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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. 2009-00548

ATTORNEY GENERAL'S PRE-FILED TESTIMONY

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

Respectfully submitted,
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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF KENTUCKY UTILITIES	)	
COMPANY FOR AN ADJUSTMENT OF ITS	)	CASE NO. 2009-00548
BASE RATES	)	

PREPARED DIRECT TESTIMONY AND SCHEDULES

OF

GLENN A. WATKINS

ON BEHALF OF THE

KENTUCKY OFFICE OF THE ATTORNEY GENERAL

APRIL 23, 2010

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glenn A. Watkins. My business address is James Center III, 1051 East Cary Street, Suite 601, Richmond, VA 23219.

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

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

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

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

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS.

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

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

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

A. Technical Associates has been retained by the OAG to evaluate the reasonableness of Kentucky Utility Company's ("KU" or "Company") proposed weather normalization adjustment, class cost of service study (CCOSS), proposed distribution of revenues by class, and residential rate design. The purpose of my testimony, therefore, is to comment on KU's proposals on these issues and to present my findings and recommendations based on the results of the studies I have undertaken on behalf of the OAG.

II. WEATHER NORMALIZATION

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

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

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

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

Q. WHAT EFFECT DOES KU'S PROPOSED WEATHER NORMALIZATION HAVE ON ITS REQUESTED INCREASE?

A. In this particular rate case, KU's proposed weather normalization has the effect of reducing its requested revenue increase. That is, as a result of Mr. Seelye's proposed methodology and analysis, he concludes that actual test year sales and revenues were less than what would be expected under a more normal weather pattern. Specifically, Mr. Seelye's proposed weather adjustment results in an increase to test year revenue of $2.987 million and an increase to variable expenses of $1.490 million. The net effect of Mr. Seelye's weather adjustment is to increase test year operating income, before income taxes of $1.497 million.

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

A. No.

Q. PLEASE EXPLAIN.

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

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

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

Mr. Seelye's Exhibit 12 shows how his monthly sales adjustments are determined. Using Mr. Seelye's definition of KU's cooling season running from May 1 through September 30 as an example, we see that the month of May is evaluated to determine if that single month's weather pattern was outside of a band of normal weather. In this instance, the weather in May 2009 was not deemed to be abnormally warm (outside the band of normalcy), such that no adjustment was made to actual May sales. The same was true for June, August, and September 2009. However, Mr. Seelye determined that the month of July 2009 was cooler than normal (and outside of his normalcy band) so this month's sales were adjusted upward. Although Mr. Seelye's mutually exclusive analysis is conducted on a month by month basis, one could also apply the same logic on a weekly, daily, or even hourly basis.

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

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

A. Mr. Seelye defines KU's cooling season as May through September. I disagree with the inclusion of May for reasons that I will explain later. For the test year months of June through September (2009), the 30-year average cooling degree days are 1,087. The standard deviation of this 30-year average, is 188. As such, using Mr. Seelye's banding approach of defining a range of normal weather, a normal weather range is between 899 CDD's and 1,275 CDD. The actual cooling degree days during the June through September 2009 (test-year) period were 905 which is within the "normal" band. As such, one may not conclude that the test year cooling season was cooler (milder) than the range of expected normal weather and hence, no sales adjustment should be made. It should be noted that the above determination is based on a subjective banding definition of plus or minus one standard deviation from the thirty-year average. What this means is that about 68% of observations are expected to fall within the plus or minus one standard deviation and would be considered as the limits of normalcy. The remaining 32% would be considered "abnormal" under Mr. Seelye's approach. Although there are no established parameters as to exactly what percentage should be considered to fall within an expected normal range, extremes are often defined as those that are expected to occur less than 5% of the time. This 5% level of significance is by statistical definition approximately plus or minus two standard deviations. As such, if the definition of normal weather is expanded from 68% (plus or minus one standard deviation) to 95% (plus or minus two standard deviations) we see that the test year experience falls even more within a band of normalcy.

In my opinion, there is no reason for this Commission to alter its long standing practice of not considering weather adjustments for electric utilities.

Q. MR. SEELYE INCLUDED THE MONTH OF MAY AS A COOLING SEASON MONTH IN HIS ANALYSIS. SHOULD THIS MONTH BE INCLUDED AS A "COOLING MONTH"?

A. No. May is considered a shoulder month. Days in May can be cool or fairly warm such that these months are comprised of heating degree days and cooling degree days. As such, heating and air conditioning loads are not predictable in May. To illustrate, consider Mr. Seelye's Exhibit 12. On average, May has 109 HDDs throughout the month and 88 CDDs. Indeed, May tends to have more heating load than air conditioning load, yet, Mr. Seelye has modeled usage in May as a "cooling" month.

III. <u>CLASS COST OF SERVICE</u>

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

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

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

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

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

Q. PLEASE EXPLAIN HOW YOU PROCEEDED WITH YOUR ANALYSIS OF KU'S CCOSS.

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

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

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

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

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

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

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

	Class ROR At Current Rates	
Class	Seelye	Watkins
Residential	2.33%	3.34%
General Service	9.25%	9.34%
All Electric School	2.19%	2.85%
Power Service-Secondary	8.29%	6.52%
Power Service-Primary	7.87%	6.04%
TOD-Secondary	5.66%	3.26%
TOD-Primary	6.44%	4.41%
Transmission Service	9.73%	6.85%
Fluctuating Load	13.11%	16.67%
Lighting	9.34%	8.52%
Total Company	5.34%	5.34%

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

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

A. Generation

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

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

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

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

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

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

Q. PLEASE EXPLAIN.

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

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

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

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

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

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

<u>Summer and Winter Coincident Peak ("S/W Peak")</u> -- The S/W Peak method was developed because some utilities' annual peak load occurs in the summer during some years and in the winter during others. Because customers' usage and load characteristics may vary by season, the S/W Peak attempts to recognize this characteristic. This method is essentially the same as the 1-CP method except that two hours of load are considered instead of one. This method has essentially the same strengths and weaknesses as the 1-CP method, and in my opinion, is only marginally more reasonable than the 1-CP method.

<u>Twelve Monthly Coincident Peak ("12-CP")</u> -- Arithmetically, the 12-CP method is essentially the same as the 1-CP method except that class contributions to each monthly peak are considered. Although the 12-CP method bears little resemblance to how utilities design and build their systems, the results produced by this method better reflect the cost incidence of a utility's generation facilities.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

A. No.

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

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

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

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

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

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

Q. IN HIS REBUTTAL TO YOUR CCOSS FINDINGS IN KU'S 2008 RATE CASE (CASE NO. 2008-000251), MR. SEELYE INDICATED THAT HE COULD NOT RECALL EVER SEEING COST OF SERVICE STUDIES THAT ALLOCATE SUCH A LARGE PERCENTAGE (82%) OF PRODUCTION AND TRANSMISSION CAPACITY COSTS ON THE BASIS OF ENERGY. ARE YOU AWARE OF OTHER UTILITY STUDIES WITH SIMILARLY HIGH PRODUCTION AND TRANSMISSION PLANT ENERGY CLASSIFICATIONS?

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

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

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

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

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

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

Class	OAG Traditional BIP	Seelye Modified BIP
Residential	3.08%	2.33%
General Service	9.26%	9.25%
All Electric School	3.56%	2.19%
Power Service-Secondary	6.92%	8.29%
Power Service-Primary	6.42%	7.87%
TOD-Secondary	3.58%	5.66%
TOD-Primary	4.76%	6.44%
Transmission Service	6.85%	9.73%
Fluctuating Load	16.67%	13.11%
Lighting	8.29%	9.34%
Total Company	5.34%	5.34%

B. Distribution

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

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

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

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

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

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

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

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

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

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

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

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

Q. IS ONE METHOD PREFERRED OVER THE OTHER?

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

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

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

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

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

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

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

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

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

cost/unit = a + b (size)

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

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

The above industry standard is in stark contrast to Mr. Seelye's method presented in his Seelye Exhibits 21, 22, and 23. Mr. Seelye refers to his approach as a "weighted regression analysis." Although this "weighted regression analysis" is a clever arithmetic exercise, it violates theoretical statistical principles of linear regression and skews his results. Moreover, on page 66 of his direct testimony, Mr. Seelye states:

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

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

To understand the bias in Mr. Seelye's "weighted regression analysis," we must fully understand the mathematical model he derives. Using Overhead Conductors as an example, consider Mr. Seelye's analysis presented in his Exhibit 21. Although not shown in his exhibit, Mr. Seelye's equation for Overhead Conductors is:

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

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

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

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

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

cost/feet = 1.75 + 0.805(size)

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

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

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

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

A. Mr. Seelye classifies distribution plant as follows:

Account	Percentage Customer	Percentage Demand
Overhead Conductors	54.45%	45.55%
Underground Conductors	30.81%	69.19%
Line Transformers	54.37%	45.63%

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

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

Transformers). In my analyses, I have relied on Mr. Seelye's account data provided in Seelye Exhibits 21, 22 and 23, except for one significant revision.

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

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

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

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

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

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

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

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

	Customer Portion		Demand Portion	
	Watkins	Seelye	Watkins	Seelye
Account 365 (Overhead Conductors)	26%	54%	74%	46%
Account 367 (Underground Conductors)	19%	31%	81%	69%
Account 368 (Transformers)	57%	54%	43%	46%

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

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

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

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

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

Class	ROR At Current Rates	
	OAG Recommended	Seelye
Residential	3.34%	2.33%
General Service	9.34%	9.25%
All Electric School	2.85%	2.19%
Power Service-Secondary	6.52%	8.29%
Power Service-Primary	6.04%	7.87%
TOD-Secondary	3.26%	5.66%
TOD-Primary	4.41%	6.44%
Transmission Service	6.85%	9.73%
Fluctuating Load	16.67%	13.11%
Lighting	8.52%	9.34%
Total Company	5.34%	5.34%

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

IV. CLASS REVENUE INCREASE DISTRIBUTION

Q. HOW DOES MR. SEELYE PROPOSE TO DISTRIBUTE KU'S PROPOSED OVERALL $135.3 MILLION INCREASE ACROSS RATE CLASSES?

A. Mr. Seelye proposes to assign varying percentage increases to the rate class, which he claims predominately reflects the results of his CCOSS. The overall jurisdictional increase of $135.3 million represents an 11.5% increase in current revenues, whereby Mr. Seelye proposes class increases ranging from a high of 13.5% for the Residential class and a low of 9.84% to the Lighting classes. A summary of Mr. Seelye's proposed class increases is provided below along with our CCOSS results:

Class	KU Proposed Increase $ Millions	%	% of Average	ROR @ Current Rates Seelye	OAG
Residential	$58.747	13.54%	118%	2.33%	3.34%
General Service	$16.388	10.06%	88%	9.25%	9.34%
All Electric School	$1.149	13.90%	121%	2.19%	2.85%
Power Service-Secondary	$23.088	10.53%	92%	8.29%	6.52%
Power Service-Primary	$8.936	10.22%	89%	7.87%	6.04%
TOD-Secondary	$1.075	10.79%	94%	5.66%	3.26%
TOD-Primary	$15.517	11.09%	97%	6.44%	4.41%
Transmission Service	$7.258	9.97%	87%	9.73%	6.85%
Fluctuating Load	$1.873	9.87%	86%	13.11%	16.67%
Lighting	$2.065	9.84%	86%	9.34%	8.52%
Total Company	$134.341	11.49%	100%	--	--
Other Revenue	$0.926	8.65%	--	--	--
Total Jurisdictional	$135.267	11.47%	--	5.34%	5.34%

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

A. Yes, given the rather narrow range of achieved class rates of return under my CCOSS and that of Mr. Seelye's analysis, an across the board (equal percentage) increase would not be unreasonable. However, Mr. Seelye does recognize the ROR disparity that exists between classes and makes some movement toward ROR parity. In these regards, Mr. Seelye's relative class revenue increases are reasonable.

Q. DO YOU HAVE A RECOMMENDATION REGARDING A CLASS REVENUE INCREASE DISTRIBUTION IF THE COMMISSION AUTHORIZES AN INCREASE LESS THAN KU'S PROPOSED $135.3 MILLION INCREASE?

A. Yes. In the event that this Commission authorizes an overall increase less than the $135.3 request, Mr. Seelye's proposed class revenue increases should be scaled back proportionately.

V. RESIDENTIAL RATE DESIGN

Q. DOES KU PROPOSE ANY SIGNIFICANT CHANGES TO ITS RESIDENTIAL RATE STRUCTURE?

A. Yes. KU proposes to substantially change its Residential rate structure from a largely volumetric basis to a much more heavily weighted fixed fee charge per month basis. That is, whereas KU currently collects approximately 12% of its non-fuel base rate revenue from fixed monthly customer charges, (88% from energy charges) its proposed changes to rate design would collect approximately 27% of non-fuel base rate revenues from fixed customer charges. In order to accomplish this shift in revenue collection, KU proposes to increase its monthly Residential customer charge by 200% from \$5.00 to \$15.00 and at the same time, marginally increase its base rate energy charge by 2.2% from 6.424¢ per KWH to 6.566¢ per KWH.

Q. MR. WATKINS, HAVE YOU IDENTIFIED A PRIMARY OBJECTIVE IN KU'S RESIDENTIAL RATE DESIGN PROPOSAL?

A. Yes. It is clear from the testimony of Mr. Seelye that the primary objective of KU's Residential rate design is to increase revenue collection and profitability associated with fixed monthly customer charges.

Q. WHY DOES KU DESIRE MORE RESIDENTIAL REVENUE RECOGNITION FROM CUSTOMER CHARGES?

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

Q. DOES MR. SEELYE PROVIDE JUSTIFICATIONS FOR HIS PROPOSAL TO COLLECT SUBSTANTIALLY MORE OF ITS RESIDENTIAL BASE RATE REVENUES FROM FIXED MONTHLY CHARGES?

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

Q. IS KU CURRENTLY COMPENSATED FOR ITS CONSERVATION EFFORTS?

A. Yes. KU currently has a Demand Side Management surcharge which compensates the Company for its conservation program costs. In fact, not only is KU compensated for its costs to administer conservation efforts, it is also allowed an extra profit incentive over and above the costs of its DSM programs.

Q. IS KU ALSO COMPENSATED FOR ANY LOST SALES RESULTING FROM ITS CONSERVATION EFFORTS?

A. Yes.

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

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

Q. HAS THE ELECTRIC UTILITY INDUSTRY BEEN ABLE TO REMAIN FINANCIALLY VIABLE OVER THE YEARS ABSENT A FIXED CHARGE RATE DESIGN?

A. Yes. For decades the pricing structure of electric utilities have been largely volume based. These industries have remained viable and have achieved at the very least, respectable returns on their investments with this volumetric based rate structure.

For example, the Value Line group of electric utility companies have achieved the following average rates of return on common equity each year since 2000:

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

a/ Calculated per Schedule GAW-5.

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

Q. DOES KU'S PROPOSAL TO COLLECT A SUBSTANTIAL PORTION OF ITS ELECTRIC NON-FUEL REVENUE FROM FIXED MONTHLY CHARGES COMPORT WITH THE ECONOMIC THEORY OF COMPETITIVE MARKETS OR THE ACTUAL PRACTICES OF SUCH COMPETITIVE MARKETS?

A. No. The most basic tenet of competition is that prices determined through a competitive market ensure the most efficient allocation of society's resources. Because public utilities are generally afforded monopoly status under the belief that resources are better utilized without the duplication of the fixed facilities required to serve consumers, a fundamental goal of regulatory policy is that regulation should serve as a surrogate for competition to the greatest extent practical.[5] As such, the pricing policy for a regulated public utility should mirror those of competitive firms to the greatest extent practical.

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

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

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

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

Marginal cost pricing only relates to efficiency. This pricing does not attempt to always address fairness or equity. From a perspective of fair and equitable pricing of a regulated monopoly's products and services, it is generally agreed that payments for a good or service should be in accordance with the benefits received. In this regard, those that receive more benefits should pay more in total than those who receive fewer benefits. With respect to electric usage, the level of energy usage is the most direct, and in my opinion the best indicator of benefits received, such that volumetric pricing promotes the fairest pricing mechanism to customers and to the utility.

The above philosophy is, and has been, the belief of economists, regulators, and the marketplace for many years. As an illustration, consider utility industry pricing in its infancy (1800s). In the beginning, customers paid a fixed monthly fee and consumed as much of the utility commodity/service as they desired (usually water). It soon became apparent that the fixed monthly fee rate schedule was inefficient and unfair. Utilities

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

soon began metering their commodity/service and charging only for the amount actually consumed. In this way, consumers receiving more benefits from the utility than others paid more in total for the utility service because they used more of the commodity.

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

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

Q. DO HIGH FIXED CUSTOMER CHARGE RATE STRUCTURES PROMOTE ADDITIONAL CONSUMPTION?

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

FERC Order 636 had two primary goals. The first was to enhance gas competition at the wellhead by completely unbundling the merchant and transportation functions of pipelines.[6] The second goal was to **encourage the increased consumption of** natural gas in the United States. In the introductory statement of the Order, the FERC stated:

> "The Commission's intent is to further facilitate the unimpeded operation of market forces to stimulate the production of natural gas . . . . [and thereby] contribute to reducing our Nation's dependence upon imported oil . . . ." [Order at 8].

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

> "Moreover, the Commission's adoption of SFV should maximize pipeline throughput over time by allowing gas to compete with alternate fuels on a timely basis as the prices of alternate fuels change. The Commission believes it is beyond doubt that it is in the national interest to promote the use of clean and abundant gas over alternate fuels such as foreign oil. SFV is the best method for doing that" [Order at 128-129].

The FERC's objective for SFV is diametrically in opposition to a major claimed need for revenue decoupling and/or guaranteed revenue recovery. That is, some natural gas LDC companies are advocating SFV Residential pricing by claiming that because retail rates have been historically volumetric based, there has been a disincentive for LDCs to promote conservation or encourage reduced consumption of natural gas. As is clearly discussed in the FERC Order, the price signal that results from SFV pricing is meant to promote additional natural gas consumption, not reduce consumption. A rate structure, therefore, that is heavily based on a fixed monthly customer charge sends an even stronger price signal to consumers to use more energy.

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

A. Yes. There is a limited amount of data available. Retail electric competition for generation services exists in several states. Invariably, customer choice for generation supply is volumetrically priced. However, competition in electric generation alone does

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

not necessarily provide a good apples-to-apples comparison with bundled electric service or natural gas LDC distribution base rates.

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

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

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

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

Of the 15 providers that utilize a traditional fixed monthly customer charge the minimum charge is $2.15 per month, the maximum customer charge is $11.69 per month, with an average customer charge of $6.24 per month. The details supporting these amounts are provided in my Schedule GAW-6.

From this data, half of the providers have maintained the traditional fixed monthly customer charge, an eighth of the companies have abandoned fixed charge pricing altogether, and somewhat more than a third of the providers waive any fixed fees once a minimum level of consumption (KWH) is achieved.[7] The conclusions that can be drawn from this data are:

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

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

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

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

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

A. Yes.

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

A. No.

Q. PLEASE EXPLAIN.

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7 As indicated in the notes to Schedule GAW-6 customer charges are waived with a minimum monthly usage of 500 KWH or 1,000 KWH. For purposes of comparison, KU's average residential customer usage is about 1,200 KWH per month.

A. Mr. Seelye estimates KU's monthly electric Residential customer "cost" to be $19.86. However, Mr. Seelye's analysis includes a significant level of distribution, administrative, general, and other overhead costs. Electric utilities are in the business of providing electric energy to customers. Administrative, general and other overhead costs are a normal cost of business for any enterprise and should be recovered based on the level of service provided (i.e., on a volumetric basis). That is, these costs are incurred in the provision of services rendered. As such, these costs should be recovered in relation to the level of services provided.

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

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

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

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

Q. HAVE YOU CONDUCTED AN ANALYSIS OF THE COSTS THAT SHOULD BE CONSIDERED IN DETERMINING KU'S RESIDENTIAL CUSTOMER CHARGES?

A. Yes. As I discussed earlier, there is no doubt that the majority of KU's non-fuel costs are fixed in the short-run and that efficient, competitive pricing dictates volumetric pricing. However, traditional ratemaking has recognized a minimum level of fixed customer charges to reflect the direct costs of maintaining a customer's account. These direct customer costs include the Company's investment in meters and service lines as well as the operating expenses associated with meter reading, customer service, accounting and customer records and collections. I have conducted a traditional direct customer cost analysis for KU which is presented in my Schedules GAW-7. These studies indicate a monthly KU customer cost of $4.59 per month.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING KU'S RESIDENTIAL CUSTOMER CHARGES?

A. Although my customer cost analyses indicate that reductions to KU's Residential customer charge is warranted, in the interest of gradualism and rate continuity I recommend that KU's current Residential customer charge be maintained at the current level of $5.00 per month.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

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

EDUCATION

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

POSITIONS

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

EXPERIENCE

I. Public Utility Regulation

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

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

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

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

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

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

II. Transportation Regulation

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

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

III. Insurance Studies

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

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

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

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IV. Anti-Trust and Commercial Business Damage Litigation

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

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

MEMBERSHIPS AND CERTIFICATIONS

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

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YEAR	CASE NAME	PRE-FILED	JURISDICTION	DOCKET NO.	SUBJECT OF TESTIMONY
1985	SAVANNAH ELECT. & PWR CO.	YES	GA. PSC	3523U	SALES FORECAST, RATE DESIGN ISSUES
1990	CENTRAL MAINE PWR CO.	YES	ME. PUC	89-68	MARGINAL COST OF SERVICE
1990	COMMONWEALTH GAS SERVICES (*Columbia Gas*)	YES	VA. SCC	PUE900034	CLASS COST OF SERVICE
1990	WARNER FRUEHAUF	NO	U.S. BANKRUPTCY CT.	n/a	VALUE OF STOCK, COST OF CAPITAL
1991	W. VA. WATER	YES	WVA PSC	91-140-W-42T	RATE DESIGN
1992	S.C. WORKERS COMPENSATION	YES	SC DEPT OF INSUR	92-034	INTERNAL RATE OF RETURN
1992	GRASS v. ATLAS PLUMBING, et.al.	NO	RICHMOND CIRCUIT CT	n/a	DAMAGES, BREACH OF COVENANT NOT TO COMPETE (PROFFERED TEST)
1992	VIRGINIA NATURAL GAS	YES	VA SCC	PUE920031	JURISDICTIONAL & CLASS COST OF SERVICE
1992	ALLSTATE INSURANCE COMPANY (DIRECT)	YES	N.J. DEPT OF INSUR	INS 06174-92	COST ALLOCATIONS, PROFITABILITY
1992	ALLSTATE INSURANCE COMPANY (REBUTTAL)	YES	N.J. DEPT OF INSUR	INS 06174-92	COST ALLOCATIONS, PROFITABILITY
1993	MOUNTAIN FORD v FORD MOTOR COMPANY	NO	FEDERAL DISTRICT CT	n/a	VEHICLE ALLOCATIONS, INVENTORY LEVELS, INCREMENTAL PROFIT, & DAMAGES
1993	SOUTH WEST GAS CO.	YES	AZ. CORP COMM	U-1551-92-253	DIRECT: CLASS COST ALLOCATIONS
1993	SOUTH WEST GAS CO.	YES	AZ. CORP COMM	U-1551-92-253	SURREBUTTAL: CLASS COST ALLOCATIONS
1993	POTOMAC EDISON CO.	YES	VA. SCC	PUE930033	COST ALLOCATIONS,RATE DESIGN
1995	VIRGINIA AMERICAN WATER CO.	YES	VA. SCC	PUE950003	JURISDICTIONAL ALLOCATIONS
1995	NEW JERSEY AMERICAN WATER COMPANY	YES	N.J. B.P.U.	WR95040165	COST ALLOCATIONS,RATE DESIGN
1995	PIEDMONT NATURAL GAS COMPANY	YES	S.C. P.S.C.	95-715-G	COST ALLOCATIONS,RATE DESIGN,WEATHER NORMALIZATION
1995	CYCLE WORLD v. HONDA MOTOR CO.	NO	VA. DMV	None	MARKET PERFORMANCE, FINANCIAL IMPACT OF NEW DEALER
1996	*HOUSE BILL # 1513*	NO	VA. GEN'L ASSEMBLY	N/A	WATER / WASTEWATER CONNECTION FEES
1996	VIRGINIA AMERICAN WATER CO.	YES	VA. SCC	PUE950003	JURISDICTIONAL ALLOCATIONS
1996	ELIZABETHTOWN WATER CO.	YES	N.J. B.P.U.	WR95110557	COST ALLOCATIONS,RATE DESIGN
1996	ELIZABETHTOWN WATER CO.	NO	N.J. B.P.U.	WR95110557	SURREBUTTAL COST ALLOCATIONS,RATE DESIGN
1996	SOUTH JERSEY GAS CO.	YES	N.J. B.P.U.	GR96010032	CLASS COST OF SERVICE
1996	VIRGINIA LIABILITY INSURANCE COMPETITION	YES	VA. SCC	INS960164	COST ALLOCATIONS, INSURANCE PROFITABILITY
1996	SOUTH JERSEY GAS CO.	YES	N.J. B.P.U.	GR96010032	REBUTTAL - CLASS COST OF SERVICE
1996	HOUSE BILL # 1513	NO	VA. GEN'L ASSEMBLY	N/A	WATER / WASTEWATER CONNECTION FEES
1997	NISSAN v. CRUMPLER NISSAN	NO	VA. DMV	None	MARKET DETERMINATION & PERFORMANCE
1997	PHILADELPHIA SUBURBAN WATER CO. (DIRECT)	YES	PA. PUC	R-00973952	COST ALLOCATIONS,RATE DESIGN,RATE DISCOUNTS
1997	PHILADELPHIA SUBURBAN WATER CO. (REBUTTAL)	YES	PA. PUC	R-00973952	COST ALLOCATIONS,RATE DESIGN,RATE DISCOUNTS
1997	PHILADELPHIA SUBURBAN WATER CO. (SURREBUTTAL)	YES	PA. PUC	R-00973952	COST ALLOCATIONS,RATE DESIGN,RATE DISCOUNTS
1997	VIRGINIA AMERICAN WATER CO.	YES	VA. SCC	PUE970523	JURISDICTIONAL/CLASS ALLOCATIONS
1998	VIRGINIA ELECTRIC POWER COMPANY	YES	VA. SCC	PUE960296	CLASS COST OF SERVICE and TIME DIFFERENTIATED FUEL COSTS
1998	NEW JERSEY AMERICAN WATER COMPANY	YES	N.J. B.P.U.	WR98010015	CLASS COST OF SERVICE,RATE DESIGN, REVENUES
1998	AMERICAN ELECTRIC POWER COMPANY	YES	VA. SCC	PUE960296	CLASS COST OF SERVICE and TIME DIFFERENTIATED FUEL COSTS
1998	FREEMAN WRONGFUL DEATH	YES	FEDERAL DISTRICT CT.		LOST INCOME, WORK EXPECTANCY
1998	EASTERN MAINE ELECTRIC COOPERATIVE	YES	MAINE PUC	98-598	REVENUE REQUIREMENT
1998	CREDIT LIFE/AH RATE FILING	YES	VA. SCC		PRIMA FACIA RATES, LEVEL OF COMPETITION
1999	CREDIT LIFE & A&H LEGISLATION	NO	VA. GEN'L ASSEMBLY	N/A	COST ALLOCATIONS, INSURANCE PROFITABILITY
1999	MILLER VOLKSWAGEN v. VOLKSWAGEN oF AMERICA	YES	VA. DMV	None	VEHICLE ALLOCATIONS/CSI
1999	COLUMBIA GAS of VIRGINIA	YES	VA. SCC	PUE980287	RATE STRUCTURE
1999	NCCI (WORKERS COMPENSATION INSURANCE)	YES	VA. SCC	INS990165	WORKERS COMPENSATION RATES
1999	ROANOKE GAS	YES	VA. SCC	PUE980626	Rate Design/ Weather Norm
2000	PERSON-SMITH v. DOMINION REALITY	NO	RICHMOND CIRCUIT	n/a	LOST INCOME
2000	CREDIT LIFE/AH RATE FILING	YES	VA. SCC		PRIMA FACIA RATES, LEVEL OF COMPETITION
2000	UNITED CITIES GAS	YESW	VA. SCC		*Cost Allocations/ Rate Design*
2001	VERMONT WORKERS COMPENSATION RATE CASE	YES	VT. INSURANCE COMM.	n/a	WORKERS COMPENSATION RATES
2001	SERRA CHEVROLET v. GENERAL MOTORS CORP.	NO	ALABAMA CIRCUIT CT.	98-2089	ECONOMIC DAMAGES
2001	VIRGINIA POWER ELECTRIC RESTRUCTURING	YES	VA. SCC	PUE000584	RATE Design (UNBUNDLING)
2001	AMERICAN ELECTRIC POWER RESTRUCTURING	YES	VA. SCC	PUE010011	RATE Design (UNBUNDLING)
2001	NCCI (WORKERS COMPENSATION INSURANCE)	YES	VA. SCC	INS010190	WORKERS COMPENSATION RATES
2002	PHILADELPHIA SUBURBAN WATER CO. (DIRECT)	YES	PA. PUC	R00016750	COST ALLOCATIONS AND RATE DESIGN
2002	HAROLD MORRIS PERSONAL INJURY	YES	FED. DIST CT (RICHMOND)	n/a	LOST WAGES
2002	PIEDMONT NATURAL GAS	YES	S.C. PSC	2002-63-G	REVENUE RQMT, COST OF CAPITAL
2002	VIRGINIA AMERICAN WATER COMPANY	YES	VA. SCC	PUE-2002-00375	JURISDICTIONAL/CLASS ALLOCATIONS
2002	ROANOKE GAS COMPANY	YES	VA. SCC	PUE-2002-00373	WEATHER NORMALIZATION RIDER
2002	SOUTH CAROLINA ELECTRIC & GAS (ELECTRIC)	YES	S.C. PSC	2002-223-E	REVENUE RQMT.
2003	NCCI (WORKERS COMPENSATION INSURANCE)	YES	VA. SCC	INS-2003-00157	WORKERS COMPENSATION RATES
2003	CREDIT LIFE/AH RATE FILING	YES	VA. SCC		PRIMA FACIA RATES, LEVEL OF COMPETITION
2003	ROANOKE GAS	YES	VA. SCC	PUE-2003-00425	WEATHER NORMALIZATION ADJUSTMENT RIDER

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

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

Schedule G(

Kentucky Utilities and Louisville Gas & Electric
Test Year Generation Statistics

Generating Unit	Fuel	Generator Nameplate (MW)	Net MWH Produced	Generation Order	Total Gross Investment	Net Investment	Capacity Factor Avg	Availability Factor Avg	B/I/P	Pct Energy	Pct Demand	Net Investment Energy	Net Investment Demand
Mill Creek 1	Coal	356	2,060,877	1	$163,196,129	$54,631,912	77.9	85.6	Base	100.00%	0.00%	$54,631,912	$0
Trimble County 1	Coal	566	3,559,440	2	$607,594,315	$342,381,617	89.6	90.1	Base	100.00%	0.00%	$342,381,617	$0
Mill Creek 4	Coal	544	3,596,774	3	$504,316,481	$251,798,310	81.3	87.5	Base	100.00%	0.00%	$251,798,310	$0
Mill Creek 3	Coal	463	2,768,596	4	$277,074,472	$129,748,881	81.2	89	Base	100.00%	0.00%	$129,748,881	$0
Mill Creek 2	Coal	356	2,084,795	5	$124,822,261	$43,236,558	70.9	86.3	Base	100.00%	0.00%	$43,236,558	$0
Ghent 2	Coal	556	2,362,899	7	$193,971,163	$77,347,614	69.7	82.4	Base	100.00%	0.00%	$77,347,614	$0
Ghent 1	Coal	557	2,950,195	8	$493,607,411	$271,159,395	84.2	87.9	Base	100.00%	0.00%	$271,159,395	$0
Ghent 4	Coal	556	2,941,478	9	$393,801,651	$208,887,124	83	85.1	Base	100.00%	0.00%	$208,887,124	$0
Cane Run 4	Coal	164	966,602	11	$72,507,681	$14,641,808	51.3	86.9	Base	100.00%	0.00%	$14,641,808	$0
Ghent 3	Coal	557	3,363,968	12	$784,290,812	$533,549,718	78	85.5	Base	100.00%	0.00%	$533,549,718	$0
Cane Run 6	Coal	272	1,350,253	13	$141,803,002	$54,133,803	51.2	84	Base	100.00%	0.00%	$54,133,803	$0
Cane Run 5	Coal	209	933,114	14	$93,964,064	$29,847,094	38.7	84.7	Intermediate	38.70%	61.30%	$11,550,825	$18,296,269
Green River 4	Coal	114	396,032	15	$44,909,090	$9,568,636	31.9	85.9	Intermediate	31.90%	68.10%	$3,052,395	$6,516,241
Green River 3	Coal	75	226,460	16	$20,882,040	$4,223,762	21.2	83	Intermediate	21.20%	78.80%	$895,438	$3,328,324
Brown 3	Coal	446	1,834,351	17	$167,769,218	$61,483,147	52.9	81.3	Intermediate	52.90%	47.10%	$32,524,565	$28,958,562
Brown 2	Coal	180	627,235	18	$51,604,493	$19,960,742	37.7	88	Intermediate	37.70%	62.30%	$7,525,200	$12,435,542
Brown 1	Coal	114	289,333	19	$58,239,565	$19,914,445	41	83.4	Intermediate	41.00%	59.00%	$8,164,922	$11,749,523
Tyrone 3	Coal	75	68,321		$26,123,876	$6,142,131	20.9	81.6	Intermediate	20.90%	79.10%	$1,283,705	$4,858,426
Trimble County 5	Gas	199	43,621	20	$63,318,704	$47,453,510	17.4	82.8	Peak	0.00%	100.00%	$0	$47,453,510
Trimble County 6	Gas	199	24,504	21	$59,494,178	$44,963,635	14.9	83.4	Peak	0.00%	100.00%	$0	$44,963,635
Trimble County 7	Gas	199	38,658	22	$52,344,925	$42,578,406	10.4	83.4	Peak	0.00%	100.00%	$0	$42,578,406
Trimble County 8	Gas	199	34,284	23	$51,954,657	$42,261,302	8.6	83.4	Peak	0.00%	100.00%	$0	$42,261,302
Trimble County 9	Gas	199	23,995	24	$52,109,272	$42,802,901	7.1	83.4	Peak	0.00%	100.00%	$0	$42,802,901
Trimble County 10	Gas	199	19,039	25	$58,438,142	$48,466,389	5.5	83.4	Peak	0.00%	100.00%	$0	$48,466,389
Brown 6	Gas,Oil	177	34,203	26	$64,152,496	$54,834,899	9	82.2	Peak	0.00%	100.00%	$0	$54,834,899
Brown 7	Gas,Oil	177	40,139	27	$65,080,354	$53,169,501	10.6	82.2	Peak	0.00%	100.00%	$0	$53,169,501
Brown 8	Gas,Oil	126	7,547	28	$38,379,638	$23,135,828	1.4	88	Peak	0.00%	100.00%	$0	$23,135,828
Brown 9	Gas,Oil	126	1,524	29	$48,505,028	$26,291,775	1	85.7	Peak	0.00%	100.00%	$0	$26,291,775
Brown 10	Gas,Oil	126	2,504	30	$29,531,409	$16,272,357	0.8	85.7	Peak	0.00%	100.00%	$0	$16,272,357
Brown 11	Gas,Oil	126	4,493	31	$44,435,742	$27,303,037	0.5	89.1	Peak	0.00%	100.00%	$0	$27,303,037
Brown 5	Gas	123	2,592	32	$47,749,126	$35,132,623	1.9	89.1	Peak	0.00%	100.00%	$0	$35,132,623
Paddys Run 13	Gas	178	1,262	33	$64,913,860	$49,849,554	10.3	88.6	Peak	0.00%	100.00%	$0	$49,849,554
Paddys Run 11	Gas	16	20	34	$1,609,957	($28,342)	0.1	50	Peak	0.00%	100.00%	$-0	($28,342)
Cane Run 11	Gas,Oil	16	212	35	$3,249,070	$1,357,866	0.1	50	Peak	0.00%	100.00%	$0	$1,357,866
Paddys Run 12	Gas	33	0	36	$3,183,011	($213,388)	0.1	50	Peak	0.00%	100.00%	$-0	($213,388)
Zorn 1	Gas	18	231	37	$1,899,048	($31,433)	0.1	50	Peak	0.00%	100.00%	$-0	($31,433)
Haefling 1-3	Gas,Oil	63	-439	38	$5,695,570	$1,417,461	0.2	50	Peak	0.00%	100.00%	$0	$1,417,461
Dix Dam 1-3	Hydro	27	56,130	-	$12,391,689	$3,980,168	28.8	none	Hydro	100.00%	0.00%	$3,980,168	$0
Ohio Falls 1-8	Hydro	88	230,869	-	$41,596,196	$33,670,611	68.3	none	Hydro	100.00%	0.00%	$33,670,611	$0
Trimble County 2	Coal	838		Projected Top 6									
					$870,200,000	$870,200,000	89.7	89.4	Base	100.00%	0.00%	$870,200,000	$0
Total		9610				$3,597,525,357						$2,954,364,589	***************
												82.12%	17.88%

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

Kentucky Utilities
Overhead Lines Classification

Exclude small Quantities

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

Regression Output:

Constant		-1.0112	0.3637823
Std Err of Y Est		0.6552882	
R Squared		0.590519	
No. of Observations		14	
Degrees of Freedom		12	
X Coefficient(s)	0.0033942		
Std Err of Coef.	0.0008159		
Intercept	0.3637823		
Q	4,693,510		
Zero load Cost	1,707,416		
Total Cost	6,510,104		
Pct Cust	26.23%		

Ampacty Source: Southwire ACSR

Kentucky Utilities
Underground Lines Classification

Excludes Small Quantities

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

Regression Output:			Anti-log
Constant		-1.228544	0.2927183
Std Err of Y Est		0.479928	
R Squared		0.8599632	
No. of Observations		9	
Degrees of Freedom		7	
X Coefficient(s)	0.0083349		
Std Err of Coef.	0.0012713		
Intercept	0.2927183		
Q	5126682		
Zero load Cost	1500673.8		
Total Cost	7822047.1		
Pct Cust	19.19%		

Ampacity Source: National Electric Code Table 310-16

Kentucky Utilities
Transformer Classification

	Size	Quantity	total Cost	Avg Cost	Ln Avg cost/ft
OH 1P	5	6008	4314550	$718.13	6.5766564
	10	29175	31012170	$1,062.97	6.9688228
	15	47570	60170140	$1,264.88	7.1427292
	25	56554	90110288	$1,593.35	7.3735937
	37.5	28328	54068636	$1,908.66	7.5541588
	50	16983	37198653	$2,190.35	7.691815
	75	6178	18549207	$3,002.46	8.0071877
	100	4013	14796083	$3,687.04	8.2125787
	167	2153	11379858	$5,285.58	8.572738
	250	309	2800673	$9,063.67	9.112029
	333	136	1379235	$10,141.43	9.2243847
	500	247	3219564	$13,034.67	9.4753682
		197654	328999057		

Linear

Regression Output:		
Constant		1001.2193
Std Err of Y Est		621.36454
R Squared		0.9792426
No. of Observations		12
Degrees of Freedom		10
X Coefficient(s)	26.117105	
Std Err of Coef.	1.2024493	
		197895006
		0.6015063

	Size	Quantity	total Cost	Avg Cost	Ln Avg cost/ft
Pad 1P					
	10	206	385421	$1,870.98	7.5342154
	15	2558	4917831	$1,922.53	7.5613972
	25	7520	15657585	$2,082.13	7.6411446
	37.5	8328	19453247	$2,335.88	7.7561459
	50	6560	15797368	$2,408.14	7.786608
	75	2666	8373425	$3,140.82	8.0522391
	100	1227	5072149	$4,133.78	8.3269477
	167	826	4309855	$5,217.74	8.55982
	250	361	3079586	$8,530.71	9.0514278
		30252	77046467		

Regression Output:		
Constant		1329.2668
Std Err of Y Est		345.20177
R Squared		0.9783264
No. of Observations		9
Degrees of Freedom		7
X Coefficient(s)	26.976425	
Std Err of Coef.	1.5176054	
		40212978
		0.5219315

	Size	Quantity	total Cost	Avg Cost	Ln Avg cost/ft
Pad 3P	45	119	926962	$7,789.60	8.9605444
	75	577	3866555	$6,701.14	8.8100322
	112.5	260	2465587	$9,483.03	9.1572588
	150	674	5849486	$8,678.76	9.0686342
	225	508	4987102	$9,817.13	9.1918841
	300	858	10072549	$11,739.57	9.3707203
	500	837	13409943	$16,021.44	9.6816829
	750	408	9043587	$22,165.65	10.006299
	1000	309	7424485	$24,027.46	10.086953
	1500	202	6924137	$34,277.91	10.442256
	2000	87	3959097	$45,506.86	10.725618
	2500	142	5747487	$40,475.26	10.608446
		4981	74676977		

Regression Output:		
Constant		7463.5887
Std Err of Y Est		3292.9146
R Squared		0.947007
No. of Observations		12
Degrees of Freedom		10
X Coefficient(s)	16.0656	
Std Err of Coef.	1.2017925	
		37176135
		0.4978259

Use Linear	Pct	Total Cost	Weighted Pct
OH 1P	0.6015063	328999057	41.17%
d 1P	0.5219315	77046467	8.37%
ad 3P	0.4978259	74676977	7.73%
Total		480722501	57.26%

Kentucky Utilities
Electric Cost of Service Study
(Summary)

Acct. No.	Account Description	Allocator	Total	Residential	Gen'l Service	All Elec. Schools	Secondary PS	Primary PS	Sec. TOD TOD	Pri. TOD TOD	Retail Transmission	Fluc. Load	St. Ltg
	Cost of Service Summary -- Pro-Forma												
	Total Operating Revenue		$1,221,660,614	$467,627,707	$156,768,038	$8,700,686	$229,562,110	$95,654,199	$11,626,139	$143,324,088	$73,116,058	$14,701,332	$20,580,256
	Pro-Forma Adjustments:												
	Eliminate Unbilled Revenue	74	($3,744,529)	($1,429,385)	($484,496)	($26,674)	($707,374)	($293,251)	($35,734)	($436,711)	($222,230)	($43,993)	($64,680)
	Mismatch in Fuel Cos Recovery	1	($49,848,679)	($17,786,542)	($5,237,328)	($375,754)	($9,768,092)	($4,288,845)	($569,620)	($7,065,633)	($3,497,695)	($902,237)	($356,935)
	To Reflect a Full Year of the FAC Roll-	43	($3,710,701)	($1,339,972)	($386,233)	($33,684)	$39,974	($296,317)	($993)	($539,386)	($694,222)	($387,783)	($72,086)
	Remove ECR Revenue	49	($92,924,384)	($34,624,476)	($11,981,422)	($646,811)	($17,590,465)	($7,274,470)	($923,786)	($11,025,922)	($5,672,045)	($1,592,149)	($1,592,837)
	To Reflect a full Year of the ECR Roll-	50	$87,584,103	$33,637,125	$11,667,441	$640,200	$16,342,562	$6,803,053	$741,661	$10,176,285	$4,884,714	$1,308,727	$1,382,335
	Remove Off-System ECR Revenues	49	($3,722,927)	($1,387,197)	($480,024)	($25,914)	($704,745)	($291,445)	($37,011)	($441,743)	($227,245)	($63,788)	($63,816)
	Eliminate Brokered Sales	1	($256,817)	($91,635)	($26,982)	($1,936)	($50,325)	($22,096)	($2,935)	($36,402)	($18,020)	($4,648)	($1,839)
	Eliminate DSM Revenue	48	($12,940,085)	($10,563,160)	($1,061,969)	$-0	($1,023,304)	($218,413)	($67,553)	($2,709)	($2,977)	$-0	$-0
	Year End Revenue Adjustment	42	$9,724,872	($3,729,851)	$12,261,395	($103,605)	($1,140,255)	($4,224,214)	($931,558)	$3,132,208	$3,532,765	$0	$927,987
	Adjustment for Merger Surecredit	Dir	$2,800,345	$1,190,523	$352,574	$21,520	$483,744	$207,745	$19,953	$289,203	$146,181	$44,498	$44,404
	Weather Normalized Electric Operating Revenues	40	$2,986,579	$2,362,666	$264,295	$12,655	$241,693	$93,420	$11,850	$0	$0	$0	$0
	VDT Surecredit Revenues	47	$42	($273)	$4,074	$0	($2,121)	($1,974)	$0	$0	$0	$0	$336
	Adjustment for Billing Corrections & Rate Switching	Dir	($186,358)	$0	$0	$0	($130,088)	($55,180)	$0	$0	($1,090)	$0	$0
	Adjustment to Late Payment Charge	76	$3,141,664	$2,331,337	$543,289	$0	$133,502	$0	$0	$84,815	$0	$0	$48,722
	Eliminate ECR, MSR, FAC, & DSM Accruals	74	$283,654	$108,278	$36,701	$2,021	$53,585	$22,214	$2,707	$33,082	$16,834	$3,333	$4,900
	Total Pro-Forma Operating Revenue		$1,180,847,393	$436,305,145	$162,239,353	$8,162,704	$215,740,401	$85,814,427	$9,833,121	$137,491,175	$71,361,028	$13,063,292	$20,836,747
	Operating Expenses												
	Operation and Maintenance Expenses		$819,700,590	$324,329,920	$91,536,912	$6,215,941	$152,090,411	$63,594,192	$8,453,436	$104,083,342	$50,026,079	$12,939,943	$6,430,415
	Depreciation and Amortization Expenses		$118,950,010	$52,624,819	$13,731,961	$990,898	$19,099,786	$7,935,064	$1,042,343	$12,937,041	$5,581,864	$1,471,377	$3,534,858
	Regulatory Credits & Accretion Expense		($258,958)	($98,584)	($27,314)	($2,115)	($48,901)	($21,342)	($2,760)	($34,887)	($17,029)	($4,489)	($1,538)
	Property and Other Taxes		$19,552,424	$8,499,733	$2,232,891	$162,485	$3,208,451	$1,342,618	$175,952	$2,189,829	$963,437	$253,964	$523,064
	Gain on Disposition of Allowance		($73,173)	($26,109)	($7,688)	($552)	($14,339)	($6,296)	($836)	($10,372)	($5,134)	($1,324)	($524)
	State and Federal Income Taxes		$72,669,576	$19,740,280	$15,317,971	$289,805	$16,295,127	$6,708,965	$501,745	$6,167,874	$4,887,008	($294,911)	$3,055,712
	Specific Assignment of Interruptible Credit	Dir	($7,430,743)					($144,565)				($7,286,178)	
	Allocation of Interruptible Credits	32	$7,430,743	$3,637,846	$796,800	$82,216	$1,163,086	$490,290	$53,077	$764,127	$340,083	$103,218	$0
	Adjustments to Operating Expenses:												
	Eliminate mismatch in fuel cost recovery	1	($42,231,035)	($15,068,485)	($4,436,983)	($318,333)	($8,275,377)	($3,633,443)	($482,573)	($5,985,895)	($2,963,194)	($764,362)	($302,389)
	Remove ECR expenses	49	($30,178,413)	($11,244,753)	($3,891,124)	($210,060)	($5,712,734)	($2,362,479)	($300,012)	($3,580,813)	($1,842,071)	($517,071)	($517,295)
	Reflect full year of ECR roll-in	50	$22,359,078	$8,587,119	$2,978,545	$163,435	$4,172,043	$1,736,731	$189,336	$2,597,873	$1,247,004	$334,101	$352,892
	Eliminate brokered sales expenses	1	($6,096)	($2,175)	($640)	($46)	($1,195)	($524)	($70)	($864)	($428)	($110)	($44)
	Eliminate DSM Expenses	48	($7,500,349)	($6,122,633)	($615,540)	$-0	($593,129)	($126,597)	($39,155)	($1,570)	($1,725)	$-0	$-0
	Year end Expense adjustment	42	$5,885,824	($2,257,433)	$7,421,014	($62,705)	($690,121)	($2,556,638)	($563,811)	$1,895,719	$2,138,150	$0	$561,649
	Depreciation adjustment	71	$19,212,820	$8,499,967	$2,217,988	$160,050	$3,085,000	$1,281,672	$168,359	$2,089,592	$901,583	$237,657	$570,951
	Labor adjustment	72	$784,464	$382,883	$102,054	$5,960	$125,053	$44,727	$5,967	$71,554	$30,359	$7,918	$7,988
	Weather Normalization Expenses	77	$1,489,506	$1,079,155	$103,622	$6,016	$209,475	$80,967	$10,271	$0	$0	$0	$0
	Adjustment for pension/post retir benefit	72	($139,829)	($68,248)	($18,191)	($1,062)	($22,290)	($7,973)	($1,064)	($12,754)	($5,411)	($1,411)	($1,424)
	Adjustment for increase in property insurance	22	$373,107	$160,496	$42,334	$3,096	$62,003	$26,053	$3,410	$42,502	$18,903	$4,983	$9,326
	Adjustment for increase in liability insurance	22	$574,164	$246,982	$65,147	$4,765	$95,415	$40,092	$5,247	$65,405	$29,090	$7,668	$14,352
	Adjustment for Hazard Tree program	39	$3,791,496	$2,518,276	$549,665	$35,718	$350,460	$101,301	$16,216	$162,663	$0	$0	$57,197
	Storm Damage Adjustment	39	($1,267,873)	($842,109)	($183,807)	($11,944)	($117,194)	($33,875)	($5,423)	($54,394)	$-0	$-0	($19,127)
	Eliminate advertising expenses (See Func. Assignment)	74	($799,431)	($305,164)	($103,436)	($5,695)	($151,020)	($62,607)	($7,629)	($93,235)	($47,445)	($9,392)	($13,809)
	Adjustment for retired mainframe	69	($843,623)	($362,331)	($95,715)	($6,984)	($140,550)	($59,025)	($7,729)	($96,297)	($42,922)	($11,308)	($20,762)
	Amortization of rate case expenses	78	$595,187	$235,497	$66,465	$4,513	$110,433	$46,176	$6,138	$75,575	$36,324	$9,396	$4,669

Kentucky Utilities
Electric Cost of Service Study
(Summary)

Acct. No.	Account Description	Allocator	Total	Residential	Gen'l Service	All Elec. Schools	Secondary PS	Primary PS	Sec. TOD TOD	Pri. TOD TOD	Retail Transmission	Fluc. Load	St. Ltg
	Adjustment for injuries and damages account 925 (See Func. Assignmer	22	$200,710	$86,337	$22,773	$1,666	$33,354	$14,015	$1,834	$22,864	$10,169	$2,681	$5,017
	Adjustment for EKPC settlement charges	1	$1,785,051	$636,925	$187,546	$13,456	$349,789	$153,581	$20,398	$253,016	$125,250	$32,309	$12,782
	Adjustment for MISO Exit Fee	52	($83,909)	($31,931)	($8,848)	($685)	($15,851)	($6,918)	($895)	($11,310)	($5,522)	($1,456)	($493)
	Adjustment for 2008 Wind Storm	39	$2,454,286	$1,630,114	$355,805	$23,121	$226,858	$65,574	$10,497	$105,294	$0	$0	$37,024
	Adjustment for 2009 Winter Storm	39	$11,447,352	$7,603,225	$1,659,558	$107,841	$1,058,116	$305,850	$48,959	$491,114	$0	$0	$172,689
	Adjustment for KCCS Asset	51	$360,504	$137,188	$38,016	$2,945	$68,101	$29,724	$3,843	$48,591	$23,723	$6,254	$2,120
	Adjustment for CMRG Asset	51	$1,940	$738	$205	$16	$366	$160	$21	$261	$128	$34	$11
	Adjustment for SW Power Pool Expense	51	($896,454)	($341,141)	($94,533)	($7,323)	($169,345)	($73,914)	($9,557)	($120,829)	($58,990)	($15,551)	($5,271)
	Adjustment for MISO RSG Settlement	52	($510,123)	($194,125)	($53,793)	($4,167)	($96,365)	($42,061)	($5,438)	($68,757)	($33,568)	($8,849)	($3,000)
	Adjustment to reflect expiration of OMU contract	51	($15,673,235)	($5,964,366)	($1,652,769)	($128,024)	($2,960,759)	($1,292,285)	($167,093)	($2,112,527)	($1,031,365)	($271,885)	($92,162)
	Adjustment for reversal of OMU uncollectible expense	51	$1,754,505	$667,668	$185,016	$14,331	$331,435	$144,662	$18,705	$236,482	$115,454	$30,436	$10,317
	Adjustment for property tax expense (See Func. Assignment)	22	$1,199,643	$516,038	$136,117	$9,955	$199,358	$83,767	$10,963	$136,656	$60,779	$16,022	$29,987
	Adjustment for reserve margin demand purchases	36	($1,339,238)	($592,213)	($134,511)	($9,509)	($233,020)	($93,117)	($12,294)	($163,931)	($76,001)	($24,643)	$-0
	Federal & State Income Tax Adjustment	25	($12,217,289)	($7,593,377)	$260,642	($119,403)	($1,872,626)	($1,340,157)	($261,507)	($665,509)	($141,541)	($259,023)	($224,787)
	Federal & State Income Tax Interest Adjustment	24	($546,180)	($148,095)	($114,918)	($2,174)	($122,249)	($50,332)	($3,764)	($46,272)	($36,663)	$2,212	($22,924)
	Prior income tax adjustments	24	$1,126,171	$305,918	$237,385	$4,491	$252,528	$103,970	$7,776	$95,584	$75,735	($4,570)	$47,355
	Adjustment for domestic production activities	24	($457,757)	($124,347)	($96,490)	($1,826)	($102,646)	($42,261)	($3,161)	($38,852)	($30,784)	$1,858	($19,248)
	Adjustment for tax basis depreciation reduction	22	$1,442,607	$620,552	$163,685	$11,971	$239,734	$100,732	$13,184	$164,333	$73,089	$19,267	$36,061
	Adjustment for 2003 Ice Storm Amortization	39	($527,718)	($350,505)	($76,505)	($4,971)	($48,779)	($14,100)	($2,257)	($22,640)	$-0	$-0	($7,961)
Total	Expense Adjustments		($38,379,137)	($17,698,354)	$5,215,777	($321,567)	($10,355,726)	($7,438,552)	($1,332,306)	($4,521,370)	($1,431,890)	($1,176,839)	$681,691
Total	Operating Expenses		$992,161,332	$391,009,550	$128,797,310	$7,417,11[illegible]	$181,437,895	$72,460,374	$8,890,652	$121,575,583	$60,344,419	$6,004,761	$14,223,678
Net	Operating Income -- Pro-Forma		$168,686,061	$45,295,595	$33,442,043	$745,593	$34,302,505	$13,354,054	$942,470	$15,915,592	$11,016,609	$7,058,531	$6,613,069
Net	Cost Rate Base		$3,176,812,337	$1,364,423,244	$360,432,846	$26,298,098	$529,266,665	$222,269,321	$29,104,299	$362,621,930	$161,630,707	$42,583,286	$78,181,940
Adjustment	to Reflect Depreciation Reserve	71	($19,212,820)	($8,499,967)	($2,217,988)	($160,050)	($3,085,000)	($1,281,672)	($168,359)	($2,089,592)	($901,583)	($237,657)	($570,951)
Cash	Working Capital	67	($306,067)	($124,139)	($34,734)	($2,318)	($55,982)	($23,068)	($3,070)	($37,687)	($17,952)	($4,644)	($2,473)
Adjusted	Net Cost Rate Base		$3,157,293,450	$1,355,799,138	$358,180,124	$26,135,730	$526,125,683	$220,964,581	$28,932,869	$360,494,650	$160,711,172	$42,340,985	$77,608,517
RoR			5.34%	3.34%	9.34%	2.85%	6.52%	6.04%	3.26%	4.41%	6.85%	16.67%	8.52%

Kentucky Utilities
Electric Cost of Service Study
(Rate Base)

Acct. No.	Account Description	Allocator	Total	Residential	Gen'l Service	All Elec. Schools	Secondary PS	Primary PS	Sec. TOD TOD	Pri. TOD TOD	Retail Transmission	Fluc. Load	St. Ltg
RATE BASE													
Plant-in-Service													
	Intangible Plant												
301.00	ORGANIZATION	54	$38,837	$17,332	$4,508	$324	$6,167	$2,553	$336	$4,161	$1,777	$468	$1,212
302.00	FRANCHISE AND CONSENTS	54	$83,453	$37,244	$9,686	$696	$13,252	$5,485	$721	$8,940	$3,817	$1,006	$2,605
303.00	SOFTWARE	54	$44,928,206	$20,050,794	$5,214,762	$374,725	$7,134,398	$2,952,837	$388,360	$4,813,188	$2,055,197	$541,746	$1,402,200
	Sub-total		$45,050,496	$20,105,370	$5,228,956	$375,745	$7,153,817	$2,960,875	$389,417	$4,826,289	$2,060,791	$543,220	$1,406,017
	Production Plant												
	Steam Production Generation												
	Base	1	$1,571,117,248	$560,591,445	$165,068,680	$11,842,908	$307,868,080	$135,174,648	$17,953,125	$222,692,707	$110,239,414	$28,436,472	$11,249,768
	Winter Peak	32	$342,029,883	$167,446,502	$36,675,941	$3,784,333	$53,535,740	$22,567,555	$2,443,062	$35,172,007	$15,653,698	$4,751,047	$0
330	Hydro Baseload Generation												
	Base	1	$8,788,064	$3,135,675	$923,314	$66,243	$1,722,064	$756,101	$100,421	$1,245,634	$616,626	$159,060	$62,926
	Winter Peak	32	$1,913,148	$936,614	$205,147	$21,168	$299,453	$126,232	$13,665	$196,735	$87,559	$26,575	$0
340	Other Production Generation												
	Base	1	$369,583,054	$131,871,188	$38,830,066	$2,785,876	$72,421,600	$31,797,919	$4,223,218	$52,385,302	$25,932,259	$6,689,277	$2,646,348
	Winter Peak	32	$80,457,680	$39,389,415	$8,627,495	$890,211	$12,593,524	$5,308,697	$574,696	$8,273,716	$3,682,310	$1,117,616	$0
	Total Production Plant		$2,373,889,077	$903,370,839	$250,330,643	$19,390,739	$448,440,460	$195,731,152	$25,308,187	$319,966,102	$156,211,866	$41,180,047	$13,959,042
	Transmission Plant												
	KENTUCKY SYSTEM PROPERTY	51	$411,004,531	$156,405,584	$43,341,127	$3,357,226	$77,640,974	$33,888,016	$4,381,746	$55,397,499	$27,045,823	$7,129,729	$2,416,806
	VIRGINIA PROPERTY - 500 KV LINE	51	$7,494,337	$2,851,930	$790,291	$61,216	$1,415,721	$617,921	$79,898	$1,010,129	$493,159	$130,005	$44,069
	Total Transmission Plant		$418,498,868	$159,257,514	$44,131,418	$3,418,442	$79,056,695	$34,505,936	$4,461,644	$56,407,628	$27,538,982	$7,259,734	$2,460,875
	Distribution Plant												
360-362	TOTAL ACCTS 360-362	28	$122,593,185	$61,776,719	$16,931,437	$1,661,887	$18,681,681	$8,320,985	$897,266	$13,406,050	$0	$0	$917,160
364-365	OVERHEAD LINES												
	Primary												
	Customer	19	$94,854,259	$75,559,084	$14,323,492	$52,519	$1,479,167	$74,642	$8,813	$11,511	$0	$0	$3,345,032
	Demand	28	$269,969,815	$136,042,223	$37,285,734	$3,659,740	$41,140,051	$18,324,140	$1,975,924	$29,522,269	$0	$0	$2,019,733
	Secondary												
	Customer	18	$30,349,356	$24,197,693	$4,587,079	$16,819	$473,701	$0	$2,822	$0	$0	$0	$1,071,242
	Demand	29	$86,378,937	$60,468,751	$12,435,484	$1,597,470	$10,868,940	$0	$562,202	$0	$0	$0	$446,090
366-367	UNDERGROUND LINES												
	Primary												
	Customer	19	$23,643,842	$18,834,232	$3,570,344	$13,091	$368,704	$18,606	$2,197	$2,869	$0	$0	$833,799
	Demand	28	$100,797,434	$50,793,482	$13,921,209	$1,366,421	$15,360,279	$6,841,603	$737,742	$11,022,599	$0	$0	$754,099
	Secondary												
	Customer	18	$185,872	$148,197	$28,093	$103	$2,901	$0	$17	$0	$0	$0	$6,561
	Demand	29	$792,401	$554,713	$114,077	$14,654	$99,707	$0	$5,157	$0	$0	$0	$4,092
368	TRANSFORMERS - POWER POOL												
	Customer	18	$3,081,108	$2,456,583	$465,686	$1,708	$48,091	$0	$287	$0	$0	$0	$108,754
	Demand	29	$2,324,344	$1,627,135	$334,623	$42,986	$292,469	$0	$15,128	$0	$0	$0	$12,004
368	TRANSFORMERS - ALL OTHER												
	Customer	18	$144,422,810	$115,149,027	$21,828,429	$80,037	$2,254,191	$0	$13,431	$0	$0	$0	$5,097,695
	Demand	29	$108,950,541	$76,269,787	$15,684,989	$2,014,904	$13,709,093	$0	$709,110	$0	$0	$0	$562,658
369	SERVICES	27	$79,642,953	$65,820,759	$12,477,423	$45,715	$1,288,543	$0	$10,513	$0	$0	$0	$0
370	METERS	26	$63,104,742	$40,516,336	$17,828,099	$128,797	$4,358,013	$211,085	$14,767	$32,499	$14,703	$442	$0
371	CUSTOMER INSTALLATION	7	$17,391,895	$0	$0	$0	$0	$0	$0	$0	$0	$0	$17,391,895
373	STREET LIGHTING	7	$76,387,118	$0	$0	$0	$0	$0	$0	$0	$0	$0	$76,387,118
	Total Distribution Plant		$1,224,870,612	$730,214,721	$171,816,198	$10,696,851	$110,425,531	$33,791,061	$4,955,377	$53,997,797	$14,703	$442	$108,957,931

Kentucky Utilities
Electric Cost of Service Study
(Rate Base)

Acct. No.	Account Description	Allocator	Total	Residential	Gen'l Service	All Elec. Schools	Secondary PS	Primary PS	Sec. TOD TOD	Pri. TOD TOD	Retail Transmission	Fluc. Load	St. Ltg
	General Plant												
	Total General Plant	54	$100,246,736	$44,738,636	$11,635,515	$836,110	$15,918,733	$6,588,563	$866,533	$10,739,498	$4,585,689	$1,208,778	$3,128,681
	TOTAL COMMON PLANT		$0										
106	COMPLETED CONSTR NOT CLASSIFIED		$0										
105	PLANT HELD FOR FUTURE USE	53	$8,757,105	$5,220,606	$1,228,385	$76,476	$789,478	$241,586	$35,428	$386,053	$105	$3	$778,985
	OTHER	53	$18,610	$11,094	$2,610	$163	$1,678	$513	$75	$820	$0	$0	$1,655
	Construction Work In Progress												
	CWIP Production	51	$911,066,142	$346,701,366	$96,073,475	$7,441,900	$172,105,312	$75,118,938	$9,712,936	$122,798,611	$59,951,976	$15,804,339	$5,357,289
	CWIP Transmission	52	$78,906,686	$30,027,519	$8,320,844	$644,537	$14,905,899	$6,505,989	$841,229	$10,635,486	$5,192,391	$1,368,801	$463,990
	CWIP Distribution Plant	53	$24,269,532	$14,468,442	$3,404,359	$211,947	$2,187,967	$669,535	$98,186	$1,069,910	$291	$9	$2,158,888
	CWIP General Plant	54	$11,316,856	$5,050,545	$1,313,534	$94,388	$1,797,066	$743,783	$97,823	$1,212,382	$517,678	$136,459	$353,197
	RWIP		$0										
	Total CWIP		$1,025,559,216	$396,247,872	$109,112,211	$8,392,773	$190,996,243	$83,038,244	$10,750,174	$135,716,390	$65,662,337	$17,309,607	$8,333,364
	TOTAL PLANT-IN-SERVICE		**$4,171,331,504**	**$1,862,918,780**	**$484,373,725**	**$34,794,626**	**$661,786,392**	**$273,819,687**	**$36,016,660**	**$446,324,186**	**$190,412,136**	**$50,192,225**	**$130,693,187**
	TOTAL UTILITY PLANT		**$5,196,890,720**	**$2,259,166,652**	**$593,485,937**	**$43,187,298**	**$852,782,636**	**$356,857,931**	**$46,766,834**	**$582,040,576**	**$256,074,474**	**$67,501,832**	**$139,026,552**
	Accumulated Reserve for Depreciation												
	Steam Production	79	$873,311,222	$332,333,932	$92,092,155	$7,133,505	$164,973,204	$72,005,981	$9,310,428	$117,709,791	$57,467,544	$15,149,401	$5,135,281
	Hydraulic Production	80	$7,263,053	$2,763,916	$765,901	$59,327	$1,372,030	$598,851	$77,432	$978,955	$477,939	$125,993	$42,709
	Other Production	81	$123,704,326	$47,075,022	$13,044,832	$1,010,459	$23,368,415	$10,199,630	$1,318,820	$16,673,564	$8,140,264	$2,145,909	$727,411
	Transmission - Kentucky System Property	51	$246,889,065	$93,952,318	$26,034,872	$2,016,674	$46,638,677	$20,356,419	$2,632,100	$33,277,095	$16,246,337	$4,282,805	$1,451,767
	Transmission - Virginia Property	51	$4,335,872	$1,649,993	$457,225	$35,417	$819,070	$357,500	$46,225	$584,413	$285,319	$75,215	$25,496
	Distribution	53	$512,383,992	$305,461,108	$71,873,607	$4,474,673	$46,192,858	$14,135,370	$2,072,917	$22,588,187	$6,151	$185	$45,578,937
	General Plant	54	$46,417,368	$20,715,385	$5,387,607	$387,145	$7,370,870	$3,050,710	$401,232	$4,972,723	$2,123,317	$559,702	$1,448,677
	Intangible Plant	54	$10,063,939	$4,491,387	$1,168,109	$83,939	$1,598,108	$661,437	$86,993	$1,078,156	$460,365	$121,351	$314,094
	TOTAL ACCUMULATED RESERVE FOR DEPRECIATION		**$1,824,368,837**	**$808,443,061**	**$210,824,308**	**$15,201,139**	**$292,333,232**	**$121,365,898**	**$15,946,147**	**$197,862,884**	**$85,207,236**	**$22,460,560**	**$54,724,372**
	Net Utility Plant		$3,372,521,883	$1,450,723,591	$382,661,629	$27,986,159	$560,449,403	$235,492,033	$30,820,687	$384,177,692	$170,867,238	$45,041,271	$84,302,180
	Rate Base Adjustments and Working Capital												
	Working Capital Assets												
	Cash Working Capital - Operation and Maintenance Expenses	67	$80,258,812	$32,552,427	$9,108,205	$607,863	$14,680,051	$6,048,935	$805,096	$9,882,644	$4,707,485	$1,217,716	$648,389
	Materials and Supplies	57	$105,065,854	$46,922,464	$12,200,214	$876,391	$16,668,815	$6,896,862	$907,173	$11,241,838	$4,796,026	$1,264,222	$3,291,848
	Prepayments	57	$3,231,585	$1,443,228	$375,251	$26,956	$512,695	$212,132	$27,903	$345,773	$147,515	$38,885	$101,250
	Sub-total		$188,556,251	$80,918,118	$21,683,670	$1,511,209	$31,861,560	$13,157,929	$1,740,172	$21,470,255	$9,651,026	$2,520,823	$4,041,488
	Other Rate Base Items												
	Deferred Debits												
	Total Production Plant	51	$177,451,063	$67,528,056	$18,712,517	$1,449,481	$33,521,464	$14,631,139	$1,891,817	$23,917,851	$11,677,025	$3,078,258	$1,043,455
	Total Transmission Plant	52	$21,004,011	$7,992,964	$2,214,909	$171,568	$3,967,771	$1,731,816	$223,925	$2,831,039	$1,382,152	$364,358	$123,509
	Total Distribution Plant	53	$92,743,758	$55,289,805	$13,009,439	$809,935	$8,361,111	$2,558,564	$375,207	$4,088,561	$1,113	$33	$8,249,988
	Total General Plant	54	$7,017,169	$3,131,659	$814,474	$58,527	$1,114,295	$461,193	$60,656	$751,754	$320,994	$84,613	$219,004
	Sub-total		$298,216,001	$133,942,485	$34,751,339	$2,489,511	$46,964,640	$19,382,712	$2,551,606	$31,589,205	$13,381,284	$3,527,263	$9,635,956
	Accumulated Deferred Investment Tax Credits												
	Production	51	$84,045,962	$31,983,243	$8,862,790	$686,516	$15,876,736	$6,929,731	$896,019	$11,328,187	$5,530,577	$1,457,952	$494,211
	Transmission	52	$4,671	$1,778	$493	$38	$882	$385	$50	$630	$307	$81	$27

Kentucky Utilities
Electric Cost of Service Study
(Rate Base)

Acct. No.	Account Description	Allocator	Total	Residential	Gen'l Service	All Elec. Schools	Secondary PS	Primary PS	Sec. TOD TOD	Pri. TOD TOD	Retail Transmission	Fluc. Load	St. Ltg
	Transmission VA	52	$275	$105	$29	$2	$52	$23	$3	$37	$18	$5	$2
	Distribution VA	53	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Distribution Plant KY,FERC & TN	53	$7,261	$4,329	$1,019	$63	$655	$200	$29	$320	$0	$0	$646
	General	54	$1,290	$576	$150	$11	$205	$85	$11	$138	$59	$16	$40
	Sub-total		$84,059,459	$31,990,030	$8,864,480	$686,631	$15,878,530	$6,930,424	$896,113	$11,329,312	$5,530,962	$1,458,054	$494,926
	Less:												
	Customer Advances	68	$2,365,522	$1,428,726	$336,198	$26,193	$272,003	$98,441	$12,841	$158,070	$0	$0	$33,051
	Asset Retirement Obligations	51	$295,630	$112,500	$31,175	$2,415	$55,846	$24,375	$3,152	$39,847	$19,454	$5,128	$1,738
	Sub-total		$2,661,152	$1,541,226	$367,373	$28,608	$327,849	$122,816	$15,993	$197,916	$19,454	$5,128	$34,790
	Emission Allowance												
	Emission Allowance	51	$670,815	$255,275	$70,739	$5,479	$126,721	$55,310	$7,152	$90,416	$44,142	$11,637	$3,945
	Sub-total		$670,815	$255,275	$70,739	$5,479	$126,721	$55,310	$7,152	$90,416	$44,142	$11,637	$3,945
	TOTAL OTHER RATE BASE		$379,614,308	$164,391,288	$43,248,445	$3,147,535	$62,515,321	$26,190,320	$3,431,726	$42,720,600	$18,892,792	$4,980,188	$10,096,093
TOTAL RATE BASE			$3,176,812,337	$1,364,423,244	$360,432,846	$26,298,098	$529,266,665	$222,269,321	$29,104,299	$362,621,930	$161,630,707	$42,583,286	$78,181,940

Kentucky Utilities
Electric Cost of Service Study
(Expenses)

Acct. No.	Account Description	Allocator	Total	Residential	Gen'l Service	All Elec. Schools	Secondary PS	Primary PS	Sec. TOD TOD	Pri. TOD TOD	Retail Transmission	Fluc. Load	St. Ltg
O & M Expenses													
	Steam Production O&M												
500	OPERATION SUPERVISION & ENGINEERING	60	$3,326,789	$1,251,985	$350,587	$26,802	$632,609	$276,415	$35,919	$452,508	$221,491	$58,154	$20,318
501	FUEL	1	$376,982,496	$134,511,388	$39,607,485	$2,841,652	$73,871,557	$32,434,547	$4,307,771	$53,434,110	$26,451,450	$6,823,203	$2,699,331
502	STEAM EXPENSES-- Labor	51	$6,792,159	$2,584,720	$716,245	$55,481	$1,283,075	$560,025	$72,412	$915,485	$446,953	$117,824	$39,940
	STEAM EXPENSES--- Other	1	$4,213,412	$1,503,390	$442,680	$31,760	$825,639	$362,510	$48,147	$597,216	$295,639	$76,261	$30,170
505	ELECTRIC EXPENSES-Labor	51	$4,157,062	$1,581,948	$438,369	$33,956	$785,291	$342,757	$44,319	$560,312	$273,552	$72,113	$24,445
	ELECTRIC EXPENSES-- Other	1	$593,150	$211,642	$62,319	$4,471	$116,231	$51,033	$6,778	$84,074	$41,619	$10,736	$4,247
506	MISC. STEAM POWER EXPENSES	51	$12,280,840	$4,673,408	$1,295,035	$100,314	$2,319,917	$1,012,576	$130,927	$1,655,281	$808,131	$213,037	$72,214
507	RENTS	51	$874,465	$332,773	$92,214	$7,143	$165,191	$72,101	$9,323	$117,865	$57,543	$15,169	$5,142
510	MAINTENANCE SUPERVISION & ENGINEERING	61	$6,719,876	$2,416,968	$706,334	$51,165	$1,311,077	$575,253	$76,167	$946,846	$467,972	$121,016	$47,079
511	MAINTENANCE OF STRUCTURES	51	$4,477,161	$1,703,760	$472,124	$36,571	$845,760	$369,149	$47,731	$603,457	$294,616	$77,666	$26,327
512	MAINTENANCE OF BOILER PLANT	1	$24,314,917	$8,675,823	$2,554,635	$183,283	$4,764,626	$2,091,989	$277,846	$3,446,436	$1,706,087	$440,088	$174,104
513	MAINTENANCE OF ELECTRIC PLANT	1	$8,610,320	$3,072,254	$904,639	$64,904	$1,687,234	$740,808	$98,390	$1,220,441	$604,154	$155,843	$61,653
514	MAINTENANCE OF MISC STEAM PLANT	1	$1,082,969	$386,415	$113,782	$8,163	$212,213	$93,176	$12,375	$153,502	$75,988	$19,601	$7,754
	Sub-total		$454,425,616	$162,906,474	$47,756,449	$3,445,666	$88,820,420	$38,982,340	$5,168,104	$64,187,533	$31,745,195	$8,200,711	$3,212,723
	Hydraulic Production O&M												
535	OPERATION SUPERVISION & ENGINEERING	62	$6,242	$2,375	$658	$51	$1,179	$515	$67	$841	$411	$108	$37
536	WATER FOR POWER	51	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
537	HYDRAULIC EXPENSES	51	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
538	ELECTRIC EXPENSES	51	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
539	MISC. HYDRAULIC POWER EXPENSES	51	$32,162	$12,239	$3,392	$263	$6,076	$2,652	$343	$4,335	$2,116	$558	$189
540	RENTS	51	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
541	MAINTENANCE SUPERVISION & ENGINEERING	63	$85,931	$31,825	$9,047	$679	$16,493	$7,217	$944	$11,839	$5,815	$1,518	$552
542	MAINTENANCE OF STRUCTURES	51	$242,633	$92,333	$25,586	$1,982	$45,835	$20,005	$2,587	$32,703	$15,966	$4,209	$1,427
543	MAINT. OF RESERVES, DAMS, AND WATERWAYS	51	$188,214	$71,624	$19,847	$1,537	$35,555	$15,519	$2,007	$25,369	$12,385	$3,265	$1,107
544	MAINTENANCE OF ELECTRIC PLANT	1	$74,422	$26,555	$7,819	$561	$14,583	$6,403	$850	$10,549	$5,222	$1,347	$533
545	MAINTENANCE OF MISC HYDRAULIC PLANT	1	$4,394	$1,568	$462	$33	$861	$378	$50	$623	$308	$80	$31
	Sub-total		$633,998	$238,519	$66,811	$5,106	$120,581	$52,689	$6,848	$86,259	$42,224	$11,085	$3,876
	Other Power Generation Operation Expense												
546	OPERATION SUPERVISION & ENGINEERING	51	$132,803	$50,537	$14,004	$1,085	$25,087	$10,950	$1,416	$17,900	$8,739	$2,304	$781
547	FUEL	1	$18,512,079	$6,605,308	$1,944,963	$139,542	$3,627,532	$1,592,729	$211,537	$2,623,932	$1,298,923	$335,060	$132,553
548	GENERATION EXPENSE	51	$227,067	$86,409	$23,945	$1,855	$42,894	$18,722	$2,421	$30,605	$14,942	$3,939	$1,335
549	MISC OTHER POWER GENERATION	51	$99,365	$37,813	$10,478	$812	$18,771	$8,193	$1,059	$13,393	$6,539	$1,724	$584
550	RENTS	51	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
551	MAINTENANCE SUPERVISION & ENGINEERING	51	$80,702	$30,711	$8,510	$659	$15,245	$6,654	$860	$10,877	$5,311	$1,400	$475
552	MAINTENANCE OF STRUCTURES	51	$229,542	$87,351	$24,206	$1,875	$43,362	$18,926	$2,447	$30,939	$15,105	$3,982	$1,350
553	MAINTENANCE OF GENERATING & ELEC PLANT	51	$2,155,168	$820,138	$227,266	$17,604	$407,123	$177,697	$22,976	$290,486	$141,819	$37,386	$12,673
554	MAINTENANCE OF MISC OTHER POWER GEN PLT	51	$405,749	$154,406	$42,787	$3,314	$76,648	$33,455	$4,326	$54,689	$26,700	$7,039	$2,386
	Sub-total		$21,842,475	$7,872,672	$2,296,159	$166,746	$4,256,662	$1,867,326	$247,043	$3,072,822	$1,518,077	$392,832	$152,137
	Other Power Supply Expense												
555	PURCHASED POWER												
	Demand	51	$22,338,727	$8,500,884	$2,355,657	$182,470	$4,219,906	$1,841,866	$238,155	$3,010,939	$1,469,982	$387,512	$131,357
	Energy	1	$155,291,365	$55,409,621	$16,315,613	$1,170,569	$30,430,100	$13,360,846	$1,774,511	$22,011,250	$10,896,214	$2,810,700	$1,111,942
555	PURCHASED POWER OPTIONS		$0										
555	BROKERAGE FEES		$0										
555	MISO TRANSMISSION EXPENSES		$0										
556	SYSTEM CONTROL AND LOAD DISPATCH	51	$1,510,099	$574,660	$159,243	$12,335	$285,266	$124,510	$16,099	$203,540	$99,371	$26,196	$8,880
557	OTHER EXPENSES	51	$801,178	$304,884	$84,486	$6,544	$151,347	$66,058	$8,541	$107,987	$52,721	$13,898	$4,711
	Sub-total		$179,941,369	$64,790,048	$18,914,998	$1,371,919	$35,086,618	$15,393,280	$2,037,307	$25,333,716	$12,518,287	$3,238,305	$1,256,890
Transmission Expenses													
560	OPERATION SUPERVISION AND ENG	51	$814,001	$309,764	$85,838	$6,649	$153,769	$67,116	$8,678	$109,716	$53,565	$14,121	$4,787
561	LOAD DISPATCHING	51	$1,185,448	$451,116	$125,008	$9,683	$223,938	$97,742	$12,638	$159,781	$78,007	$20,564	$6,971
562	STATION EXPENSES	51	$320,896	$122,115	$33,839	$2,621	$60,619	$26,458	$3,421	$43,252	$21,116	$5,567	$1,887
563	OVERHEAD LINE EXPENSES	51	$310,792	$118,270	$32,774	$2,539	$58,710	$25,625	$3,313	$41,890	$20,451	$5,391	$1,828

Kentucky Utilities
Electric Cost of Service Study
(Expenses)

Acct. No.	Account Description	Allocator	Total	Residential	Gen'l Service	All Elec. Schools	Secondary PS	Primary PS	Sec. TOD TOD	Pri. TOD TOD	Retail Transmission	Fluc. Load	St. Ltg
565	TRANSMISSION OF ELECTRICITY BY OTHERS	51	$4,699,657	$1,788,429	$495,587	$38,388	$887,791	$387,495	$50,103	$633,446	$309,257	$81,525	$27,635
566	MISC. TRANSMISSION EXPENSES	51	$3,945,201	$1,501,325	$416,028	$32,226	$745,270	$325,288	$42,060	$531,756	$259,611	$68,438	$23,199
567	RENTS	51	$97,238	$37,003	$10,254	$794	$18,369	$8,017	$1,037	$13,106	$6,399	$1,687	$572
568	MAINTENACE SUPERVISION AND ENG		$0										
569	STRUCTURES		$0										
570	MAINT OF STATION EQUIPMENT	51	$1,036,205	$394,322	$109,270	$8,464	$195,745	$85,437	$11,047	$139,666	$68,187	$17,975	$6,093
571	MAINT OF OVERHEAD LINES	51	$2,862,225	$1,089,204	$301,826	$23,380	$540,690	$235,995	$30,514	$385,787	$188,346	$49,651	$16,831
572	UNDERGROUND LINES		$0										
573	MISC PLANT	51	$306,622	$116,683	$32,334	$2,505	$57,923	$25,282	$3,269	$41,328	$20,177	$5,319	$1,803
575	MISO DAY 1&2 EXPENSE	51	$1,049,893	$399,531	$110,713	$8,576	$198,330	$86,565	$11,193	$141,510	$69,087	$18,213	$6,174
	Sub-total		$16,628,178	$6,327,765	$1,753,470	$135,825	$3,141,153	$1,371,021	$177,274	$2,241,239	$1,094,204	$288,450	$97,778
	Distribution Expense - Operating												
580	OPERATION SUPERVISION AND ENGI	64	$1,924,475	$1,162,539	$376,878	$14,036	$183,726	$50,488	$6,333	$77,415	$181	$5	$52,875
581	LOAD DISPATCHING	28	$660,868	$333,022	$91,273	$8,959	$100,708	$44,856	$4,837	$72,269	$0	$0	$4,944
582	STATION EXPENSES	28	$1,096,591	$552,590	$151,451	$14,866	$167,107	$74,431	$8,026	$119,917	$0	$0	$8,204
583	OVERHEAD LINE EXPENSES	55	$2,835,179	$1,744,301	$404,075	$31,360	$317,705	$108,324	$15,012	$173,883	$0	$0	$40,519
584	UNDERGROUND LINE EXPENSES	58	$62,206	$34,883	$8,746	$692	$7,852	$3,403	$370	$5,468	$0	$0	$793
585	STREET LIGHTING EXPENSE	15	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
586	METER EXPENSES	26	$6,008,989	$3,858,065	$1,697,636	$12,264	$414,981	$20,100	$1,406	$3,095	$1,400	$42	$0
586	METER EXPENSES - LOAD MANAGEMENT		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
587	CUSTOMER INSTALLATIONS EXPENSE	7	($55,569)	$-0	$-0	$-0	$-0	$-0	$-0	$-0	$-0	$-0	($55,569)
588	MISCELLANEOUS DISTRIBUTION EXP	53	$3,892,874	$2,320,763	$546,065	$33,997	$350,954	$107,394	$15,749	$171,615	$47	$1	$346,289
588	MISC DISTR EXP -- MAPPIN		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
589	RENTS	53	$13,465	$8,027	$1,889	$118	$1,214	$371	$54	$594	$0	$0	$1,198
590	MAINTENANCE SUPERVISION AND EN	65	$38,514	$23,372	$5,471	$431	$4,411	$1,552	$209	$2,492	($0)	($0)	$576
591	STRUCTURES	28	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
592	MAINTENANCE OF STATION EQUIPME	28	$665,204	$335,207	$91,872	$9,018	$101,369	$45,151	$4,869	$72,743	$0	$0	$4,977
593	MAINTENANCE OF OVERHEAD LINES	55	$18,303,308	$11,260,831	$2,608,623	$202,457	$2,051,035	$699,319	$96,914	$1,122,548	$0	$0	$261,581
594	MAINTENANCE OF UNDERGROUND LIN	58	$614,672	$344,685	$86,422	$6,833	$77,589	$33,621	$3,652	$54,035	$0	$0	$7,834
595	MAINTENANCE OF LINE TRANSFORME	70	($290,262)	($219,287)	($42,975)	($2,400)	($18,287)	$-0	($828)	$-0	$-0	$-0	($6,484)
596	MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	15	$23,113	$0	$0	$0	$0	$0	$0	$0	$0	$0	$23,113
597	MAINTENANCE OF METERS	26	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
598	MISCELLANEOUS DISTRIBUTION EXPENSES	53	($27,831)	($16,592)	($3,904)	($243)	($2,509)	($768)	($113)	($1,227)	($0)	($0)	($2,476)
	Sub-total		$35,765,796	$21,742,406	$6,023,521	$332,386	$3,757,853	$1,188,243	$156,490	$1,874,846	$1,628	$49	$688,374
	Customer Accounts Expense												
901	SUPERVISION/CUSTOMER ACCTS	6	$2,015,177	$1,408,476	$293,414	$9,934	$278,213	$14,379	$3,704	$3,839	$2,020	$337	$862
902	METER READING EXPENSES	6	$3,772,608	$2,636,804	$549,299	$18,597	$520,842	$26,918	$6,934	$7,187	$3,782	$630	$1,614
903	RECORDS AND COLLECTION	6	$14,047,412	$9,818,212	$2,045,330	$69,246	$1,939,371	$100,231	$25,821	$26,760	$14,084	$2,347	$6,009
904	UNCOLLECTIBLE ACCOUNTS	6	$1,608,202	$1,124,027	$234,157	$7,928	$222,027	$11,475	$2,956	$3,064	$1,612	$269	$688
905	MISC CUST ACCOUNTS	6	$360,967	$252,292	$52,557	$1,779	$49,835	$2,576	$663	$688	$362	$60	$154
	Sub-total		$21,804,366	$15,239,810	$3,174,757	$107,484	$3,010,288	$155,579	$40,079	$41,536	$21,861	$3,644	$9,327
	Customer Service & Information Expense												
907	SUPERVISION	6	$192,450	$134,510	$28,021	$949	$26,569	$1,373	$354	$367	$193	$32	$82
908	CUSTOMER ASSISTANCE EXPENSES	6	$7,989,989	$5,584,474	$1,163,358	$39,387	$1,103,090	$57,010	$14,686	$15,221	$8,011	$1,335	$3,418
908	CUSTOMER ASSISTANCE EXP-INCENTIVES		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
909	INFORMATIONAL AND INSTRUCTIONA	6	$86,651	$60,563	$12,617	$427	$11,963	$618	$159	$165	$87	$14	$37
909	INFORM AND INSTRUC -LOAD MGMT		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
910	MISCELLANEOUS CUSTOMER SERVICE	6	$3,263,787	$2,281,171	$475,214	$16,089	$450,595	$23,288	$5,999	$6,217	$3,272	$545	$1,396
911	DEMONSTRATION AND SELLING EXP		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
912	DEMONSTRATION AND SELLING EXP	6	$7,533	$5,265	$1,097	$37	$1,040	$54	$14	$14	$8	$1	$3
913	ADVERTISING EXPENSES	6	$61,726	$43,142	$8,987	$304	$8,522	$440	$113	$118	$62	$10	$26
915	MDSE-JOBBING-CONTRACT		$0										
916	MISC SALES EXPENSE		$0										
	Sub-total		$11,602,136	$8,109,126	$1,689,283	$57,193	$1,601,779	$82,784	$21,326	$22,102	$11,632	$1,939	$4,863
	General Expenses												
920	ADMIN. & GEN. SALARIES-	66	$16,108,237	$7,886,446	$2,103,744	$121,945	$2,568,202	$913,374	$121,929	$1,460,051	$619,299	$161,447	$151,800

Kentucky Utilities
Electric Cost of Service Study
(Expenses)

Acct. No.	Account Description	Allocator	Total	Residential	Gen'l Service	All Elec. Schools	Secondary PS	Primary PS	Sec. TOD TOD	Pri. TOD TOD	Retail Transmission	Fluc. Load	St. Ltg
921	OFFICE SUPPLIES AND EXPENSES	66	$5,126,832	$2,510,050	$669,567	$38,812	$817,392	$290,703	$38,807	$464,696	$197,107	$51,384	$48,314
922	ADMINISTRATIVE EXPENSES TRANSFERRED	66	($1,896,900)	($928,705)	($247,736)	($14,360)	($302,431)	($107,559)	($14,358)	($171,935)	($72,928)	($19,012)	($17,876)
923	OUTSIDE SERVICES EMPLOYED	66	$7,140,177	$3,495,765	$932,511	$54,054	$1,138,388	$404,864	$54,047	$647,186	$274,512	$71,563	$67,287
924	PROPERTY INSURANCE	23	$2,774,423	$1,206,083	$316,840	$23,056	$455,268	$190,513	$24,967	$310,729	$136,708	$36,037	$74,221
925	INJURIES AND DAMAGES - INSURAN	66	$1,456,895	$713,282	$190,271	$11,029	$232,279	$82,609	$11,028	$132,053	$56,012	$14,602	$13,729
926	EMPLOYEE BENEFITS	66	$33,266,029	$16,281,848	$4,343,254	$251,760	$5,302,145	$1,885,693	$251,727	$3,014,327	$1,278,565	$333,313	$313,397
928	REGULATORY COMMISSION FEES	23	$659,999	$286,912	$75,372	$5,485	$108,302	$45,321	$5,939	$73,918	$32,521	$8,573	$17,656
929	DUPLICATE CHARGES	66	($3,076)	($1,506)	($402)	($23)	($490)	($174)	($23)	($279)	($118)	($31)	($29)
930	MISCELLANEOUS GENERAL EXPENSES	66	$2,396,793	$1,173,448	$313,022	$18,145	$382,131	$135,904	$18,142	$217,245	$92,147	$24,022	$22,587
931	RENTS AND LEASES	59	$1,701,003	$759,132	$197,433	$14,187	$270,112	$111,796	$14,703	$182,230	$77,811	$20,511	$53,088
932	MAINTENANCE OF GENERAL PLANT		$0										
935	MAINTENANCE OF GENERAL PLANT	59	$8,336,244	$3,720,342	$967,578	$69,529	$1,323,758	$547,887	$72,059	$893,067	$381,333	$100,519	$260,173
	Sub-total		$77,056,656	$37,103,099	$9,861,454	$593,617	$12,295,056	$4,500,930	$598,966	$7,223,289	$3,072,970	$802,927	$1,004,347
	TOTAL O & M EXPENSES		$819,700,590	$324,329,920	$91,536,912	$6,215,941	$152,090,411	$63,594,192	$8,453,436	$104,083,342	$50,026,079	$12,939,943	$6,430,415
	TOTAL O&M EXPENSE Less PURCHASED POWER		$642,070,498	$260,419,415	$72,865,643	$4,862,902	$117,440,405	$48,391,480	$6,440,770	$79,061,152	$37,659,883	$9,741,731	$5,187,116
	Depreciation Expense												
	Power Production - Energy	1	$61,735,750	$22,027,976	$6,486,237	$465,357	$12,097,421	$5,311,576	$705,453	$8,750,525	$4,331,766	$1,117,388	$442,050
	Power Production - Demand	32	$13,439,781	$6,579,672	$1,441,151	$148,702	$2,103,643	$886,773	$95,998	$1,382,055	$615,099	$186,688	$0
	Transmission Energy	1	$7,919,524	$2,825,771	$832,061	$59,696	$1,551,869	$681,374	$90,496	$1,122,526	$555,683	$143,340	$56,707
	Transmission Demand	32	$1,724,068	$844,047	$184,872	$19,076	$269,857	$113,756	$12,315	$177,291	$78,906	$23,949	$0
	Dist. Poles - Specific	28	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Dist Substation - General	28	$3,416,046	$1,721,402	$471,793	$46,308	$520,563	$231,863	$25,002	$373,558	$0	$0	$25,557
	Dist. Primary Lines	83	$13,633,326	$7,836,416	$1,925,486	$141,882	$1,625,866	$703,839	$75,923	$1,130,179	$0	$0	$193,735
	Dist. Secondary Lines	84	$3,279,881	$2,378,808	$478,293	$45,393	$318,921	$0	$15,889	$0	$0	$0	$42,577
	Dist. Line Transformers - Demand	85	$7,210,843	$5,447,657	$1,067,608	$59,621	$454,305	$0	$20,563	$0	$0	$0	$161,090
	Dist. Services - Customer	27	$2,219,242	$1,834,088	$347,682	$1,274	$35,905	$0	$293	$0	$0	$0	$0
	Dist. Meters - Customer	26	$1,758,407	$1,128,983	$496,778	$3,589	$121,436	$5,882	$411	$906	$410	$12	$0
	Dist Street & Customer Lighting	7	$2,613,142	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,613,142
	TOTAL DEPRECIATION EXPENSES		$118,950,010	$52,624,819	$13,731,961	$990,898	$19,099,786	$7,935,064	$1,042,343	$12,937,041	$5,581,864	$1,471,377	$3,534,858
	Other Expenses												
	Regulatory Credits and Accretion Expense												
	Production	51	($258,682)	($98,440)	($27,278)	($2,113)	($48,866)	($21,329)	($2,758)	($34,867)	($17,022)	($4,487)	($1,521)
	Transmission	52	($94)	($36)	($10)	($1)	($18)	($8)	($1)	($13)	($6)	($2)	($1)
	Distribution	53	($182)	($109)	($26)	($2)	($16)	($5)	($1)	($8)	($0)	($0)	($16)
	Property Taxes & Other	23	$11,424,756	$4,966,513	$1,304,709	$94,942	$1,874,743	$784,510	$102,811	$1,279,548	$562,950	$148,395	$305,634
	Other Taxes	23	$8,127,668	$3,533,220	$928,181	$67,543	$1,333,708	$558,107	$73,141	$910,281	$400,487	$105,569	$217,430
	Gain on Disposition of Allowances	1	($73,173)	($26,109)	($7,688)	($552)	($14,339)	($6,296)	($836)	($10,372)	($5,134)	($1,324)	($524)
	Interest	23	$65,253,543	$28,366,698	$7,451,967	$542,271	$10,707,766	$4,480,803	$587,217	$7,308,256	$3,215,339	$847,571	$1,745,654
	Other Expenses		$0										
	Total Other Expenses		$84,473,836	$36,741,738	$9,649,856	$702,089	$13,852,977	$5,795,784	$759,573	$9,452,827	$4,156,613	$1,095,722	$2,266,657
TOTAL EXPENSES			$1,023,124,436	$413,696,477	$114,918,729	$7,908,929	$185,043,173	$77,325,039	$10,255,353	$126,473,209	$59,764,556	$15,507,041	$12,231,930
Calculation of Taxable Income and Allocation of Income Taxes:													
	Total Operating Revenue		$1,221,660,614	$467,627,707	$156,768,038	$8,700,686	$229,562,110	$95,654,199	$11,626,139	$143,324,088	$73,116,058	$14,701,332	$20,580,256
	Operating Expenses		$957,870,893	$385,329,779	$107,466,762	$7,366,657	$174,335,408	$72,844,236	$9,668,136	$119,164,952	$56,549,217	$14,659,470	$10,486,275
	Interest Expense		$65,253,543	$28,366,698	$7,451,967	$542,271	$10,707,766	$4,480,803	$587,217	$7,308,256	$3,215,339	$847,571	$1,745,654
	Taxable Income		$198,536,178	$53,931,231	$41,849,308	$791,758	$44,518,937	$18,329,160	$1,370,787	$16,850,879	$13,351,502	($805,708)	$8,348,326

Kentucky Utilities
Electric Cost of Service Study
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Acct. No.	Account Description	Allocator	Total	Residential	Gen'l Service	All Elec. Schools	Secondary PS	Primary PS	Sec. TOD TOD	Pri. TOD TOD	Retail Transmission	Fluc. Load	St. Ltg
	Income Taxes												
	State & Federal Income Taxes		$72,669,576	$19,740,280	$15,317,971	$289,805	$16,295,127	$6,708,965	$501,745	$6,167,874	$4,887,008	($294,911)	$3,055,712

Kentucky Utilities
Electric Cost of Service Study
(Labor)

Acct. No.	Account Description	Allocator	Total	Residential	Gen'l Service	All Elec. Schools	Secondary PS	Primary PS	Sec. TOD TOD	Pri. TOD TOD	Retail Transmission	Fluc. Load	St. Ltg
	Labor O & M Expenses												
	Labor Expenses												
	Steam Power Generation Operation Expenses												
500	OPERATION SUPERVISION & ENGINEERING	60	$2,907,951	$1,094,362	$306,449	$23,428	$552,964	$241,615	$31,397	$395,538	$193,606	$50,833	$17,760
501	FUEL	1	$2,538,739	$905,849	$266,731	$19,137	$497,478	$218,426	$29,010	$359,845	$178,134	$45,950	$18,178
502	STEAM EXPENSES	51	$6,792,159	$2,584,720	$716,245	$55,481	$1,283,075	$560,025	$72,412	$915,485	$446,953	$117,824	$39,940
505	ELECTRIC EXPENSES	51	$4,157,062	$1,581,948	$438,369	$33,956	$785,291	$342,757	$44,319	$560,312	$273,552	$72,113	$24,445
506	MISC. STEAM POWER EXPENSES	51	$823,166	$313,251	$86,804	$6,724	$155,501	$67,871	$8,776	$110,951	$54,168	$14,280	$4,840
507	RENTS	51	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Steam Power Operation Expenses		$17,219,077	$6,480,130	$1,814,598	$138,726	$3,274,310	$1,430,694	$185,913	$2,342,132	$1,146,412	$300,999	$105,163
	Steam Power Generation Maintenance Expenses												
510	MAINTENANCE SUPERVISION & ENGINEERING	61	$4,502,139	$1,619,304	$473,225	$34,279	$878,387	$385,404	$51,030	$634,362	$313,529	$81,078	$31,542
511	MAINTENANCE OF STRUCTURES	51	$1,007,636	$383,451	$106,257	$8,231	$190,348	$83,081	$10,742	$135,815	$66,307	$17,480	$5,925
512	MAINTENANCE OF BOILER PLANT	1	$5,484,321	$1,956,864	$576,208	$41,340	$1,074,679	$471,856	$62,669	$777,357	$384,814	$99,264	$39,270
513	MAINTENANCE OF ELECTRIC PLANT	1	$1,701,680	$607,178	$178,786	$12,827	$333,452	$146,408	$19,445	$241,199	$119,401	$30,800	$12,185
514	MAINTENANCE OF MISC STEAM PLANT	1	$157,379	$56,155	$16,535	$1,186	$30,839	$13,540	$1,798	$22,307	$11,043	$2,848	$1,127
	Total Steam Power Generation Maintenance Expense		$12,853,155	$4,622,951	$1,351,011	$97,863	$2,507,706	$1,100,290	$145,685	$1,811,039	$895,093	$231,469	$90,048
	Total Steam Power Generation Expense		$30,072,232	$11,103,082	$3,165,609	$236,589	$5,782,015	$2,530,984	$331,598	$4,153,171	$2,041,505	$532,468	$195,211
	Hydraulic Power Generation Operation Expenses												
535	OPERATION SUPERVISION & ENGINEERING	62	$6,180	$2,352	$652	$50	$1,167	$510	$66	$833	$407	$107	$36
536	WATER FOR POWER	51	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
537	HYDRAULIC EXPENSES	51	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
538	ELECTRIC EXPENSES	51	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
539	MISC. HYDRAULIC POWER EXPENSES	51	$3,139	$1,195	$331	$26	$593	$259	$33	$423	$207	$54	$18
540	RENTS	51	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Hydraulic Power Operation Expenses		$9,319	$3,546	$983	$76	$1,760	$768	$99	$1,256	$613	$162	$55
	Hydraulic Power Generation Maintenance Expenses												
541	MAINTENANCE SUPERVISION & ENGINEERING	63	$81,366	$30,135	$8,567	$643	$15,617	$6,834	$894	$11,210	$5,507	$1,438	$523
542	MAINTENANCE OF STRUCTURES	51	$73,669	$28,034	$7,769	$602	$13,916	$6,074	$785	$9,930	$4,848	$1,278	$433
543	MAINT. OF RESERVES, DAMS, AND WATERWAYS	51	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
544	MAINTENANCE OF ELECTRIC PLANT	1	$53,089	$18,943	$5,578	$400	$10,403	$4,568	$607	$7,525	$3,725	$961	$380
545	MAINTENANCE OF MISC HYDRAULIC PLANT	1	$2,287	$816	$240	$17	$448	$197	$26	$324	$160	$41	$16
	Total Hydraulic Power Generation Maint. Expense		$210,411	$77,928	$22,153	$1,662	$40,384	$17,672	$2,312	$28,988	$14,240	$3,718	$1,353
	Total Hydraulic Power Generation Expense		$219,730	$81,474	$23,136	$1,738	$42,145	$18,441	$2,412	$30,245	$14,853	$3,880	$1,408
	Other Power Generation Operation Expense												
546	OPERATION SUPERVISION & ENGINEERING	51	$125,103	$47,607	$13,192	$1,022	$23,633	$10,315	$1,334	$16,862	$8,232	$2,170	$736
547	FUEL	1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
548	GENERATION EXPENSE	51	$164,974	$62,780	$17,397	$1,348	$31,164	$13,602	$1,759	$22,236	$10,856	$2,862	$970
549	MISC OTHER POWER GENERATION	51	$26	$10	$3	$0	$5	$2	$0	$4	$2	$0	$0
550	RENTS	51	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Other Power Generation Expenses		$290,103	$110,397	$30,592	$2,370	$54,802	$23,919	$3,093	$39,102	$19,090	$5,032	$1,706
	Other Power Generation Maintenance Expense												
551	MAINTENANCE SUPERVISION & ENGINEERING	51	$69,040	$26,273	$7,280	$564	$13,042	$5,692	$736	$9,306	$4,543	$1,198	$406

Kentucky Utilities
Electric Cost of Service Study
(Labor)

Acct. No.	Account Description	Allocator	Total	Residential	Gen'l Service	All Elec. Schools	Secondary PS	Primary PS	Sec. TOD TOD	Pri. TOD TOD	Retail Transmission	Fluc. Load	St. Ltg
552	MAINTENANCE OF STRUCTURES	51	$92,309	$35,128	$9,734	$754	$17,438	$7,611	$984	$12,442	$6,074	$1,601	$543
553	MAINTENANCE OF GENERATING & ELEC PLANT	51	$394,806	$150,241	$41,633	$3,225	$74,581	$32,552	$4,209	$53,214	$25,980	$6,849	$2,322
554	MAINTENANCE OF MISC OTHER POWER GEN PLT	51	$100,119	$38,100	$10,558	$818	$18,913	$8,255	$1,067	$13,495	$6,588	$1,737	$589
	Total Other Power Generation Maintenance Expense		$656,274	$249,742	$69,205	$5,361	$123,974	$54,111	$6,997	$88,456	$43,186	$11,384	$3,859
	Total Other Power Generation Expense		$946,377	$360,139	$99,797	$7,730	$178,776	$78,030	$10,089	$127,558	$62,276	$16,417	$5,565
	Total Production Expense		$31,238,339	$11,544,694	$3,288,542	$246,057	$6,002,936	$2,627,455	$344,099	$4,310,973	$2,118,633	$552,765	$202,183
Purchased Power													
555	PURCHASED POWER		$0										
556	SYSTEM CONTROL AND LOAD DISPATCH	51	$1,364,100	$519,101	$143,847	$11,142	$257,686	$112,472	$14,543	$183,861	$89,764	$23,663	$8,021
557	OTHER EXPENSES	51	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Purchased Power Labor		$1,364,100	$519,101	$143,847	$11,142	$257,686	$112,472	$14,543	$183,861	$89,764	$23,663	$8,021
Transmission Labor Expenses													
560	OPERATION SUPERVISION AND ENG	51	$754,996	$287,310	$79,616	$6,167	$142,623	$62,251	$8,049	$101,763	$49,682	$13,097	$4,440
561	LOAD DISPATCHING	51	$1,149,852	$437,570	$121,254	$9,392	$217,213	$94,807	$12,259	$154,984	$75,665	$19,947	$6,761
562	STATION EXPENSES	51	$189,552	$72,133	$19,989	$1,548	$35,807	$15,629	$2,021	$25,549	$12,473	$3,288	$1,115
563	OVERHEAD LINE EXPENSES	51	$50,152	$19,085	$5,289	$410	$9,474	$4,135	$535	$6,760	$3,300	$870	$295
566	MISC. TRANSMISSION EXPENSES	51	$227,539	$86,589	$23,994	$1,859	$42,983	$18,761	$2,426	$30,669	$14,973	$3,947	$1,338
568	MAINTENACE SUPERVISION AND ENG	51	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
570	MAINT OF STATION EQUIPMENT	51	$493,314	$187,728	$52,021	$4,030	$93,190	$40,675	$5,259	$66,492	$32,462	$8,558	$2,901
571	MAINT OF OVERHEAD LINES	51	$113,056	$43,023	$11,922	$923	$21,357	$9,322	$1,205	$15,238	$7,440	$1,961	$665
572	UNDERGROUND LINES	51	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
573	MISC PLANT	51	$35,126	$13,367	$3,704	$287	$6,635	$2,896	$374	$4,734	$2,311	$609	$207
Total Transmission Labor Expenses			$3,013,587	$1,146,804	$317,788	$24,616	$569,283	$248,475	$32,128	$406,188	$198,307	$52,277	$17,721
Distribution Operation Labor Expense													
580	OPERATION SUPERVISION AND ENGI	64	$1,536,179	$927,976	$300,836	$11,204	$146,656	$40,301	$5,055	$61,795	$144	$4	$42,206
581	LOAD DISPATCHING	28	$675,400	$340,345	$93,280	$9,156	$102,923	$45,843	$4,943	$73,858	$0	$0	$5,053
582	STATION EXPENSES	28	$579,618	$292,079	$80,051	$7,857	$88,327	$39,341	$4,242	$63,384	$0	$0	$4,336
583	OVERHEAD LINE EXPENSES	55	$1,682,083	$1,034,876	$239,734	$18,606	$188,491	$64,268	$8,906	$103,163	$0	$0	$24,039
584	UNDERGROUND LINE EXPENSES	58	$56,801	$31,852	$7,986	$631	$7,170	$3,107	$337	$4,993	$0	$0	$724
585	STREET LIGHTING EXPENSE	15	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
586	METER EXPENSES	26	$3,367,327	$2,161,989	$951,324	$6,873	$232,548	$11,264	$788	$1,734	$785	$24	$0
586	METER EXPENSES - LOAD MANAGEMENT		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
587	CUSTOMER INSTALLATIONS EXPENSE	7	$666	$0	$0	$0	$0	$0	$0	$0	$0	$0	$666
588	MISCELLANEOUS DISTRIBUTION EXP	53	$2,276,745	$1,357,297	$319,366	$19,883	$205,255	$62,810	$9,211	$100,369	$27	$1	$202,527
589	RENTS		$0										
Total Distribution Operation Labor Expense			$10,174,819	$6,146,414	$1,992,577	$74,210	$971,369	$266,933	$33,484	$409,295	$956	$29	$279,552
Distribution Maintenance Labor Expense													
590	MAINTENANCE SUPERVISION AND EN	65	$31,589	$19,169	$4,487	$353	$3,618	$1,273	$171	$2,044	($0)	($0)	$473
591	MAINTENANCE OF STRUCTURES	28	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
592	MAINTENANCE OF STATION EQUIPME	28	$349,276	$176,006	$48,239	$4,735	$53,225	$23,707	$2,556	$38,195	$0	$0	$2,613
593	MAINTENANCE OF OVERHEAD LINES	55	$5,056,600	$3,110,996	$720,677	$55,932	$566,633	$193,199	$26,774	$310,123	$0	$0	$72,266
594	MAINTENANCE OF UNDERGROUND LIN	58	$232,809	$130,551	$32,732	$2,588	$29,387	$12,734	$1,383	$20,466	$0	$0	$2,967
595	MAINTENANCE OF LINE TRANSFORME	70	$54,417	$41,111	$8,057	$450	$3,428	$0	$155	$0	$0	$0	$1,216
596	MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	15	$369	$0	$0	$0	$0	$0	$0	$0	$0	$0	$369
597	MAINTENANCE OF METERS		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
598	MAINTENANCE OF MISC DISTR PLANT	53	$7,869	$4,691	$1,104	$69	$709	$217	$32	$347	$0	$0	$700

Kentucky Utilities
Electric Cost of Service Study
(Labor)

Acct. No.	Account Description	Allocator	Total	Residential	Gen'l Service	All Elec. Schools	Secondary PS	Primary PS	Sec. TOD TOD	Pri. TOD TOD	Retail Transmission	Fluc. Load	St. Ltg
	Total Distribution Maintenance Labor Expense		$5,732,929	$3,482,524	$815,296	$64,127	$657,002	$231,130	$31,072	$371,175	$0	$0	$80,604
	Total Distribution Operation and Maintenance Labor Expenses		$15,907,748	$9,628,938	$2,807,873	$138,337	$1,628,370	$498,063	$64,555	$780,470	$956	$29	$360,156
	Transmission and Distribution Labor Expenses		$18,921,335	$10,775,743	$3,125,661	$162,953	$2,197,653	$746,539	$96,683	$1,186,658	$199,263	$52,306	$377,877
	Production, Transmission and Distribution Labor Expenses		$51,523,774	$22,839,538	$6,558,050	$420,153	$8,458,275	$3,486,466	$455,325	$5,681,493	$2,407,660	$628,733	$588,081
	Customer Accounts Expense												
901	SUPERVISION/CUSTOMER ACCTS	6	$1,911,446	$1,335,974	$278,310	$9,422	$263,892	$13,639	$3,513	$3,641	$1,916	$319	$818
902	METER READING EXPENSES	6	$273,009	$190,815	$39,751	$1,346	$37,691	$1,948	$502	$520	$274	$46	$117
903	RECORDS AND COLLECTION	6	$7,682,671	$5,369,679	$1,118,611	$37,872	$1,060,662	$54,818	$14,122	$14,635	$7,703	$1,284	$3,286
904	UNCOLLECTIBLE ACCOUNTS		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
905	MISC CUST ACCOUNTS	6	$292,629	$204,528	$42,607	$1,443	$40,400	$2,088	$538	$557	$293	$49	$125
	Total Customer Accounts Labor Expense		$10,159,755	$7,100,997	$1,479,280	$50,082	$1,402,645	$72,492	$18,675	$19,354	$10,186	$1,698	$4,346
	Customer Service Expense												
907	SUPERVISION	6	$163,720	$114,429	$23,838	$807	$22,603	$1,168	$301	$312	$164	$27	$70
908	CUSTOMER ASSISTANCE EXPENSES	6	$544,754	$380,747	$79,317	$2,685	$75,208	$3,887	$1,001	$1,038	$546	$91	$233
908	CUSTOMER ASSISTANCE EXP-LOAD MGMT		$0										
909	INFORMATIONAL AND INSTRUCTIONA		$0										
909	INFORM AND INSTRUC -LOAD MGMT		$0										
910	MISCELLANEOUS CUSTOMER SERVICE	6	$529,482	$370,073	$77,094	$2,610	$73,100	$3,778	$973	$1,009	$531	$88	$227
911	DEMONSTRATION AND SELLING EXP		$0										
912	DEMONSTRATION AND SELLING EXP		$0										
913	WATER HEATER - HEAT PUMP PROGRAM		$0										
915	MDSE-JOBBING-CONTRACT		$0										
916	MISC SALES EXPENSE		$0										
	Total Customer Service Labor Expense		$1,237,956	$865,249	$180,249	$6,102	$170,911	$8,833	$2,276	$2,358	$1,241	$207	$530
	Sub-Total Labor Exp		$62,921,485	$30,805,785	$8,217,578	$476,338	$10,031,831	$3,567,791	$476,276	$5,703,205	$2,419,087	$630,638	$592,957
	Administrative and General Expense												
920	ADMIN. & GEN. SALARIES-	66	$16,107,782	$7,886,223	$2,103,685	$121,942	$2,568,130	$913,348	$121,926	$1,460,010	$619,282	$161,442	$151,796
921	OFFICE SUPPLIES AND EXPENSES	66	$2,954	$1,446	$386	$22	$471	$167	$22	$268	$114	$30	$28
922	ADMIN. EXPENSES TRANSFERRED - CREDIT	66	($1,438,980)	($704,511)	($187,932)	($10,894)	($229,422)	($81,593)	($10,892)	($130,429)	($55,323)	($14,422)	($13,561)
923	OUTSIDE SERVICES EMPLOYED		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
924	PROPERTY INSURANCE		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
925	INJURIES AND DAMAGES - INSURAN	66	$244,673	$119,790	$31,954	$1,852	$39,009	$13,874	$1,852	$22,177	$9,407	$2,452	$2,306
926	EMPLOYEE BENEFITS	66	$33,256,029	$16,281,848	$4,343,254	$251,760	$5,302,145	$1,885,693	$251,727	$3,014,327	$1,278,565	$333,313	$313,397
928	REGULATORY COMMISSION FEES		$0										
929	DUPLICATE CHARGES-CR		$0										
930	MISCELLANEOUS GENERAL EXPENSES	66	$221	$108	$29	$2	$35	$13	$2	$20	$8	$2	$2
931	RENTS AND LEASES		$0										
932	MAINTENANCE OF GENERAL PLANT		$0										
935	MAINTENANCE OF GENERAL PLANT	59	$4,008,483	$1,788,927	$465,260	$33,433	$636,529	$263,451	$34,649	$429,431	$183,364	$48,334	$125,104
	Total Administrative and General Expense		$52,181,162	$25,373,831	$6,756,636	$398,117	$8,316,897	$2,994,952	$399,286	$4,795,804	$2,035,417	$531,151	$579,071
	Total Operation and Maintenance Expenses		$115,102,647	$56,179,615	$14,974,214	$874,454	$18,348,728	$6,562,743	$875,562	$10,499,009	$4,454,504	$1,161,789	$1,172,028
	Operation and Maintenance Expenses Less Purchase Power		$115,102,647	$56,179,615	$14,974,214	$874,454	$18,348,728	$6,562,743	$875,562	$10,499,009	$4,454,504	$1,161,789	$1,172,028

Kentucky Utilities
(Revenue)

Acct. No.	Account Description	Allocator	Total	Residential	Gen'l Service	All Elec. Schools	Secondary PS	Primary PS	Sec. TOD TOD	Pri. TOD TOD	Retail Transmission	Fluc. Load	St. Ltg
REVENUE													
	Sales	74	$1,172,951,987	447,746,696	151,765,496	8,355,396	221,580,886	91,859,279	11,193,618	136,797,218	69,612,366	13,780,439	20,260,593
	Franchise Fees and HEA	Dir	($10,546,741)	(4,238,759)	(1,545,964)	(62,957)	(2,571,689)	(700,129)	(161,733)	(938,623)	(111,756)	0	(215,131)
	Accrued Revenues	74	$394,807	150,708	51,083	2,812	74,582	30,919	3,768	46,045	23,431	4,638	6,820
	Intercompany Sales	1	$37,366,206	13,332,662	3,925,863	281,662	7,322,090	3,214,887	426,983	5,296,347	2,621,847	676,310	267,556
	Off-System Sales	82	$3,910,909	1,419,370	411,288	30,115	759,258	332,871	43,918	547,329	270,018	70,027	26,714
	Brokered Sales	1	$256,817	91,635	26,982	1,936	50,325	22,096	2,935	36,402	18,020	4,648	1,839
	LATE PAYMENT - DIRECT	76	$4,397,443	3,263,214	760,451	0	186,865	0	0	118,716	0	0	68,197
x	POLE ATTACHMENT - DIRECT	55	$439,828	270,597	62,685	4,865	49,286	16,805	2,329	26,975	0	0	6,286
	FACILITY LEASE - DIRECT	22	$1,200,742	516,511	136,242	9,964	199,541	83,844	10,973	136,781	60,835	16,036	30,015
	POWER CHARGES	52	$7,078,857	2,693,821	746,478	57,823	1,337,234	583,664	75,468	954,128	465,819	122,798	41,625
	MISO SCHEUDLE 10 OFFSET-KY	52	($1,064,694)	(405,164)	(112,274)	(8,697)	(201,126)	(87,786)	(11,351)	(143,505)	(70,061)	(18,469)	(6,261)
	MATERIAL SALES - DIRECT	22	$44,401	19,100	5,038	368	7,379	3,100	406	5,058	2,250	593	1,110
	SERVICE ON/OFF/RET CHK - DIRECT	DIR	$1,467,665	1,331,113	47,864	597	56,732	0	2,921	2,423	0	109	25,906
	SALES TAX COLLECT'N FEES-KY	74	$17,858	6,817	2,311	127	3,374	1,399	170	2,083	1,060	210	308
	Unbilled Revenue	74	$3,744,529	1,429,385	484,496	26,674	707,374	293,251	35,734	436,711	222,230	43,993	64,680
	TOTAL REVENUE		$1,221,660,614	$467,627,707	$156,768,038	$8,700,686	$229,562,110	$95,654,199	$11,626,139	$143,324,088	$73,116,058	$14,701,332	$20,580,256

Kentucky Utilities
Electric Cost of Service Study
(Allocator Amounts)

Alloc.	Description	Total	Residential	Gen'l Service	All Elec. Schools	Secondary PS	Primary PS	Sec. TOD TOD	Pri. TOD TOD	Retail Transmission	Fluc. Load	St. Ltg
1	Energy (Loss Adjusted)	18,799,862,138	6,707,991,987	1,975,198,498	141,711,283	3,683,924,586	1,617,488,927	214,825,644	2,664,722,954	1,319,115,928	340,268,532	134,613,819
2	Energy	17,519,177,405	6,171,949,620	1,817,358,411	130,386,993	3,389,538,488	1,536,781,082	197,658,712	2,531,761,273	1,287,717,012	332,169,120	123,856,694
3	Customers (Monthly Bills)	6,116,225	5,019,241	950,552	3,539	99,144	5,121	657	682	364	12	36,913
4	Average Customers (Bills/12)	509,686	418,270	79,213	295	8,262	427	55	57	30	1	3,076
5	Average Customers (Lighting = Lights)	509,686	418,270	79,213	295	8,262	427	55	57	30	1	3,076
6	Weighted Average Customers (Lighting =9 Lights per Cust)	598,440	418,270	87,134	2,850	82,620	4,270	1,100	1,140	600	100	256
7	Street Lighting	43,956,496	0	0	0	0	0	0	0	0	0	43,956,496
8	Average Customers	509,686	418,270	79,213	295	8,262	427	55	57	30	1	3,076
9	Average Customers (Lighting = 9 Lights per Cust)	506,952	418,270	79,213	295	8,262	427	55	57	30	1	342
10	Average Secondary Customers	506,382	418,270	79,213	295	8,262	0	0	0	0	0	342
11	Average Primary Customers	506,952	418,270	79,213	295	8,262	427	55	57	30	1	342
12	Year End Customers	676,199	420,100	79,637	292	8,224	416	49	64	32	1	167,385
13	Year End Customers (Lighting = Lights)	676,199	420,100	79,637	292	8,224	415	49	64	32	1	167,385
14	Weighted Year End Customers (Lighting =9 Lights per Cust)	610,762	420,100	87,601	292	82,240	4,150	490	1,280	640	20	13,949
15	Street Lighting	76,387,118	0	0	0	0	0	0	0	0	0	76,387,118
16	Year End Customers	676,199	420,100	79,637	292	8,224	415	49	64	32	1	167,385
17	Year End Customers (Lighting = 9 Lights per Cust)	527,412	420,100	79,637	292	8,224	415	49	64	32	1	18,598
18	Year End Secondary Customers	526,800	420,100	79,637	292	8,224	0	49	0	0	0	18,698
19	Year End Primary Customers	527,379	420,100	79,637	292	8,224	415	49	64	0	0	18,598
20	Maximum Class Non-Coincident Peak Demands	4,233,651	1,962,568	537,890	52,796	593,493	264,347	28,505	425,893	221,378	117,644	29,137
21	Total Transmission Plant	418,498,868	159,257,514	44,131,418	3,418,442	79,056,695	34,505,936	4,461,644	56,407,628	27,538,982	7,259,734	2,460,875
22	Net Utility Plant	3,372,521,883	1,450,723,591	382,661,629	27,986,159	560,449,403	235,492,033	30,820,687	384,177,692	170,867,238	45,041,271	84,302,180
23	Total Utility Plant	5,196,890,720	2,259,166,852	593,485,937	43,187,298	852,782,636	356,857,931	46,766,834	582,040,576	256,074,474	67,501,832	139,026,552
24	Taxable Income	198,536,178	53,931,231	41,849,308	791,758	44,518,937	18,329,160	1,370,787	16,850,879	13,351,602	(805,708)	8,348,326
25	Revenue and Expense Adjust before IT	(33,085,532)	(20,563,558)	705,842	(323,355)	(5,071,242)	(3,629,267)	(708,185)	(1,802,258)	(383,305)	(701,459)	(608,744)
26	Meter Cost - Wighted Cost of Meters	100.0000%	64.2049%	28.2516%	0.2041%	6.9060%	0.3346%	0.0234%	0.0515%	0.0233%	0.0007%	0.0000%
27	Customer Services - Weighted cost of Services	100.0000%	82.6448%	15.6667%	0.0574%	1.6179%	0.0000%	0.0132%	0.0000%	0.0000%	0.0000%	0.0000%
28	Maximum Class Demands (Primary)	3,894,628	1,962,567	537,890	52,796	593,493	264,347	28,505	425,893	0	0	29,137
29	Sum of the Individual Customer Demands (Secondary)	5,641,961	3,949,601	812,241	104,341	709,920	0	36,721	0	0	0	29,137
30	Summer Peak Period Demand Allocator	3,358,153	1,484,982	337,287	23,844	684,301	233,491	30,826	411,058	190,572	61,792	0
31	Winter Peak Period Demand Allocator	3,957,154	2,096,350	447,135	57,095	560,717	249,182	21,426	341,198	144,228	39,823	0
32	Weighted Avg Summer Winter Peak	7,315,307	3,581,332	784,422	80,939	1,145,018	482,673	52,252	752,256	334,800	101,615	0
33	Production Residual Winter Demand Allocator	3,957,154	2,096,351	447,135	57,095	560,716	249,182	21,426	341,198	144,228	39,823	0
34	Production Winter Demand Allocator	37,687,119	19,965,212	4,258,419	543,763	5,340,155	2,373,156	204,055	3,249,600	1,373,593	379,266	0
35	Production Residual Summer Demand Allocator	3,358,153	1,484,981	337,287	23,844	584,302	233,491	30,826	411,058	190,572	61,792	0
36	Production Summer Demand Allocator	19,048,333	8,423,204	1,913,183	135,250	3,314,310	1,324,424	174,855	2,331,630	1,080,977	350,500	0
37	Production Residual Summer Demand Allocator	3,358,153	1,484,981	337,287	23,844	584,302	233,491	30,826	411,058	190,572	61,792	0
38	Production Summer Demand Total	19,048,333	8,423,204	1,913,183	135,250	3,314,310	1,324,424	174,855	2,331,630	1,080,977	350,500	0
39	Distribution O&M-- (Lines, Transformers & Services Plant)	945,393,672	627,921,666	137,056,662	8,906,167	87,385,837	25,258,991	4,043,344	40,559,248	0	0	14,261,758
40	Temperature Normalization Revenues	2,986,578	2,362,665	264,295	12,655	241,693	93,420	11,850	0	0	0	0
41	Customer Specific Assignment	0		0	0	0	0	0	0	0	0	0
42	Year-End Customers	9,724,872	(3,729,851)	12,261,395	(103,605)	(1,140,255)	(4,224,214)	(931,558)	3,132,208	3,532,765	0	927,987
43	FAC Roll-In	(3,710,704)	(1,339,973)	(386,233)	(33,684)	39,974	(296,317)	(993)	(539,386)	(694,223)	(387,783)	(72,086)
44	Interruptible Credit Allocator	1,601,542,287	801,355,196	174,213,519	19,167,275	244,300,313	104,376,219	10,695,966	157,545,488	69,288,279	20,600,032	0
45	Operation and Maintenance Less Fuel											
46	Base Rate Revenue	908,837,718	364,691,143	121,479,709	6,648,873	186,103,586	72,898,865	1,110,048	8,187,097	107,887,035	32,985,640	6,846,722
47	VDT Revenue	2	(13)	194	0	(101)	(94)	0	0	0	0	16
48	Remove DSM Revenues	12,945,697	10,567,741	1,062,430	0	1,023,748	218,508	67,582	2,710	2,978	0	0
49	Remove ECR Revenues	92,931,133	34,626,991	11,982,292	646,858	17,591,743	7,274,998	923,853	11,026,723	5,672,457	1,592,265	1,592,953
50	Remove Changes in ECR Roll-in	87,584,103	33,637,125	11,667,441	640,200	16,342,562	6,803,053	741,661	10,176,285	4,884,714	1,308,727	1,382,335
51	Gross Production Plant	2,373,889,077	903,370,839	250,330,643	19,390,739	448,440,460	195,731,152	25,308,187	319,966,102	156,211,866	41,180,047	13,959,042
52	Gross Transmission Plant	418,498,868	159,257,514	44,131,418	3,418,442	79,056,695	34,505,936	4,461,644	56,407,628	27,538,982	7,259,734	2,460,875
53	Gross Distribution Plant	1,224,870,612	730,214,721	171,816,198	10,696,851	110,425,631	33,791,061	4,955,377	53,997,797	14,703	442	108,957,931
54	Total Prod.,Ttrans., Distrib Plant	4,017,258,557	1,792,843,074	466,278,259	33,508,032	637,922,686	264,028,150	34,725,207	430,371,526	183,765,551	48,440,223	125,377,849
55	Dist. Overhead Lines Gross Plant	481,552,367	296,267,751	68,631,788	5,326,549	53,961,859	18,398,782	2,549,762	29,633,780	0	0	6,882,097
56	Gross Intangible Plant	45,050,496	20,105,370	5,228,958	375,745	7,163,817	2,960,875	389,417	4,826,289	2,060,791	543,220	1,406,017
57	Gross Total Plant in Service	4,171,331,504	1,862,918,780	484,373,725	34,794,525	661,786,392	273,819,687	36,016,680	446,324,186	190,412,136	50,192,225	130,693,187
58	Dist. Underground Lines Gross Plant	125,419,549	70,330,623	17,633,724	1,394,270	15,831,591	6,860,209	745,114	11,025,468	0	0	1,598,551
59	Gross General Plant	100,246,736	44,738,636	11,635,515	836,110	15,918,733	6,688,563	866,533	10,739,498	4,585,689	1,208,778	3,128,681
60	Labor Accts 501-507	14,311,126	5,385,768	1,508,150	115,298	2,721,346	1,189,079	154,516	1,946,593	952,806	250,167	87,403
61	Labor Accts 511-514	8,351,016	3,003,647	877,788	63,584	1,629,319	714,886	94,655	1,176,677	581,564	150,391	58,506
62	Labor Accts 536-540	3,139	1,195	331	26	593	259	33	423	207	54	18
63	Labor Accts 542-545	129,045	47,783	13,587	1,019	24,768	10,839	1,418	17,779	8,733	2,280	830
64	Labor Accts 581-588	8,638,640	5,218,438	1,691,741	63,006	824,713	226,632	28,428	347,501	812	24	237,346
65	Labor Accts 591-598	19,288,204	11,704,844	2,740,038	215,664	2,209,196	777,323	104,494	1,248,099	(0)	(0)	288,545

Kentucky Utilities
Electric Cost of Service Study
(Allocator Amounts)

Alloc.	Description	Total	Residential	Gen'l Service	All Elec. Schools	Secondary PS	Primary PS	Sec. TOD TOD	Pri. TOD TOD	Retail Transmission	Fluc. Load	St. Ltg
66	Labor Accts 500-916	62,921,485	30,805,785	8,217,578	476,338	10,031,831	3,567,791	476,276	5,703,205	2,419,087	630,638	592,957
67	O&M less Purchased Power	642,070,498	260,419,415	72,865,643	4,862,902	117,440,405	48,391,480	6,440,770	79,061,152	37,659,883	9,741,731	5,187,116
68	Dist. Lines Gross Plant	606,971,916	366,598,374	86,265,512	6,720,818	69,793,450	25,258,991	3,294,875	40,559,248	0	0	8,480,648
69	Rate Base	3,176,812,337	1,364,423,244	360,432,846	28,298,098	529,266,665	222,269,321	29,104,299	362,621,930	161,630,707	42,583,286	78,181,940
70	Gross Transformer Plant	258,778,803	195,502,532	38,313,727	2,139,634	16,303,844	0	737,956	0	0	0	5,781,110
71	Dpreciation Expense	118,950,010	52,624,819	13,731,961	990,898	19,099,786	7,935,064	1,042,343	12,937,041	5,581,864	1,471,377	3,534,858
72	Total Labor	115,102,647	56,179,616	14,974,214	874,454	18,348,728	6,562,743	875,562	10,499,009	4,454,504	1,161,789	1,172,028
73	Distribution O&M	35,765,796	21,742,406	6,023,521	332,386	3,757,853	1,188,243	156,490	1,874,846	1,628	49	688,374
74	Sales Revenue	1,172,951,987	447,746,696	151,765,496	8,355,396	221,580,886	91,859,279	11,193,618	136,797,218	69,612,366	13,780,439	20,260,593
75	Distribution Poles, Lines, Transform & Services	945,393,672	627,921,666	137,056,862	8,906,167	87,385,837	25,258,991	4,043,344	40,559,248	0	0	14,261,758
76	Late Payment Revenue	4,398,330	3,263,872	780,604	0	186,902	0	0	118,740	0	0	68,211
77	Temperature Normalization Expenses	50,756,000	36,773,000	3,531,000	205,000	7,138,000	2,759,000	350,000	0	0	0	0
78	O&M Expenses	819,700,590	324,329,920	91,536,912	6,215,941	152,090,411	63,594,192	8,453,436	104,083,342	50,026,079	12,839,943	6,430,415
79	Steam Production Plant	1,913,147,131	728,037,946	201,744,621	15,627,241	361,403,820	157,742,203	20,396,187	257,864,715	125,893,112	33,187,519	11,249,768
80	Hydro Production Plant	10,701,212	4,072,289	1,128,461	87,411	2,021,517	882,333	114,086	1,442,369	704,185	185,635	62,926
81	Other Production Plant	450,040,734	171,260,603	47,457,561	3,676,087	85,015,124	37,106,616	4,797,914	60,659,018	29,614,569	7,806,893	2,646,348
82	Off-System Sales	3,910,909	1,419,370	411,288	30,115	759,258	332,871	43,918	547,329	270,018	70,027	26,714
83	Dist Primary Lines	489,265,350	281,229,020	69,100,779	5,091,771	58,348,201	25,268,991	2,724,676	40,559,248	0	0	6,952,663
84	Dist Seconary Lines	117,706,566	85,369,354	17,164,733	1,629,047	11,445,249	0	570,199	0	0	0	1,627,985
85	Dist Transformers	258,778,803	195,502,532	38,313,727	2,139,634	16,303,844	0	737,956	0	0	0	5,781,110
86												
87												
88												
89												
MEMO	Interruptible Credit Allocator											
91	Production Portion	1,545,639,177	773,383,254	168,132,458	18,498,226	235,772,815	100,732,884	10,322,615	152,046,238	66,869,716	19,880,971	0
92	Intangible & General Plant Portion	55,903,110	27,971,942	6,081,062	669,049	8,527,497	3,643,335	373,351	5,499,251	2,418,563	719,061	0
93	Total Interruptible Credit Allocator	1,601,542,287	801,355,196	174,213,519	19,167,275	244,300,313	104,376,219	10,695,966	157,545,488	69,288,279	20,600,032	0
94												
95												
MEMO	Off-System Sales Allocator											
	Off-System Sales	3,910,909	1,488,276	412,412	31,946	738,792	322,461	41,694	527,134	257,354	67,843	22,997
	Less: Adjustment to Reallocate Expenses											
	Costs allocated on Energy to be reallocated on RBPPT	(2,903,251)	(1,035,911)	(305,029)	(21,884)	(568,906)	(249,788)	(33,175)	(411,512)	(203,710)	(52,547)	(20,788)
	Costs allocated on Energy reallocated on RBPPT	2,903,251	1,104,817	308,153	23,715	548,440	239,378	30,952	391,316	191,046	50,363	17,072
	Net Adjustment	0	68,906	1,124	1,830	(20,466)	(10,410)	(2,224)	(20,195)	(12,664)	(2,185)	(3,717)
	Off System Sales Allocator	3,910,909	1,419,370	411,288	30,115	759,258	332,871	43,918	547,329	270,018	70,027	26,714

Kentucky Utilities
Electric Cost of Service Study
(Allocator Percentages)

Alloc.	Description	Total	Residential	Gen'l Service	All Elec. Schools	Secondary PS	Primary PS	Sec. TOD TOD	Pri. TOD TOD	Retail Transmission	Fluc. Load	St. Ltg
1	Energy (Loss Adjusted)	100.0000%	35.6811%	10.5065%	0.7538%	19.5955%	8.6037%	1.1427%	14.1742%	7.0166%	1.8100%	0.7160%
2	Energy	100.0000%	35.2297%	10.3735%	0.7443%	19.3476%	8.7720%	1.1282%	14.4514%	7.3503%	1.8960%	0.7070%
3	Customers (Monthly Bills)	100.0000%	82.0644%	15.5415%	0.0579%	1.6210%	0.0837%	0.0107%	0.0112%	0.0060%	0.0002%	0.6035%
4	Average Customers (Bills/12)	100.0000%	82.0643%	15.5415%	0.0579%	1.6210%	0.0838%	0.0108%	0.0112%	0.0059%	0.0002%	0.6035%
5	Average Customers (Lighting = Lights)	100.0000%	82.0643%	15.5415%	0.0579%	1.6210%	0.0838%	0.0108%	0.0112%	0.0059%	0.0002%	0.6035%
6	Weighted Average Customers (Lighting =9 Lights per Cust)	100.0000%	69.8934%	14.5602%	0.4929%	13.8059%	0.7135%	0.1838%	0.1905%	0.1003%	0.0167%	0.0428%
7	Street Lighting	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
8	Average Customers	100.0000%	82.0643%	15.5415%	0.0579%	1.6210%	0.0838%	0.0108%	0.0112%	0.0059%	0.0002%	0.6035%
9	Average Customers (Lighting = 9 Lights per Cust)	100.0000%	82.5068%	15.6253%	0.0582%	1.6297%	0.0842%	0.0108%	0.0112%	0.0059%	0.0002%	0.0675%
10	Average Secondary Customers	100.0000%	82.5997%	15.6429%	0.0583%	1.6316%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0675%
11	Average Primary Customers	100.0000%	82.5068%	15.6253%	0.0582%	1.6297%	0.0842%	0.0108%	0.0112%	0.0059%	0.0002%	0.0675%
12	Year End Customers	100.0000%	62.1267%	11.7772%	0.0432%	1.2162%	0.0614%	0.0072%	0.0095%	0.0047%	0.0001%	24.7538%
13	Year End Customers (Lighting = Lights)	100.0000%	62.1267%	11.7772%	0.0432%	1.2162%	0.0614%	0.0072%	0.0095%	0.0047%	0.0001%	24.7538%
14	Weighted Year End Customers (Lighting =9 Lights per Cust)	100.0000%	68.7829%	14.3429%	0.0478%	13.4651%	0.6795%	0.0802%	0.2096%	0.1048%	0.0033%	2.2839%
15	Street Lighting	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
16	Year End Customers	100.0000%	62.1267%	11.7772%	0.0432%	1.2162%	0.0614%	0.0072%	0.0095%	0.0047%	0.0001%	24.7538%
17	Year End Customers (Lighting = 9 Lights per Cust)	100.0000%	79.6531%	15.0996%	0.0554%	1.5593%	0.0787%	0.0093%	0.0121%	0.0061%	0.0002%	3.5263%
18	Year End Secondary Customers	100.0000%	79.7305%	15.1143%	0.0554%	1.5608%	0.0000%	0.0093%	0.0000%	0.0000%	0.0000%	3.5297%
19	Year End Primary Customers	100.0000%	79.6581%	15.1005%	0.0554%	1.5594%	0.0787%	0.0093%	0.0121%	0.0000%	0.0000%	3.5265%
20	Maximum Class Non-Coincident Peak Demands	100.0000%	46.3564%	12.7051%	1.2471%	14.0185%	6.2439%	0.6733%	10.0597%	5.2290%	2.7788%	0.6882%
21	Total Transmission Plant	100.0000%	38.0545%	10.5452%	0.8168%	18.8905%	8.2452%	1.0661%	13.4786%	6.5804%	1.7347%	0.5880%
22	Net Utility Plant	100.0000%	43.0160%	11.3465%	0.8298%	16.6181%	6.9827%	0.9139%	11.3914%	5.0665%	1.3355%	2.4997%
23	Total Utility Plant	100.0000%	43.4715%	11.4200%	0.8310%	16.4095%	6.8668%	0.8999%	11.1998%	4.9275%	1.2989%	2.6752%
24	Taxable Income	100.0000%	27.1644%	21.0789%	0.3988%	22.4236%	9.2322%	0.6904%	8.4876%	6.7250%	-0.4058%	4.2049%
25	Revenue and Expense Adjust before IT	100.0000%	62.1527%	-2.1334%	0.9773%	15.3277%	10.9693%	2.1405%	5.4473%	1.1585%	2.1201%	1.8399%
26	Meter Cost - Wighted Cost of Meters	100.0000%	64.2049%	28.2516%	0.2041%	6.9060%	0.3345%	0.0234%	0.0515%	0.0233%	0.0007%	0.0000%
27	Customer Services - Weighted cost of Services	100.0000%	82.6448%	15.6667%	0.0574%	1.6179%	0.0000%	0.0132%	0.0000%	0.0000%	0.0000%	0.0000%
28	Maximum Class Demands (Primary)	100.0000%	50.3916%	13.8111%	1.3556%	15.2388%	6.7875%	0.7319%	10.9354%	0.0000%	0.0000%	0.7481%
29	Sum of the Individual Customer Demands (Secondary)	100.0000%	70.0040%	14.3964%	1.8494%	12.5829%	0.0000%	0.6509%	0.0000%	0.0000%	0.0000%	0.5164%
30	Summer Peak Period Demand Allocator	100.0000%	44.2202%	10.0438%	0.7100%	17.3995%	6.9530%	0.9179%	12.2406%	5.6749%	1.8401%	0.0000%
31	Winter Peak Period Demand Allocator	100.0000%	52.9762%	11.2994%	1.4428%	14.1697%	6.2970%	0.5414%	8.6223%	3.6447%	1.0064%	0.0000%
32	Weighted Avg Summer Winter Peak	100.0000%	48.9567%	10.7230%	1.1064%	15.6524%	6.5981%	0.7143%	10.2833%	4.5767%	1.3891%	0.0000%
33	Production Residual Winter Demand Allocator	100.0000%	52.9762%	11.2994%	1.4428%	14.1697%	6.2970%	0.5414%	8.6223%	3.6447%	1.0064%	0.0000%
34	Production Winter Demand Allocator	100.0000%	52.9762%	11.2994%	1.4428%	14.1697%	6.2970%	0.5414%	8.6223%	3.6447%	1.0064%	0.0000%
35	Production Residual Summer Demand Allocator	100.0000%	44.2202%	10.0438%	0.7100%	17.3995%	6.9530%	0.9179%	12.2406%	5.6749%	1.8401%	0.0000%
36	Production Summer Demand Allocator	100.0000%	44.2202%	10.0438%	0.7100%	17.3995%	6.9530%	0.9180%	12.2406%	5.6749%	1.8401%	0.0000%
37	Production Residual Summer Demand Allocator	100.0000%	44.2202%	10.0438%	0.7100%	17.3995%	6.9530%	0.9179%	12.2406%	5.6749%	1.8401%	0.0000%
38	Production Summer Demand Total	100.0000%	44.2202%	10.0438%	0.7100%	17.3995%	6.9530%	0.9180%	12.2406%	5.6749%	1.8401%	0.0000%
39	Distribution O&M-- (Lines, Transformers & Services Plant)	100.0000%	66.4191%	14.4973%	0.9421%	9.2433%	2.6718%	0.4277%	4.2902%	0.0000%	0.0000%	1.5086%
40	Temperature Normalization Revenues	100.0000%	79.1094%	8.8494%	0.4237%	8.0926%	3.1280%	0.3968%	0.0000%	0.0000%	0.0000%	0.0000%
41	Customer Specific Assignment											
42	Year-End Customers	100.0000%	-38.3537%	126.0828%	-1.0654%	-11.7251%	-43.4372%	-9.5791%	32.2082%	36.3271%	0.0000%	9.5424%
43	FAC Roll-In	100.0000%	36.1110%	10.4086%	0.9078%	-1.0773%	7.9855%	0.0268%	14.5359%	18.7087%	10.4504%	1.9427%
44	Interruptible Credit Allocator	100.0000%	50.0365%	10.8779%	1.1968%	15.2541%	6.5172%	0.6679%	9.8371%	4.3263%	1.2863%	0.0000%
45	Operation and Maintenance Less Fuel											
46	Base Rate Revenue	100.0000%	40.1272%	13.3665%	0.7316%	20.4771%	8.0211%	0.1221%	0.9008%	11.8709%	3.6294%	0.7532%
47	VDT Revenue	100.0000%	-650.0000%	9700.0000%	0.0000%	-5050.0000%	-4700.0000%	0.0000%	0.0000%	0.0000%	0.0000%	800.0000%
48	Remove DSM Revenues	100.0000%	81.6313%	8.2068%	0.0000%	7.9080%	1.6879%	0.5220%	0.0209%	0.0230%	0.0000%	0.0000%

Kentucky Utilities
Electric Cost of Service Study
(Allocator Percentages)

Alloc.	Description	Total	Residential	Gen'l Service	All Elec. Schools	Secondary PS	Primary PS	Sec. TOD TOD	Pri. TOD TOD	Retail Transmission	Fluc. Load	St. Ltg
49	Remove ECR Revenues	100.0000%	37.2609%	12.8937%	0.6961%	18.9299%	7.8284%	0.9941%	11.8655%	6.1039%	1.7134%	1.7141%
50	Remove Changes in ECR Roll-in	100.0000%	38.4055%	13.3214%	0.7310%	18.6593%	7.7675%	0.8468%	11.6189%	5.5772%	1.4943%	1.5783%
51	Gross Production Plant	100.0000%	38.0545%	10.5452%	0.8168%	18.8905%	8.2452%	1.0661%	13.4786%	6.5804%	1.7347%	0.5880%
52	Gross Transmission Plant	100.0000%	38.0545%	10.5452%	0.8168%	18.8905%	8.2452%	1.0661%	13.4786%	6.5804%	1.7347%	0.5880%
53	Gross Distribution Plant	100.0000%	59.6157%	14.0273%	0.8733%	9.0153%	2.7587%	0.4046%	4.4084%	0.0012%	0.0000%	8.8955%
54	Total Prod.,Ttrans., Distrib Plant	100.0000%	44.6285%	11.6069%	0.8341%	15.8796%	6.5723%	0.8644%	10.7131%	4.5744%	1.2058%	3.1210%
55	Dist. Overhead Lines Gross Plant	100.0000%	61.5235%	14.2522%	1.1061%	11.2058%	3.8207%	0.5295%	6.1330%	0.0000%	0.0000%	1.4291%
56	Gross Intangible Plant	100.0000%	44.6285%	11.6069%	0.8341%	15.8796%	6.5723%	0.8644%	10.7131%	4.5744%	1.2058%	3.1210%
57	Gross Total Plant in Service	100.0000%	44.6601%	11.6120%	0.8341%	15.8651%	6.5643%	0.8634%	10.6998%	4.5648%	1.2033%	3.1331%
58	Dist. Underground Lines Gross Plant	100.0000%	56.0763%	14.0598%	1.1117%	12.6229%	5.4698%	0.5941%	8.7909%	0.0000%	0.0000%	1.2746%
59	Gross General Plant	100.0000%	44.6285%	11.6069%	0.8341%	15.8796%	6.5723%	0.8644%	10.7131%	4.5744%	1.2058%	3.1210%
60	Labor Accts 501-507	100.0000%	37.6334%	10.5383%	0.8057%	19.0156%	8.3088%	1.0797%	13.6020%	6.6578%	1.7481%	0.6107%
61	Labor Accts 511-514	100.0000%	35.9674%	10.5111%	0.7614%	19.5104%	8.5605%	1.1335%	14.0902%	6.9640%	1.8009%	0.7006%
62	Labor Accts 536-540	100.0000%	38.0545%	10.5452%	0.8168%	18.8905%	8.2452%	1.0661%	13.4786%	6.5804%	1.7347%	0.5880%
63	Labor Accts 542-545	100.0000%	37.0360%	10.5286%	0.7898%	19.1930%	8.3990%	1.0990%	13.7771%	6.7676%	1.7670%	0.6430%
64	Labor Accts 581-588	100.0000%	60.4081%	19.5834%	0.7294%	9.5468%	2.6235%	0.3291%	4.0226%	0.0094%	0.0003%	2.7475%
65	Labor Accts 591-598	100.0000%	60.6840%	14.2058%	1.1181%	11.4536%	4.0300%	0.5418%	6.4708%	-0.0000%	-0.0000%	1.4960%
66	Labor Accts 500-916	100.0000%	48.9591%	13.0601%	0.7570%	15.9434%	5.6702%	0.7569%	9.0640%	3.8446%	1.0023%	0.9424%
67	O&M less Purchased Power	100.0000%	40.5593%	11.3485%	0.7574%	18.2909%	7.5368%	1.0031%	12.3135%	5.8654%	1.5172%	0.8079%
68	Dist. Lines Gross Plant	100.0000%	60.3979%	14.2124%	1.1073%	11.4986%	4.1615%	0.5428%	6.6822%	0.0000%	0.0000%	1.3972%
69	Rate Base	100.0000%	42.9494%	11.3457%	0.8278%	16.6603%	6.9966%	0.9161%	11.4146%	5.0878%	1.3404%	2.4610%
70	Gross Transformer Plant	100.0000%	75.5481%	14.8056%	0.8268%	6.3003%	0.0000%	0.2852%	0.0000%	0.0000%	0.0000%	2.2340%
71	Dpreciation Expense	100.0000%	44.2411%	11.5443%	0.8330%	16.0570%	6.6709%	0.8763%	10.8760%	4.6926%	1.2370%	2.9717%
72	Total Labor	100.0000%	48.8083%	13.0094%	0.7597%	15.9412%	5.7016%	0.7607%	9.1214%	3.8700%	1.0094%	1.0182%
73	Distribution O&M	100.0000%	60.7911%	16.8416%	0.9293%	10.5068%	3.3223%	0.4375%	5.2420%	0.0046%	0.0001%	1.9247%
74	Sales Revenue	100.0000%	38.1726%	12.9388%	0.7123%	18.8909%	7.8315%	0.9543%	11.6626%	5.9348%	1.1749%	1.7273%
75	Distribution Poles, Lines, Transform & Services	100.0000%	66.4191%	14.4973%	0.9421%	9.2433%	2.6718%	0.4277%	4.2902%	0.0000%	0.0000%	1.5086%
76	Late Payment Revenue	100.0000%	74.2071%	17.2930%	0.0000%	4.2494%	0.0000%	0.0000%	2.6997%	0.0000%	0.0000%	1.5508%
77	Temperature Normalization Expenses	100.0000%	72.4505%	6.9568%	0.4039%	14.0634%	5.4358%	0.6896%	0.0000%	0.0000%	0.0000%	0.0000%
78	O&M Expenses	100.0000%	39.5669%	11.1671%	0.7583%	18.5544%	7.7582%	1.0313%	12.6977%	6.1030%	1.5786%	0.7845%
79	Steam Production Plant	100.0000%	38.0545%	10.5452%	0.8168%	18.8905%	8.2452%	1.0661%	13.4786%	6.5804%	1.7347%	0.5880%
80	Hydro Production Plant	100.0000%	38.0545%	10.5452%	0.8168%	18.8905%	8.2452%	1.0661%	13.4786%	6.5804%	1.7347%	0.5880%
81	Other Production Plant	100.0000%	38.0545%	10.5452%	0.8168%	18.8905%	8.2452%	1.0661%	13.4786%	6.5804%	1.7347%	0.5880%
82	Off-System Sales	100.0000%	36.2926%	10.5164%	0.7700%	19.4139%	8.5113%	1.1230%	13.9949%	6.9042%	1.7906%	0.6831%
83	Dist Primary Lines	100.0000%	57.4799%	14.1234%	1.0407%	11.9257%	5.1626%	0.5569%	8.2898%	0.0000%	0.0000%	1.4210%
84	Dist Seconary Lines	100.0000%	72.5273%	14.5826%	1.3840%	9.7235%	0.0000%	0.4844%	0.0000%	0.0000%	0.0000%	1.2981%
85	Dist Transformers	100.0000%	75.5481%	14.8056%	0.8268%	6.3003%	0.0000%	0.2852%	0.0000%	0.0000%	0.0000%	2.2340%
86												
87												
88												
89												
MEMO	Interruptible Credit Allocator											
91	Production Portion	100.0000%	50.0365%	10.8779%	1.1968%	15.2541%	6.5172%	0.6679%	9.8371%	4.3263%	1.2863%	0.0000%
92	Intangible & General Plant Portion	100.0000%	50.0365%	10.8779%	1.1968%	15.2541%	6.5172%	0.6679%	9.8371%	4.3263%	1.2863%	0.0000%
93	Total Interruptible Credit Allocator	100.0000%	50.0365%	10.8779%	1.1968%	15.2541%	6.5172%	0.6679%	9.8371%	4.3263%	1.2863%	0.0000%
94												
95												
MEMO	Off-System Sales Allocator											
	Off-System Sales	100.0000%	38.0545%	10.5452%	0.8168%	18.8905%	8.2452%	1.0661%	13.4786%	6.5804%	1.7347%	0.5880%
	Less: Adjustment to Reallocate Expenses											

Schedule GAW-5

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

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

Source: Value Line Investment Analyzer, April 12, 2010 except where otherwise noted.

1/ Source: February 2010 AUS Monthly Utility Reports

Competitive Fixed Period Electric Residential Rates in Texas 1/

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

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

Avg. Non-Waivable Customer Charge: $6.24

1/ "Fixed Period" means customer enters a contract to not switch provider for at least a predetermined time period, in this case 12 months.

2a/ Customer charge is waived with a minimum usage of 500kWh.

2b/ Customer charge is waived with a minimum usage of 1000 kWh.

Schedule GAW-7

Kentucky Utilities
Residential Customer Charge

	Residential Amount
Rate Base:	
Gross Plant	
Services	65,820,759
Meters	40,516,336

Kentucky Utilities
Residential Customer Charge

	Residential Amount
Rate Base:	
Gross Plant	
Services	65,820,759
Meters	40,516,336
Total	106,337,096
Depreciation Reserve	
Services	(46,561,906)
Meters	(18,190,035)
Total	(64,751,941)
Net Rate Base	41,585,155
Operation & Maintenance Expenses	
Meter Operations	3,858,065
Meter Maint.	0
Meter Reading	2,636,804
Records & Collections	9,818,212
Misc. Customer Accts.	252,292
Total	16,565,373
Depreciation Expense	
Services	1,309,833
Meters	713,088
Total	2,022,921
Revenue Requirement	
Interest	884,539
Equity Return	2,239,776
Income Tax @ effective rate	1,326,260
Revenue for Return	4,450,575
Total Customer Revenue Requirement	23,038,869
Number of Bills	5,019,241
Monthly Cost	**$4.59**

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

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

AFFIDAVIT OF GLENN A. WATKINS

Commonwealth of Virginia)

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

Glenn A. Watkins

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

NOTARY PUBLIC

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

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