ 93,263,354	$ 27,818,601
Production Demand - Inter.	TPIS	PLPPDI	PPWDA	$ 9,537,833	$ 113,936,262	$ 44,197,669	$ 1,022,758	$ 5,460,369	$ 538,160	$ 75,833,368	$ 22,868,970
Production Demand - Peak	TPIS	PLPPDP	PPSDA	$ 3,488,271	$ 97,996,494	$ 37,105,578	$ 661,955	$ 4,884,135	$ 298,851	$ 58,509,329	$ 15,694,913
Production Energy - Base	TPIS	PLPPEB	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Inter.	TPIS	PLPPEI	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Peak	TPIS	PLPPEP	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		PLPPT		$ 17,651,000	$ 345,037,621	$ 136,464,165	$ 2,567,073	$ 18,980,601	$ 1,375,074	$ 227,606,051	$ 66,382,483
Transmission Plant											
Transmission Demand - Base	TPIS	PLTRB	BDEM	$ 1,031,781	$ 29,694,716	$ 12,305,985	$ 192,386	$ 1,480,484	$ 120,034	$ 20,806,368	$ 6,206,125
Transmission Demand - Inter.	TPIS	PLTRI	PPWDA	$ 2,127,820	$ 25,418,342	$ 9,860,175	$ 228,169	$ 1,218,168	$ 120,064	$ 16,917,866	$ 5,101,899
Transmission Demand - Peak	TPIS	PLTRP	PPSDA	$ 778,207	$ 21,862,297	$ 8,277,981	$ 152,139	$ 1,089,615	$ 66,671	$ 13,053,001	$ 3,501,420
Total Transmission Plant		PLTRT		$ 3,937,808	$ 76,975,355	$ 30,444,151	$ 572,695	$ 3,788,247	$ 306,769	$ 50,777,235	$ 14,809,444
Distribution Poles											
Specific	TPIS	PLDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation											
General	TPIS	PLDSG	NCPP	$ 1,117,239	$ 17,066,230	$ 6,702,746	$ -	$ 744,905	$ 53,492	$ 10,131,463	$ -
Distribution Primary & Secondary Lines											
Primary Specific	TPIS	PLDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TPIS	PLDPLD	NCPP	$ 879,588	$ 13,436,032	$ 5,276,989	$ -	$ 586,455	$ 42,114	$ 7,976,376	$ -
Primary Customer	TPIS	PLDPLC	YECust08	$ 184,338	$ 5,177,508	$ 206,339	$ 1,189	$ 30,327	$ 1,189	$ 23,785	$ 4,162
Secondary Demand	TPIS	PLDSLD	SICD	$ 116,328	$ 1,400,841	$ -	$ -	$ 78,119	$ -	$ -	$ -
Secondary Customer	TPIS	PLDSLC	YECust07	$ 41,933	$ 1,177,762	$ -	$ -	$ 6,899	$ 271	$ -	$ -
Total Distribution Primary & Secondary Lines		PLDLT		$ 1,222,187	$ 21,192,164	$ 5,483,328	$ 1,189	$ 701,798	$ 43,574	$ 8,000,161	$ 4,162
Distribution Line Transformers											
Demand	TPIS	PLDLTD	SICD	$ 777,414	$ 9,361,751	$ -	$ -	$ 522,063	$ -	$ -	$ -
Customer	TPIS	PLDLTC	YECust07	$ 68,768	$ 1,931,490	$ -	$ -	$ 11,313	$ 444	$ -	$ -
Total Line Transformers		PLDLTT		$ 846,182	$ 11,293,241	$ -	$ -	$ 533,377	$ 444	$ -	$ -
Distribution Services											
Customer	TPIS	PLDSC	C02	$ 503,737	$ 23,773,157	$ -	$ -	$ 8,228	$ -	$ -	$ -
Distribution Meters											
Customer	TPIS	PLDMC	C03	$ 135,294	$ 5,018,263	$ 201,953	$ 1,150	$ 14,931	$ 579	$ 23,029	$ 4,644
Distribution Street & Customer Lighting											
Customer	TPIS	PLDSCL	YECust04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
Customer Accounts Expense											
Customer	TPIS	PLCAE	YECust05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.											
Customer	TPIS	PLCSI	YECust06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense											
Customer	TPIS	PLSEC	YECust06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		PLT		$ 25,413,448	$ 500,358,050	$ 179,296,344	$ 3,142,107	$ 22,772,085	$ 1,779,931	$ 296,537,940	$ 81,200,733

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Description	Ref	Name	Allocation Vector	Coal Mining Power Primary MPP	Coal Mining Power Transmission MPT	Large Power Mine Power TOD Primary LMPP	Large Power Mine Power TOD Transmission LMPT	Large Industrial Time-of-Day LITOD	Street Lighting SL	Decorative Street Lighting SLDEC	Private Outdoor Lighting POL	Customer Outdoor Lighting OL
Plant in Service												
Power Production Plant												
Production Demand - Base	TPIS	PLPPDB	BDEM	$ 3,732,785	$ 2,282,360	$ 2,958,655	$ 8,663,803	$ 12,843,972	$ 1,466,914	$ 123,430	$ 1,099,940	$ 1,682,590
Production Demand - Inter.	TPIS	PLPPDI	PPWDA	$ 5,307,957	$ 2,748,007	$ 3,446,717	$ 7,239,376	$ 7,149,177	$ 470,179	$ 39,508	$ 352,076	$ 538,574
Production Demand - Peak	TPIS	PLPPDP	PPSDA	$ 3,363,545	$ 2,076,688	$ 1,985,088	$ 6,197,369	$ 6,868,955	$ -	$ -	$ -	$ -
Production Energy - Base	TPIS	PLPPEB	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Inter.	TPIS	PLPPEI	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Peak	TPIS	PLPPEP	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		PLPPT		$ 12,404,287	$ 7,105,055	$ 8,390,460	$ 22,300,348	$ 26,862,103	$ 1,939,093	$ 162,939	$ 1,452,016	$ 2,221,164
Transmission Plant												
Transmission Demand - Base	TPIS	PLTRB	BDEM	$ 832,757	$ 509,178	$ 660,054	$ 1,977,405	$ 2,865,398	$ 327,704	$ 27,536	$ 245,389	$ 375,373
Transmission Demand - Inter.	TPIS	PLTRI	PPWDA	$ 1,184,166	$ 612,614	$ 768,937	$ 1,615,051	$ 1,594,929	$ 104,893	$ 8,814	$ 78,546	$ 120,152
Transmission Demand - Peak	TPIS	PLTRP	PPSDA	$ 750,382	$ 463,294	$ 442,859	$ 1,382,587	$ 1,532,413	$ -	$ -	$ -	$ -
Total Transmission Plant		PLTRT		$ 2,767,305	$ 1,585,085	$ 1,871,850	$ 4,975,044	$ 5,992,738	$ 432,597	$ 36,350	$ 323,934	$ 495,525
Distribution Poles												
Specific	TPIS	PLDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation												
General	TPIS	PLDSG	NCPP	$ 761,202	$ -	$ 522,136	$ -	$ 3,031,286	$ 51,811	$ 4,354	$ 38,797	$ 59,347
Distribution Primary & Secondary Lines												
Primary Specific	TPIS	PLDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TPIS	PLDPLD	NCPP	$ 599,285	$ -	$ 411,071	$ -	$ 2,386,494	$ 40,790	$ 3,428	$ 30,544	$ 46,723
Primary Customer	TPIS	PLDPLC	YECust06	$ 18,434	$ 7,136	$ 1,764	$ 3,568	$ 595	$ 4,660,438	$ 540,856	$ 4,660,438	$ 3,761,808
Secondary Demand	TPIS	PLDSLD	SICD	$ -	$ -	$ -	$ -	$ -	$ 5,136	$ 432	$ 3,846	$ 5,883
Secondary Customer	TPIS	PLDSLC	YECust07	$ -	$ -	$ -	$ -	$ -	$ 1,060,159	$ 123,034	$ 1,060,159	$ 855,738
Total Distribution Primary & Secondary Lines		PLDLT		$ 617,719	$ 7,136	$ 412,855	$ 3,568	$ 2,367,069	$ 5,766,522	$ 667,749	$ 5,754,986	$ 4,670,152
Distribution Line Transformers												
Demand	TPIS	PLDLTD	SICD	$ -	$ -	$ -	$ -	$ -	$ 34,321	$ 2,884	$ 25,700	$ 39,314
Customer	TPIS	PLDLTC	YECust07	$ -	$ -	$ -	$ -	$ -	$ 1,738,595	$ 201,768	$ 1,738,595	$ 1,403,358
Total Line Transformers		PLDLTT		$ -	$ -	$ -	$ -	$ -	$ 1,772,916	$ 204,652	$ 1,764,295	$ 1,442,672
Distribution Services												
Customer	TPIS	PLDSC	C02	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters												
Customer	TPIS	PLDMC	C03	$ 17,360	$ 5,748	$ 1,727	$ 3,483	$ 457	$ 508,450	$ -	$ 555,938	$ -
Distribution Street & Customer Lighting												
Customer	TPIS	PLDSCL	YECust04	$ -	$ -	$ -	$ -	$ -	$ 45,432,119	$ 8,782,733	$ 7,271,016	$ 10,728,989
Customer Accounts Expense												
Customer	TPIS	PLCAE	YECust05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.												
Customer	TPIS	PLCSI	YECust06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense												
Customer	TPIS	PLSEC	YECust06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		PLT		$ 18,567,872	$ 8,703,024	$ 11,199,027	$ 27,282,442	$ 38,273,672	$ 55,903,508	$ 9,858,777	$ 17,160,982	$ 19,617,849

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Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Secondary GSS	General Service Primary GSP
Net Utility Plant							
Power Production Plant							
Production Demand - Base	NTPLANT	UPPPDB	BDEM	$ 622,857,142	$ 216,160,338	$ 61,092,434	$ 1,421,525
Production Demand - Inter.	NTPLANT	UPPPDI	PPWDA	$ 741,143,715	$ 390,961,548	$ 57,298,081	$ 4,900,126
Production Demand - Peak	NTPLANT	UPPPDP	PPSDA	$ 490,449,119	$ 204,122,379	$ 54,284,100	$ 2,993,282
Production Energy - Base	NTPLANT	UPPPEB	E01	$ -	$ -	$ -	$ -
Production Energy - Inter.	NTPLANT	UPPPEI	E01	$ -	$ -	$ -	$ -
Production Energy - Peak	NTPLANT	UPPPEP	E01	$ -	$ -	$ -	$ -
Total Power Production Plant		UPPPT		$ 1,854,249,976	$ 813,244,265	$ 172,674,615	$ 9,314,933
Transmission Plant							
Transmission Demand - Base	NTPLANT	UPTRB	BDEM	$ 76,869,802	$ 26,932,867	$ 7,542,134	$ 175,494
Transmission Demand - Inter.	NTPLANT	UPTRI	PPWDA	$ 91,497,499	$ 48,265,948	$ 7,073,704	$ 604,942
Transmission Demand - Peak	NTPLANT	UPTRP	PPSDA	$ 60,548,132	$ 25,199,819	$ 6,701,614	$ 369,534
Total Transmission Plant		UPTRT		$ 228,915,433	$ 100,398,633	$ 21,317,452	$ 1,149,970
Distribution Poles							
Specific	NTPLANT	UPDPS	NCPP	$ -	$ -	$ -	$ -
Distribution Substation							
General	NTPLANT	UPDSG	NCPP	$ 71,071,886	$ 38,201,916	$ 7,457,359	$ 417,555
Distribution Primary & Secondary Lines							
Primary Specific	NTPLANT	UPDPLS	NCPP	$ -	$ -	$ -	$ -
Primary Demand	NTPLANT	UPDPLD	NCPP	$ 55,954,019	$ 28,501,322	$ 5,871,086	$ 328,736
Primary Customer	NTPLANT	UPDPLC	YECust08	$ 209,469,510	$ 165,132,151	$ 31,386,497	$ 28,690
Secondary Demand	NTPLANT	UPDSLD	SICD	$ 12,715,833	$ 7,736,114	$ 3,900,464	$ -
Secondary Customer	NTPLANT	UPDSLC	YECust07	$ 47,603,001	$ 37,564,342	$ 7,139,816	$ -
Total Distribution Primary & Secondary Lines		UPDLT		$ 325,742,362	$ 238,933,929	$ 48,297,863	$ 357,426
Distribution Line Transformers							
Demand	NTPLANT	UPDLTD	SICD	$ 84,979,249	$ 51,700,046	$ 26,066,597	$ -
Customer	NTPLANT	UPDLTC	YECust07	$ 78,066,009	$ 61,603,223	$ 11,708,861	$ -
Total Line Transformers		UPDLTT		$ 163,045,259	$ 113,303,270	$ 37,775,458	$ -
Distribution Services							
Customer	NTPLANT	UPDSC	C02	$ 54,043,430	$ 31,776,294	$ 5,993,633	$ -
Distribution Meters							
Customer	NTPLANT	UPDMC	C03	$ 42,578,400	$ 26,505,280	$ 11,693,829	$ 28,303
Distribution Street & Customer Lighting							
Customer	NTPLANT	UPDSCL	YECust04	$ 48,391,308	$ -	$ -	$ -
Customer Accounts Expense							
Customer	NTPLANT	UPCAE	YECust05	$ -	$ -	$ -	$ -
Customer Service & Info.							
Customer	NTPLANT	UPCSI	YECust06	$ -	$ -	$ -	$ -
Sales Expense							
Customer	NTPLANT	UPSEC	YECust06	$ -	$ -	$ -	$ -
Total		UPT		$ 2,786,038,055	$ 1,360,363,586	$ 305,210,209	$ 11,268,187

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Description	Ref	Name	Allocation Vector	All Electric School AES	Combined Light & Power LPS	Combined Light & Power LPP	Combined Light & Power LPT	Small Time-of-Day Secondary STODS	Small Time-of-Day Primary STODP	Large Comm/Ind TOD Primary LCIP	Large Comm/Ind TOD Transmission LCIT
Net Utility Plant											
Power Production Plant											
Production Demand - Base	NTPLANT	UPPPDB	BDEM	$ 4,429,540	$ 127,482,478	$ 52,830,906	$ 825,935	$ 6,355,786	$ 515,317	$ 89,323,884	$ 26,643,535
Production Demand - Inter.	NTPLANT	UPPPDI	PPWDA	$ 9,134,952	$ 109,123,563	$ 42,330,748	$ 979,555	$ 5,229,722	$ 515,447	$ 72,630,145	$ 21,902,978
Production Demand - Peak	NTPLANT	UPPPDP	PPSDA	$ 3,340,925	$ 93,857,094	$ 35,538,226	$ 653,149	$ 4,677,826	$ 286,227	$ 56,037,879	$ 15,031,955
Production Energy - Base	NTPLANT	UPPPEB	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Inter.	NTPLANT	UPPPEI	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Peak	NTPLANT	UPPPEP	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		UPPPT		$ 16,905,417	$ 330,463,136	$ 130,699,881	$ 2,458,639	$ 16,263,336	$ 1,316,990	$ 217,991,908	$ 63,578,469
Transmission Plant											
Transmission Demand - Base	NTPLANT	UPTRB	BDEM	$ 546,847	$ 15,738,281	$ 6,522,211	$ 101,965	$ 784,650	$ 63,618	$ 11,027,432	$ 3,289,263
Transmission Demand - Inter.	NTPLANT	UPTRI	PPWDA	$ 1,127,751	$ 13,471,791	$ 5,225,920	$ 120,930	$ 645,632	$ 63,634	$ 8,966,516	$ 2,704,020
Transmission Demand - Peak	NTPLANT	UPTRP	PPSDA	$ 412,452	$ 11,587,077	$ 4,387,353	$ 80,634	$ 577,499	$ 35,336	$ 6,918,126	$ 1,855,762
Total Transmission Plant		*UPTRT*		$ *2,087,049*	$ *40,797,149*	$ 16,135,483	$ 303,530	$ 2,007,781	$ 162,588	$ 26,912,074	$ 7,849,046
Distribution Poles											
Specific	NTPLANT	UPDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation											
General	NTPLANT	UPDSG	NCPP	$ 746,664	$ 11,436,112	$ 4,491,522	$ -	$ 499,162	$ 35,845	$ 6,789,112	$ -
Distribution Primary & Secondary Lines											
Primary Specific	NTPLANT	UPDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	NTPLANT	UPDPLD	NCPP	$ 589,414	$ 9,003,510	$ 3,536,120	$ -	$ 392,984	$ 28,220	$ 5,344,984	$ -
Primary Customer	NTPLANT	UPDPLC	YECust08	$ 123,525	$ 3,469,458	$ 138,268	$ 797	$ 20,322	$ 797	$ 15,939	$ 2,789
Secondary Demand	NTPLANT	UPDSLD	SICD	$ 77,952	$ 938,706	$ -	$ -	$ 52,347	$ -	$ -	$ -
Secondary Customer	NTPLANT	UPDSLC	YECust07	$ 28,100	$ 789,234	$ -	$ -	$ 4,623	$ 181	$ -	$ -
Total Distribution Primary & Secondary Lines		UPDLT		$ 818,990	$ 14,200,908	$ 3,674,388	$ 797	$ 470,276	$ 29,199	$ 5,360,923	$ 2,789
Distribution Line Transformers											
Demand	NTPLANT	UPDLTD	SICD	$ 520,947	$ 6,273,327	$ -	$ -	$ 349,836	$ -	$ -	$ -
Customer	NTPLANT	UPDLTC	YECust07	$ 46,081	$ 1,294,295	$ -	$ -	$ 7,581	$ 297	$ -	$ -
Total Line Transformers		UPDLTT		$ *567,028*	$ *7,567,622*	$ -	$ -	$ 357,417	$ 297	$ -	$ -
Distribution Services											
Customer	NTPLANT	UPDSC	C02	$ 337,555	$ 15,930,436	$ -	$ -	$ 5,512	$ -	$ -	$ -
Distribution Meters											
Customer	NTPLANT	UPDMC	C03	$ 90,661	$ 3,382,761	$ 135,329	$ 771	$ 10,005	$ 388	$ 15,432	$ 3,112
Distribution Street & Customer Lighting											
Customer	NTPLANT	UPDSCL	YECust04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense											
Customer	NTPLANT	UPCAE	YECust05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.											
Customer	NTPLANT	UPCSI	YECust06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense											
Customer	NTPLANT	UPSEC	YECust06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		UPT		$ 21,555,384	$ 423,758,122	$ 155,136,804	$ 2,763,736	$ 19,613,490	$ 1,545,308	$ 257,069,449	$ 71,433,416

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Description	Ref	Name	Allocation Vector	Coal Mining Power Primary MPP	Coal Mining Power Transmission MPT	Large Power Mine Power TOD Primary LMPP	Large Power Mine Power TOD Transmission LMPT	Large Industrial Time-of-Day LITOD	Street Lighting SL	Decorative Street Lighting SLDEC	Private Outdoor Lighting POL	Customer Outdoor Lighting OL
Net Utility Plant												
Power Production Plant												
Production Demand - Base	NTPLANT	UPPPDB	BDEM	$ 3,575,111	$ 2,185,953	$ 2,833,680	$ 8,469,202	$ 12,301,439	$ 1,406,867	$ 118,217	$ 1,053,479	$ 1,611,517
Production Demand - Inter.	NTPLANT	UPPPDI	PPWDA	$ 5,083,747	$ 2,630,015	$ 3,301,127	$ 6,933,582	$ 6,847,193	$ 450,318	$ 37,839	$ 337,204	$ 515,824
Production Demand - Peak	NTPLANT	UPPPDP	PPSDA	$ 3,221,468	$ 1,988,968	$ 1,901,237	$ 5,935,591	$ 6,578,808	$ -	$ -	$ -	$ -
Production Energy - Base	NTPLANT	UPPPEB	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Inter.	NTPLANT	UPPPEI	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Peak	NTPLANT	UPPPEP	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		UPPPT		$ 11,880,327	$ 6,804,935	$ 8,036,044	$ 21,358,375	$ 25,727,440	$ 1,857,185	$ 156,056	$ 1,390,683	$ 2,127,341
Transmission Plant												
Transmission Demand - Base	NTPLANT	UPTRB	BDEM	$ 441,363	$ 269,866	$ 349,830	$ 1,048,030	$ 1,518,667	$ 173,684	$ 14,594	$ 130,057	$ 198,949
Transmission Demand - Inter.	NTPLANT	UPTRI	PPWDA	$ 627,611	$ 324,687	$ 407,539	$ 855,982	$ 845,317	$ 55,594	$ 4,671	$ 41,629	$ 63,681
Transmission Demand - Peak	NTPLANT	UPTRP	PPSDA	$ 397,705	$ 245,547	$ 234,716	$ 732,775	$ 812,183	$ -	$ -	$ -	$ -
Total Transmission Plant		UPTRT		$ 1,466,679	$ 840,100	$ 992,086	$ 2,636,787	$ 3,176,167	$ 229,278	$ 19,266	$ 171,686	$ 262,630
Distribution Poles												
Specific	NTPLANT	UPDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation												
General	*NTPLANT*	*UPDSG*	*NCPP*	$ *510,083*	$ -	$ 349,884	$ -	$ 2,031,270	$ 34,718	$ 2,917	$ 25,998	$ 39,769
Distribution Primary & Secondary Lines												
Primary Specific	NTPLANT	UPDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	NTPLANT	UPDPLD	NCPP	$ 401,582	$ -	$ 275,459	$ -	$ 1,599,194	$ 27,333	$ 2,297	$ 20,468	$ 31,309
Primary Customer	NTPLANT	UPDPLC	YECust08	$ 12,352	$ 4,782	$ 1,195	$ 2,391	$ 398	$ 3,122,968	$ 362,428	$ 3,122,968	$ 2,520,785
Secondary Demand	NTPLANT	UPDSLD	SICD	$ -	$ -	$ -	$ -	$ -	$ 3,441	$ 289	$ 2,577	$ 3,942
Secondary Customer	NTPLANT	UPDSLC	YECust07	$ -	$ -	$ -	$ -	$ -	$ 710,414	$ 82,445	$ 710,414	$ 573,432
Total Distribution Primary & Secondary Lines		UPDLT		$ 413,934	$ 4,782	$ 276,655	$ 2,391	$ 1,599,592	$ 3,864,157	$ 447,460	$ 3,856,427	$ 3,129,478
Distribution Line Transformers												
Demand	NTPLANT	UPDLTD	SICD	$ -	$ -	$ -	$ -	$ -	$ 22,999	$ 1,933	$ 17,222	$ 26,344
Customer	NTPLANT	UPDLTC	YECust07	$ -	$ -	$ -	$ -	$ -	$ 1,165,036	$ 135,205	$ 1,165,036	$ 940,393
Total Line Transformers		UPDLTT		$ -	$ -	$ -	$ -	$ -	$ 1,188,034	$ 137,138	$ 1,182,258	$ 966,737
Distribution Services												
Customer	NTPLANT	UPDSC	C02	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters												
Customer	NTPLANT	UPDMC	C03	$ 11,633	$ 3,852	$ 1,157	$ 2,334	$ 306	$ 340,713	$ -	$ 372,535	$ -
Distribution Street & Customer Lighting												
Customer	NTPLANT	UPDSCL	YECust04	$ -	$ -	$ -	$ -	$ -	$ 30,444,146	$ 5,865,325	$ 4,672,321	$ 7,189,515
Customer Accounts Expense												
Customer	NTPLANT	UPCAE	YECust05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.												
Customer	NTPLANT	UPCSI	YECust06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense												
Customer	NTPLANT	UPSEC	YECust06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		UPT		$ 14,282,656	$ 7,653,669	$ 9,655,826	$ 23,989,886	$ 32,534,777	$ 37,958,232	$ 6,648,162	$ 11,871,907	$ 13,715,469

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Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Secondary GSS	General Service Primary GSP
Net Cost Rate Base							
Power Production Plant							
Production Demand - Base	RB	RBPPDB	BDEM	$ 573,685,245	$ 201,002,058	$ 56,287,523	$ 1,309,722
Production Demand - Inter.	RB	RBPPDI	PPWDA	$ 682,852,867	$ 360,212,478	$ 52,791,595	$ 4,514,732
Production Demand - Peak	RB	RBPPDP	PPSDA	$ 451,875,365	$ 168,068,163	$ 50,014,663	$ 2,757,861
Production Energy - Base	RB	RBPPEB	E01	$ 58,273,194	$ 20,417,175	$ 5,717,514	$ 133,038
Production Energy - Inter.	RB	RBPPEI	E01	$ -	$ -	$ -	$ -
Production Energy - Peak	RB	RBPPEP	E01	$ -	$ -	$ -	$ -
Total Power Production Plant		RBPPT		$ 1,766,686,670	$ 769,699,893	$ 164,811,296	$ 8,715,353
Transmission Plant							
Transmission Demand - Base	RB	RBTRB	BDEM	$ 72,404,237	$ 25,368,267	$ 7,103,992	$ 165,299
Transmission Demand - Inter.	RB	RBTRI	PPWDA	$ 86,182,172	$ 45,462,054	$ 6,662,774	$ 569,800
Transmission Demand - Peak	RB	RBTRP	PPSDA	$ 57,030,734	$ 23,735,896	$ 6,312,300	$ 348,067
Total Transmission Plant		RBTRT		$ 215,617,143	$ 94,566,217	$ 20,079,066	$ 1,083,165
Distribution Poles							
Specific	RB	RBDPS	NCPP	$ -	$ -	$ -	$ -
Distribution Substation							
General	RB	RBDSG	NCPP	$ 65,512,019	$ 33,369,884	$ 6,873,979	$ 384,890
Distribution Primary & Secondary Lines							
Primary Specific	RB	RBDPLS	NCPP	$ -	$ -	$ -	$ -
Primary Demand	RB	RBDPLD	NCPP	$ 51,434,073	$ 26,198,895	$ 5,396,822	$ 302,181
Primary Customer	RB	RBDPLC	YECust08	$ 192,548,635	$ 151,792,833	$ 28,851,107	$ 26,372
Secondary Demand	RB	RBDSLD	SICD	$ 11,688,652	$ 7,111,193	$ 3,585,366	$ -
Secondary Customer	RB	RBDSLC	YECust07	$ 43,757,647	$ 34,529,908	$ 6,563,064	$ -
Total Distribution Primary & Secondary Lines		RBDLT		$ 299,429,007	$ 219,632,929	$ 44,396,378	$ 328,553
Distribution Line Transformers							
Demand	RB	RBDLTD	SICD	$ 77,944,290	$ 47,420,087	$ 23,908,689	$ -
Customer	RB	RBDLTC	YECust07	$ 71,603,359	$ 56,503,435	$ 10,739,549	$ -
Total Line Transformers		RBDLTT		$ 149,547,649	$ 103,923,523	$ 34,648,238	$ -
Distribution Services							
Customer	RB	RBDSC	C02	$ 49,564,903	$ 29,143,023	$ 5,496,946	$ -
Distribution Meters							
Customer	RB	RBDMC	C03	$ 39,867,151	$ 24,817,513	$ 10,949,205	$ 26,501
Distribution Street & Customer Lighting							
Customer	RB	RBDSCL	YECust04	$ 44,380,543	$ -	$ -	$ -
Customer Accounts Expense							
Customer	RB	RBCAE	YECust05	$ 3,553,632	$ 2,404,524	$ 502,729	$ 4,178
Customer Service & Info.							
Customer	RB	RBCSI	YECust06	$ 814,994	$ 642,489	$ 122,117	$ 112
Sales Expense							
Customer	RB	RBSEC	YECust06	$ -	$ -	$ -	$ -
Total		RBT		$ 2,634,973,711	$ 1,278,199,993	$ 287,879,954	$ 10,542,751

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Description	Ref	Name	Allocation Vector	All Electric School AES	Combined Light & Power LPS	Combined Light & Power LPP	Combined Light & Power LPT	Small Time-of-Day Secondary STODS	Small Time-of-Day Primary STODP	Large Comm/Ind TOD Primary LCIP	Large Comm/Ind TOD Transmission LCIT
Net Cost Rate Base											
Power Production Plant											
Production Demand - Base	RB	RBPPDB	BDEM	$ 4,081,158	$ 117,455,999	$ 48,675,762	$ 760,975	$ 5,855,904	$ 474,787	$ 82,298,573	$ 24,548,025
Production Demand - Inter.	RB	RBPPDI	PPWDA	$ 8,416,489	$ 100,541,010	$ 39,001,440	$ 902,513	$ 4,818,405	$ 474,907	$ 66,917,795	$ 20,180,312
Production Demand - Peak	RB	RBPPDP	PPSDA	$ 3,078,162	$ 86,475,247	$ 32,743,151	$ 601,779	$ 4,309,917	$ 263,715	$ 51,630,507	$ 13,849,894
Production Energy - Base	RB	RBPPEB	E01	$ 414,552	$ 11,930,821	$ 4,944,335	$ 77,298	$ 594,825	$ 48,228	$ 8,359,637	$ 2,493,513
Production Energy - Inter.	RB	RBPPEI	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Peak	RB	RBPPEP	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		RBPPT		$ 15,990,360	$ 316,403,078	$ 125,364,689	$ 2,342,565	$ 15,579,052	$ 1,261,637	$ 209,206,513	$ 61,071,544
Transmission Plant											
Transmission Demand - Base	RB	RBTRB	BDEM	$ 515,079	$ 14,824,003	$ 6,143,319	$ 96,042	$ 739,068	$ 59,922	$ 10,386,820	$ 3,098,182
Transmission Demand - Inter.	RB	RBTRI	PPWDA	$ 1,062,237	$ 12,689,180	$ 4,922,332	$ 113,905	$ 608,126	$ 59,938	$ 8,445,627	$ 2,546,937
Transmission Demand - Peak	RB	RBTRP	PPSDA	$ 388,492	$ 10,913,954	$ 4,132,480	$ 75,950	$ 543,950	$ 33,283	$ 6,516,234	$ 1,747,956
Total Transmission Plant		RBTRT		$ 1,965,807	$ 38,427,137	$ 15,198,131	$ 285,897	$ 1,891,144	$ 153,143	$ 25,348,682	$ 7,393,074
Distribution Poles											
Specific	RB	RBDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation											
General	RB	RBDSG	NCPP	$ 690,097	$ 10,541,479	$ 4,140,156	$ -	$ 460,113	$ 33,041	$ 8,258,008	$ -
Distribution Primary & Secondary Lines											
Primary Specific	RB	RBDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	RB	RBDPLD	NCPP	$ 541,801	$ 8,278,209	$ 3,250,474	$ -	$ 361,239	$ 25,941	$ 4,913,218	$ -
Primary Customer	RB	RBDPLC	YECust08	$ 113,547	$ 3,189,196	$ 127,099	$ 733	$ 18,680	$ 733	$ 14,651	$ 2,564
Secondary Demand	RB	RBDSLD	SICD	$ 71,655	$ 882,878	$ -	$ -	$ 48,119	$ -	$ -	$ -
Secondary Customer	*RB*	*RBDSLC*	*YECust07*	$ 25,830	$ 725,480	$ -	$ -	$ 4,249	$ 167	$ -	$ -
Total Distribution Primary & Secondary Lines		RBDLT		$ 752,832	$ 13,053,763	$ 3,377,573	$ 733	$ 432,288	$ 26,840	$ 4,927,869	$ 2,564
Distribution Line Transformers											
Demand	RB	RBDLTD	SICD	$ 477,820	$ 5,753,993	$ -	$ -	$ 320,875	$ -	$ -	$ -
Customer	RB	RBDLTC	YECust07	$ 42,267	$ 1,187,148	$ -	$ -	$ 6,954	$ 273	$ -	$ -
Total Line Transformers		RBDLTT		$ 520,087	$ 6,941,141	$ -	$ -	$ 327,828	$ 273	$ -	$ -
Distribution Services											
Customer	*RB*	*RBDSC*	*C02*	*$ 309,582*	*$ 14,810,296*	$ -	$ -	$ 5,056	$ -	$ -	$ -
Distribution Meters											
Customer	RB	RBDMC	C03	$ 84,886	$ 3,146,631	$ 126,712	$ 721	$ 9,366	$ 363	$ 14,449	$ 2,914
Distribution Street & Customer Lighting											
Customer	RB	RBDSCL	YECust04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense											
Customer	RB	RBCAE	YECust05	$ 1,799	$ 505,195	$ 20,134	$ 116	$ 5,916	$ 232	$ 4,642	$ 812
Customer Service & Info.											
Customer	RB	RBCSI	YECust06	$ 481	$ 13,499	$ 538	$ 3	$ 79	$ 3	$ 62	$ 11
Sales Expense											
Customer	RB	RBSEC	YECust06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		RBT		$ 20,315,933	$ 403,644,218	$ 148,227,932	$ 2,630,035	$ 18,710,846	$ 1,475,532	$ 245,760,225	$ 68,470,920

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Description	Ref	Name	Allocation Vector	Coal Mining Power Primary MPP	Coal Mining Power Transmission MPT	Large Power Mine Power TOD Primary LMPP	Large Power Mine Power TOD Transmission LMPT	Large Industrial Time-of-Day LITOD	Street Lighting SL	Decorative Street Lighting SLDEC	Private Outdoor Lighting POL	Customer Outdoor Lighting OL
Net Cost Rate Base												
Power Production Plant												
Production Demand - Base	RB	RBPPDB	BDEM	$ 3,293,929	$ 2,014,028	$ 2,610,812	$ 7,821,528	$ 11,333,932	$ 1,296,217	$ 108,919	$ 970,623	$ 1,484,771
Production Demand - Inter.	RB	RBPPDI	PPWDA	$ 4,663,911	$ 2,423,165	$ 3,041,493	$ 6,386,257	$ 6,308,663	$ 414,901	$ 34,863	$ 310,683	$ 475,255
Production Demand - Peak	RB	RBPPDP	PPSDA	$ 2,968,100	$ 1,832,536	$ 1,751,705	$ 5,468,757	$ 6,061,386	$ -	$ -	$ -	$ -
Production Energy - Base	RB	RBPPEB	E01	$ 334,587	$ 204,579	$ 265,198	$ 794,487	$ 1,151,266	$ 131,666	$ 11,064	$ 98,593	$ 150,819
Production Energy - Inter.	RB	RBPPEI	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Peak	RB	RBPPEP	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		RBPPT		$ 11,260,528	$ 6,474,307	$ 7,669,209	$ 20,473,029	$ 24,855,247	$ 1,842,783	$ 154,846	$ 1,379,899	$ 2,110,845
Transmission Plant												
Transmission Demand - Base	RB	RBTRB	BDEM	$ 415,723	$ 254,188	$ 329,508	$ 987,147	$ 1,430,444	$ 163,594	$ 13,747	$ 122,501	$ 187,391
Transmission Demand - Inter.	RB	RBTRI	PPWDA	$ 591,152	$ 305,825	$ 383,864	$ 806,255	$ 796,210	$ 52,364	$ 4,400	$ 39,211	$ 59,981
Transmission Demand - Peak	RB	RBTRP	PPSDA	$ 374,601	$ 231,282	$ 221,081	$ 690,206	$ 765,001	$ -	$ -	$ -	$ -
Total Transmission Plant		RBTRT		$ 1,381,476	$ 791,296	$ 934,453	$ 2,483,609	$ 2,991,656	$ 215,958	$ 18,147	$ 161,712	$ 247,373
Distribution Poles												
Specific	RB	RBDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation												
General	RB	RBDSG	NCPP	$ 470,180	$ -	$ 322,513	$ -	$ 1,872,366	$ 32,002	$ 2,689	$ 23,964	$ 36,658
Distribution Primary & Secondary Lines												
Primary Specific	RB	RBDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	RB	RBDPLD	NCPP	$ 369,142	$ -	$ 253,208	$ -	$ 1,470,012	$ 25,125	$ 2,111	$ 18,814	$ 28,780
Primary Customer	RB	RBDPLC	YECust08	$ 11,355	$ 4,395	$ 1,099	$ 2,198	$ 366	$ 2,870,698	$ 333,152	$ 2,870,696	$ 2,317,166
Secondary Demand	RB	RBDSLD	SICD	$ -	$ -	$ -	$ -	$ -	$ 3,163	$ 266	$ 2,369	$ 3,624
Secondary Customer	RB	RBDSLC	YECust07	$ -	$ -	$ -	$ -	$ -	$ 653,027	$ 75,765	$ 653,027	$ 527,110
Total Distribution Primary & Secondary Lines		RBDLT		$ 380,497	$ 4,395	$ 254,307	$ 2,198	$ 1,470,378	$ 3,552,012	$ 411,314	$ 3,544,906	$ 2,876,680
Distribution Line Transformers												
Demand	RB	RBDLTD	SICD	$ -	$ -	$ -	$ -	$ -	$ 21,095	$ 1,773	$ 15,796	$ 24,163
Customer	RB	RBDLTC	YECust07	$ -	$ -	$ -	$ -	$ -	$ 1,068,589	$ 124,013	$ 1,068,589	$ 862,543
Total Line Transformers		RBDLTT		$ -	$ -	$ -	$ -	$ -	$ 1,089,684	$ 125,785	$ 1,084,385	$ 886,706
Distribution Services												
Customer	RB	RBDSC	C02	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters												
Customer	RB	RBDMC	C03	$ 10,892	$ 3,607	$ 1,083	$ 2,165	$ 287	$ 319,018	$ -	$ 348,813	$ -
Distribution Street & Customer Lighting												
Customer	RB	RBDSCL	YECust04	$ -	$ -	$ -	$ -	$ -	$ 27,920,677	$ 5,397,538	$ 4,468,494	$ 6,593,634
Customer Accounts Expense												
Customer	RB	RBCAE	YECust05	$ 1,789	$ 696	$ 348	$ 696	$ 118	$ 34,105	$ 3,957	$ 34,105	$ 27,531
Customer Service & Info.												
Customer	RB	RBCSI	YECust06	$ 48	$ 19	$ 5	$ 9	$ 2	$ 12,150	$ 1,411	$ 12,150	$ 9,807
Sales Expense												
Customer	RB	RBSEC	YECust06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		RBT		$ 13,525,419	$ 7,274,320	$ 9,181,918	$ 22,961,726	$ 31,190,051	$ 35,018,589	$ 6,115,667	$ 11,058,428	$ 12,769,234

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Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Secondary GSS	General Service Primary GSP
Operation and Maintenance Expenses							
Power Production Plant							
Production Demand - Base	TOM	OMPPDB	BDEM	$ 23,092,436	$ 8,090,895	$ 2,285,730	$ 52,720
Production Demand - Inter.	TOM	OMPPDI	PPWDA	$ 27,486,739	$ 14,499,560	$ 2,125,009	$ 181,731
Production Demand - Peak	TOM	OMPPDP	PPSDA	$ 18,189,248	$ 7,570,271	$ 2,013,230	$ 111,012
Production Energy - Base	TOM	OMPPEB	E01	$ 608,955,489	$ 213,359,689	$ 59,748,085	$ 1,390,246
Production Energy - Inter.	TOM	OMPPEI	E01	$ -	$ -	$ -	$ -
Production Energy - Peak	TOM	OMPPEP	E01	$ -	$ -	$ -	$ -
Total Power Production Plant		OMPPT		$ 677,723,912	$ 243,520,415	$ 66,152,055	$ 1,735,708
Transmission Plant							
Transmission Demand - Base	TOM	OMTRB	BDEM	$ 6,632,487	$ 2,323,824	$ 650,751	$ 15,142
Transmission Demand - Inter.	TOM	OMTRI	PPWDA	$ 7,894,595	$ 4,164,487	$ 610,334	$ 52,196
Transmission Demand - Peak	TOM	OMTRP	PPSDA	$ 5,224,219	$ 2,174,293	$ 578,229	$ 31,884
Total Transmission Plant		OMTRT		$ 19,751,302	$ 8,662,604	$ 1,839,314	$ 99,222
Distribution Poles							
Specific	TOM	OMDPS	NCPP	$ -	$ -	$ -	$ -
Distribution Substation							
General	TOM	OMDSG	NCPP	$ 4,962,747	$ 2,527,877	$ 520,726	$ 29,157
Distribution Primary & Secondary Lines							
Primary Specific	TOM	OMDPLS	NCPP	$ -	$ -	$ -	$ -
Primary Demand	TOM	OMDPLD	NCPP	$ 6,073,965	$ 3,093,898	$ 637,323	$ 35,685
Primary Customer	TOM	OMDPLC	Cust08	$ 22,738,501	$ 18,083,445	$ 3,422,662	$ 3,195
Secondary Demand	TOM	OMDSLD	SICD	$ 1,360,339	$ 839,777	$ 423,406	$ -
Secondary Customer	TOM	OMDSLC	Cust07	$ 5,187,439	$ 4,113,703	$ 778,602	$ -
Total Distribution Primary & Secondary Lines		OMDLT		$ 35,360,244	$ 26,130,823	$ 5,261,993	$ 38,880
Distribution Line Transformers							
Demand	TOM	OMDLTD	SICD	$ 2,833,062	$ 1,723,591	$ 869,015	$ -
Customer	TOM	OMDLTC	Cust07	$ 2,602,586	$ 2,071,871	$ 392,144	$ -
Total Line Transformers		OMDLTT		$ 5,435,648	$ 3,795,462	$ 1,261,159	$ -
Distribution Services							
Customer	TOM	OMDSC	C02	$ 1,765,090	$ 1,037,832	$ 195,756	$ -
Distribution Meters							
Customer	TOM	OMDMC	C03	$ 7,935,921	$ 4,940,153	$ 2,179,539	$ 5,275
Distribution Street & Customer Lighting							
Customer	TOM	OMDSCL	C04	$ 1,575,493	$ -	$ -	$ -
Customer Accounts Expense							
Customer	TOM	OMCAE	C05	$ 28,483,115	$ 19,300,593	$ 4,018,325	$ 34,100
Customer Service & Info.							
Customer	TOM	OMCSI	C06	$ 6,527,764	$ 5,191,402	$ 982,579	$ 917
Sales Expense							
Customer	TOM	OMSEC	C06	$ -	$ -	$ -	$ -
Total		OMT		$ 789,501,236	$ 315,107,161	$ 82,411,447	$ 1,943,259

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Description	Ref	Name	Allocation Vector	All Electric School AES	Combined Light & Power LPS	Combined Light & Power LPP	Combined Light & Power LPT	Small Time-of-Day Secondary STODS	Small Time-of-Day Primary STODP	Large Comm/Ind TOD Primary LCIP	Large Comm/Ind TOD Transmission LCIT
Operation and Maintenance Expenses											
Power Production Plant											
Production Demand - Base	TOM	OMPPDB	BDEM	$ 164,278	$ 4,727,933	$ 1,959,336	$ 30,631	$ 235,717	$ 19,112	$ 3,312,748	$ 988,127
Production Demand - Inter.	TOM	OMPPDI	PPWDA	$ 338,787	$ 4,047,057	$ 1,569,917	$ 36,329	$ 193,954	$ 19,116	$ 2,693,628	$ 812,314
Production Demand - Peak	TOM	OMPPDP	PPSDA	$ 123,905	$ 3,480,871	$ 1,318,003	$ 24,223	$ 173,486	$ 10,615	$ 2,078,272	$ 557,489
Production Energy - Base	*TOM*	*OMPPEB*	*E01*	*$ 4,332,068*	*$ 124,677,209*	*$ 51,668,355*	*$ 807,761*	*$ 6,215,926*	*$ 503,978*	*$ 87,358,299*	*$ 26,057,239*
Production Energy - Inter.	TOM	OMPPEI	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Peak	TOM	OMPPEP	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		OMPPT		$ 4,959,038	$ 136,933,060	$ 56,515,611	$ 898,944	$ 6,819,083	$ 552,822	$ 95,442,947	$ 28,415,169
Transmission Plant											
Transmission Demand - Base	TOM	OMTRB	BDEM	$ 47,183	$ 1,357,932	$ 562,750	$ 8,798	$ 67,701	$ 5,489	$ 951,470	$ 283,805
Transmission Demand - Inter.	TOM	OMTRI	PPWDA	$ 97,305	$ 1,162,374	$ 450,903	$ 10,434	$ 55,707	$ 5,490	$ 773,650	$ 233,309
Transmission Demand - Peak	TOM	OMTRP	PPSDA	$ 35,587	$ 999,757	$ 378,550	$ 6,957	$ 49,828	$ 3,049	$ 596,910	$ 160,119
Total Transmission Plant		OMTRT		$ 180,075	$ 3,520,063	$ 1,392,203	$ 26,189	$ 173,236	$ 14,028	$ 2,322,030	$ 677,232
Distribution Poles											
Specific	TOM	OMDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation											
General	*TOM*	*OMDSG*	*NCPP*	$ 52,277	$ 798,551	$ 313,830	$ -	$ 34,855	$ 2,503	$ 474,064	$ -
Distribution Primary & Secondary Lines											
Primary Specific	TOM	OMDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TOM	OMDPLD	NCPP	$ 63,983	$ 977,356	$ 383,856	$ -	$ 42,660	$ 3,063	$ 580,213	$ -
Primary Customer	TOM	OMDPLC	Cust08	$ 13,393	$ 390,401	$ 15,318	$ 88	$ 2,232	$ 88	$ 1,707	$ 306
Secondary Demand	TOM	OMDSLD	SICD	$ 8,462	$ 101,899	$ -	$ -	$ 5,682	$ -	$ -	$ -
Secondary Customer	TOM	OMDSLC	Cust07	$ 3,047	$ 88,810	$ -	$ -	$ 508	$ -	$ -	$ -
Total Distribution Primary & Secondary Lines		OMDLT		$ 88,884	$ 1,558,467	$ 399,174	$ 88	$ 51,082	$ 3,151	$ 581,920	$ 306
Distribution Line Transformers											
Demand	TOM	OMDLTD	SICD	$ 17,367	$ 209,142	$ -	$ -	$ 11,663	$ -	$ -	$ -
Customer	TOM	OMDLTC	Cust07	$ 1,534	$ 44,729	$ -	$ -	$ 256	$ -	$ -	$ -
Total Line Transformers		OMDLTT		$ 18,902	$ 253,871	$ -	$ -	$ 11,919	$ -	$ -	$ -
Distribution Services											
Customer	TOM	OMDSC	C02	$ 11,025	$ 520,297	$ -	$ -	$ 180	$ -	$ -	$ -
Distribution Meters											
Customer	TOM	OMDMC	C03	$ 16,898	$ 626,764	$ 25,223	$ 144	$ 1,665	$ 72	$ 2,876	$ 580
Distribution Street & Customer Lighting											
Customer	TOM	OMDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense											
Customer	TOM	OMCAE	C05	$ 14,294	$ 4,166,779	$ 163,495	$ 934	$ 47,647	$ 1,869	$ 36,436	$ 6,540
Customer Service & Info.											
Customer	TOM	OMCSI	C06	$ 3,845	$ 112,076	$ 4,398	$ 25	$ 641	$ 25	$ 490	$ 88
Sales Expense											
Customer	TOM	OMSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		OMT		$ 5,345,237	$ 148,469,937	$ 58,613,734	$ 926,324	$ 7,140,507	$ 574,470	$ 98,860,764	$ 29,099,915

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Description	Ref	Name	Allocation Vector	Coal Mining Power Primary MPP	Coal Mining Power Transmission MPT	Large Power Mine Power TOD Primary LMPP	Large Power Mine Power TOD Transmission LMPT	Large Industrial Time-of-Day LITOD	Street Lighting SL	Decorative Street Lighting SLDEC	Private Outdoor Lighting POL	Customer Outdoor Lighting OL
Operation and Maintenance Expenses												
Power Production Plant												
Production Demand - Base	TOM	OMPPDB	BDEM	$ 132,590	$ 81,070	$ 105,092	$ 314,838	$ 456,222	$ 52,176	$ 4,384	$ 39,070	$ 59,766
Production Demand - Inter.	TOM	OMPPDI	PPWDA	$ 188,541	$ 97,539	$ 122,429	$ 257,145	$ 253,941	$ 16,701	$ 1,403	$ 12,506	$ 19,130
Production Demand - Peak	TOM	OMPPDP	PPSDA	$ 119,474	$ 73,765	$ 70,511	$ 220,133	$ 243,988	$ -	$ -	$ -	$ -
Production Energy - Base	TOM	OMPPEB	E01	$ 3,496,441	$ 2,137,852	$ 2,771,325	$ 8,302,395	$ 12,030,744	$ 1,375,908	$ 115,615	$ 1,030,297	$ 1,576,056
Production Energy - Inter.	TOM	OMPPEI	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Peak	TOM	OMPPEP	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		OMPPT		$ 3,937,046	$ 2,390,226	$ 3,069,357	$ 9,094,512	$ 12,984,896	$ 1,444,785	$ 121,403	$ 1,081,874	$ 1,654,953
Transmission Plant												
Transmission Demand - Base	TOM	OMTRB	BDEM	$ 38,082	$ 23,285	$ 30,184	$ 90,426	$ 131,034	$ 14,986	$ 1,259	$ 11,222	$ 17,166
Transmission Demand - Inter.	TOM	OMTRI	PPWDA	$ 54,152	$ 28,015	$ 35,163	$ 73,856	$ 72,936	$ 4,797	$ 403	$ 3,592	$ 5,495
Transmission Demand - Peak	TOM	OMTRP	PPSDA	$ 34,315	$ 21,188	$ 20,252	$ 63,225	$ 70,077	$ -	$ -	$ -	$ -
Total Transmission Plant		OMTRT		$ 126,548	$ 72,488	$ 85,599	$ 227,507	$ 274,046	$ 19,783	$ 1,662	$ 14,813	$ 22,660
Distribution Poles												
Specific	TOM	OMDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation												
General	TOM	OMDSG	NCPP	$ 35,618	$ -	$ 24,431	$ -	$ 141,838	$ 2,424	$ 204	$ 1,815	$ 2,777
Distribution Primary & Secondary Lines												
Primary Specific	TOM	OMDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TOM	OMDPLD	NCPP	$ 43,593	$ -	$ 29,902	$ -	$ 173,597	$ 2,967	$ 249	$ 2,222	$ 3,399
Primary Customer	TOM	OMDPLC	Cust08	$ 1,313	$ 438	$ 131	$ 306	$ 44	$ 342,311	$ 43,952	$ 141,430	$ 275,741
Secondary Demand	TOM	OMDSLD	SICD	$ -	$ -	$ -	$ -	$ -	$ 374	$ 31	$ 280	$ 428
Secondary Customer	TOM	OMDSLC	Cust07	$ -	$ -	$ -	$ -	$ -	$ 77,870	$ 9,998	$ 32,173	$ 62,727
Total Distribution Primary & Secondary Lines		OMDLT		$ 44,906	$ 438	$ 30,033	$ 306	$ 173,641	$ 423,522	$ 54,231	$ 176,105	$ 342,295
Distribution Line Transformers												
Demand	TOM	OMDLTD	SICD	$ -	$ -	$ -	$ -	$ -	$ 767	$ 64	$ 574	$ 878
Customer	TOM	OMDLTC	Cust07	$ -	$ -	$ -	$ -	$ -	$ 39,220	$ 5,036	$ 16,204	$ 31,592
Total Line Transformers		OMDLTT		$ -	$ -	$ -	$ -	$ -	$ 39,986	$ 5,100	$ 16,778	$ 32,471
Distribution Services												
Customer	TOM	OMDSC	C02	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters												
Customer	TOM	OMDMC	C03	$ 2,168	$ 718	$ 216	$ 435	$ 57	$ 63,503	$ -	$ 69,434	$ -
Distribution Street & Customer Lighting												
Customer	TOM	OMDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ 991,181	$ 191,611	$ 158,630	$ 234,072
Customer Accounts Expense												
Customer	TOM	OMCAE	C05	$ 14,014	$ 4,671	$ 2,803	$ 6,540	$ 934	$ 274,017	$ 35,175	$ 113,232	$ 220,718
Customer Service & Info.												
Customer	TOM	OMCSI	C06	$ 377	$ 126	$ 38	$ 88	$ 13	$ 98,268	$ 12,615	$ 40,596	$ 79,157
Sales Expense												
Customer	TOM	OMSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		OMT		$ 4,160,678	$ 2,468,664	$ 3,212,477	$ 9,329,388	$ 13,575,425	$ 3,357,470	$ 422,000	$ 1,673,278	$ 2,589,102

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Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Secondary GSS	General Service Primary GSP
Labor Expenses							
Power Production Plant							
Production Demand - Base	TLB	LBPPDB	BDEM	$ 5,557,600	$ 1,947,266	$ 545,307	$ 12,666
Production Demand - Inter.	TLB	LBPPDI	PPWDA	$ 6,615,405	$ 3,489,699	$ 511,439	$ 43,736
Production Demand - Peak	TLB	LBPPDP	PPSDA	$ 4,377,720	$ 1,821,984	$ 484,537	$ 26,718
Production Energy - Base	TLB	LBPPEB	E01	$ 11,878,822	$ 4,161,982	$ 1,165,499	$ 27,119
Production Energy - Inter.	TLB	LBPPEI	E01	$ -	$ -	$ -	$ -
Production Energy - Peak	TLB	LBPPEP	E01	$ -	$ -	$ -	$ -
Total Power Production Plant		LBPPT		$ 28,429,747	$ 11,420,952	$ 2,706,782	$ 110,264
Transmission Plant							
Transmission Demand - Base	TLB	LBTRB	BDEM	$ 817,727	$ 286,507	$ 80,232	$ 1,867
Transmission Demand - Inter.	TLB	LBTRI	PPWDA	$ 973,334	$ 513,444	$ 75,249	$ 6,435
Transmission Demand - Peak	TLB	LBTRP	PPSDA	$ 644,100	$ 268,071	$ 71,291	$ 3,931
Total Transmission Plant		LBTRT		$ 2,435,161	$ 1,068,023	$ 226,771	$ 12,233
Distribution Poles							
Specific	TLB	LBDPS	NCPP	$ -	$ -	$ -	$ -
Distribution Substation							
General	TLB	LBDSG	NCPP	$ 1,599,784	$ 814,662	$ 167,860	$ 9,399
Distribution Primary & Secondary Lines							
Primary Specific	TLB	LBDPLS	NCPP	$ -	$ -	$ -	$ -
Primary Demand	TLB	LBDPLD	NCPP	$ 1,259,490	$ 641,547	$ 132,154	$ 7,400
Primary Customer	TLB	LBDPLC	Cust08	$ 4,715,028	$ 3,749,761	$ 709,719	$ 663
Secondary Demand	TLB	LBDSLD	SICD	$ 286,225	$ 174,135	$ 87,797	$ -
Secondary Customer	TLB	LBDSLC	Cust07	$ 1,071,514	$ 853,012	$ 161,450	$ -
Total Distribution Primary & Secondary Lines		LBDLT		$ 7,332,257	$ 5,418,455	$ 1,091,120	$ 8,062
Distribution Line Transformers							
Demand	TLB	LBDLTD	SICD	$ 1,912,830	$ 1,163,736	$ 586,743	$ -
Customer	TLB	LBDLTC	Cust07	$ 1,757,217	$ 1,398,888	$ 264,768	$ -
Total Line Transformers		LBDLTT		$ 3,670,047	$ 2,562,624	$ 851,511	$ -
Distribution Services							
Customer	TLB	LBDSC	C02	$ 1,216,484	$ 715,265	$ 134,913	$ -
Distribution Meters							
Customer	TLB	LBDMC	C03	$ 958,413	$ 596,617	$ 263,221	$ 637
Distribution Street & Customer Lighting							
Customer	TLB	LBDSCL	C04	$ 1,089,258	$ -	$ -	$ -
Customer Accounts Expense							
Customer	TLB	LBCAE	C05	$ 8,147,910	$ 5,525,027	$ 1,150,294	$ 9,762
Customer Service & Info.							
Customer	TLB	LBCSI	C06	$ 286,300	$ 227,689	$ 43,095	$ 40
Sales Expense							
Customer	TLB	LBSEC	C06	$ -	$ -	$ -	$ -
Total		LBT		$ 55,165,360	$ 28,349,534	$ 6,635,566	$ 150,397

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Description	Ref	Name	Allocation Vector	All Electric School AES	Combined Light & Power LPS	Combined Light & Power LPP	Combined Light & Power LPT	Small Time-of-Day Secondary STODS	Small Time-of-Day Primary STODP	Large Comm/Ind TOD Primary LCIP	Large Comm/Ind TOD Transmission LCIT
Labor Expenses											
Power Production Plant											
Production Demand - Base	TLB	LBPPDB	BDEM	$ 39,538	$ 1,137,901	$ 471,566	$ 7,372	$ 56,731	$ 4,600	$ 797,300	$ 237,619
Production Demand - Inter.	TLB	LBPPDI	PPWDA	$ 81,538	$ 974,030	$ 377,842	$ 8,743	$ 46,680	$ 4,601	$ 648,292	$ 195,505
Production Demand - Peak	TLB	LBPPDP	PPSDA	$ 29,821	$ 837,763	$ 317,212	$ 5,830	$ 41,754	$ 2,555	$ 500,191	$ 134,174
Production Energy - Base	TLB	LBPPEB	E01	$ 84,505	$ 2,432,064	$ 1,007,868	$ 15,757	$ 121,253	$ 9,831	$ 1,704,088	$ 508,295
Production Energy - Inter.	TLB	LBPPEI	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Peak	TLB	LBPPEP	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		LBPPT		$ 235,402	$ 5,381,758	$ 2,174,508	$ 37,703	$ 266,419	$ 21,588	$ 3,649,871	$ 1,075,793
Transmission Plant											
Transmission Demand - Base	TLB	LBTRB	BDEM	$ 5,817	$ 167,421	$ 69,382	$ 1,085	$ 8,347	$ 677	$ 117,308	$ 34,991
Transmission Demand - Inter.	TLB	LBTRI	PPWDA	$ 11,997	$ 143,310	$ 55,592	$ 1,286	$ 6,868	$ 677	$ 95,384	$ 28,765
Transmission Demand - Peak	TLB	LBTRP	PPSDA	$ 4,388	$ 123,261	$ 46,672	$ 858	$ 6,143	$ 376	$ 73,594	$ 19,741
Total Transmission Plant		LBTRT		$ 22,202	$ 433,993	$ 171,646	$ 3,229	$ 21,358	$ 1,730	$ 286,286	$ 83,497
Distribution Poles											
Specific	TLB	LBDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation											
General	TLB	LBDSG	NCPP	$ 18,652	$ 257,420	$ 101,101	$ -	$ 11,238	$ 807	$ 152,819	$ -
Distribution Primary & Secondary Lines											
Primary Specific	TLB	LBDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TLB	LBDPLD	NCPP	$ 13,267	$ 202,683	$ 79,598	$ -	$ 8,846	$ 635	$ 120,312	$ -
Primary Customer	TLB	LBDPLC	Cust08	$ 2,777	$ 80,953	$ 3,176	$ 18	$ 463	$ 18	$ 354	$ 64
Secondary Demand	TLB	LBDSLD	SICD	$ 1,755	$ 21,130	$ -	$ -	$ 1,178	$ -	$ -	$ -
Secondary Customer	TLB	LBDSLC	Cust07	$ 632	$ 18,416	$ -	$ -	$ 105	$ -	$ -	$ -
Total Distribution Primary & Secondary Lines		LBDLT		$ 18,431	$ 323,162	$ 82,772	$ 18	$ 10,592	$ 653	$ 120,668	$ 64
Distribution Line Transformers											
Demand	TLB	LBDLTD	SICD	$ 11,726	$ 141,209	$ -	$ -	$ 7,875	$ -	$ -	$ -
Customer	TLB	LBDLTC	Cust07	$ 1,036	$ 30,200	$ -	$ -	$ 173	$ -	$ -	$ -
Total Line Transformers		LBDLTT		$ 12,762	$ 171,409	$ -	$ -	$ 8,047	$ -	$ -	$ -
Distribution Services											
Customer	TLB	LBDSC	C02	$ 7,596	$ 358,584	$ -	$ -	$ 124	$ -	$ -	$ -
Distribution Meters											
Customer	TLB	LBDMC	C03	$ 2,041	$ 75,694	$ 3,046	$ 17	$ 225	$ 9	$ 347	$ 70
Distribution Street & Customer Lighting											
Customer	TLB	LBDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense											
Customer	TLB	LBCAE	C05	$ 4,092	$ 1,192,791	$ 46,802	$ 267	$ 13,640	$ 535	$ 10,430	$ 1,872
Customer Service & Info.											
Customer	TLB	LBCSI	C06	$ 169	$ 4,916	$ 193	$ 1	$ 28	$ 1	$ 21	$ 4
Sales Expense											
Customer	TLB	LBSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		LBT		$ 319,546	$ 8,199,725	$ 2,580,069	$ 41,235	$ 331,670	$ 25,321	$ 4,220,440	$ 1,161,299

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Description	Ref	Name	Allocation Vector	Coal Mining Power Primary MPP	Coal Mining Power Transmission MPT	Large Power Mine Power TOD Primary LMPP	Large Power Mine Power TOD Transmission LMPT	Large Industrial Time-of-Day LITOD	Street Lighting SL	Decorative Street Lighting SLDEC	Private Outdoor Lighting POL	Customer Outdoor Lighting OL
Labor Expenses												
Power Production Plant												
Production Demand - Base	TLB	LBPPDB	BDEM	$ 31,911	$ 19,512	$ 25,293	$ 75,774	$ 109,802	$ 12,558	$ 1,055	$ 9,403	$ 14,384
Production Demand - Inter.	TLB	LBPPDI	PPWDA	$ 45,377	$ 23,475	$ 29,466	$ 61,889	$ 61,118	$ 4,020	$ 338	$ 3,010	$ 4,604
Production Demand - Peak	TLB	LBPPDP	PPSDA	$ 28,755	$ 17,753	$ 16,970	$ 52,981	$ 58,722	$ -	$ -	$ -	$ -
Production Energy - Base	TLB	LBPPEB	E01	$ 68,205	$ 41,703	$ 54,060	$ 161,954	$ 234,682	$ 26,840	$ 2,255	$ 20,098	$ 30,744
Production Energy - Inter.	TLB	LBPPEI	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Peak	TLB	LBPPEP	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		LBPPT		$ 174,248	$ 102,443	$ 125,789	$ 352,597	$ 464,324	$ 43,417	$ 3,648	$ 32,511	$ 49,732
Transmission Plant												
Transmission Demand - Base	TLB	LBTRB	BDEM	$ 4,695	$ 2,871	$ 3,721	$ 11,149	$ 16,155	$ 1,848	$ 155	$ 1,384	$ 2,116
Transmission Demand - Inter.	TLB	LBTRI	PPWDA	$ 6,676	$ 3,454	$ 4,335	$ 9,106	$ 8,992	$ 591	$ 50	$ 443	$ 677
Transmission Demand - Peak	TLB	LBTRP	PPSDA	$ 4,231	$ 2,612	$ 2,497	$ 7,795	$ 8,640	$ -	$ -	$ -	$ -
Total Transmission Plant		LBTRT		$ 15,602	$ 8,937	$ 10,554	$ 28,050	$ 33,787	$ 2,439	$ 205	$ 1,826	$ 2,794
Distribution Poles												
Specific	TLB	LBDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation												
General	TLB	LBDSG	NCPP	$ 11,482	$ -	$ 7,876	$ -	$ 45,723	$ 781	$ 66	$ 585	$ 895
Distribution Primary & Secondary Lines												
Primary Specific	TLB	LBDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TLB	LBDPLD	NCPP	$ 9,039	$ -	$ 6,200	$ -	$ 35,997	$ 615	$ 52	$ 461	$ 705
Primary Customer	TLB	LBDPLC	Cust08	$ 272	$ 91	$ 27	$ 64	$ 9	$ 70,981	$ 9,114	$ 29,327	$ 57,177
Secondary Demand	TLB	LBDSLD	SICD	$ -	$ -	$ -	$ -	$ -	$ 77	$ 7	$ 58	$ 89
Secondary Customer	TLB	LBDSLC	Cust07	$ -	$ -	$ -	$ -	$ -	$ 16,147	$ 2,073	$ 6,671	$ 13,007
Total Distribution Primary & Secondary Lines		LBDLT		$ 9,312	$ 91	$ 6,228	$ 64	$ 36,006	$ 87,821	$ 11,245	$ 36,517	$ 70,978
Distribution Line Transformers												
Demand	TLB	LBDLTD	SICD	$ -	$ -	$ -	$ -	$ -	$ 518	$ 43	$ 388	$ 593
Customer	TLB	LBDLTC	Cust07	$ -	$ -	$ -	$ -	$ -	$ 26,480	$ 3,400	$ 10,941	$ 21,331
Total Line Transformers		LBDLTT		$ -	$ -	$ -	$ -	$ -	$ 26,998	$ 3,443	$ 11,328	$ 21,924
Distribution Services												
Customer	TLB	LBDSC	C02	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters												
Customer	TLB	LBDMC	C03	$ 262	$ 87	$ 28	$ 53	$ 7	$ 7,669	$ -	$ 8,386	$ -
Distribution Street & Customer Lighting												
Customer	TLB	LBDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ 685,279	$ 132,475	$ 109,673	$ 161,831
Customer Accounts Expense												
Customer	TLB	LBCAE	C05	$ 4,012	$ 1,337	$ 802	$ 1,672	$ 267	$ 78,441	$ 10,069	$ 32,414	$ 63,183
Customer Service & Info.												
Customer	TLB	LBCSI	C06	$ 17	$ 6	$ 2	$ 4	$ 1	$ 4,310	$ 553	$ 1,781	$ 3,472
Sales Expense												
Customer	TLB	LBSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		LBT		$ 214,933	$ 112,900	$ 151,276	$ 382,639	$ 580,115	$ 937,155	$ 181,705	$ 235,021	$ 374,809

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Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Secondary GSS	General Service Primary GSP
Depreciation Expenses							
Power Production Plant							
Production Demand - Base	TDEPR	DEPPDB	BDEM	$ 20,990,500	$ 7,354,440	$ 2,059,497	$ 47,921
Production Demand - Inter.	TDEPR	DEPPDI	PPWDA	$ 24,984,821	$ 13,179,771	$ 1,931,585	$ 165,189
Production Demand - Peak	TDEPR	DEPPDP	PPSDA	$ 16,533,613	$ 6,881,204	$ 1,829,980	$ 100,907
Production Energy - Base	TDEPR	DEPPEB	E01	$ -	$ -	$ -	$ -
Production Energy - Inter.	TDEPR	DEPPEI	E01	$ -	$ -	$ -	$ -
Production Energy - Peak	TDEPR	DEPPEP	E01	$ -	$ -	$ -	$ -
Total Power Production Plant		DEPPT		$ 62,508,934	$ 27,415,415	$ 5,821,063	$ 314,017
Transmission Plant							
Transmission Demand - Base	TDEPR	DETRB	BDEM	$ 4,589,091	$ 1,607,879	$ 450,262	$ 10,477
Transmission Demand - Inter.	TDEPR	DETRI	PPWDA	$ 5,462,357	$ 2,881,454	$ 422,297	$ 36,115
Transmission Demand - Peak	TDEPR	DETRP	PPSDA	$ 3,614,695	$ 1,504,417	$ 400,083	$ 22,061
Total Transmission Plant		DETRT		$ 13,666,143	$ 5,993,751	$ 1,272,642	$ 68,653
Distribution Poles							
Specific	TDEPR	DEDPS	NCPP	$ -	$ -	$ -	$ -
Distribution Substation							
General	TDEPR	DEDSG	NCPP	$ 3,383,940	$ 1,723,679	$ 355,067	$ 19,881
Distribution Primary & Secondary Lines							
Primary Specific	TDEPR	DEDPLS	NCPP	$ -	$ -	$ -	$ -
Primary Demand	TDEPR	DEDPLD	NCPP	$ 2,664,134	$ 1,357,031	$ 279,540	$ 15,652
Primary Customer	TDEPR	DEDPLC	Cust08	$ 9,973,455	$ 7,931,677	$ 1,501,232	$ 1,401
Secondary Demand	TDEPR	DEDSLD	SICD	$ 605,438	$ 368,339	$ 165,712	$ -
Secondary Customer	TDEPR	DEDSLC	Cust07	$ 2,266,518	$ 1,804,333	$ 341,507	$ -
Total Distribution Primary & Secondary Lines		DEDLT		$ 15,509,546	$ 11,461,380	$ 2,307,991	$ 17,053
Distribution Line Transformers							
Demand	TDEPR	DEDLTD	SICD	$ 4,046,110	$ 2,461,590	$ 1,241,107	$ -
Customer	TDEPR	DEDLTC	Cust07	$ 3,716,951	$ 2,958,996	$ 560,050	$ -
Total Line Transformers		DEDLTT		$ 7,763,061	$ 5,420,586	$ 1,801,157	$ -
Distribution Services							
Customer	TDEPR	DEDSC	C02	$ 2,573,166	$ 1,512,962	$ 285,374	$ -
Distribution Meters							
Customer	TDEPR	DEDMC	C03	$ 2,027,282	$ 1,261,994	$ 556,777	$ 1,348
Distribution Street & Customer Lighting							
Customer	TDEPR	DEDSCL	C04	$ 2,304,052	$ -	$ -	$ -
Customer Accounts Expense							
Customer	TDEPR	DECAE	C05	$ -	$ -	$ -	$ -
Customer Service & Info.							
Customer	TDEPR	DECSI	C06	$ -	$ -	$ -	$ -
Sales Expense							
Customer	TDEPR	DESEC	C06	$ -	$ -	$ -	$ -
Total		DET		$ 109,736,123	$ 54,789,767	$ 12,400,071	$ 420,952

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Description	Ref	Name	Allocation Vector	All Electric School AES	Combined Light & Power LPS	Combined Light & Power LPP	Combined Light & Power LPT	Small Time-of-Day Secondary STODS	Small Time-of-Day Primary STODP	Large Comm/Ind TOD Primary LCIP	Large Comm/Ind TOD Transmission LCIT
Depreciation Expenses											
Power Production Plant											
Production Demand - Base	TDEPR	DEPPDB	BDEM	$ 149,325	$ 4,297,583	$ 1,760,992	$ 27,843	$ 214,261	$ 17,372	$ 3,011,213	$ 898,185
Production Demand - Inter.	TDEPR	DEPPDI	PPWDA	$ 307,950	$ 3,678,883	$ 1,427,019	$ 33,022	$ 176,300	$ 17,376	$ 2,448,447	$ 738,375
Production Demand - Peak	TDEPR	DEPPDP	PPSDA	$ 112,626	$ 3,164,032	$ 1,198,035	$ 22,018	$ 157,695	$ 9,649	$ 1,889,102	$ 506,745
Production Energy - Base	TDEPR	DEPPEB	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Inter.	TDEPR	DEPPEI	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Peak	TDEPR	DEPPEP	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		DEPPT		$ 569,901	$ 11,140,298	$ 4,406,046	$ 82,884	$ 548,256	$ 44,397	$ 7,348,762	$ 2,143,304
Transmission Plant											
Transmission Demand - Base	TDEPR	DETRB	BDEM	$ 32,646	$ 939,568	$ 389,373	$ 6,087	$ 46,843	$ 3,798	$ 658,332	$ 196,367
Transmission Demand - Inter.	TDEPR	DETRI	PPWDA	$ 67,326	$ 804,260	$ 311,985	$ 7,219	$ 38,544	$ 3,799	$ 535,297	$ 161,429
Transmission Demand - Peak	TDEPR	DETRP	PPSDA	$ 24,623	$ 691,743	$ 261,923	$ 4,814	$ 34,476	$ 2,110	$ 413,009	$ 110,786
Total Transmission Plant		DETRT		$ 124,596	$ 2,435,570	$ 963,281	$ 18,121	$ 119,864	$ 9,706	$ 1,606,638	$ 468,584
Distribution Poles											
Specific	TDEPR	DEDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation											
General	TDEPR	DEDSG	NCPP	$ 35,646	$ 544,507	$ 213,855	$ -	$ 23,767	$ 1,707	$ 323,249	$ -
Distribution Primary & Secondary Lines											
Primary Specific	TDEPR	DEDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TDEPR	DEDPLD	NCPP	$ 28,064	$ 428,883	$ 168,365	$ -	$ 18,711	$ 1,344	$ 254,490	$ -
Primary Customer	TDEPR	DEDPLC	Cust08	$ 5,874	$ 171,236	$ 6,719	$ 38	$ 979	$ 38	$ 749	$ 134
Secondary Demand	TDEPR	DEDSLD	SICD	$ 3,712	$ 44,695	$ -	$ -	$ 2,492	$ -	$ -	$ -
Secondary Customer	TDEPR	DEDSLC	Cust07	$ 1,336	$ 38,954	$ -	$ -	$ 223	$ -	$ -	$ -
Total Distribution Primary & Secondary Lines		DEDLT		$ 38,986	$ 683,567	$ 175,084	$ 38	$ 22,405	$ 1,382	$ 255,239	$ 134
Distribution Line Transformers											
Demand	TDEPR	DEDLTD	SICD	$ 24,804	$ 298,691	$ -	$ -	$ 16,657	$ -	$ -	$ -
Customer	TDEPR	DEDLTC	Cust07	$ 2,191	$ 63,881	$ -	$ -	$ 365	$ -	$ -	$ -
Total Line Transformers		DEDLTT		$ 26,995	$ 362,573	$ -	$ -	$ 17,022	$ -	$ -	$ -
Distribution Services											
Customer	TDEPR	DEDSC	C02	$ 16,072	$ 758,495	$ -	$ -	$ 262	$ -	$ -	$ -
Distribution Meters											
Customer	TDEPR	DEDMC	C03	$ 4,317	$ 160,111	$ 6,443	$ 37	$ 476	$ 18	$ 735	$ 148
Distribution Street & Customer Lighting											
Customer	TDEPR	DEDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense											
Customer	TDEPR	DECAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$	$ -
Customer Service & Info.											
Customer	TDEPR	DECSI	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense											
Customer	TDEPR	DESEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		DET		$ 816,513	$ 16,085,121	$ 5,764,708	$ 101,079	$ 732,052	$ 57,211	$ 9,534,623	$ 2,612,171

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Description	Ref	Name	Allocation Vector	Coal Mining Power Primary MPP	Coal Mining Power Transmission MPT	Large Power Mine Power TOD Primary LMPP	Large Power Mine Power TOD Transmission LMPT	Large Industrial Time-of-Day LITOD	Street Lighting SL	Decorative Street Lighting SLDEC	Private Outdoor Lighting POL	Customer Outdoor Lighting OL
Depreciation Expenses												
Power Production Plant												
Production Demand - Base	TDEPR	DEPPDB	BDEM	$ 120,521	$ 73,691	$ 95,527	$ 286,181	$ 414,696	$ 47,427	$ 3,985	$ 35,514	$ 54,326
Production Demand - Inter.	TDEPR	DEPPDI	PPWDA	$ 171,379	$ 88,661	$ 111,285	$ 233,739	$ 230,827	$ 15,181	$ 1,276	$ 11,368	$ 17,389
Production Demand - Peak	TDEPR	DEPPDP	PPSDA	$ 108,599	$ 67,050	$ 64,093	$ 200,096	$ 221,779	$ -	$ -	$ -	$ -
Production Energy - Base	TDEPR	DEPPEB	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Inter.	TDEPR	DEPPEI	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Peak	TDEPR	DEPPEP	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		DEPPT		$ 400,500	$ 229,402	$ 270,904	$ 720,016	$ 867,302	$ 62,608	$ 5,261	$ 46,882	$ 71,715
Transmission Plant												
Transmission Demand - Base	TDEPR	DETRB	BDEM	$ 26,349	$ 16,111	$ 20,885	$ 62,567	$ 90,664	$ 10,369	$ 871	$ 7,764	$ 11,877
Transmission Demand - Inter.	TDEPR	DETRI	PPWDA	$ 37,468	$ 19,384	$ 24,330	$ 51,102	$ 50,465	$ 3,319	$ 279	$ 2,485	$ 3,802
Transmission Demand - Peak	TDEPR	DETRP	PPSDA	$ 23,743	$ 14,659	$ 14,012	$ 43,746	$ 48,487	$ -	$ -	$ -	$ -
Total Transmission Plant		DETRT		$ 87,560	$ 50,154	$ 59,227	$ 157,415	$ 189,616	$ 13,688	$ 1,150	$ 10,250	$ 15,679
Distribution Poles												
Specific	TDEPR	DEDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation												
General	TDEPR	DEDSG	NCPP	$ 24,267	$ -	$ 16,659	$ -	$ 96,715	$ 1,653	$ 139	$ 1,238	$ 1,894
Distribution Primary & Secondary Lines												
Primary Specific	TDEPR	DEDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TDEPR	DEDPLD	NCPP	$ 19,120	$ -	$ 13,115	$ -	$ 76,142	$ 1,301	$ 109	$ 975	$ 1,491
Primary Customer	TDEPR	DEDPLC	Cust08	$ 576	$ 192	$ 58	$ 134	$ 19	$ 150,143	$ 19,278	$ 62,034	$ 120,944
Secondary Demand	TDEPR	DEDSLD	SICD	$ -	$ -	$ -	$ -	$ -	$ 164	$ 14	$ 123	$ 188
Secondary Customer	TDEPR	DEDSLC	Cust07	$ -	$ -	$ -	$ -	$ -	$ 34,155	$ 4,385	$ 14,112	$ 27,513
Total Distribution Primary & Secondary Lines		DEDLT		$ 19,696	$ 192	$ 13,173	$ 134	$ 76,161	$ 185,763	$ 23,786	$ 77,242	$ 150,136
Distribution Line Transformers												
Demand	TDEPR	DEDLTD	SICD	$ -	$ -	$ -	$ -	$ -	$ 1,095	$ 92	$ 820	$ 1,254
Customer	TDEPR	DEDLTC	Cust07	$ -	$ -	$ -	$ -	$ -	$ 56,012	$ 7,192	$ 23,142	$ 45,120
Total Line Transformers		DEDLTT		$ -	$ -	$ -	$ -	$ -	$ 57,107	$ 7,284	$ 23,962	$ 46,374
Distribution Services												
Customer	TDEPR	DEDSC	C02	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters												
Customer	TDEPR	DEDMC	C03	$ 554	$ 183	$ 55	$ 111	$ 15	$ 16,222	$ -	$ 17,737	$ -
Distribution Street & Customer Lighting												
Customer	TDEPR	DEDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ 1,449,535	$ 260,218	$ 231,985	$ 342,314
Customer Accounts Expense												
Customer	TDEPR	DECAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.												
Customer	TDEPR	DECSI	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense												
Customer	TDEPR	DESEC	C08	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$	$ -
Total		DET		$ 532,597	$ 279,931	$ 360,019	$ 877,676	$ 1,229,809	$ 1,786,576	$ 317,838	$ 409,297	$ 628,111

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Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Secondary GSS	General Service Primary GSP
Accretion Expenses							
Power Production Plant							
Production Demand - Base	TACRT	ACPPDB	BDEM	$ (85,641)	$ (30,008)	$ (8,403)	$ (196)
Production Demand - Inter.	TACRT	ACPPDI	PPWDA	$ (101,938)	$ (53,773)	$ (7,881)	$ (674)
Production Demand - Peak	TACRT	ACPPDP	PPSDA	$ (67,457)	$ (28,075)	$ (7,466)	$ (412)
Production Energy - Base	TACRT	ACPPEB	E01	$ -	$ -	$ -	$ -
Production Energy - Inter.	TACRT	ACPPEI	E01	$ -	$ -	$ -	$ -
Production Energy - Peak	TACRT	ACPPEP	E01	$ -	$ -	$ -	$ -
Total Power Production Plant		ACPPT		$ (255,036)	$ (111,855)	$ (23,750)	$ (1,281)
Transmission Plant							
Transmission Demand - Base	TACRT	ACTRB	BDEM	$ (52)	$ (18)	$ (5)	$ (0)
Transmission Demand - Inter.	TACRT	ACTRI	PPWDA	$ (62)	$ (33)	$ (5)	$ (0)
Transmission Demand - Peak	TACRT	ACTRP	PPSDA	$ (41)	$ (17)	$ (5)	$ (0)
Total Transmission Plant		ACTRT		$ (156)	$ (68)	$ (14)	$ (1)
Distribution Poles							
Specific	TACRT	ACDPS	NCPP	$ -	$ -	$ -	$ -
Distribution Substation							
General	TACRT	ACDSG	NCPP	$ (18)	$ (9)	$ (2)	$ (0)
Distribution Primary & Secondary Lines							
Primary Specific	TACRT	ACDPLS	NCPP	$ -	$ -	$ -	$ -
Primary Demand	TACRT	ACDPLD	NCPP	$ (14)	$ (7)	$ (2)	$ (0)
Primary Customer	TACRT	ACDPLC	Cust08	$ (54)	$ (43)	$ (8)	$ (0)
Secondary Demand	TACRT	ACDSLD	SICD	$ (3)	$ (2)	$ (1)	$ -
Secondary Customer	TACRT	ACDSLC	Cust07	$ (12)	$ (10)	$ (2)	$ -
Total Distribution Primary & Secondary Lines		ACDLT		$ (84)	$ (62)	$ (13)	$ (0)
Distribution Line Transformers							
Demand	TACRT	ACDLTD	SICD	$ (22)	$ (13)	$ (7)	$ -
Customer	TACRT	ACDLTC	Cust07	$ (20)	$ (16)	$ (3)	$ -
Total Line Transformers		ACDLTT		$ (42)	$ (29)	$ (10)	$ -
Distribution Services							
Customer	TACRT	ACDSC	C02	$ (14)	$ (8)	$ (2)	$ -
Distribution Meters							
Customer	TACRT	ACDMC	C03	$ (11)	$ (7)	$ (3)	$ (0)
Distribution Street & Customer Lighting							
Customer	TACRT	ACDSCL	C04	$ (12)	$ -	$ -	$ -
Customer Accounts Expense							
Customer	TACRT	ACCAE	C05	$ -	$ -	$ -	$ -
Customer Service & Info.							
Customer	TACRT	ACCSI	C06	$ -	$ -	$ -	$ -
Sales Expense							
Customer	TACRT	DESEC	C06	$ -	$ -	$ -	$ -
Total		ACT		$ (255,373)	$ (112,039)	$ (23,793)	$ (1,282)

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Description	Ref	Name	Allocation Vector	All Electric School AES	Combined Light & Power LPS	Combined Light & Power LPP	Combined Light & Power LPT	Small Time-of-Day Secondary STODS	Small Time-of-Day Primary STODP	Large Comm/Ind TOD Primary LCIP	Large Comm/Ind TOD Transmission LCIT
Accretion Expenses											
Power Production Plant											
Production Demand - Base	TACRT	ACPPDB	BDEM	$ (609)	$ (17,534)	$ (7,266)	$ (114)	$ (874)	$ (71)	$ (12,266)	$ (3,865)
Production Demand - Inter.	TACRT	ACPPDI	PPWDA	$ (1,256)	$ (15,009)	$ (5,822)	$ (135)	$ (719)	$ (71)	$ (9,990)	$ (3,013)
Production Demand - Peak	TACRT	ACPPDP	PPSDA	$ (460)	$ (12,909)	$ (4,888)	$ (90)	$ (643)	$ (39)	$ (7,708)	$ (2,068)
Production Energy - Base	TACRT	ACPPEB	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Inter.	TACRT	ACPPEI	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Peak	TACRT	ACPPEP	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		ACPPT		$ (2,325)	$ (45,452)	$ (17,977)	$ (338)	$ (2,237)	$ (181)	$ (29,983)	$ (8,745)
Transmission Plant											
Transmission Demand - Base	TACRT	ACTRB	BDEM	$ (0)	$ (11)	$ (4)	$ (0)	$ (1)	$ (0)	$ (7)	$ (2)
Transmission Demand - Inter.	TACRT	ACTRI	PPWDA	$ (1)	$ (9)	$ (4)	$ (0)	$ (0)	$ (0)	$ (6)	$ (2)
Transmission Demand - Peak	TACRT	ACTRP	PPSDA	$ (0)	$ (8)	$ (3)	$ (0)	$ (0)	$ (0)	$ (5)	$ (1)
Total Transmission Plant		ACTRT		$ (1)	$ (28)	$ (11)	$ (0)	$ (1)	$ (0)	$ (18)	$ (5)
Distribution Poles											
Specific	TACRT	ACDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation											
General	TACRT	ACDSG	NCPP	$ (0)	$ (3)	$ (1)	$ -	$ (0)	$ (0)	$ (2)	$ -
Distribution Primary & Secondary Lines											
Primary Specific	TACRT	ACDPLS	NCPP	$ -	$ -	$ -	$ -	$	$ -	$ -	$ -
Primary Demand	TACRT	ACDPLD	NCPP	$ (0)	$ (2)	$ (1)	$ -	$ (0)	$ (0)	$ (1)	$ -
Primary Customer	TACRT	ACDPLC	Cust08	$ (0)	$ (1)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)
Secondary Demand	TACRT	ACDSLD	SICD	$ (0)	$ (0)	$ -	$ -	$ (0)	$ -	$ -	$ -
Secondary Customer	TACRT	ACDSLC	Cust07	$ (0)	$ (0)	$ -	$ -	$ (0)	$ -	$ -	$ -
Total Distribution Primary & Secondary Lines		ACDLT		$ (0)	$ (4)	$ (1)	$ (0)	$ (0)	$ (0)	$ (1)	$ (0)
Distribution Line Transformers											
Demand	TACRT	ACDLTD	SICD	$ (0)	$ (2)	$ -	$ -	$ (0)	$ -	$ -	$ -
Customer	TACRT	ACDLTC	Cust07	$ (0)	$ (0)	$ -	$ -	$ (0)	$ -	$ -	$ -
Total Line Transformers		ACDLTT		$ (0)	$ (2)	$ -	$ -	$ (0)	$ -	$ -	$ -
Distribution Services											
Customer	TACRT	ACDSC	C02	$ (0)	$ (4)	$ -	$ -	$ (0)	$ -	$ -	$ -
Distribution Meters											
Customer	TACRT	ACDMC	C03	$ (0)	$ (1)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)
Distribution Street & Customer Lighting											
Customer	TACRT	ACDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense											
Customer	TACRT	ACCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.											
Customer	TACRT	ACCSI	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense											
Customer	TACRT	DESEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		ACT		$ (2,327)	$ (45,494)	$ (17,990)	$ (338)	$ (2,239)	$ (181)	$ (30,004)	$ (8,750)

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Description	Ref	Name	Allocation Vector	Coal Mining Power Primary MPP	Coal Mining Power Transmission MPT	Large Power Mine Power TOD Primary LMPP	Large Power Mine Power TOD Transmission LMPT	Large Industrial Time-of-Day LITOD	Street Lighting SL	Decorative Street Lighting SLDEC	Private Outdoor Lighting POL	Customer Outdoor Lighting OL
Accretion Expenses												
Power Production Plant												
Production Demand - Base	TACRT	ACPPDB	BDEM	$ (492)	$ (301)	$ (390)	$ (1,188)	$ (1,692)	$ (194)	$ (16)	$ (145)	$ (222)
Production Demand - Inter.	TACRT	ACPPDI	PPWDA	$ (699)	$ (362)	$ (454)	$ (954)	$ (942)	$ (62)	$ (5)	$ (46)	$ (71)
Production Demand - Peak	TACRT	ACPPDP	PPSDA	$ (443)	$ (274)	$ (281)	$ (616)	$ (905)	$ -	$ -	$ -	$ -
Production Energy - Base	TACRT	ACPPEB	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Inter.	TACRT	ACPPEI	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Peak	TACRT	ACPPEP	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		ACPPT		$ (1,634)	$ (936)	$ (1,105)	$ (2,938)	$ (3,539)	$ (255)	$ (21)	$ (191)	$ (293)
Transmission Plant												
Transmission Demand - Base	TACRT	ACTRB	BDEM	$ (0)	$ (0)	$ (0)	$ (1)	$ (1)	$ (0)	$ (0)	$ (0)	$ (0)
Transmission Demand - Inter.	TACRT	ACTRI	PPWDA	$ (0)	$ (0)	$ (0)	$ (1)	$ (1)	$ (0)	$ (0)	$ (0)	$ (0)
Transmission Demand - Peak	TACRT	ACTRP	PPSDA	$ (0)	$ (0)	$ (0)	$ (0)	$ (1)	$ -	$ -	$ -	$ -
Total Transmission Plant		ACTRT		$ (1)	$ (1)	$ (1)	$ (2)	$ (2)	$ (0)	$ (0)	$ (0)	$ (0)
Distribution Poles												
Specific	TACRT	ACDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation												
General	TACRT	ACDSG	NCPP	$ (0)	$ -	$ (0)	$ -	$ (1)	$ (0)	$ (0)	$ (0)	$ (0)
Distribution Primary & Secondary Lines												
Primary Specific	TACRT	ACDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TACRT	ACDPLD	NCPP	$ (0)	$ -	$ (0)	$ -	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)
Primary Customer	TACRT	ACDPLC	Cust08	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (1)	$ (0)	$ (0)	$ (1)
Secondary Demand	TACRT	ACDSLD	SICD	$ -	$ -	$ -	$ -	$ -	$ (0)	$ (0)	$ (0)	$ (0)
Secondary Customer	TACRT	ACDSLC	Cust07	$ -	$ -	$ -	$ -	$ -	$ (0)	$ (0)	$ (0)	$ (0)
Total Distribution Primary & Secondary Lines		ACDLT		$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (1)	$ (0)	$ (0)	$ (1)
Distribution Line Transformers												
Demand	TACRT	ACDLTD	SICD	$ -	$ -	$ -	$ -	$ -	$ (0)	$ (0)	$ (0)	$ (0)
Customer	TACRT	ACDLTC	Cust07	$ -	$ -	$ -	$ -	$ -	$ (0)	$ (0)	$ (0)	$ (0)
Total Line Transformers		ACDLTT		$ -	$ -	$ -	$ -	$ -	$ (0)	$ (0)	$ (0)	$ (0)
Distribution Services												
Customer	TACRT	ACDSC	C02	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters												
Customer	TACRT	ACDMC	C03	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ -	$ (0)	$ -
Distribution Street & Customer Lighting												
Customer	TACRT	ACDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ (8)	$ (2)	$ (1)	$ (2)
Customer Accounts Expense												
Customer	TACRT	ACCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.												
Customer	TACRT	ACCSI	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense												
Customer	TACRT	DESEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$	$ -	$ -
Total		ACT		$ (1,635)	$ (937)	$ (1,106)	$ (2,939)	$ (3,542)	$ (265)	$ (23)	$ (193)	$ (296)

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Description	*Ref*	*Name*	Allocation *Vector*	Total System	Residential Rate RS	General Service Secondary GSS	General Service Primary GSP
Property Taxes							
Power Production Plant							
Production Demand - Base	PTAX	PTPPDB	BDEM	$ 2,192,376	$ 768,143	$ 215,106	$ 5,005
Production Demand - Inter.	PTAX	PTPPDI	PPWDA	$ 2,609,567	$ 1,378,578	$ 201,747	$ 17,253
Production Demand - Peak	PTAX	PTPPDP	PPSDA	$ 1,726,871	$ 716,715	$ 191,134	$ 10,539
Production Energy - Base	PTAX	PTPPEB	E01	$ -	$ -	$ -	$ -
Production Energy - Inter.	PTAX	PTPPEI	E01	$ -	$ -	$ -	$ -
Production Energy - Peak	PTAX	PTPPEP	E01	$ -	$ -	$ -	$ -
Total Power Production Plant		PTPPT		$ 6,528,814	$ 2,863,433	$ 607,987	$ 32,798
Transmission Plant							
Transmission Demand - Base	PTAX	PTTRB	BDEM	$ 387,516	$ 135,774	$ 38,021	$ 885
Transmission Demand - Inter.	PTAX	PTTRI	PPWDA	$ 461,258	$ 243,319	$ 35,660	$ 3,050
Transmission Demand - Peak	PTAX	PTTRP	PPSDA	$ 305,236	$ 127,037	$ 33,784	$ 1,863
Total Transmission Plant		PTTRT		$ 1,154,010	$ 506,130	$ 107,468	$ 5,797
Distribution Poles							
Specific	PTAX	PTDPS	NCPP	$ -	$ -	$ -	$ -
Distribution Substation							
General	PTAX	PTDSG	NCPP	$ 281,338	$ 143,305	$ 29,520	$ 1,653
Distribution Primary & Secondary Lines							
Primary Specific	PTAX	PTDPLS	NCPP	$ -	$ -	$ -	$ -
Primary Demand	PTAX	PTDPLD	NCPP	$ 221,494	$ 112,823	$ 23,241	$ 1,301
Primary Customer	PTAX	PTDPLC	Cust08	$ 829,166	$ 659,434	$ 124,811	$ 117
Secondary Demand	PTAX	PTDSLD	SICD	$ 50,336	$ 30,623	$ 15,440	$ -
Secondary Customer	PTAX	PTDSLC	Cust07	$ 188,437	$ 150,011	$ 28,393	$ -
Total Distribution Primary & Secondary Lines		PTDLT		$ 1,289,452	$ 952,891	$ 191,885	$ 1,418
Distribution Line Transformers							
Demand	PTAX	PTDLTD	SICD	$ 336,391	$ 204,655	$ 103,185	$ -
Customer	PTAX	PTDLTC	Cust07	$ 309,025	$ 246,009	$ 46,562	$ -
Total Line Transformers		PTDLTT		$ 645,415	$ 450,664	$ 149,747	$ -
Distribution Services							
Customer	PTAX	PTDSC	C02	$ 213,931	$ 125,787	$ 23,726	$ -
Distribution Meters							
Customer	PTAX	PTDMC	C03	$ 168,547	$ 104,921	$ 46,290	$ 112
Distribution Street & Customer Lighting							
Customer	PTAX	PTDSCL	C04	$ 191,557	$ -	$ -	$ -
Customer Accounts Expense							
Customer	PTAX	PTCAE	C05	$ -	$ -	$ -	$ -
Customer Service & Info.							
Customer	PTAX	PTCSI	C06	$ -	$ -	$ -	$ -
Sales Expense							
Customer	PTAX	PTSEC	C06	$ -	$ -	$ -	$ -
Total		PTT		$ 10,473,065	$ 5,147,131	$ 1,156,620	$ 41,778

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation
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Description	Ref	Name	Allocation Vector	All Electric School AES	Combined Light & Power LPS	Combined Light & Power LPP	Combined Light & Power LPT	Small Time-of-Day Secondary STODS	Small Time-of-Day Primary STODP	Large Comm/Ind TOD Primary LCIP	Large Comm/Ind TOD Transmission LCIT
Property Taxes											
Power Production Plant											
Production Demand - Base	PTAX	PTPPDB	BDEM	$ 15,596	$ 448,886	$ 186,018	$ 2,906	$ 22,379	$ 1,814	$ 314,509	$ 93,812
Production Demand - Inter.	PTAX	PTPPDI	PPWDA	$ 32,164	$ 384,224	$ 149,047	$ 3,449	$ 18,414	$ 1,815	$ 255,731	$ 77,120
Production Demand - Peak	PTAX	PTPPDP	PPSDA	$ 11,763	$ 330,471	$ 125,130	$ 2,300	$ 16,471	$ 1,008	$ 197,309	$ 52,928
Production Energy - Base	PTAX	PTPPEB	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Inter.	PTAX	PTPPEI	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Peak	PTAX	PTPPEP	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		PTPPT		$ 59,524	$ 1,163,581	$ 460,194	$ 8,657	$ 57,263	$ 4,637	$ 767,550	$ 223,860
Transmission Plant											
Transmission Demand - Base	PTAX	PTTRB	BDEM	$ 2,757	$ 79,340	$ 32,880	$ 514	$ 3,956	$ 321	$ 55,592	$ 16,582
Transmission Demand - Inter.	PTAX	PTTRI	PPWDA	$ 5,685	$ 67,914	$ 26,345	$ 610	$ 3,255	$ 321	$ 45,202	$ 13,632
Transmission Demand - Peak	PTAX	PTTRP	PPSDA	$ 2,079	$ 58,413	$ 22,118	$ 406	$ 2,911	$ 178	$ 34,876	$ 9,355
Total Transmission Plant		PTTRT		$ 10,521	$ 205,667	$ 81,342	$ 1,530	$ 10,122	$ 820	$ 135,669	$ 39,569
Distribution Poles											
Specific	PTAX	PTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation											
General	*PTAX*	*PTDSG*	*NCPP*	$ 2,964	$ 45,270	$ 17,780	$ -	$ 1,976	$ 142	$ 26,875	$ -
Distribution Primary & Secondary Lines											
Primary Specific	PTAX	PTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	PTAX	PTDPLD	NCPP	$ 2,333	$ 35,640	$ 13,998	$ -	$ 1,556	$ 112	$ 21,158	$ -
Primary Customer	PTAX	PTDPLC	Cust08	$ 488	$ 14,236	$ 559	$ 3	$ 81	$ 3	$ 62	$ 11
Secondary Demand	PTAX	PTDSLD	SICD	$ 309	$ 3,716	$ -	$ -	$ 207	$ -	$ -	$ -
Secondary Customer	PTAX	PTDSLC	Cust07	$ 111	$ 3,239	$ -	$ -	$ 19	$ -	$ -	$ -
Total Distribution Primary & Secondary Lines		PTDLT		$ 3,241	$ 56,831	$ 14,556	$ 3	$ 1,863	$ 115	$ 21,220	$ 11
Distribution Line Transformers											
Demand	PTAX	PTDLTD	SICD	$ 2,062	$ 24,833	$ -	$ -	$ 1,385	$ -	$ -	$ -
Customer	PTAX	PTDLTC	Cust07	$ 182	$ 5,311	$ -	$ -	$ 30	$ -	$ -	$ -
Total Line Transformers		PTDLTT		$ 2,244	$ 30,144	$ -	$ -	$ 1,415	$ -	$ -	$ -
Distribution Services											
Customer	PTAX	PTDSC	C02	$ 1,338	$ 63,061	$ -	$ -	$ 22	$ -	$ -	$ -
Distribution Meters											
Customer	PTAX	PTDMC	C03	$ 359	$ 13,311	$ 536	$ 3	$ 40	$ 2	$ 61	$ 12
Distribution Street & Customer Lighting											
Customer	PTAX	PTDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense											
Customer	PTAX	PTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.											
Customer	PTAX	PTCSI	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Sales Expense											
Customer	PTAX	PTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Total		PTT		$ 80,190	$ 1,577,845	$ 574,408	$ 10,193	$ 72,700	$ 5,715	$ 951,375	$ 263,452

KENTUCKY UTILITIES
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Description	Ref	Name	Allocation Vector	Coal Mining Power Primary MPP	Coal Mining Power Transmission MPT	Large Power Mine Power TOD Primary LMPP	Large Power Mine Power TOD Transmission LMPT	Large Industrial Time-of-Day LITOD	Street Lighting SL	Decorative Street Lighting SLDEC	Private Outdoor Lighting POL	Customer Outdoor Lighting OL
Property Taxes												
Power Production Plant												
Production Demand - Base	PTAX	PTPPDB	BDEM	$ 12,588	$ 7,697	$ 9,977	$ 28,890	$ 43,313	$ 4,954	$ 416	$ 3,709	$ 5,674
Production Demand - Inter.	PTAX	PTPPDI	PPWDA	$ 17,900	$ 9,260	$ 11,623	$ 24,413	$ 24,109	$ 1,586	$ 133	$ 1,187	$ 1,816
Production Demand - Peak	PTAX	PTPPDP	PPSDA	$ 11,343	$ 7,003	$ 8,694	$ 20,899	$ 23,184	$ -	$ -	$ -	$ -
Production Energy - Base	PTAX	PTPPEB	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Inter.	PTAX	PTPPEI	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Peak	PTAX	PTPPEP	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		PTPPT		$ 41,831	$ 23,960	$ 28,295	$ 75,203	$ 90,586	$ 6,539	$ 549	$ 4,897	$ 7,490
Transmission Plant												
Transmission Demand - Base	PTAX	PTTRB	BDEM	$ 2,225	$ 1,360	$ 1,764	$ 5,283	$ 7,656	$ 876	$ 74	$ 656	$ 1,003
Transmission Demand - Inter.	PTAX	PTTRI	PPWDA	$ 3,164	$ 1,637	$ 2,054	$ 4,315	$ 4,261	$ 280	$ 24	$ 210	$ 321
Transmission Demand - Peak	PTAX	PTTRP	PPSDA	$ 2,005	$ 1,238	$ 1,183	$ 3,694	$ 4,094	$ -	$ -	$ -	$
Total Transmission Plant		PTTRT		$ 7,394	$ 4,235	$ 5,001	$ 13,293	$ 16,012	$ 1,156	$ 97	$ 866	$ 1,324
Distribution Poles												
Specific	PTAX	PTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation												
General	PTAX	PTDSG	NCPP	$ 2,019	$ -	$ 1,385	$ -	$ 8,041	$ 137	$ 12	$ 103	$ 157
Distribution Primary & Secondary Lines												
Primary Specific	PTAX	PTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	PTAX	PTDPLD	NCPP	$ 1,590	$ -	$ 1,090	$ -	$ 6,330	$ 108	$ 9	$ 81	$ 124
Primary Customer	PTAX	PTDPLC	Cust08	$ 48	$ 16	$ 5	$ 11	$ 2	$ 12,483	$ 1,603	$ 5,157	$ 10,055
Secondary Demand	PTAX	PTDSLD	SICD	$ -	$ -	$ -	$ -	$ -	$ 14	$ 1	$ 10	$ 18
Secondary Customer	PTAX	PTDSLC	Cust07	$ -	$ -	$ -	$ -	$ -	$ 2,840	$ 365	$ 1,173	$ 2,287
Total Distribution Primary & Secondary Lines		PTDLT		$ 1,638	$ 16	$ 1,095	$ 11	$ 6,332	$ 15,444	$ 1,978	$ 6,422	$ 12,482
Distribution Line Transformers												
Demand	PTAX	PTDLTD	SICD	$ -	$ -	$ -	$ -	$ -	$ 91	$ 8	$ 68	$ 104
Customer	PTAX	PTDLTC	Cust07	$ -	$ -	$ -	$ -	$ -	$ 4,657	$ 598	$ 1,924	$ 3,751
Total Line Transformers		PTDLTT		$ -	$ -	$ -	$ -	$ -	$ 4,748	$ 606	$ 1,992	$ 3,855
Distribution Services												
Customer	PTAX	PTDSC	C02	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters												
Customer	PTAX	PTDMC	C03	$ 48	$ 15	$ 5	$ 9	$ 1	$ 1,349	$ -	$ 1,475	$ -
Distribution Street & Customer Lighting												
Customer	PTAX	PTDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ 120,513	$ 23,297	$ 19,287	$ 28,460
Customer Accounts Expense												
Customer	PTAX	PTCAE	C05	$ -	$	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.												
Customer	PTAX	PTCSI	C06	$ -	$	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense												
Customer	PTAX	PTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		PTT		$ 52,927	$ 28,227	$ 35,761	$ 88,516	$ 120,972	$ 149,886	$ 26,538	$ 35,041	$ 53,769

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Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Secondary GSS	General Service Primary GSP
Other Taxes							
Power Production Plant							
Production Demand - Base	OTAX	OTPPDB	BDEM	$ 1,415,933	$ 496,100	$ 138,925	$ 3,233
Production Demand - Inter.	OTAX	OTPPDI	PPWDA	$ 1,685,373	$ 889,053	$ 130,297	$ 11,143
Production Demand - Peak	OTAX	OTPPDP	PPSDA	$ 1,115,289	$ 464,178	$ 123,443	$ 6,807
Production Energy - Base	OTAX	OTPPEB	E01	$ -	$ -	$ -	$ -
Production Energy - Inter.	OTAX	OTPPEI	E01	$ -	$ -	$ -	$ -
Production Energy - Peak	OTAX	OTPPEP	E01	$ -	$ -	$ -	$ -
Total Power Production Plant		OTPPT		$ 4,216,595	$ 1,849,331	$ 392,665	$ 21,182
Transmission Plant							
Transmission Demand - Base	OTAX	OTTRB	BDEM	$ 250,275	$ 87,689	$ 24,556	$ 571
Transmission Demand - Inter.	OTAX	OTTRI	PPWDA	$ 297,900	$ 157,146	$ 23,031	$ 1,970
Transmission Demand - Peak	OTAX	OTTRP	PPSDA	$ 197,135	$ 82,046	$ 21,819	$ 1,203
Total Transmission Plant		OTTRT		$ 745,310	$ 326,881	$ 69,406	$ 3,744
Distribution Poles							
Specific	OTAX	OTDPS	NCPP	$ -	$ -	$ -	$ -
Distribution Substation							
General	OTAX	OTDSG	NCPP	$ 161,701	$ 92,553	$ 19,065	$ 1,068
Distribution Primary & Secondary Lines							
Primary Specific	OTAX	OTDPLS	NCPP	$ -	$ -	$ -	$ -
Primary Demand	OTAX	OTDPLD	NCPP	$ 143,051	$ 72,866	$ 15,010	$ 840
Primary Customer	OTAX	OTDPLC	Cust08	$ 535,525	$ 425,891	$ 80,609	$ 75
Secondary Demand	OTAX	OTDSLD	SICD	$ 32,509	$ 19,778	$ 9,972	$ -
Secondary Customer	OTAX	OTDSLC	Cust07	$ 121,701	$ 96,884	$ 18,337	$ -
Total Distribution Primary & Secondary Lines		OTDLT		$ 832,785	$ 615,419	$ 123,928	$ 916
Distribution Line Transformers							
Demand	OTAX	OTDLTD	SICD	$ 217,256	$ 132,175	$ 66,641	$ -
Customer	OTAX	OTDLTC	Cust07	$ 199,582	$ 158,883	$ 30,072	$ -
Total Line Transformers		OTDLTT		$ 416,837	$ 291,058	$ 96,713	$ -
Distribution Services							
Customer	OTAX	OTDSC	C02	$ 138,166	$ 81,238	$ 15,323	$ -
Distribution Meters							
Customer	OTAX	OTDMC	C03	$ 108,855	$ 67,783	$ 29,896	$ 72
Distribution Street & Customer Lighting							
Customer	OTAX	OTDSCL	C04	$ 123,716	$ -	$ -	$ -
Customer Accounts Expense							
Customer	OTAX	OTCAE	C05	$ -	$ -	$ -	$ -
Customer Service & Info.							
Customer	OTAX	OTCSI	C06	$ -	$ -	$ -	$ -
Sales Expense							
Customer	OTAX	OTSEC	C06	$ -	$ -	$ -	$ -
Total		OTT		$ 6,763,965	$ 3,324,243	$ 746,996	$ 28,982

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation
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Description	Ref	Name	Allocation Vector	All Electric School AES	Combined Light & Power LPS	Combined Light & Power LPP	Combined Light & Power LPT	Small Time-of-Day Secondary STODS	Small Time-of-Day Primary STODP	Large Comm/Ind TOD Primary LCIP	Large Comm/Ind TOD Transmission LCIT
Other Taxes											
Power Production Plant											
Production Demand - Base	OTAX	OTPPDB	BDEM	$ 10,073	$ 289,897	$ 120,138	$ 1,878	$ 14,453	$ 1,172	$ 203,124	$ 60,588
Production Demand - Inter.	OTAX	OTPPDI	PPWDA	$ 20,773	$ 246,149	$ 96,281	$ 2,228	$ 11,892	$ 1,172	$ 165,162	$ 49,808
Production Demand - Peak	OTAX	OTPPDP	PPSDA	$ 7,597	$ 213,433	$ 80,815	$ 1,485	$ 10,837	$ 651	$ 127,431	$ 34,183
Production Energy - Base	OTAX	OTPPEB	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Inter.	OTAX	OTPPEI	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Peak	OTAX	OTPPEP	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		OTPPT		$ 38,443	$ 751,479	$ 297,214	$ 5,591	$ 36,983	$ 2,995	$ 495,717	$ 144,578
Transmission Plant											
Transmission Demand - Base	OTAX	OTTRB	BDEM	$ 1,780	$ 51,241	$ 21,235	$ 332	$ 2,555	$ 207	$ 35,903	$ 10,709
Transmission Demand - Inter.	OTAX	OTTRI	PPWDA	$ 3,672	$ 43,862	$ 17,015	$ 394	$ 2,102	$ 207	$ 29,193	$ 8,804
Transmission Demand - Peak	OTAX	OTTRP	PPSDA	$ 1,343	$ 37,726	$ 14,284	$ 263	$ 1,880	$ 115	$ 22,524	$ 6,042
Total Transmission Plant		OTTRT		$ 6,795	$ 132,829	$ 52,534	$ 988	$ 6,537	$ 529	$ 87,621	$ 25,555
Distribution Poles											
Specific	OTAX	OTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation											
General	OTAX	OTDSG	NCPP	$ 1,914	$ 29,237	$ 11,483	$ -	$ 1,276	$ 92	$ 17,357	$ -
Distribution Primary & Secondary Lines											
Primary Specific	OTAX	OTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	OTAX	OTDPLD	NCPP	$ 1,507	$ 23,018	$ 9,040	$ -	$ 1,005	$ 72	$ 13,665	$ -
Primary Customer	OTAX	OTDPLC	Cust08	$ 315	$ 9,195	$ 361	$ 2	$ 53	$ 2	$ 40	$ 7
Secondary Demand	OTAX	OTDSLD	SICD	$ 199	$ 2,400	$ -	$ -	$ 134	$ -	$ -	$ -
Secondary Customer	OTAX	OTDSLC	Cust07	$ 72	$ 2,092	$ -	$ -	$ 12	$ -	$ -	$ -
Total Distribution Primary & Secondary Lines		OTDLT		$ 2,093	$ 36,704	$ 9,401	$ 2	$ 1,203	$ 74	$ 13,705	$ 7
Distribution Line Transformers											
Demand	OTAX	OTDLTD	SICD	$ 1,332	$ 16,038	$ -	$ -	$ 894	$ -	$ -	$ -
Customer	OTAX	OTDLTC	Cust07	$ 118	$ 3,430	$ -	$ -	$ 20	$ -	$ -	$ -
Total Line Transformers		OTDLTT		$ 1,450	$ 19,468	$ -	$ -	$ 914	$ -	$ -	$ -
Distribution Services											
Customer	OTAX	OTDSC	C02	$ 863	$ 40,727	$ -	$ -	$ 14	$ -	$ -	$ -
Distribution Meters											
Customer	OTAX	OTDMC	C03	$ 232	$ 8,597	$ 346	$ 2	$ 26	$ 1	$ 39	$ 8
Distribution Street & Customer Lighting											
Customer	OTAX	OTDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense											
Customer	OTAX	OTCAE	C05	$ -	$ -	$ -	$ -	$	$ -	$ -	$ -
Customer Service & Info.											
Customer	OTAX	OTCSI	C06	$ -	$	$ -	$ -	$	$ -	$ -	$ -
Sales Expense											
Customer	OTAX	OTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		OTT		$ 51,790	$ 1,019,042	$ 370,978	$ 6,583	$ 46,953	$ 3,691	$ 614,440	$ 170,149

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Description	Ref	Name	Allocation Vector	Coal Mining Power Primary MPP	Coal Mining Power Transmission MPT	Large Power Mine Power TOD Primary LMPP	Large Power Mine Power TOD Transmission LMPT	Large Industrial Time-of-Day LITOD	Street Lighting SL	Decorative Street Lighting SLDEC	Private Outdoor Lighting POL	Customer Outdoor Lighting OL
Other Taxes												
Power Production Plant												
Production Demand - Base	OTAX	OTPPDB	BDEM	$ 8,130	$ 4,971	$ 6,444	$ 19,305	$ 27,974	$ 3,199	$ 269	$ 2,396	$ 3,665
Production Demand - Inter.	OTAX	OTPPDI	PPWDA	$ 11,561	$ 5,981	$ 7,507	$ 15,767	$ 15,571	$ 1,024	$ 66	$ 767	$ 1,173
Production Demand - Peak	OTAX	OTPPDP	PPSDA	$ 7,326	$ 4,523	$ 4,323	$ 13,498	$ 14,960	$ -	$	$ -	$ -
Production Energy - Base	OTAX	OTPPEB	E01	$ -	$ -	$ -	$ -	$ -	$ -	$	$ -	$
Production Energy - Inter.	OTAX	OTPPEI	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
Production Energy - Peak	OTAX	OTPPEP	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		OTPPT		$ 27,016	$ 15,475	$ 18,274	$ 48,569	$ 58,505	$ 4,223	$ 355	$ 3,162	$ 4,838
Transmission Plant												
Transmission Demand - Base	OTAX	OTTRB	BDEM	$ 1,437	$ 879	$ 1,139	$ 3,412	$ 4,945	$ 565	$ 48	$ 423	$ 648
Transmission Demand - Inter.	OTAX	OTTRI	PPWDA	$ 2,043	$ 1,057	$ 1,327	$ 2,787	$ 2,752	$ 181	$ 15	$ 136	$ 207
Transmission Demand - Peak	OTAX	OTTRP	PPSDA	$ 1,295	$ 799	$ 764	$ 2,386	$ 2,644	$ -	$ -	$ -	$ -
Total Transmission Plant		OTTRT		$ 4,775	$ 2,735	$ 3,230	$ 8,585	$ 10,341	$ 746	$ 63	$ 559	$ 855
Distribution Poles												
Specific	OTAX	OTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation												
General	OTAX	OTDSG	NCPP	$ 1,304	$ -	$ 895	$ -	$ 5,193	$ 89	$ 7	$ 66	$ 102
Distribution Primary & Secondary Lines												
Primary Specific	OTAX	OTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	OTAX	OTDPLD	NCPP	$ 1,027	$ -	$ 704	$ -	$ 4,088	$ 70	$ 6	$ 52	$ 80
Primary Customer	OTAX	OTDPLC	Cust08	$ 31	$ 10	$ 3	$ 7	$ 1	$ 8,062	$ 1,035	$ 3,331	$ 6,494
Secondary Demand	OTAX	OTDSLD	SICD	$ -	$ -	$ -	$ -	$ -	$ 9	$ 1	$ 7	$ 10
Secondary Customer	OTAX	OTDSLC	Cust07	$ -	$ -	$ -	$ -	$ -	$ 1,834	$ 235	$ 758	$ 1,477
Total Distribution Primary & Secondary Lines		OTDLT		$ 1,058	$ 10	$ 707	$ 7	$ 4,089	$ 9,975	$ 1,277	$ 4,148	$ 8,062
Distribution Line Transformers												
Demand	OTAX	OTDLTD	SICD	$ -	$ -	$ -	$ -	$ -	$ 59	$ 5	$ 44	$ 67
Customer	OTAX	OTDLTC	Cust07	$ -	$ -	$ -	$ -	$ -	$ 3,008	$ 386	$ 1,243	$ 2,423
Total Line Transformers		OTDLTT		$ -	$ -	$ -	$ -	$ -	$ 3,066	$ 391	$ 1,287	$ 2,490
Distribution Services												
Customer	OTAX	OTDSC	C02	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters												
Customer	OTAX	OTDMC	C03	$ 30	$ 10	$ 3	$ 6	$ 1	$ 871	$ -	$ 952	$ -
Distribution Street & Customer Lighting												
Customer	OTAX	OTDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ 77,833	$ 15,046	$ 12,456	$ 18,381
Customer Accounts Expense												
Customer	OTAX	OTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
Customer Service & Info.												
Customer	OTAX	OTCSI	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense												
Customer	OTAX	OTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		OTT		$ 34,183	$ 18,230	$ 23,109	$ 57,167	$ 78,129	$ 96,803	$ 17,140	$ 22,631	$ 34,726

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Description	Ref	Name	Allocation Vector		Total System	Residential Rate RS	General Service Secondary GSS	General Service Primary GSP
Gain Disposition of Allowances								
Power Production Plant								
Production Demand - Base	GAIN	OTPPDB	BDEM	$	-	$ -	$ -	$ -
Production Demand - Inter.	GAIN	OTPPDI	PPWDA	$	-	$ -	$ -	$ -
Production Demand - Peak	GAIN	OTPPDP	PPSDA	$	-	$ -	$ -	$ -
Production Energy - Base	GAIN	OTPPEB	E01	$	(504,602)	$ (176,797)	$ (49,509)	$ (1,152)
Production Energy - Inter.	GAIN	OTPPEI	E01	$	-	$ -	$ -	$ -
Production Energy - Peak	GAIN	OTPPEP	E01	$	-	$ -	$ -	$ -
Total Power Production Plant		OTPPT		$	(504,602)	$ (176,797)	$ (49,509)	$ (1,152)
Transmission Plant								
Transmission Demand - Base	GAIN	OTTRB	BDEM	$	-	$ -	$ -	$ -
Transmission Demand - Inter.	GAIN	OTTRI	PPWDA	$	-	$ -	$ -	$ -
Transmission Demand - Peak	GAIN	OTTRP	PPSDA	$	-	$ -	$ -	$ -
Total Transmission Plant		OTTRT		$	-	$ -	$ -	$ -
Distribution Poles								
Specific	GAIN	OTDPS	NCPP	$	-	$ -	$ -	$ -
Distribution Substation								
General	GAIN	OTDSG	NCPP	$	-	$ -	$ -	$ -
Distribution Primary & Secondary Lines								
Primary Specific	GAIN	OTDPLS	NCPP	$	-	$ -	$ -	$ -
Primary Demand	GAIN	OTDPLD	NCPP	$	-	$ -	$ -	$ -
Primary Customer	GAIN	OTDPLC	Cust08	$	-	$ -	$ -	$ -
Secondary Demand	GAIN	OTDSLD	SICD	$	-	$ -	$ -	$ -
Secondary Customer	GAIN	OTDSLC	Cust07	$	-	$ -	$ -	$ -
Total Distribution Primary & Secondary Lines		OTDLT		$	-	$ -	$ -	$ -
Distribution Line Transformers								
Demand	GAIN	OTDLTD	SICD	$	-	$ -	$ -	$ -
Customer	GAIN	OTDLTC	Cust07	$	-	$ -	$ -	$ -
Total Line Transformers		OTDLTT		$	-	$ -	$ -	$ -
Distribution Services								
Customer	GAIN	OTDSC	C02	$	-	$ -	$ -	$ -
Distribution Meters								
Customer	GAIN	OTDMC	C03	$	-	$ -	$ -	$ -
Distribution Street & Customer Lighting								
Customer	GAIN	OTDSCL	C04	$	-	$ -	$ -	$ -
Customer Accounts Expense								
Customer	GAIN	OTCAE	C05	$	-	$ -	$ -	$ -
Customer Service & Info.								
Customer	GAIN	OTCSI	C06	$	-	$ -	$ -	$ -
Sales Expense								
Customer	GAIN	OTSEC	C06	$	-	$ -	$ -	$ -
Total		OTT		$	(504,602)	$ (176,797)	$ (49,509)	$ (1,152)

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation
12 Months Ended
April 30, 2008

Description	Ref	Name	Allocation Vector	All Electric School AES	Combined Light & Power LPS	Combined Light & Power LPP	Combined Light & Power LPT	Small Time-of-Day Secondary STODS	Small Time-of-Day Primary STODP	Large Comm/Ind TOD Primary LCIP	Large Comm/Ind TOD Transmission LCIT
Gain Disposition of Allowances											
Power Production Plant											
Production Demand - Base	GAIN	OTPPDB	BDEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Demand - Inter.	GAIN	OTPPDI	PPWDA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Demand - Peak	GAIN	OTPPDP	PPSDA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Base	GAIN	OTPPEB	E01	$ (3,590)	$ (103,312)	$ (42,814)	$ (669)	$ (5,151)	$ (418)	$ (72,388)	$ (21,592)
Production Energy - Inter.	GAIN	OTPPEI	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Peak	GAIN	OTPPEP	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		OTPPT		$ (3,590)	$ (103,312)	$ (42,814)	$ (669)	$ (5,151)	$ (418)	$ (72,388)	$ (21,592)
Transmission Plant											
Transmission Demand - Base	GAIN	OTTRB	BDEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Demand - Inter.	GAIN	OTTRI	PPWDA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Demand - Peak	GAIN	OTTRP	PPSDA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Transmission Plant		OTTRT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Poles											
Specific	GAIN	OTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation											
General	GAIN	OTDSG	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Primary & Secondary Lines											
Primary Specific	GAIN	OTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	GAIN	OTDPLD	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Customer	GAIN	OTDPLC	Cust08	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Secondary Demand	GAIN	OTDSLD	SICD	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Secondary Customer	GAIN	OTDSLC	Cust07	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Distribution Primary & Secondary Lines		OTDLT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Line Transformers											
Demand	GAIN	OTDLTD	SICD	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer	GAIN	OTDLTC	Cust07	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Line Transformers		OTDLTT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Services											
Customer	GAIN	OTDSC	C02	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters											
Customer	GAIN	OTDMC	C03	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Street & Customer Lighting											
Customer	GAIN	OTDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense											
Customer	GAIN	OTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.											
Customer	GAIN	OTCSI	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense											
Customer	GAIN	OTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		OTT		$ (3,590)	$ (103,312)	$ (42,814)	$ (669)	$ (5,151)	$ (418)	$ (72,388)	$ (21,592)

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation
12 Months Ended
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Description	Ref	Name	Allocation Vector	Coal Mining Power Primary MPP	Coal Mining Power Transmission MPT	Large Power Mine Power TOD Primary LMPP	Large Power Mine Power TOD Transmission LMPT	Large Industrial Time-of-Day LITOD	Street Lighting SL	Decorative Street Lighting SLDEC	Private Outdoor Lighting POL	Customer Outdoor Lighting OL
Gain Disposition of Allowances												
Power Production Plant												
Production Demand - Base	GAIN	OTPPDB	BDEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Demand - Inter.	GAIN	OTPPDI	PPWDA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Demand - Peak	GAIN	OTPPDP	PPSDA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Base	GAIN	OTPPEB	E01	$ (2,897)	$ (1,772)	$ (2,296)	$ (6,880)	$ (9,969)	$ (1,140)	$ (96)	$ (854)	$ (1,306)
Production Energy - Inter.	GAIN	OTPPEI	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Peak	GAIN	OTPPEP	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		OTPPT		$ (2,897)	$ (1,772)	$ (2,296)	$ (6,880)	$ (9,969)	$ (1,140)	$ (96)	$ (854)	$ (1,306)
Transmission Plant												
Transmission Demand - Base	GAIN	OTTRB	BDEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Demand - Inter.	GAIN	OTTRI	PPWDA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Demand - Peak	GAIN	OTTRP	PPSDA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Transmission Plant		OTTRT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Poles												
Specific	GAIN	OTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation												
General	GAIN	OTDSG	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Primary & Secondary Lines												
Primary Specific	GAIN	OTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	GAIN	OTDPLD	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Customer	GAIN	OTDPLC	Cust08	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Secondary Demand	GAIN	OTDSLD	SICD	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Secondary Customer	GAIN	OTDSLC	Cust07	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Distribution Primary & Secondary Lines		OTDLT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Line Transformers												
Demand	GAIN	OTDLTD	SICD	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer	GAIN	OTDLTC	Cust07	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Line Transformers		OTDLTT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Services												
Customer	GAIN	OTDSC	C02	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters												
Customer	GAIN	OTDMC	C03	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$	$ -
Distribution Street & Customer Lighting												
Customer	GAIN	OTDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense												
Customer	GAIN	OTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.												
Customer	GAIN	OTCSI	C06	$ -	$ -	$ -	$	$ -	$ -	$ -	$ -	$ -
Sales Expense												
Customer	GAIN	OTSEC	C06	$ -	$ -	$	$ -	$ -	$ -	$ -	$ -	$ -
Total		OTT		$ (2,897)	$ (1,772)	$ (2,296)	$ (6,880)	$ (9,969)	$ (1,140)	$ (96)	$ (854)	$ (1,306)

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation
12 Months Ended
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Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Secondary GSS	General Service Primary GSP
Interest							
Power Production Plant							
Production Demand - Base	INTLTD	INTPPDB	BDEM	$ 11,772,334	$ 4,124,872	$ 1,155,051	$ 28,876
Production Demand - Inter.	INTLTD	INTPPDI	PPWDA	$ 14,012,513	$ 7,391,756	$ 1,083,312	$ 92,645
Production Demand - Peak	INTLTD	INTPPDP	PPSDA	$ 9,272,728	$ 3,859,262	$ 1,026,328	$ 56,593
Production Energy - Base	INTLTD	INTPPEB	E01	$ -	$ -	$ -	$ -
Production Energy - Inter.	INTLTD	INTPPEI	E01	$ -	$ -	$ -	$ -
Production Energy - Peak	INTLTD	INTPPEP	E01	$ -	$ -	$ -	$ -
Total Power Production Plant		INTPPT		$ 35,057,575	$ 15,375,889	$ 3,264,691	$ 178,114
Transmission Plant							
Transmission Demand - Base	INTLTD	INTTRB	BDEM	$ 2,080,835	$ 729,062	$ 204,163	$ 4,751
Transmission Demand - Inter.	INTLTD	INTTRI	PPWDA	$ 2,476,801	$ 1,306,540	$ 191,482	$ 16,376
Transmission Demand - Peak	INTLTD	INTTRP	PPSDA	$ 1,639,014	$ 682,149	$ 181,410	$ 10,003
Total Transmission Plant		INTTRT		$ 6,196,651	$ 2,717,752	$ 577,055	$ 31,129
Distribution Poles							
Specific	INTLTD	INTDPS	NCPP	$ -	$ -	$ -	$ -
Distribution Substation							
General	INTLTD	INTDSG	NCPP	$ 1,510,694	$ 769,503	$ 156,513	$ 8,675
Distribution Primary & Secondary Lines							
Primary Specific	INTLTD	INTDPLS	NCPP	$ -	$ -	$ -	$ -
Primary Demand	INTLTD	INTDPLD	NCPP	$ 1,189,350	$ 605,820	$ 124,795	$ 6,988
Primary Customer	INTLTD	INTDPLC	Cust08	$ 4,452,453	$ 3,540,941	$ 670,195	$ 626
Secondary Demand	INTLTD	INTDSLD	SICD	$ 270,288	$ 164,438	$ 82,908	$ -
Secondary Customer	INTLTD	INTDSLC	Cust07	$ 1,011,842	$ 805,509	$ 152,459	$ -
Total Distribution Primary & Secondary Lines		INTDLT		$ 6,923,932	$ 5,116,708	$ 1,030,357	$ 7,613
Distribution Line Transformers							
Demand	INTLTD	INTDLTD	SICD	$ 1,806,306	$ 1,098,929	$ 554,068	$ -
Customer	INTLTD	INTDLTC	Cust07	$ 1,659,360	$ 1,320,986	$ 250,024	$ -
Total Line Transformers		INTDLTT		$ 3,465,666	$ 2,419,914	$ 804,091	$ -
Distribution Services							
Customer	INTLTD	INTDSC	C02	$ 1,148,739	$ 875,432	$ 127,400	$ -
Distribution Meters							
Customer	INTLTD	INTDMC	C03	$ 905,040	$ 563,392	$ 248,562	$ 602
Distribution Street & Customer Lighting							
Customer	INTLTD	INTDSCL	C04	$ 1,028,599	$ -	$ -	$ -
Customer Accounts Expense							
Customer	INTLTD	INTCAE	C05	$ -	$ -	$ -	$ -
Customer Service & Info.							
Customer	INTLTD	INTCSI	C06	$ -	$ -	$ -	$ -
Sales Expense							
Customer	INTLTD	INTSEC	C06	$ -	$ -	$ -	$ -
Total		INTT		$ 56,236,895	$ 27,638,390	$ 6,210,669	$ 224,333

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation
12 Months Ended
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Description	Ref	Name	Allocation Vector	All Electric School AES	Combined Light & Power LPS	Combined Light & Power LPP	Combined Light & Power LPT	Small Time-of-Day Secondary STODS	Small Time-of-Day Primary STODP	Large Comm/Ind TOD Primary LCIP	Large Comm/Ind TOD Transmission LCIT
Interest											
Power Production Plant											
Production Demand - Base	INTLTD	INTPPDB	BDEM	$ 83,748	$ 2,410,261	$ 998,853	$ 15,616	$ 120,166	$ 9,743	$ 1,686,812	$ 503,739
Production Demand - Inter.	INTLTD	INTPPDI	PPWDA	$ 172,711	$ 2,063,156	$ 800,331	$ 18,520	$ 98,876	$ 9,745	$ 1,373,190	$ 414,111
Production Demand - Peak	INTLTD	INTPPDP	PPSDA	$ 63,166	$ 1,774,519	$ 671,907	$ 12,349	$ 88,442	$ 5,412	$ 1,059,486	$ 284,203
Production Energy - Base	INTLTD	INTPPEB	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Inter.	INTLTD	INTPPEI	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Peak	INTLTD	INTPPEP	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		INTPPT		$ 319,624	$ 6,247,936	$ 2,471,091	$ 46,485	$ 307,484	$ 24,900	$ 4,121,487	$ 1,202,053
Transmission Plant											
Transmission Demand - Base	INTLTD	INTTRB	BDEM	$ 14,803	$ 426,029	$ 176,554	$ 2,760	$ 21,240	$ 1,722	$ 298,508	$ 89,039
Transmission Demand - Inter.	INTLTD	INTTRI	PPWDA	$ 30,528	$ 364,676	$ 141,464	$ 3,274	$ 17,477	$ 1,723	$ 242,720	$ 73,197
Transmission Demand - Peak	INTLTD	INTTRP	PPSDA	$ 11,165	$ 313,658	$ 118,764	$ 2,183	$ 15,633	$ 957	$ 187,271	$ 50,235
Total Transmission Plant		INTTRT		$ 56,496	$ 1,104,363	$ 436,781	$ 8,218	$ 54,350	$ 4,401	$ 728,499	$ 212,471
Distribution Poles											
Specific	INTLTD	INTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation											
General	INTLTD	INTDSG	NCPP	$ 15,913	$ 243,084	$ 95,471	$ -	$ 10,610	$ 762	$ 144,308	$ -
Distribution Primary & Secondary Lines											
Primary Specific	INTLTD	INTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	INTLTD	INTDPLD	NCPP	$ 12,528	$ 191,377	$ 75,163	$ -	$ 8,353	$ 600	$ 113,612	$ -
Primary Customer	INTLTD	INTDPLC	Cust08	$ 2,622	$ 76,445	$ 3,000	$ 17	$ 437	$ 17	$ 334	$ 60
Secondary Demand	INTLTD	INTDSLD	SICD	$ 1,657	$ 19,953	$ -	$ -	$ 1,113	$ -	$ -	$ -
Secondary Customer	*INTLTD*	*INTDSLC*	*Cust07*	$ 597	$ 17,390	$ -	$ -	$ 99	$ -	$ -	$ -
Total Distribution Primary & Secondary Lines		INTDLT		$ 17,404	$ 305,165	$ 78,163	$ 17	$ 10,002	$ 617	$ 113,946	$ 60
Distribution Line Transformers											
Demand	INTLTD	INTDLTD	SICD	$ 11,073	$ 133,345	$ -	$ -	$ 7,436	$ -	$ -	$ -
Customer	INTLTD	INTDLTC	Cust07	$ 978	$ 28,519	$ -	$ -	$ 163	$ -	$ -	$ -
Total Line Transformers		INTDLTT		$ 12,051	$ 161,863	$ -	$ -	$ 7,599	$ -	$ -	$ -
Distribution Services											
Customer	INTLTD	INTDSC	C02	$ 7,175	$ 338,615	$ -	$ -	$ 117	$ -	$ -	$ -
Distribution Meters											
Customer	INTLTD	INTDMC	C03	$ 1,927	$ 71,478	$ 2,677	$ 16	$ 213	$ 8	$ 328	$ 66
Distribution Street & Customer Lighting											
Customer	INTLTD	INTDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense											
Customer	INTLTD	INTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.											
Customer	INTLTD	INTCSI	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense											
Customer	INTLTD	INTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		INTT		$ 430,591	$ 8,472,506	$ 3,084,383	$ 54,734	$ 390,378	$ 30,688	$ 5,108,569	$ 1,414,650

KENTUCKY UTILITIES
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Description	Ref	Name	Allocation Vector	Coal Mining Power Primary MPP	Coal Mining Power Transmission MPT	Large Power Mine Power TOD Primary LMPP	Large Power Mine Power TOD Transmission LMPT	Large Industrial Time-of-Day LITOD	Street Lighting SL	Decorative Street Lighting SLDEC	Private Outdoor Lighting POL	Customer Outdoor Lighting OL
<u>Interest</u>												
Power Production Plant												
Production Demand - Base	INTLTD	INTPPDB	BDEM	$ 67,593	$ 41,329	$ 53,575	$ 160,502	$ 232,578	$ 26,599	$ 2,235	$ 19,918	$ 30,466
Production Demand - Inter.	INTLTD	INTPPDI	PPWDA	$ 96,116	$ 49,725	$ 62,413	$ 131,091	$ 129,457	$ 8,514	$ 715	$ 6,375	$ 9,752
Production Demand - Peak	INTLTD	INTPPDP	PPSDA	$ 60,907	$ 37,605	$ 35,946	$ 112,222	$ 124,383	$ -	$ -	$ -	$ -
Production Energy - Base	INTLTD	INTPPEB	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Inter.	INTLTD	INTPPEI	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Energy - Peak	INTLTD	INTPPEP	E01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		INTPPT		$ 224,617	$ 128,658	$ 151,934	$ 403,814	$ 486,419	$ 35,113	$ 2,950	$ 26,293	$ 40,221
Transmission Plant												
Transmission Demand - Base	INTLTD	INTTRB	BDEM	$ 11,946	$ 7,305	$ 9,470	$ 28,370	$ 41,110	$ 4,702	$ 395	$ 3,521	$ 5,385
Transmission Demand - Inter.	INTLTD	INTTRI	PPWDA	$ 16,989	$ 8,789	$ 11,032	$ 23,171	$ 22,882	$ 1,505	$ 126	$ 1,127	$ 1,724
Transmission Demand - Peak	INTLTD	INTTRP	PPSDA	$ 10,766	$ 6,647	$ 6,354	$ 19,836	$ 21,985	$ -	$ -	$ -	$ -
Total Transmission Plant		INTTRT		$ 39,702	$ 22,741	$ 26,855	$ 71,377	$ 85,978	$ 6,206	$ 522	$ 4,647	$ 7,109
Distribution Poles												
Specific	INTLTD	INTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation												
General	INTLTD	INTDSG	NCPP	$ 10,842	$ -	$ 7,437	$ -	$ 43,176	$ 738	$ 62	$ 553	$ 845
Distribution Primary & Secondary Lines												
Primary Specific	INTLTD	INTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	INTLTD	INTDPLD	NCPP	$ 8,536	$ -	$ 5,855	$ -	$ 33,992	$ 581	$ 49	$ 435	$ 666
Primary Customer	INTLTD	INTDPLC	Cust08	$ 257	$ 86	$ 26	$ 60	$ 9	$ 67,028	$ 8,606	$ 27,694	$ 53,993
Secondary Demand	INTLTD	INTDSLD	SICD	$ -	$ -	$ -	$ -	$ -	$ 73	$ 6	$ 55	$ 84
Secondary Customer	INTLTD	INTDSLC	Cust07	$ -	$ -	$ -	$ -	$ -	$ 15,248	$ 1,958	$ 6,300	$ 12,283
Total Distribution Primary & Secondary Lines		INTDLT		$ 8,793	$ 86	$ 5,881	$ 60	$ 34,001	$ 82,930	$ 10,619	$ 34,483	$ 67,025
Distribution Line Transformers												
Demand	INTLTD	INTDLTD	SICD	$ -	$ -	$ -	$ -	$ -	$ 489	$ 41	$ 366	$ 560
Customer	INTLTD	INTDLTC	Cust07	$ -	$ -	$ -	$ -	$ -	$ 25,006	$ 3,211	$ 10,331	$ 20,143
Total Line Transformers		INTDLTT		$ -	$ -	$ -	$ -	$ -	$ 25,494	$ 3,252	$ 10,697	$ 20,703
Distribution Services												
Customer	INTLTD	INTDSC	C02	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters												
Customer	INTLTD	INTDMC	C03	$ 247	$ 82	$ 25	$ 50	$ 7	$ 7,242	$ -	$ 7,919	$ -
Distribution Street & Customer Lighting												
Customer	INTLTD	INTDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ 647,116	$ 125,098	$ 103,565	$ 152,819
Customer Accounts Expense												
Customer	INTLTD	INTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.												
Customer	INTLTD	INTCSI	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense												
Customer	INTLTD	INTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		INTT		$ 284,202	$ 151,567	$ 192,132	$ 475,301	$ 649,580	$ 804,841	$ 142,502	$ 188,158	$ 288,723

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation
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Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Secondary GSS	General Service Primary GSP
Cost of Service Summary -- Unadjusted							
Operating Revenues							
Sales		REVUC	R01	$ 1,112,461,756	$ 419,658,059	$ 136,859,016	$ 3,021,554
Accrued Revenues		REFUND	R01	$ (17,662,129)	$ (6,670,295)	$ (2,175,319)	$ (48,026)
Intercompany Sales		SFRS	E01	$ 41,161,812	$ 14,421,791	$ 4,036,600	$ 93,972
Off-System Sales		WHOS	OSSALL	$ 6,327,778	$ 1,802,945	$ 644,289	$ 1,581
Brokered Sales		BRKS	Energy	$ (90,748)	$ (31,795)	$ (8,904)	$ (207)
Redundant Capacity				$ 10,854	$ -	$ -	$ -
Misc Service Revenues		REVMISC	MISCA	$ 1,578,059	$ 760,288	$ 343,576	$ 7,585
Rent From Electric Property		RENT	RENTA	$ 1,994,812	$ 282,465	$ 339,282	$ 7,490
Other Electric Revenue		OTHREV	OREV	$ 2,585,939	$ 1,383,113	$ 309,712	$ 7,434
Unbilled Revenue		*UNBREV*	*R01*	$ 6,878,000	$ 2,594,813	$ 846,156	$ 18,681
Merger Surcredit Amortization				$ (1,069,892)	$ -	$ -	$ -
Total Operating Revenues		TOR		$ 1,154,156,041	$ 434,201,182	$ 141,198,389	$ 3,110,064
Operating Expenses							
Operation and Maintenance Expenses				$ 789,501,236	$ 315,107,181	$ 82,411,447	$ 1,943,259
Depreciation and Amortization Expenses				109,736,123	54,789,767	12,400,071	420,952
Regulatory Credits and *Accretion Expenses*				*(255,373)*	*(112,039)*	(23,793)	(1,282)
Property Taxes			NPT	10,473,065	5,147,131	1,156,820	41,776
Other Taxes				6,763,965	3,324,243	746,996	26,982
Gain Disposition of Allowances				(504,602)	(176,797)	(49,509)	(1,152)
State and Federal Income Taxes			TAXINC	66,273,491	$ 10,001,701	$ 13,679,623	$ 160,812
Specific Assignment of Curtailable Service Rider Avoided Cost				(2,040,216)	-	-	-
Allocation of Curtailable Service Rider Credits			INTCRE	2,040,216	$ 985,797	$ 184,643	$ 13,076
Total Operating Expenses		TOE		$ 981,987,904	$ 389,066,963	$ 110,706,299	$ 2,604,425
Net Operating Income (Unadjusted)		TOM		$ 172,168,137	$ 45,134,218	$ 30,490,090	$ 505,639
Net Cost Rate Base				$ 2,634,973,711	$ 1,278,199,993	$ 287,879,954	$ 10,542,751

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Cost of Service Study
Class Allocation
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Description	Ref	Name	Allocation Vector	All Electric School AES	Combined Light & Power LPS	Combined Light & Power LPP	Combined Light & Power LPT	Small Time-of-Day Secondary STODS	Small Time-of-Day Primary STODP	Large Comm/Ind TOD Primary LCIP	Large Comm/Ind TOD Transmission LCIT
Cost of Service Summary – Unadjusted											
Operating Revenues											
Sales		REVUC	R01	$ 7,663,577	$ 217,223,150	$ 83,319,633	$ 1,313,122	$ 9,082,579	$ 729,069	$ 129,712,936	$ 34,065,000
Accrued Revenues		REFUND	R01	$ (121,809)	$ (3,452,674)	$ (1,324,332)	$ (20,872)	$ (144,364)	$ (11,588)	$ (2,061,735)	$ (541,449)
Intercompany Sales		SFRS	E01	$ 292,821	$ 8,427,406	$ 3,492,460	$ 54,600	$ 420,158	$ 34,066	$ 5,904,879	$ 1,761,308
Off-System Sales		WHOS	OSSALL	$ 35,611	$ 1,420,044	$ 604,313	$ 8,398	$ 71,335	$ 5,788	$ 1,029,309	$ 310,679
Brokered Sales		BRKS	Energy	$ (646)	$ (18,580)	$ (7,700)	$ (120)	$ (926)	$ (75)	$ (13,018)	$ (3,883)
Redundant Capacity				$ -	$ 7,793	$ 3,061	$ -	$ -	$ -	$ -	$ -
Misc Service Revenues		REVMISC	MISCA	$ 4,405	$ 305,527	$ 117,190	$ 1,847	$ 19,622	$ 1,575	$ 12,234	$ 3,213
Rent From Electric Property		RENT	RENTA	$ 3,710	$ 506,849	$ 194,334	$ 3,063	$ 16,405	$ 1,317	$ 376,299	$ 99,346
Other Electric Revenue		OTHREV	OREV	$ 15,161	$ 340,842	$ 128,036	$ 2,206	$ 15,153	$ 1,215	$ 208,683	$ 57,050
Unbilled Revenue		UNBREV	R01	$ 47,381	$ 1,343,022	$ 515,139	$ 8,119	$ 56,155	$ 4,508	$ 801,974	$ 210,613
Merger Surcredit Amortization				$ -	$ (28,815)	$ (90,782)	$ -	$ -	$ -	$ (797,953)	$ (152,342)
Total Operating Revenues		TOR		$ 7,940,212	$ 226,074,363	$ 86,951,352	$ 1,370,360	$ 9,536,117	$ 765,874	$ 135,173,609	$ 35,809,536
Operating Expenses											
Operation and Maintenance Expenses				$ 5,345,237	$ 148,489,937	$ 58,613,734	$ 926,324	$ 7,140,507	$ 574,470	$ 98,860,764	$ 29,098,915
Depreciation and Amortization Expenses				818,513	18,085,121	5,764,708	101,079	732,052	57,211	9,534,623	2,812,171
Regulatory Credits and Accretion Expenses				(2,327)	(45,494)	(17,990)	(338)	(2,239)	(181)	(30,004)	(8,750)
Property Taxes			*NPT*	*80,190*	*1,577,845*	*574,408*	10,193	72,700	5,715	951,375	263,452
Other Taxes				51,790	1,019,042	370,978	6,583	46,953	3,691	614,440	170,149
Gain Disposition of Allowances				(3,590)	(103,312)	(42,814)	(669)	(5,151)	(416)	(72,388)	(21,592)
State and Federal Income Taxes			TAXINC	$ 436,892	$ 18,274,736	$ 6,490,653	$ 98,116	$ 416,292	$ 33,961	$ 7,506,593	$ 1,240,556
Specific Assignment of Curtailable Service Rider Avoided Cost				-	-	430,293	-	-	-	(644,684)	(1,192,286)
Allocation of Curtailable Service Rider Credits			INTCRE	$ 20,667	$ 336,251	$ 128,995	$ 2,705	$ 18,413	$ 1,328	$ 213,147	$ 61,165
Total Operating Expenses		TOE		$ 6,745,372	$ 185,634,128	$ 72,512,965	$ 1,143,993	$ 8,417,528	$ 675,777	$ 116,933,866	$ 32,224,800
Net Operating Income (Unadjusted)		TOM		$ 1,194,840	$ 40,440,235	$ 14,438,386	$ 226,367	$ 1,118,589	$ 90,096	$ 18,239,742	$ 3,584,736
Net Cost Rate Base				$ 20,315,933	$ 403,644,218	$ 148,227,932	$ 2,630,035	$ 18,710,846	$ 1,475,532	$ 245,760,225	$ 68,470,920

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Description	Ref	Name	Allocation Vector	Coal Mining Power Primary MPP	Coal Mining Power Transmission MPT	Large Power Mine Power TOD Primary LMPP	Large Power Mine Power TOD Transmission LMPT	Large Industrial Time-of-Day LITOD	Street Lighting SL	Decorative Street Lighting SLDEC	Private Outdoor Lighting POL	Customer Outdoor Lighting OL
Cost of Service Summary -- Unadjusted												
Operating Revenues												
Sales		REVUC	R01	$ 6,647,734	$ 3,858,665	$ 4,738,074	$ 13,387,914	$ 22,399,700	$ 7,312,068	$ 1,378,194	$ 4,076,500	$ 6,015,214
Accrued Revenues		REFUND	R01	$ (105,663)	$ (81,332)	$ (75,310)	$ (212,795)	$ (358,034)	$ (116,222)	$ (21,906)	$ (64,794)	$ (95,609)
Intercompany Sales		SFRS	E01	$ 236,338	$ 144,505	$ 187,324	$ 561,190	$ 813,204	$ 93,003	$ 7,815	$ 69,642	$ 106,532
Off-System Sales		WHOS	OSSALL	$ 33,209	$ 21,487	$ 29,817	$ 98,202	$ 152,624	$ 20,202	$ 1,898	$ 15,128	$ 23,141
Brokered Sales		BRKS	Energy	$ (521)	$ (319)	$ (413)	$ (1,237)	$ (1,793)	$ (205)	$ (17)	$ (154)	$ (235)
Redundant Capacity				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Misc Service Revenues		REVMISC	MISCA	$ 200	$ 0	$ 0	$ 339	$ 458	$ 0	$ -	$ 0	$ -
Rent From Electric Property		RENT	RENTA	$ 33,370	$ 0	$ 0	$ 57,364	$ 71,737	$ 0	$ 0	$ 0	$ 0
Other Electric Revenue		OTHREV	OREV	$ 11,108	$ 6,252	$ 7,639	$ 20,376	$ 29,333	$ 17,762	$ 2,478	$ 9,635	$ 14,751
Unbilled Revenue		UNBREV	R01	$ 41,101	$ 23,657	$ 29,294	$ 82,773	$ 138,490	$ 45,208	$ 8,521	$ 25,204	$ 37,190
Merger Surcredit Amortization				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Operating Revenues		TOR		$ 6,896,675	$ 3,993,097	$ 4,916,425	$ 13,992,128	$ 23,247,719	$ 7,371,815	$ 1,376,782	$ 4,131,160	$ 6,100,984
Operating Expenses												
Operation and Maintenance Expenses				$ 4,160,676	$ 2,468,664	$ 3,212,477	$ 9,329,388	$ 13,575,425	$ 3,357,470	$ 422,000	$ 1,673,278	$ 2,589,102
Depreciation and Amortization Expenses				532,597	279,931	360,019	877,676	1,229,809	1,786,578	317,838	409,297	628,111
Regulatory Credits and Accretion Expenses				(1,635)	(937)	(1,106)	(2,939)	(3,542)	(265)	(23)	(193)	(296)
Property Taxes			NPT	52,927	28,227	35,761	88,516	120,972	149,886	26,538	35,041	53,769
Other Taxes				34,183	18,230	23,109	57,167	78,129	96,803	17,140	22,631	34,726
Gain Disposition of Allowances				(2,897)	(1,772)	(2,296)	(6,880)	(9,969)	(1,140)	(96)	(854)	(1,306)
State and Federal Income Taxes			TAXINC	$ 663,105	$ 378,838	$ 395,627	$ 1,148,690	$ 2,989,364	$ 428,074	$ 183,977	$ 655,896	$ 911,982
Specific Assignment of Curtailable Service Rider Avoided Cost				-	-	-	-	(633,539)	-	-	-	-
Allocation of Curtailable Service Rider Credits			INTCRE	$ 13,758	$ 7,652	$ 8,618	$ 21,319	$ 22,241	$ 746	$ 63	$ 559	$ 854
Total Operating Expenses		TOE		$ 5,452,713	$ 3,178,833	$ 4,032,229	$ 11,510,937	$ 17,368,889	$ 5,818,151	$ 947,437	$ 2,795,654	$ 4,216,944
Net Operating Income (Unadjusted)		TOM		$ 1,444,162	$ 814,263	$ 884,197	$ 2,481,189	$ 5,878,830	$ 1,553,664	$ 429,345	$ 1,335,507	$ 1,884,040
Net Cost Rate Base				$ 13,525,419	$ 7,274,320	$ 9,181,918	$ 22,961,728	$ 31,190,051	$ 35,018,589	$ 6,115,687	$ 11,058,428	$ 12,789,234

KENTUCKY UTILITIES
Cost of Service Study
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Description	Ref	Name	Allocation Vector		Total System	Residential Rate RS	General Service Secondary GSS	General Service Primary GSP
Taxable Income Unadjusted								
Total Operating Revenue					$ 1,154,156,041	$ 434,201,182	$ 141,196,389	$ 3,110,064
Operating Expenses					$ 915,714,413	$ 379,065,262	$ 96,826,676	$ 2,443,613
Interest Expense		INTEXP			$ 56,236,895	$ 27,638,390	$ 6,210,669	$ 224,333
Taxable Income		TAXINC			$ 182,204,733	$ 27,497,529	$ 38,159,044	$ 442,118
Cost of Service Summary -- Pro-Forma								
Operating Revenues								
Total Operating Revenue -- Actual					$ 1,154,156,041	$ 434,201,182	$ 141,196,389	$ 3,110,064
Pro-Forma Adjustments:								
Eliminate unbilled revenue			R01		(6,878,000)	$ (2,594,613)	$ (848,156)	$ (18,681)
Adjustment for Mismatch in fuel cost recovery			Energy		(116,253,633)	$ (40,731,777)	$ (11,406,305)	$ (265,407)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI	Energy		98,267	$ 34,430	$ 9,642	$ 224
Remove ECR revenues			ECRREV		(54,342,557)	$ (20,826,165)	$ (6,855,772)	$ (150,005)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI	ECRREV		21,935,853	$ 8,325,868	$ 2,686,637	$ 60,550
Remove off-system ECR revenues			OSSALL		(371,295)	$ (105,791)	$ (37,805)	$ (93)
Eliminate brokered sales			Energy		90,748	$ 31,795	$ 8,904	$ 207
Eliminate ESM,FAC,ECR from rate refund acct.			R01		17,682,129	$ 6,670,295	$ 2,175,319	$ 48,028
Eliminate DSM Revenue		DSMREV			(4,429,150)	(3,999,569)	(123,092)	(2,670)
Year end adjustment		YREND			(4,243,045)	$ 843,080	$ 1,130,682	$ (40,127)
Merger Surcredit Revenues			MSCREV		18,568,431	$ 7,355,580	$ 2,396,449	$ 53,506
Weather Normalized electric operating revenues			Energy		(8,721,229)	$ (3,055,858)	$ (855,689)	$ (19,911)
VDT Surcredit Revenues			VDTREV		3,405,550	1,281,117	416,427	9,403
Total Pro-Forma Operating Revenue				(46,571,428)	$ 1,020,697,910	$ 387,629,753	$ 130,095,608	$ 2,785,088
					(126,580,131)	(43,976,815)		

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation
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Description	Ref	Name	Allocation Vector	All Electric School AES	Combined Light & Power LPS	Combined Light & Power LPP	Combined Light & Power LPT	Small Time-of-Day Secondary STODS	Small Time-of-Day Primary STODP	Large Comm/Ind TOD Primary LCIP	Large Comm/Ind TOD Transmission LCIT
Taxable Income Unadjusted											
Total Operating Revenue				$ 7,940,212	$ 226,074,383	$ 86,951,352	$ 1,370,360	$ 9,536,117	$ 765,874	$ 135,173,609	$ 35,809,536
Operating Expenses				$ 6,308,460	$ 167,359,391	$ 68,022,313	$ 1,045,877	$ 8,001,236	$ 641,816	$ 109,427,273	$ 30,984,244
Interest Expense		INTEXP		$ 430,591	$ 8,472,506	$ 3,084,383	$ 54,734	$ 390,376	$ 30,888	$ 5,108,569	$ 1,414,650
Taxable Income		TAXINC		$ 1,201,141	$ 50,242,467	$ 17,844,856	$ 269,749	$ 1,144,505	$ 93,369	$ 20,637,766	$ 3,410,642
Cost of Service Summary -- Pro-Forma											
Operating Revenues											
Total Operating Revenue -- Actual				$ 7,940,212	$ 226,074,383	$ 86,951,352	$ 1,370,360	$ 9,536,117	$ 765,874	$ 135,173,609	$ 35,809,536
Pro-Forma Adjustments:											
Eliminate unbilled revenue			R01	$ (47,381)	$ (1,343,022)	$ (515,139)	$ (8,119)	$ (56,155)	$ (4,508)	$ (801,974)	$ (210,613)
Adjustment for Mismatch in fuel cost recovery			Energy	$ (827,021)	$ (23,801,704)	$ (9,863,831)	$ (154,207)	$ (1,186,681)	$ (96,213)	$ (16,677,277)	$ (4,974,499)
Adjustment to Reflect Full Year of FAC Roll-in	FACRI		Energy	$ 699	$ 20,119	$ 8,338	$ 130	$ 1,003	$ 81	$ 14,097	$ 4,205
Remove ECR revenues			ECRREV	$ (375,764)	$ (10,481,263)	$ (4,017,702)	$ (63,714)	$ (439,539)	$ (35,499)	$ (6,234,270)	$ (1,899,807)
Adjustment to reflect Full Year of ECR Roll-in	ECRRI		ECRREV	$ 151,679	$ 4,230,816	$ 1,621,766	$ 25,718	$ 177,422	$ 14,329	$ 2,516,495	$ 766,867
Remove off-system ECR revenues			OSSALL	$ (2,090)	$ (83,324)	$ (35,459)	$ (483)	$ (4,186)	$ (340)	$ (60,397)	$ (18,230)
Eliminate brokered sales			Energy	$ 648	$ 18,580	$ 7,700	$ 120	$ 926	$ 75	$ 13,018	$ 3,883
Eliminate ESM,FAC,ECR from rate refund acct.			R01	$ 121,809	$ 3,452,874	$ 1,324,332	$ 20,872	$ 144,364	$ 11,588	$ 2,061,735	$ 541,449
Eliminate DSM Revenue		DSMREV		-	(240,135)	(45,915)	(2,128)	(15,427)	(215)	-	-
Year end adjustment		YREND		$ -	$ (6,373,654)	$ -	$ -	$ -	$ -	$ -	$ -
Merger Surcredit Revenues			MSCREV	$ 132,778	$ 3,766,072	$ 1,337,070	$ 22,650	$ 158,633	$ 12,665	$ 1,629,902	$ 488,942
Weather Normalized electric operating revenues			Energy	$ (62,042)	$ (1,785,580)	$ (739,975)	$ (11,568)	$ (89,022)	$ (7,218)	$ (1,251,112)	$ (373,182)
VDT Surcredit Revenues			VDTREV	23,364	660,193	253,206	3,888	27,621	2,222	394,429	120,177
Total Pro-Forma Operating Revenue			(48,571,428)	$ 7,056,889	$ 194,114,135	$ 78,285,742	$ 1,203,609	$ 8,255,297	$ 662,643	$ 116,778,254	$ 30,258,728

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Description	Ref	Name	Allocation Vector	Coal Mining Power Primary MPP	Coal Mining Power Transmission MPT	Large Power Mine Power TOD Primary LMPP	Large Power Mine Power TOD Transmission LMPT
Taxable Income Unadjusted							
Total Operating Revenue				$ 6,896,875	$ 3,993,097	$ 4,916,425	$ 13,992,126
Operating Expenses				$ 4,789,608	$ 2,799,995	$ 3,636,601	$ 10,364,247
Interest Expense		INTEXP		$ 284,202	$ 151,567	$ 192,132	$ 475,301
Taxable Income		TAXINC		$ 1,823,065	$ 1,041,535	$ 1,087,692	$ 3,152,578
Cost of Service Summary -- Pro-Forma							
Operating Revenues							
Total Operating Revenue -- Actual				$ 6,896,875	$ 3,993,097	$ 4,916,425	$ 13,992,126
Pro-Forma Adjustments:							
Eliminate unbilled revenue			R01	$ (41,101)	$ (23,857)	$ (29,294)	$ (82,773)
Adjustment for Mismatch in fuel cost recovery			Energy	$ (667,494)	$ (408,130)	$ (529,064)	$ (1,584,982)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI	Energy	$ 584	$ 345	$ 447	$ 1,340
Remove ECR revenues			ECRREV	$ (322,310)	$ (185,614)	$ (226,786)	$ (653,519)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI	ECRREV	$ 130,102	$ 74,924	$ 91,543	$ 263,798
Remove off-system ECR revenues			OSSALL	$ (1,949)	$ (1,260)	$ (1,750)	$ (5,645)
Eliminate brokered sales			Energy	$ 521	$ 319	$ 413	$ 1,237
Eliminate ESM,FAC,ECR from rate refund acct.			R01	$ 105,663	$ 61,332	$ 75,310	$ 212,795
Eliminate DSM Revenue		DSMREV		-	-	-	-
Year end adjustment		YREND		$ 215,149	$ -	$ -	$ -
Merger Surcredit Revenues			MSCREV	$ 115,118	$ 67,619	$ 82,168	$ 232,283
Weather Normalized electric operating revenues			Energy	$ (50,075)	$ (30,617)	$ (39,690)	$ (118,904)
VDT Surcredit Revenues			VDTREV	20,226	11,701	14,392	40,804
Total Pro-Forma Operating Revenue			(46,571,428)	$ 6,401,292	$ 3,560,058	$ 4,354,116	$ 12,298,559

Description	Large Industrial Time-of-Day LITOD	Street Lighting SL	Decorative Street Lighting SLDEC	Private Outdoor Lighting POL	Customer Outdoor Lighting OL
Taxable Income Unadjusted					
Total Operating Revenue	$ 23,247,719	$ 7,371,815	$ 1,376,782	$ 4,131,160	$ 6,100,984
Operating Expenses	$ 14,379,525	$ 5,390,077	$ 783,459	$ 2,139,758	$ 3,304,962
Interest Expense	$ 849,580	$ 804,841	$ 142,502	$ 188,158	$ 288,723
Taxable Income	$ 8,218,614	$ 1,176,897	$ 450,820	$ 1,803,244	$ 2,507,300
Cost of Service Summary -- Pro-Forma					
Operating Revenues					
Total Operating Revenue -- Actual	$ 23,247,719	$ 7,371,815	$ 1,376,782	$ 4,131,160	$ 6,100,984
Pro-Forma Adjustments:					
Eliminate unbilled revenue	$ (138,490)	$ (45,208)	$ (6,521)	$ (25,204)	$ (37,180)
Adjustment for Mismatch in fuel cost recovery	$ (2,296,749)	$ (262,670)	$ (22,072)	$ (196,891)	$ (300,880)
Adjustment to Reflect Full Year of FAC Roll-in	$ 1,941	$ 222	$ 19	$ 166	$ 254
Remove ECR revenues	$ (1,074,407)	$ (351,687)	$ (62,947)	$ (196,492)	$ (289,276)
Adjustment to reflect Full Year of ECR Roll-in	$ 433,690	$ 141,960	$ 25,409	$ 79,315	$ 116,768
Remove off-system ECR revenues	$ (8,956)	$ (1,185)	$ (100)	$ (888)	$ (1,358)
Eliminate brokered sales	$ 1,793	$ 205	$ 17	$ 154	$ 235
Eliminate ESM,FAC,ECR from rate refund acct.	$ 356,034	$ 116,222	$ 21,906	$ 64,794	$ 95,609
Eliminate DSM Revenue	-	-	-	-	-
Year end adjustment	$ -	$ 5,436	$ (87,075)	$ 65,957	$ (2,475)
Merger Surcredit Revenues	$ 388,337	$ 127,483	$ 24,581	$ 70,852	$ 105,042
Weather Normalized electric operating revenues	$ (172,300)	$ (19,705)	$ (1,656)	$ (14,756)	$ (22,572)
VDT Surcredit Revenues	68,105	22,193	4,259	12,408	19,315
Total Pro-Forma Operating Revenue	$ 20,806,717	$ 7,105,064	$ 1,270,603	$ 3,990,877	$ 5,764,458

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Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Secondary GSS	General Service Primary GSP
Operating Expenses							
Operation and Maintenance Expenses				$ 789,501,236	$ 315,107,161	$ 82,411,447	$ 1,943,259
Depreciation and Amortization Expenses				109,738,123	54,789,767	12,400,071	420,952
Regulatory Credits and Accretion Expenses				(255,373)	(112,039)	(23,793)	(1,282)
Property Taxes			NPT	10,473,065	5,147,131	1,156,620	41,778
Other Taxes				6,763,965	3,324,243	746,996	26,982
Gain Disposition of Allowances				(504,602)	(176,797)	(49,509)	(1,152)
State and Federal Income Taxes			TXINCPF	56,064,882	$ 7,686,681	$ 12,893,776	$ 131,458
Specific Assignment of Curtailable Service Rider Credit				(2,040,216)	-	-	-
Allocation of Curtailable Service Rider Credits			INTCRE	$ 2,040,216	$ 985,797	$ 184,643	$ 13,076
Adjustments to Operating Expenses:							
Eliminate mismatch in fuel cost recovery			Energy	(96,155,056)	$ (33,689,840)	$ (9,434,319)	$ (219,522)
Remove ECR expenses			ECRREV	(16,467,656)	$ (8,250,440)	$ (2,016,927)	$ (45,457)
Adjust base expenses for full year of ECR roll-in			ECRREV	8,506,554	$ 3,228,736	$ 1,041,866	$ 23,481
Eliminate brokered sales expenses			Energy	(8,127)	$ (2,847)	$ (797)	$ (19)
Eliminate DSM Expenses			DSMREV	(4,437,148)	$ (4,006,791)	$ (123,314)	$ (2,674)
Year end adjustment			YREND	(2,747,550)	$ 545,930	$ 732,151	$ (25,984)
Adjustment for change in depreciation rate			DET	236,248	$ 117,955	$ 26,696	$ 906
Labor adjustment			LBT	1,549,969	$ 796,531	$ 186,438	$ 4,226
Weather Normalized electric operating expenses			Energy	(4,355,146)	$ (1,525,912)	$ (427,308)	$ (9,943)
Adjustment for pension/post retir benefit (See Functional Assignment)				-	$ -	$ -	$ -
Storm damage adjustment			SDALL	(2,731,370)	$ (1,869,618)	$ (442,602)	$ (3,448)
Eliminate advertising expenses (See Functional Assignment)			REVUC	-	$ -	$ -	$ -
Adjustment for amortization of ESM and mgmt audit expense			R01	(37,986)	$ (14,330)	$ (4,673)	$ (103)
Amortization of rate case expenses			OMT	324,904	$ 129,676	$ 33,915	$ 800
Adjustment for injuries and damages account 925 (See Functional Assignment)					$ -	$ -	$ -
Adjustment for FERC assessment fee (See Functional Assign			LBT	-	$ -	$ -	$ -
Adjustment for EKPC settlement charges			Energy	(1,338,790)	$ (469,072)	$ (131,356)	$ (3,056)
Adjustment for merger amortization expenses			LBT	-	$ -	$ -	$ -
Adjustment for MISO schedule 10 expenses			PLTRT	1,961,979	$ 860,492	$ 182,707	$ 9,856
Adjustment for effect of accounting change			DET	-	$ -	$ -	$ -
Adjustment for IT prepaid amortizaton (See Functional Assignment)					$ -	$ -	$ -
Adjustment for postage rate increase (See Functional Assignment)					$ -	$ -	$ -
Adjustment for property tax expense (See Functional Assignment)					$ -	$ -	$ -
Adjustment to reflect reallocation of OVEC demand charges			BDEM	2,721,857	$ 953,657	$ 267,057	$ 6,214
Adjustment for reserve margin demand purchases			PPSDA	1,199,403	$ 499,165	$ 132,753	$ 7,320
Adjustment to reflect annualized vehicle fuel costs			R01	198,606	$ 74,922	$ 24,433	$ 539
Adjustment for Retirement of Tyrone Units 1 & 2			OMPPT	(9,565)	$ (3,444)	$ (936)	$ (25)
Adjustment for new credit facilities bank fees			RBT	2,005,628	$ 972,911	$ 219,122	$ 8,025
Total Expense Adjustments				(109,583,264)	(39,652,299)	(9,735,296)	(246,863)
Total Operating Expenses	TOE			$ 662,196,011	$ 347,099,643	$ 99,985,156	$ 2,326,208
Net Operating Income (Adjusted)				$ 158,501,899	$ 40,530,110	$ 30,110,452	$ 458,680
Net Cost Rate Base				$ 2,634,973,711	$ 1,278,199,993	$ 287,879,954	$ 10,542,751
Less: ECR Rate Base			RBPPDB	$ 415,886,486	$ 145,714,118	$ 40,604,989	$ 949,468
Adjustment to Reflect Depreciation Reserve			DET	$ (236,248)	$ (117,955)	$ (26,696)	$ (906)
Cash Working Capital			OMLF	$ (1,942,732)	$ (1,094,836)	$ (243,865)	$ (5,951)
Adjusted Net Cost Rate Base				$ 2,216,908,245	$ 1,131,273,083	$ 246,604,404	$ 9,586,426
Rate of Return				7.15%	3.58%	12.20%	4.79%

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation
12 Months Ended
April 30, 2008

Description	Ref	Name	Allocation Vector	All Electric School AES	Combined Light & Power LPS	Combined Light & Power LPP	Combined Light & Power LPT	Small Time-of-Day Secondary STODS	Small Time-of-Day Primary STODP	Large Comm/Ind TOD Primary LCIP	Large Comm/Ind TOD Transmission LCIT
Operating Expenses											
Operation and Maintenance Expenses				$ 5,345,237	$ 148,489,937	$ 58,813,734	$ 926,324	$ 7,140,507	$ 574,470	$ 98,860,764	$ 29,099,915
Depreciation and Amortization Expenses				816,513	16,065,121	5,764,708	101,079	732,052	57,211	9,534,623	2,612,171
Regulatory Credits and Accretion Expenses				(2,327)	(45,494)	(17,990)	(336)	(2,239)	(181)	(30,004)	(8,750)
Property Taxes			NPT	80,190	1,577,845	574,408	10,193	72,700	5,715	951,375	263,452
Other Taxes				51,790	1,019,042	370,978	6,583	46,953	3,691	614,440	170,149
Gain Disposition of Allowances				(3,590)	(103,312)	(42,614)	(669)	(5,151)	(418)	(72,388)	(21,592)
State and Federal Income Taxes			TXINCPF	$ 367,253	$ 15,251,954	$ 5,546,127	$ 83,701	$ 321,278	$ 28,168	$ 5,890,156	$ 780,812
Specific Assignment of Curtailable Service Rider Credit				-	-	430,293	-	-	-	(644,684)	(1,192,286)
Allocation of Curtailable Service Rider Credits			INTCRE	$ 20,667	$ 336,251	$ 128,995	$ 2,705	$ 16,413	$ 1,328	$ 213,147	$ 61,185
Adjustments to Operating Expenses:											
Eliminate mismatch in fuel cost recovery			Energy	$ (664,041)	$ (19,686,733)	$ (8,158,517)	$ (127,547)	$ (981,505)	$ (78,579)	$ (13,794,017)	$ (4,114,480)
Remove ECR expenses			ECRREV	$ (113,669)	$ (3,178,182)	$ (1,217,501)	$ (19,307)	$ (133,195)	$ (10,757)	$ (1,889,197)	$ (575,707)
Adjust base expenses for full year of ECR roll-in			ECRREV	$ 58,821	$ 1,640,693	$ 628,914	$ 9,973	$ 68,804	$ 5,557	$ 975,886	$ 297,388
Eliminate brokered sales expenses			Energy	$ (58)	$ (1,664)	$ (690)	$ (11)	$ (83)	$ (7)	$ (1,166)	$ (348)
Eliminate DSM Expenses			DSMREV	$ -	$ (240,569)	$ (45,997)	$ (2,132)	$ (15,455)	$ (215)	$ -	$ -
Year end adjustment			YREND	$ -	$ (4,127,209)	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for change in depreciation rate			DET	$ 1,758	$ 34,629	$ 12,411	$ 218	$ 1,576	$ 123	$ 20,527	$ 5,624
Labor adjustment			LBT	$ 8,978	$ 230,388	$ 72,492	$ 1,159	$ 9,319	$ 711	$ 118,581	$ 32,629
Weather Normalized electric operating expenses			Energy	$ (30,962)	$ (891,670)	$ (369,523)	$ (5,777)	$ (44,455)	$ (3,604)	$ (624,772)	$ (186,357)
Adjustment for pension/post retir benefit (See Functional Assignment)				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storm damage adjustment			SDALL	$ (10,999)	$ (216,611)	$ (38,332)	$ (4)	$ (5,928)	$ (291)	$ (54,058)	$ (12)
Eliminate advertising expenses (See Functional Assignment)			REVUC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for amortization of ESM and mgmt audit expense			R01	$ (262)	$ (7,417)	$ (2,845)	$ (45)	$ (310)	$ (25)	$ (4,429)	$ (1,163)
Amortization of rate case expenses			OMT	$ 2,200	$ 61,108	$ 24,204	$ 381	$ 2,939	$ 236	$ 40,684	$ 11,976
Adjustment for injuries and damages account 925 (See Functional Assignment)				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for FERC assessment fee (See Functional Assign			LBT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for EKPC settlement charges			Energy	$ (9,524)	$ (274,103)	$ (113,593)	$ (1,776)	$ (13,666)	$ (1,108)	$ (192,057)	$ (57,267)
Adjustment for merger amortization expenses			LBT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for MISO schedule 10 expenses			PLTRT	$ 17,868	$ 349,663	$ 138,293	$ 2,601	$ 17,208	$ 1,394	$ 230,657	$ 67,272
Adjustment for effect of accounting change			DET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for IT prepaid amortizaton (See Functional Assignment)				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for postage rate increase (See Functional Assignment)				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for property tax expense (See Functional Assignment)				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment to reflect reallocation of OVEC demand charges			BDEM	$ 19,363	$ 557,271	$ 230,943	$ 3,610	$ 27,783	$ 2,253	$ 390,467	$ 116,468
Adjustment for reserve margin demand purchases			PPSDA	$ 8,170	$ 229,529	$ 86,909	$ 1,597	$ 11,440	$ 700	$ 137,042	$ 36,761
Adjustment to reflect annualized vehicle fuel costs			R01	$ 1,368	$ 36,781	$ 14,875	$ 234	$ 1,822	$ 130	$ 23,158	$ 6,062
Adjustment for Retirement of Tyrone Units 1 & 2			OMPPT	$ (70)	$ (1,937)	$ (799)	$ (13)	$ (96)	$ (8)	$ (1,350)	$ (402)
Adjustment for new credit facilities bank fees			RBT	$ 15,464	$ 307,237	$ 112,625	$ 2,002	$ 14,242	$ 1,123	$ 187,062	$ 52,117
Total Expense Adjustments				(715,796)	(25,178,798)	(8,623,932)	(134,835)	(1,039,761)	(83,367)	(14,436,983)	(4,309,440)
Total Operating Expenses		TOE		$ 5,959,936	$ 157,434,547	$ 62,944,507	$ 994,743	$ 7,262,753	$ 584,637	$ 100,880,447	$ 27,455,617
Net Operating Income (Adjusted)				$ 1,096,953	$ 36,679,588	$ 13,341,235	$ 209,066	$ 972,544	$ 78,206	$ 15,897,808	$ 2,803,111
Net Cost Rate Base				$ 20,315,933	$ 403,644,218	$ 148,227,932	$ 2,630,035	$ 18,710,646	$ 1,475,532	$ 245,760,225	$ 68,470,920
Less: ECR Rate Base			RBPPDB	$ 2,956,588	$ 85,148,369	$ 35,288,931	$ 551,660	$ 4,245,170	$ 344,191	$ 59,661,389	$ 17,795,607
Adjustment to Reflect Depreciation Reserve			DET	$ (1,758)	$ (34,629)	$ (12,411)	$ (218)	$ (1,576)	$ (123)	$ (20,527)	$ (5,624)
Cash Working Capital			OMLF	$ (10,902)	$ (256,233)	$ (76,887)	$ (1,276)	$ (9,949)	$ (759)	$ (123,770)	$ (32,740)
Adjusted Net Cost Rate Base				$ 17,344,685	$ 318,204,987	$ 112,851,704	$ 2,076,882	$ 14,454,151	$ 1,130,459	$ 185,954,528	$ 50,636,749
Rate of Return				6.32%	11.53%	11.82%	10.07%	6.73%	6.92%	8.55%	5.54%

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation
12 Months Ended
April 30, 2008

Description	Ref	Name	Allocation Vector	Coal Mining Power Primary MPP	Coal Mining Power Transmission MPT	Large Power Mine Power TOD Primary LMPP	Large Power Mine Power TOD Transmission LMPT	Large Industrial Time-of-Day LITOD	Street Lighting SL	Decorative Street Lighting SLDEC	Private Outdoor Lighting POL	Customer Outdoor Lighting OL
Operating Expenses												
Operation and Maintenance Expenses				$ 4,160,676	$ 2,468,664	$ 3,212,477	$ 9,329,388	$ 13,575,425	$ 3,357,470	$ 422,000	$ 1,673,278	$ 2,589,102
Depreciation and Amortization Expenses				532,597	279,931	360,019	877,676	1,229,809	1,786,576	317,838	409,297	628,111
Regulatory Credits and Accretion Expenses				(1,835)	(937)	(1,106)	(2,939)	(3,542)	(285)	(23)	(193)	(296)
Property Taxes			NPT	52,927	28,227	35,781	88,516	120,972	149,886	26,536	35,041	53,769
Other Taxes				34,183	18,230	23,109	57,167	78,129	96,803	17,140	22,631	34,726
Gain Disposition of Allowances				(2,897)	(1,772)	(2,296)	(6,860)	(9,969)	(1,140)	(96)	(854)	(1,306)
State and Federal Income Taxes			TXINCPF	$ 619,343	$ 336,499	$ 345,835	$ 992,893	$ 2,725,514	$ 412,763	$ 149,030	$ 635,682	$ 867,897
Specific Assignment of Curtailable Service Rider Credit				-	-	-	-	(633,539)	-	-	-	-
Allocation of Curtailable Service Rider Credits			INTCRE	$ 13,758	$ 7,652	$ 8,618	$ 21,319	$ 22,241	$ 746	$ 63	$ 559	$ 854
Adjustments to Operating Expenses:												
Eliminate mismatch in fuel cost recovery			Energy	$ (552,094)	$ (337,570)	$ (437,597)	$ (1,310,962)	$ (1,899,674)	$ (217,258)	$ (18,256)	$ (162,686)	$ (248,862)
Remove ECR expenses			ECRREV	$ (97,671)	$ (56,247)	$ (68,724)	$ (198,039)	$ (325,582)	$ (106,573)	$ (19,075)	$ (59,544)	$ (87,660)
Adjust base expenses for full year of ECR roll-in			ECRREV	$ 50,453	$ 29,055	$ 35,500	$ 102,299	$ 168,183	$ 55,052	$ 9,853	$ 30,758	$ 45,282
Eliminate brokered sales expenses			Energy	$ (47)	$ (29)	$ (37)	$ (111)	$ (161)	$ (18)	$ (2)	$ (14)	$ (21)
Eliminate DSM Expenses			DSMREV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Year end adjustment			YREND	$ 139,318	$ -	$ -	$ -	$ -	$ 3,521	$ (56,385)	$ 42,710	$ (1,603)
Adjustment for change in depreciation rate			DET	$ 1,147	$ 603	$ 775	$ 1,890	$ 2,648	$ 3,846	$ 684	$ 881	$ 1,352
Labor adjustment			LBT	$ 6,039	$ 3,172	$ 4,250	$ 10,751	$ 16,299	$ 26,331	$ 4,543	$ 6,603	$ 10,531
Weather Normalized electric operating expenses			Energy	$ (25,006)	$ (15,290)	$ (19,820)	$ (59,377)	$ (86,042)	$ (9,840)	$ (827)	$ (7,369)	$ (11,272)
Adjustment for pension/post retir benefit (See Functional Assignment)				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storm damage adjustment			SDALL	$ (4,111)	$ (21)	$ (2,788)	$ (11)	$ (16,154)	$ (22,633)	$ (2,614)	$ (22,534)	$ (18,402)
Eliminate advertising expenses (See Functional Assignment)			REVUC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for amortization of ESM and mgmt audit expense			R01	$ (227)	$ (132)	$ (162)	$ (457)	$ (765)	$ (250)	$ (47)	$ (139)	$ (205)
Amortization of rate case expenses			OMT	$ 1,712	$ 1,016	$ 1,322	$ 3,839	$ 5,587	$ 1,382	$ 174	$ 689	$ 1,065
Adjustment for injuries and damages account 925 (See Functional Assignment)				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for FERC assessment fee (See Functional Assign			LBT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for EKPC settlement charges			Energy	$ (7,687)	$ (4,700)	$ (6,093)	$ (18,253)	$ (26,450)	$ (3,025)	$ (254)	$ (2,265)	$ (3,465)
Adjustment for merger amortization expenses			LBT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for MISO schedule 10 expenses			PLTRT	$ 12,571	$ 7,200	$ 8,503	$ 22,599	$ 27,222	$ 1,965	$ 165	$ 1,471	$ 2,251
Adjustment for effect of accounting change			DET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for IT prepaid amortizaton (See Functional Assignment)				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for postage rate increase (See Functional Assignment)				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for property tax expense (See Functional Assignment)				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment to reflect reallocation of OVEC demand charges			BDEM	$ 15,626	$ 9,556	$ 12,387	$ 37,109	$ 53,774	$ 6,150	$ 517	$ 4,605	$ 7,045
Adjustment for reserve margin demand purchases			PPSDA	$ 7,878	$ 4,864	$ 4,650	$ 14,518	$ 16,089	$ -	$ -	$ -	$ -
Adjustment to reflect annualized vehicle fuel costs			R01	$ 1,167	$ 689	$ 846	$ 2,390	$ 3,899	$ 1,305	$ 246	$ 728	$ 1,074
Adjustment for Retirement of Tyrone Units 1 & 2			OMPPT	$ (56)	$ (34)	$ (43)	$ (129)	$ (184)	$ (20)	$ (2)	$ (15)	$ (23)
Adjustment for new credit facilities bank fees			RBT	$ 10,295	$ 5,537	$ 6,989	$ 17,477	$ 23,741	$ 26,655	$ 4,655	$ 8,417	$ 9,735
Total Expense Adjustments				(440,671)	(352,331)	(460,041)	(1,374,467)	(2,037,470)	(233,411)	(76,623)	(157,702)	(293,178)
Total Operating Expenses		TOE		$ 4,966,281	$ 2,784,163	$ 3,522,395	$ 9,982,673	$ 15,067,569	$ 5,569,450	$ 855,866	$ 2,617,737	$ 3,879,681
Net Operating Income (Adjusted)				$ 1,433,011	$ 775,895	$ 831,721	$ 2,315,885	$ 5,739,148	$ 1,535,634	$ 414,737	$ 1,373,140	$ 1,904,777
Net Cost Rate Base				$ 13,525,419	$ 7,274,320	$ 9,181,918	$ 22,961,726	$ 31,190,051	$ 35,018,589	$ 6,115,687	$ 11,058,428	$ 12,789,234
Less: ECR Rate Base			RBPPDB	$ 2,387,896	$ 1,460,048	$ 1,892,678	$ 5,670,128	$ 8,216,403	$ 939,677	$ 78,960	$ 703,642	$ 1,076,368
Adjustment to Reflect Depreciation Reserve			DET	$ (1,147)	$ (603)	$ (775)	$ (1,890)	$ (2,648)	$ (3,846)	$ (684)	$ (881)	$ (1,352)
Cash Working Capital			OMLF	$ (7,147)	$ (3,560)	$ (4,747)	$ (11,051)	$ (18,621)	$ (21,322)	$ (3,297)	$ (6,919)	$ (10,901)
Adjusted Net Cost Rate Base				$ 11,129,229	$ 5,810,112	$ 7,283,718	$ 17,278,660	$ 22,954,379	$ 34,053,743	$ 6,032,746	$ 10,346,986	$ 11,700,613
Rate of Return				12.88%	13.35%	11.42%	13.40%	25.00%	4.51%	6.87%	13.27%	16.28%

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation
12 Months Ended
April 30, 2008

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Secondary GSS	General Service Primary GSP
Taxable Income Pro-Forma							
Total Operating Revenue				$ 1,020,697,910	$ 387,629,753	$ 130,095,608	$ 2,785,088
Operating Expenses				$ 806,131,149	$ 339,412,963	$ 87,091,381	$ 2,194,749
Interest Expense		INTEXP		$ 56,236,895	$ 27,638,390	$ 6,210,669	$ 224,333
Interest Syncronization Adjustment			INTEXP	$ (3,188,461)	$ (1,566,030)	$ (351,905)	$ (12,711)
Taxable Income		TXINCPF		$ 161,518,328	$ 22,144,430	$ 37,145,463	$ 378,717

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation
12 Months Ended
April 30, 2008

Description	Ref	Name	Allocation Vector	All Electric School AES	Combined Light & Power LPS	Combined Light & Power LPP	Combined Light & Power LPT	Small Time-of-Day Secondary STODS	Small Time-of-Day Primary STODP	Large Comm/Ind TOD Primary LCIP	Large Comm/Ind TOD Transmission LCIT
Taxable Income Pro-Forma											
Total Operating Revenue				$ 7,056,889	$ 194,114,135	$ 78,285,742	$ 1,203,809	$ 8,255,297	$ 682,843	$ 118,778,254	$ 30,256,728
Operating Expenses				$ 5,592,684	$ 142,182,593	$ 57,398,381	$ 911,042	$ 6,961,474	$ 558,449	$ 94,890,290	$ 26,674,805
Interest Expense		INTEXP		$ 430,591	$ 8,472,506	$ 3,084,383	$ 54,734	$ 390,378	$ 30,688	$ 5,108,569	$ 1,414,650
Interest Syncronization Adjustment			INTEXP	$ (24,398)	$ (480,064)	$ (174,765)	$ (3,101)	$ (22,119)	$ (1,739)	$ (289,459)	$ (80,156)
Taxable Income		TXINCPF		$ 1,058,012	$ 43,939,101	$ 15,977,744	$ 241,134	$ 925,566	$ 75,444	$ 18,968,853	$ 2,249,430

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation
12 Months Ended
April 30, 2008

Description	Ref	Name	Allocation Vector	Coal Mining Power Primary MPP	Coal Mining Power Transmission MPT	Large Power Mine Power TOD Primary LMPP	Large Power Mine Power TOD Transmission LMPT	Large Industrial Time-of-Day LITOD	Street Lighting SL	Decorative Street Lighting SLDEC	Private Outdoor Lighting POL	Customer Outdoor Lighting OL
Taxable Income Pro-Forms												
Total Operating Revenue				$ 6,401,292	$ 3,560,058	$ 4,354,116	$ 12,298,559	$ 20,806,717	$ 7,105,084	$ 1,270,603	$ 3,990,877	$ 5,784.458
Operating Expenses				$ 4,348,938	$ 2,447,664	$ 3,176,560	$ 8,989,780	$ 12,342,055	$ 5,158,667	$ 706,836	$ 1,982,056	$ 3,011,783
Interest Expense		INTEXP		$ 284,202	$ 151,567	$ 192,132	$ 475,301	$ 649,580	$ 804,841	$ 142,502	$ 168,158	$ 266,723
Interest Syncronization Adjustment			INTEXP	$ (16,103)	$ (8,588)	$ (10,886)	$ (26,931)	$ (36,806)	$ (45,603)	$ (8,074)	$ (10,661)	$ (16,359)
Taxable Income		TXINCPF		$ 1,784,256	$ 969,415	$ 996,310	$ 2,860,409	$ 7,851,886	$ 1,189,180	$ 429,339	$ 1,831,325	$ 2,500,311

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation
12 Months Ended
April 30, 2008

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Secondary GSS	General Service Primary GSP
Net Operating Income -- Adjusted for Increase							
Operating Revenue							
Total Operating Revenue				$ 1,020,697,910	$ 387,629,753	$ 130,095,608	$ 2,785,088
Proposed Increase				$ 19,573,831	$ 17,329,356	$ -	$ 446,784
Increase in Miscellaneous Charges			MISCA	$ 2,536,008	$ 1,221,813	$ 552,142	$ 12,190
			RENT	$ -	$ -	$ -	$ -
Total Pro-Forma Operating Revenue				$ 1,042,807,749	$ 406,180,922	$ 130,647,750	$ 3,244,062
Operating Expenses							
Total Operating Expenses				$ 971,779,275	$ 386,751,943	$ 109,720,452	$ 2,575,071
Pro-Forma Adjustments				$ (109,583,264)	$ (39,652,299)	$ (9,735,296)	$ (246,863)
Incremental Income Taxes				$ 8,313,919	$ 6,975,759	$ 207,621	$ 172,587
Total Pro-Forma Operating Expenses				$ 870,509,930	$ 354,075,403	$ 100,192,777	$ 2,498,795
Net Operating Income				$ 172,297,819	$ 52,105,519	$ 30,454,973	$ 745,267
Net Cost Rate Base				$ 2,216,908,245	$ 1,131,273,083	$ 246,804,404	$ 9,588,426
Rate of Return				7.77%	4.61%	12.34%	7.77%

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation
12 Months Ended
April 30, 2008

Description	Ref	Name	Allocation Vector	All Electric School AES	Combined Light & Power LPS	Combined Light & Power LPP	Combined Light & Power LPT	Small Time-of-Day Secondary STODS	Small Time-of-Day Primary STODP	Large Comm/Ind TOD Primary LCIP	Large Comm/Ind TOD Transmission LCIT
Net Operating Income -- Adjusted for Increase											
Operating Revenue											
Total Operating Revenue				$ 7,056,889	$ 194,114,135	$ 76,285,742	$ 1,203,809	$ 8,255,297	$ 662,843	$ 116,778,254	$ 30,258,728
Proposed Increase				$ 321,938	$ -	$ -	$ (70,621)	$ 82,070	$ 6,637	$ -	$ (38,022)
Increase in Miscellaneous Charges			MISCA	$ 7,079	$ 490,995	$ 168,330	$ 2,968	$ 31,534	$ 2,531	$ 19,661	$ 5,163
			RENT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Pro-Forma Operating Revenue				$ 7,385,906	$ 194,605,130	$ 76,474,072	$ 1,136,156	$ 8,368,900	$ 672,011	$ 116,797,915	$ 30,225,869
Operating Expenses											
Total Operating Expenses				$ 6,675,732	$ 182,611,345	$ 71,568,439	$ 1,129,578	$ 8,322,514	$ 668,004	$ 115,317,429	$ 31,765,057
Pro-Forma Adjustments				$ (715,796)	$ (25,176,798)	$ (8,623,932)	$ (134,835)	$ (1,039,761)	$ (83,367)	$ (14,436,983)	$ (4,309,440)
Incremental Income Taxes				$ 123,720	$ 184,628	$ 70,817	$ (25,439)	$ 42,718	$ 3,448	$ 7,393	$ (12,356)
Total Pro-Forma Operating Expenses				$ 6,083,656	$ 157,619,175	$ 63,015,324	$ 969,304	$ 7,325,471	$ 588,085	$ 100,887,840	$ 27,443,261
Net Operating Income				$ 1,302,250	$ 36,985,956	$ 13,458,747	$ 166,852	$ 1,043,429	$ 83,926	$ 15,910,075	$ 2,782,608
Net Cost Rate Base				$ 17,344,665	$ 318,204,987	$ 112,851,704	$ 2,076,882	$ 14,454,151	$ 1,130,459	$ 185,954,528	$ 50,636,749
Rate of Return				7.51%	11.62%	11.93%	8.03%	7.22%	7.42%	8.56%	5.50%

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation
12 Months Ended
April 30, 2008

Description	Ref	Name	Allocation Vector	Coal Mining Power Primary MPP	Coal Mining Power Transmission MPT	Large Power Mine Power TOD Primary LMPP	Large Power Mine Power TOD Transmission LMPT	Large Industrial Time-of-Day LITOD	Street Lighting SL	Decorative Street Lighting SLDEC	Private Outdoor Lighting POL	Customer Outdoor Lighting OL
Net Operating Income -- Adjusted for Increase												
Operating Revenue												
Total Operating Revenue				$ 6,401,292	$ 3,560,058	$ 4,354,116	$ 12,298,559	$ 20,806,717	$ 7,105,064	$ 1,270,603	$ 3,990,877	$ 5,784,458
Proposed Increase				$ 575,463	$ 100,123	$ 29,196	$ 5,099	$ -	$ 304,645	$ 61,720	$ 195,020	$ 224,423
Increase in Miscellaneous Charges			MISCA	$ 322	$ 0	$ 0	$ 545	$ 736	$ 0	$ -	$ 0	$ -
			RENT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Pro-Forma Operating Revenue				$ 6,977,077	$ 3,660,181	$ 4,383,312	$ 12,304,203	$ 20,807,453	$ 7,409,729	$ 1,332,323	$ 4,185,897	$ 6,008,881
Operating Expenses												
Total Operating Expenses				$ 5,408,952	$ 3,136,494	$ 3,982,438	$ 11,357,140	$ 17,105,039	$ 5,802,860	$ 932,490	$ 2,775,440	$ 4,172,859
Pro-Forma Adjustments				$ (440,671)	$ (352,331)	$ (460,041)	$ (1,374,467)	$ (2,037,470)	$ (233,411)	$ (76,623)	$ (157,702)	$ (293,178)
Incremental Income Taxes				$ 216,511	$ 37,649	$ 10,979	$ 2,122	$ 277	$ 114,555	$ 23,208	$ 73,333	$ 84,389
Total Pro-Forma Operating Expenses				$ 5,184,792	$ 2,821,812	$ 3,533,374	$ 9,984,796	$ 15,067,848	$ 5,684,005	$ 879,075	$ 2,691,070	$ 3,964,070
Net Operating Income				$ 1,792,285	$ 838,368	$ 849,938	$ 2,319,407	$ 5,739,607	$ 1,725,724	$ 453,248	$ 1,494,827	$ 2,044,811
Net Cost Rate Base				$ 11,129,229	$ 5,810,112	$ 7,283,718	$ 17,278,660	$ 22,954,379	$ 34,053,743	$ 6,032,746	$ 10,346,986	$ 11,700,613
Rate of Return				16.10%	14.43%	11.67%	13.42%	25.00%	5.07%	7.51%	14.45%	17.48%

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation
12 Months Ended
April 30, 2008

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Secondary GSS	General Service Primary GSP
Allocation Factors							
Energy Allocation Factors							
Energy Usage by Class		E01	Energy	1.000000	0.350370	0.098116	0.002283
Customer Allocation Factors							
Primary Distribution Plant -- Average Number of Custom		C08	Cust08	1.000000	0.79528	0.15052	0.00014
Customer Services -- Weighted cost of Services		C02		1.000000	0.587977	0.110904	-
Meter Costs -- Weighted Cost of Meters		C03		1.000000	0.622505	0.274642	0.000665
Lighting Systems -- Lighting Customers		C04	Cust04	1.000000	-	-	-
Meter Reading and Billing -- Weighted Cost		C05	Cust05	1.000000	0.67609	0.14118	0.00120
Marketing/Economic Development		C06	Cust06	1.000000	0.79528	0.15052	0.00014
Total billed revenue per Billing Determinants		R01		1,112,462,069	419,658,185	136,859,057	3,021,555
Redundant Capacity revenues not included in billing determinants			R01	10,854	$ -	$ -	$ -
Unbilled revenues not included in billing determinants			R01	6,878,000	$ 2,594,613	$ 846,156	$ 18,661
Accrued revenues not included in billing determinants			R01	(17,682,129)	$ (6,670,295)	$ (2,175,319)	$ (48,026)
Merger surcredit amortization			R01	(1,069,892)	$ (403,599)	$ (131,622)	$ (2,906)
Revenue adjustment			R01	(334)	$ (126)	$ (41)	$ (1)
Revenue per Jurisdictional Separation Study				1,100,598,569	415,176,778	135,398,231	2,989,303
Energy				18,783,418,257	6,487,809,251	1,819,611,111	43,720,664
Energy (Loss Adjusted)		Energy		20,156,276,125	7,062,152,956	1,977,646,648	46,016,763
O&M Customer Allocators							
Customers (Monthly Bills)				7,996,703	4,958,111	938,420	872
Average Customers (Bills/12)				666,393	413,176	78,202	73
Average Customers (Lighting = Lights)				666,393	413,176	78,202	73
Weighted Average Customers (Lighting =9 Lights per Cu		Cust05		609,322	413,176	86,022	730
Street Lighting		Cust04		69,869,338	-	-	-
Average Customers		Cust01		666,393	413,176	78,202	73
Average Customers (Lighting = 9 Lights per Cust)		Cust06		519,535	413,176	78,202	73
Average Secondary Customers		Cust07		519,012	413,176	78,202	-
Average Primary Customers		Cust08		519,536	413,176	78,202	73
Plant Customer Allocators							
Year End Customers				502,777	414,418	78,768	72
Year End Customers (Lighting = Lights)				708,973	414,418	78,768	72
Weighted Year End Customers (Lighting =9 Lights per C		YECust05		612,466	414,418	86,645	720
Street Lighting		YECust04		52,453,968	-	-	-
Year End Customers		YECust01		708,973	414,418	78,768	72
Year End Customers (Lighting = 9 Lights per Cust)		YECust06		525,687	414,418	78,768	72
Year End Secondary Customers		YECust07		525,167	414,418	78,768	-
Year End Primary Customers		YECust08		525,688	414,418	78,768	72
Demand Allocators							
Maximum Class Non-Coincident Peak Demands		NCP		4,667,350	2,277,441	469,138	26,268
Maximum Class Demands (Primary)		NCPP		4,471,090	2,277,441	469,138	26,268
Sum of the Individual Customer Demands (Secondary)		SICD		8,070,265	4,909,823	2,475,479	-
Summer Peak Period Demand Allocator		SCP		3,555,506	1,479,783	393,532	21,700
Winter Peak Period Demand Allocator		WCP		3,594,667	1,896,227	277,905	23,766
Base Demand Allocator		BDEM		2,294,658	803,979	225,142	5,239
				2,279,717	803,979	225,142	5,239

Seelye Exhibit 20

Kentucky Utilties Company

Zero Intercept Analysis
Account 365 -- Overhead Conductor

April 30, 2008

Weighted Linear Regression Statistics

	Estimate	Standard Error
Size Coefficient ($ per MCM)	0 0024414	0 0008277
Zero Intercept ($ per Unit)	1 5561915	0 1921036
R-Square	0 9045373	

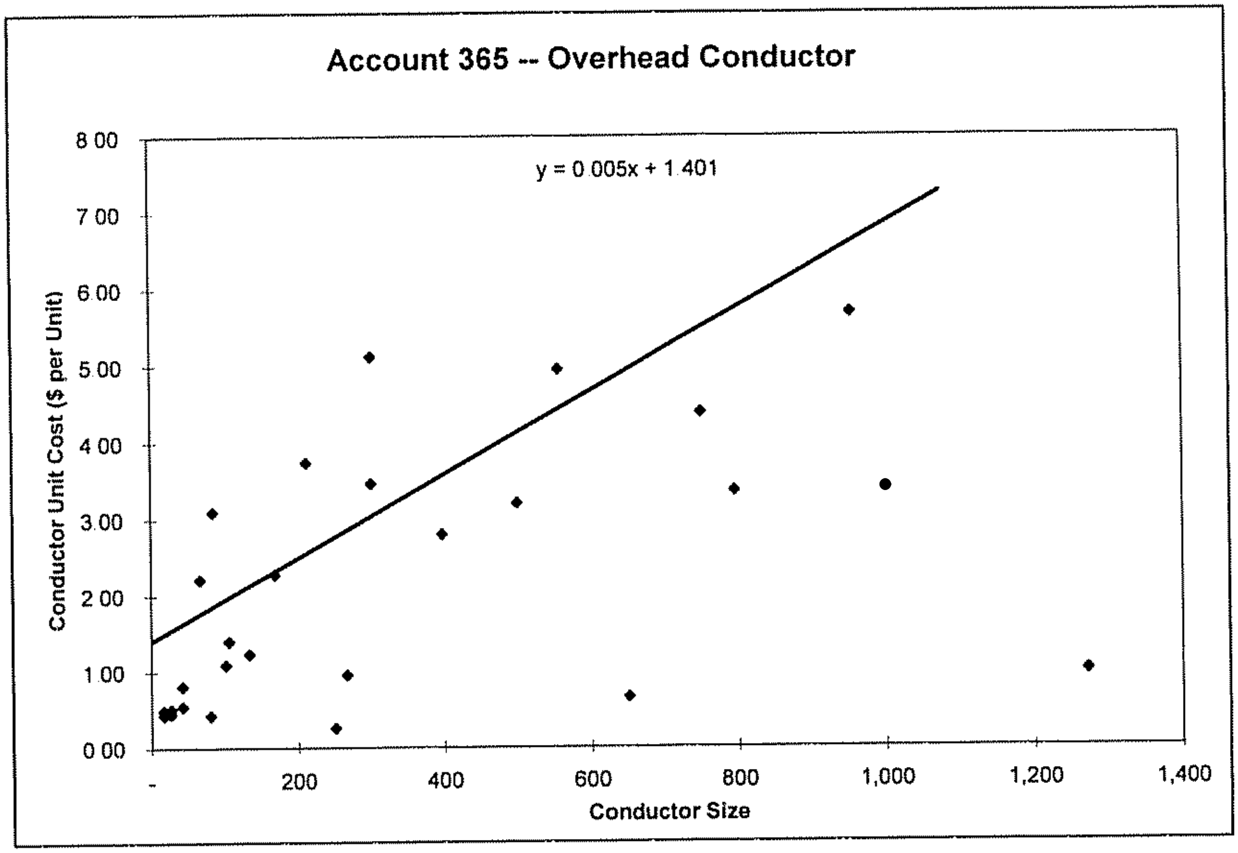
Plant Classification

Total Number of Units	70,828,782
Zero Intercept	1 5561915
Zero Intercept Cost	$ 110,223,148
Total Cost of Sample	$ 139,666,231
Percentage of Total	*0 789189679*
Percentage Classified as Customer-Related	78.92%
Percentage Classified as Demand-Related	21.08%

Kentucky Utilties Company

Zero Intercept Analysis
Account 365 -- Overhead Conductor

April 30, 2008



Kentucky Utilties Company

Zero Intercept Analysis
Account 365 -- Overhead Conductor

April 30, 2008

	Size	Units	Costs	Ave Cost
1 CONDUCTOR	83 69	1,178,419	3,646,002	3 09
1/0 CONDUCTOR	105 6	3,889,448	5,436,705	1 40
1000 MCM CONDUCTOR	1000	25,418	86,350	3 40
101 MCM ACSR CONDUCTOR	101	20,676	22,522	1 09
1272 MCM ACSR CONDUCTOR	1272	11,889	11,866	1 00
2 COPPER CONDUCTOR	66 36	20,881,079	46,206,112	2 21
2/0 COPPER CONDUCTOR	133 1	13,396,036	16,472,356	1 23
250 MCM COPPER CONDUCTOR	250	15,077	3,899	0 26
266 MCM ACSR CONDUCTOR	266	3,177,930	3,032,195	0 95
3/0 COPPER CONDUCTOR	167 8	10,833,994	24,633,416	2 27
300 MCM COPPER CONDUCTOR	300	45,764	234,231	5 12
350 MCM COPPER CONDUCTOR	300	1,540	5,335	3 46
397 MCM ACSR CONDUCTOR	397	8,469,662	23,685,484	2 80
4 COPPER CONDUCTOR	41 74	2,182,398	1,774,472	0 81
4/0 COPPER CONDUCTOR	211 6	1,345,716	5,031,401	3 74
4A COPPER CONDUCTOR	41 74	72,667	39.661	0 55
500 MCM COPPER CONDUCTOR	500	78,298	250,849	3 20
556 MCM ACSR CONDUCTOR	556	660	3,265	4 95
6 COPPER CONDUCTOR	26 24	1,329,850	596,023	0 45
650 MCM COPPER CONDUCTOR	650	617	406	0 66
6A COPPER CONDUCTOR	26 24	1,563,121	796,055	0 51
750 MCM COPPER CONDUCTOR	750	27,495	120,529	4 38
795 MCM ALUMINUM CONDUCTOR	795	2,207,081	7,413,682	3 36
8 COPPER CONDUCTOR	16 51	26,081	12,771	0 49
80 MCM ACSR CONDUCTOR	80	18,929	8,059	0 43
8A COPPER CONDUCTOR	16 51	4,188	1,809	0 43
954 MCM ACSR CONDUCTOR	954	24.749	140,776	5 69

Kentucky Utilties Company

Zero Intercept Analysis
Account 365 -- Overhead Conductor

April 30, 2008

n	y	x	est y	y*n^.5	n^.5	xn^.5
1,178,419	3.09398	83.69	1.761	3358.66807	1,085.55	90849.6871
3,889,448	1.39781	105.60	1.814	2756.7145	1,972.17	208260.978
25.418	3.39721	1,000.00	3.998	541.618343	159.43	159430.236
20,676	1.08928	101.00	1.803	156.628991	143.79	14522.9431
11,889	0.99808	1,272.00	4.662	108.827587	109.04	138694.671
20,881,079	2.21282	66.36	1.718	10111.6716	4,569.58	303237.457
13,396.036	1.22964	133.10	1.881	4500.57042	3,660.06	487153.928
15,077	0.25863	250.00	2.167	31.7564921	122.79	30697.109
3,177,930	0.95414	266.00	2.206	1700.92415	1,782.67	474191.538
10,833,994	2.27372	167.80	1.966	7483.94092	3,291.50	552314.254
45,764	5.11824	300.00	2.289	1094.92158	213.93	64177.5662
1,540	3.46425	300.00	2.289	135.946859	39.24	11772.8501
8,469,662	2.79651	397.00	2.525	8138.59098	2,910.27	1155376.54
2,182,398	0.81308	41.74	1.658	1201.16339	1,477.29	61662.2577
1,345,716	3.73883	211.60	2.073	4337.22801	1,160.05	245466.58
72,667	0.54579	41.74	1.658	147.127384	269.57	11251.7755
78,298	3.20378	500.00	2.777	896.473641	279.82	139908.899
660	4.94695	556.00	2.914	127.089563	25.69	14283.8986
1,329,850	0.44819	26.24	1.620	516.846684	1,153.19	30259.7377
617	0.65749	650.00	3.143	16.3316592	24.84	16145.6651
1,563,121	0.50927	26.24	1.620	636.717484	1,250.25	32806.5174
27,495	4.38367	750.00	3.387	726.884024	165.82	124362.122
2,207,081	3.35904	795.00	3.497	4990.27873	1,485.62	1181071.7
26,081	0.48967	16.51	1.596	79.0797278	161.50	2666.30111
18,929	0.42574	80.00	1.752	58.5740784	137.58	11006.6162
4,188	0.43190	16.51	1.596	27.9505021	64.71	1068.44067
24,749	5.68814	954.00	3.885	894.847994	157.32	150081.514

Seelye Exhibit 21

Kentucky Utilities Company

Zero Intercept Analysis
Account 367 -- Underground Conductor

April 30, 2008

Weighted Linear Regression Statistics

	Estimate	Standard Error
Size Coefficient ($ per MCM)	0 0109857	0 0023381
Zero Intercept ($ per Unit)	3 0686653	0 3579679
R-Square	0 9588170	

Plant Classification

Total Number of Units	18,998,509
Zero Intercept	3 0686653
Zero Intercept Cost	$ 58,300,065
Total Cost of Sample	$ 80,820,029
Percentage of Total	0.721356643
Percentage Classified as Customer-Related	72.14%
Percentage Classified as Demand-Related	27.86%

Kentucky Utilities Company

Zero Intercept Analysis
Account 367 -- Underground Conductor

April 30, 2008

Weighted Linear Regression Statistics

	Estimate	Standard Error
Size Coefficient ($ per MCM)	0.0109857	0.0023381
Zero Intercept ($ per Unit)	3.0686653	0.3579679
R-Square	0.9588170	

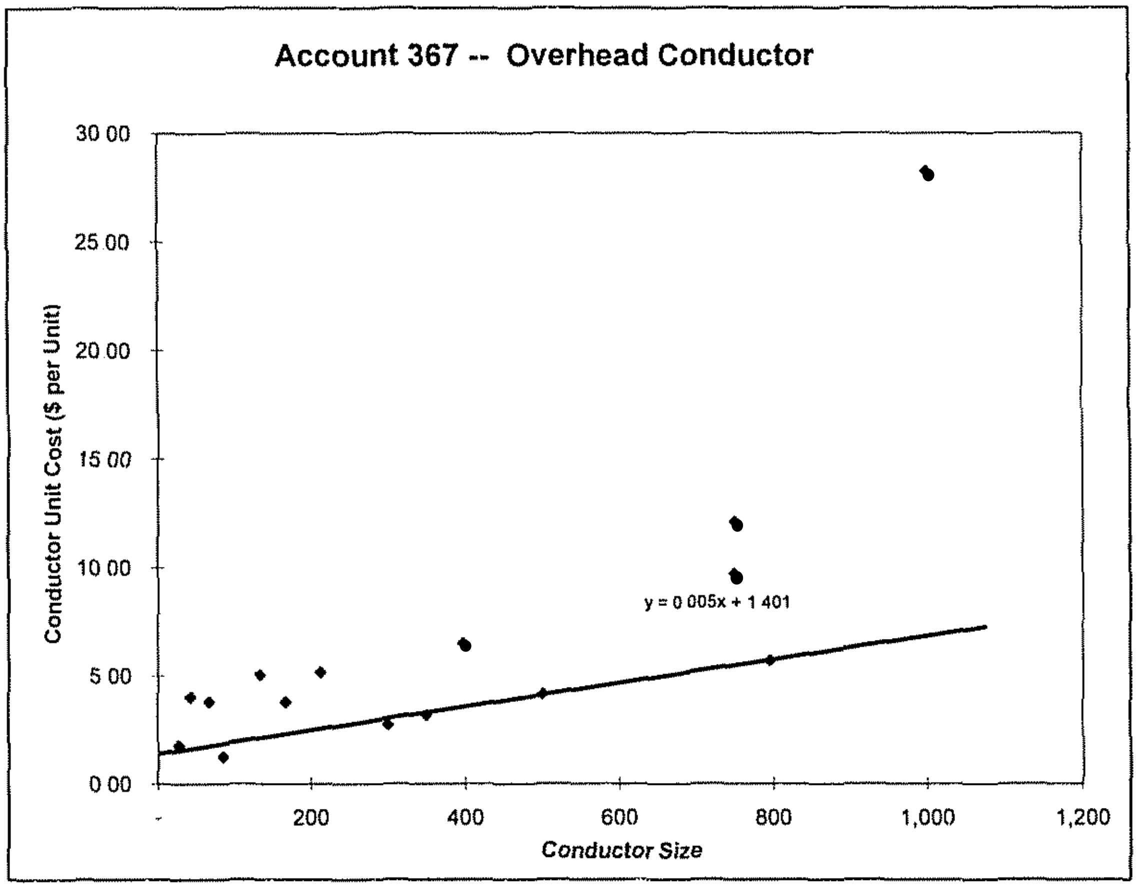
Plant Classification

Total Number of Units	18,998,509
Zero Intercept	3.0686653
Zero Intercept Cost	$ 58,300,065
Total Cost of Sample	$ 80,820,029
Percentage of Total	0.721356643
Percentage Classified as Customer-Related	72.14%
Percentage Classified as Demand-Related	27.86%

Kentucky Utilities Company

Zero Intercept Analysis
Account 367 -- Underground Conductor

April 30, 2008



Kentucky Utilities Company

Zero Intercept Analysis
Account 367 -- Underground Conductor

April 30, 2008

	Size	Units	Cost	Ave Cost
1 CONDUCTOR	83.69	219	274	1 25
1/0 CONDUCTOR	750	194,260	1,884,319	9 70
1000 MCM CONDUCTOR	1000	42,943	1,213,600	28 26
2 COPPER CONDUCTOR	66 36	13,557,625	51,479,876	3 80
2/0 COPPER CONDUCTOR	133 1	3,135,519	15,818,289	5 04
3/0 COPPER CONDUCTOR	167 8	188,086	714,446	3.80
300 MCM COPPER CONDUCTOR	300	73	199	2 73
350 MCM COPPER CONDUCTOR	350	319,234	1,016,281	3.18
397 MCM ACSR CONDUCTOR	397	15,560	101,318	6 51
4 COPPER CONDUCTOR	41 74	5	20	4 03
4/0 COPPER CONDUCTOR	211 6	1,387,099	7,172,345	5.17
500 MCM COPPER CONDUCTOR	500	55,778	231,321	4 15
6 COPPER CONDUCTOR	26 24	4,466	7,956	1 78
750 MCM COPPER CONDUCTOR	750	97,306	1,177,863	12 10
795 MCM ALUMINUM CONDUCTOR	795	336	1,921	5 72

Kentucky Utilities Company

Zero Intercept Analysis
Account 367 -- Underground Conductor

April 30, 2008

n	y	x	est y	y*n^.5	n^.5	xn^.5
219	1 25224	83 69	3 988	18 53142187	14 80	1238 4989
194,260	9 69998	750 00	11 308	4275 261731	440 75	330562 02
42,943	28 26073	1,000 00	14 054	5856 38347	207.23	207226 93
13,557,625	3 79712	66 36	3 798	13981 23976	3,682 07	244342 03
3,135,519	5 04487	133 10	4 531	8933 153255	1,770 74	235685 45
188,086	3 79851	167 80	4 912	1647 370103	433 69	72772 985
73	2 73260	300 00	6 364	23 34736804	8 54	2563 2011
319.234	3 18350	350 00	6 914	1798 702255	565 01	197752 79
15,560	6 51145	397 00	7 430	812 2365728	124 74	49521 672
5	4 02800	41 74	3 527	9 006881813	2 24	93 333477
1,387,099	5 17075	211 60	5 393	6089 861685	1,177 75	249212 25
55,778	4 14718	500 00	8 562	979 4542507	236 17	118086 83
4,466	1 78135	26 24	3 357	119 0444664	66 83	1753 5703
97.306	12 10473	750 00	11 308	3775 939383	311 94	233954 32
336	5 71872	795 00	11 802	104 8258735	18 33	14572 591

Seelye Exhibit 22

KENTUCKY UTILITIES

Zero Intercept Analysis
Account 368 -- Line Transformers

April 2008

Weighted Linear Regression Statistics	**Estimate**	**Standard Error**
Size Coefficient ($ per MCM)	9.1730499	0.4189377
Zero Intercept ($ per Unit)	345.7682388	47.6632850
R-Square	0.9381560	

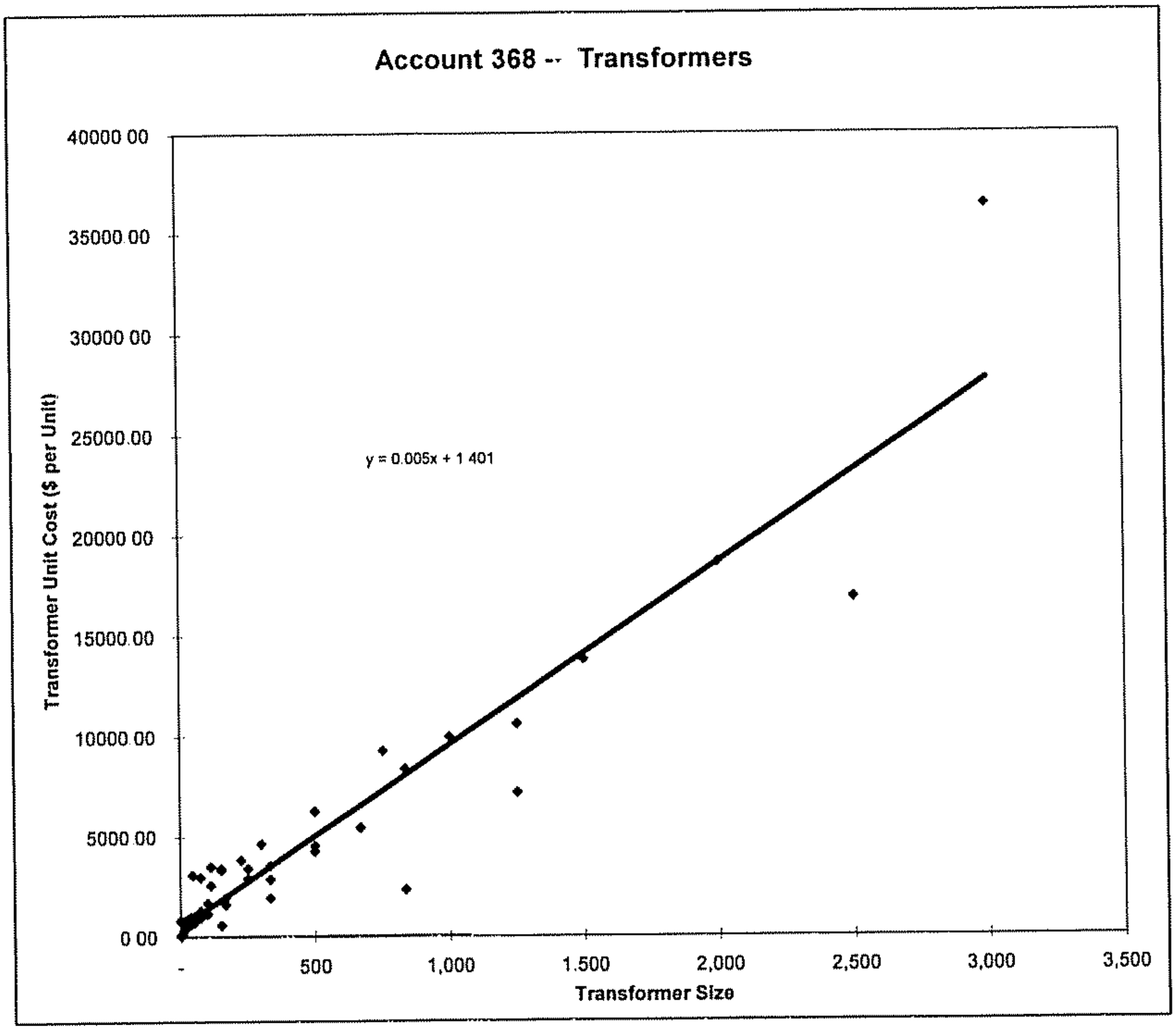
Plant Classification

Total Number of Units	235,978
Zero Intercept	345.7682388
Zero Intercept Cost	$ 81,593.697
Total Cost of Sample	$ 170,413,034
Percentage of Total	0.478799629
Percentage Classified as Customer-Related	47.88%
Percentage Classified as Demand-Related	52.12%

KENTUCKY UTILITIES

Zero Intercept Analysis
Account 368 -- Line Transformers

April 2008



KENTUCKY UTILITIES

Zero Intercept Analysis
Account 368 -- Line Transformers

April 2008

	Size	Units	Cost	Ave Cost
TRANSFORMER				
TRANSFORMERS - OH 1P - 6 KVA	0 6	7	5877 45	839 64
TRANSFORMERS - OH 1P - 1 KVA	1	45	34862 02	774 71
TRANSFORMERS - OH 1P - 1 5 KVA	1 5	134	9326 55	69 60
TRANSFORMERS - OH 1P - 10 KVA	10	29753	9327208 71	313 49
TRANSFORMERS - OH 1P - 100 KVA	100	4009	4693694 64	1,170 79
TRANSFORMERS - OH 1P - 1250 KVA	1250	14	148540 75	10,610 05
TRANSFORMERS - OH 1P - 15 KVA	15	47366	20311822 25	428 83
TRANSFORMERS - OH 1P - 150 KVA	150	5	2988 84	597 77
TRANSFORMERS - OH 1P - 167 KVA	167	2169	3494109 09	1,610 93
TRANSFORMERS - OH 1P - 2 5 KVA	2 5	61	6852 17	112 33
TRANSFORMERS - OH 1P - 25 KVA	25	58002	30440286 34	524 81
TRANSFORMERS - OH 1P - 250 KVA	250	323	939538 9	2,908 79
TRANSFORMERS - OH 1P - 3 KVA	3	1440	86951 04	60 38
TRANSFORMERS - OH 1P - 333 KVA	333	144	415230	2,883 54
TRANSFORMERS - OH 1P - 37 5 KVA	37 5	28109	18499226 04	658 12
TRANSFORMERS - OH 1P - 5 KVA	5	6837	873618 6	127 78
TRANSFORMERS - OH 1P - 50 KVA	50	16903	12173557 36	720 20
TRANSFORMERS - OH 1P - 500 KVA	500	252	1074289 03	4,263 05
TRANSFORMERS - OH 1P - 667 KVA	667	17	92692 95	5,452 53
TRANSFORMERS - OH 1P - 7 5 KVA	7 5	68	9189 86	135 15
TRANSFORMERS - OH 1P - 75 KVA	75	6109	6073456 02	994 18
TRANSFORMERS - OH 1P - 833 KVA	833	32	268139 91	8,379 37
TRANSFORMERS - PM 1P - 10 KVA	10	210	156155 32	743 60
TRANSFORMERS - PM 1P - 100 KVA	100	1228	2077963	1,692 15
TRANSFORMERS - PM 1P - 15 KVA	15	2472	2031211 32	821 69
TRANSFORMERS - PM 1P - 150 KVA	150	14	46750 31	3,339 31
TRANSFORMERS - PM 1P - 167 KVA	167	805	1582671 94	1,966 05
TRANSFORMERS - PM 1P - 25 KVA	25	7206	6552386 39	909 30
TRANSFORMERS - PM 1P - 250 KVA	250	346	1185905 38	3,427 47
TRANSFORMERS - PM 1P - 333 KVA	333	2	3901 9	1,950 95
TRANSFORMERS - PM 1P - 37 5 KVA	37 5	8081	8213226 91	1,016 36
TRANSFORMERS - PM 1P - 50 KVA	50	6364	6728494 84	1,057 27
TRANSFORMERS - PM 1P - 500 KVA	500	2	9101 56	4,550 78
TRANSFORMERS - PM 1P - 75 KVA	75	2690	3619138 21	1,345 40
TRANSFORMERS - PM 3P - 1000 KVA	1000	298	2969090 07	9,963 39
TRANSFORMERS - PM 3P - 112 KVA	112	33	85554 2	2,592 55
TRANSFORMERS - PM 3P - 112 5 KVA	112 5	232	817415 77	3,523 34
TRANSFORMERS - PM 3P - 1250 KVA	1250	2	14355 37	7,177 69
TRANSFORMERS - PM 3P - 150 KVA	150	635	2170379 3	3,417 92
TRANSFORMERS - PM 3P - 1500 KVA	1500	201	2777689 14	13,819 35
TRANSFORMERS - PM 3P - 2000 KVA	2000	80	1492839 64	18,660 50
TRANSFORMERS - PM 3P - 225 KVA	225	497	1906195 46	3,835 40
TRANSFORMERS - PM 3P - 2500 KVA	2500	133	2245435 64	16,882 97
TRANSFORMERS - PM 3P - 300 KVA	300	835	3874332 21	4,639 92
TRANSFORMERS - PM 3P - 3000 KVA	3000	8	291310 98	36,413 87
TRANSFORMERS - PM 3P - 333 KVA	333	33	117861 4	3,571 56
TRANSFORMERS - PM 3P - 45 KVA	45	123	381081 67	3,098 22
TRANSFORMERS - PM 3P - 500 KVA	500	809	5073654 57	6,271 51
TRANSFORMERS - PM 3P - 75 KVA	75	435	1299950 19	2,988 39
TRANSFORMERS - PM 3P - 750 KVA	750	398	3691109 17	9,274 14
TRANSFORMERS - PM 3P - 833 KVA	833	7	16413 78	2,344 83
VOLTAGE CONTROL				

KENTUCKY UTILITIES

Zero Intercept Analysis
Account 368 -- Line Transformers

April 2008

n	y	x	est y	y*n^.5	n^.5	xn^.5
7	839 63571	0 60	351 272	2221 467292	2 65	1 5874508
45	774 71156	1 00	354 941	5196 923104	6 71	6 7082039
134	69 60112	1 50	359 528	805 6912065	11 58	17.363755
29,753	313.48801	10 00	437 499	54073 7282	172.49	1724 9058
4,009	1,170 78938	100 00	1,263 073	74130 47859	63 32	6331 6664
14	10,610 05357	1.250 00	11,812 081	39699 18532	3 74	4677 0717
47,366	428 82705	15 00	483 364	93328 76781	217 64	3264 5597
5	597 76800	150 00	1,721 726	1336 649883	2 24	335 4102
2,169	1,610 93089	167 00	1,877 668	75025 11746	46 57	7777 6115
61	112 33066	2 50	368 701	877 3304676	7 81	19 525624
58,002	524 81443	25 00	575 094	126394 2301	240 84	6020 9011
323	2,908 78916	250 00	2,639 031	52277 34281	17 97	4493 0502
1,440	60 38267	3 00	373 287	2291 361094	37 95	113 842
144	2,883 54167	333 00	3,400 394	34602 5	12 00	3996
28,109	658 12466	37 50	689 758	110339 4618	167 66	6287 1521
6,837	127 77806	5 00	391 633	10565 47634	82 69	413 43077
16,903	720 20099	50 00	804 421	93634 43854	130 01	6500 5769
252	4,263 05171	500 00	4,932 293	67673 84785	15 87	7937 2539
17	5,452 52647	667 00	6,464 192	22481 34256	4 12	2750 1115
68	135 14500	7 50	414 566	1114 43422	8 25	61 846584
6,109	994 18170	75 00	1,033 747	77705 33344	78 16	5862 0069
32	8,379 37219	833 00	7,986 919	47400 88717	5 66	4712 1596
210	743 59676	10 00	437 499	10775 74082	14 49	144 91377
1,228	1,692 15228	100 00	1,263 073	59297 80627	35 04	3504 2831
2,472	821 68743	15 00	483 364	40853 65104	49 72	745 78817
14	3,339 30786	150 00	1,721 726	12494 54591	3 74	561 24861
805	1,966 05210	167 00	1,877 668	55781 85628	28 37	4738 2112
7,206	909 29592	25 00	575 094	77188 459	84 89	2122 204
346	3,427 47220	250 00	2,639 031	63754 6682	18 60	4650 2688
2	1,950 95000	333 00	3,400 394	2759 05995	1 41	470 93312
8,081	1,016 36269	37 50	689 758	91365 29652	89 89	3371 0393
6,364	1,057 27449	50 00	804 421	84343 73679	79 77	3988 7341
2	4,550 78000	500 00	4,932 293	6435 774795	1 41	707 10678
2,690	1,345 40454	75 00	1,033 747	69779 68884	51 87	3889 8907
298	9,963 38950	1,000 00	9,518 818	171994 7697	17 26	17262 677
33	2,592 55152	112 00	1,373 150	14893 07459	5 74	643 39102
232	3,523 34384	112 50	1,377 736	53665 97446	15 23	1713 5489
2	7,177 68500	1,250 00	11,812 081	10150 77947	1 41	1767 767
635	3,417 92016	150 00	1,721 726	86128 87529	25 20	3779 881
201	13,819 34896	1,500 00	14,105 343	195923 0857	14 18	21266 17
80	18,660 49550	2,000 00	18,691 868	166904 5457	8 94	17888 544
497	3,835 40334	225 00	2,409 704	85504 55212	22 29	5016 0368
133	16,882 97474	2,500 00	23,278 393	194703 9629	11 53	28831 406
835	4,639 91881	300 00	3,097 683	134076 7948	28 90	8668 91
8	36,413 87250	3,000 00	27,864 918	102993 9847	2 83	8485 2814
33	3,571 55758	333 00	3,400 394	20517 03624	5 74	1912 9394
123	3,098 22496	45 00	758 555	34360 97702	11 09	499 07414
809	6,271 51368	500 00	4,932 293	178380 1953	28 44	14221 463
435	2,988 39124	75 00	1,033 747	62327 84099	20 86	1564 249
398	9,274 14364	750 00	7,225 556	185018 5846	19 95	14962 453
7	2,344 82571	833 00	7,986 919	6203 825708	2 65	2203 9108