COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

# PREPARED DIRECT TESTIMONY AND SCHEDULES

OF

GLENN A. WATKINS

ON BEHALF OF THE

KENTUCKY OFFICE OF THE ATTORNEY GENERAL

APRIL 23, 2010

## TABLE OF CONTENTS


| | | PAGE |
|---|---|---|
| I. | INTRODUCTION | 1 |
| II. | WEATHER NORMALIZATION | 2 |
| III. | CLASS COST OF SERVICE | 5 |
| | A. Generation | 9 |
| | B. Distribution | 20 |
| IV. | CLASS REVENUE INCREASE DISTRIBUTION | 29 |
| V. | RESIDENTIAL RATE DESIGN | 31 |

## 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.

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

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

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

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

**Peak and Average ("P&A")** -- The various P&A methodologies rest on the premise that a utility's actual generation facilities are placed into service to meet peak load and serve consumers demands throughout the entire year. Hence, the P&A method assigns capacity costs partially on the basis of contributions to peak load and partially on the basis of consumption throughout the year. Although there is not universal agreement

on how peak demands should be measured or how the weighting between Peak and Average demands should be performed, many P&A studies use class contributions to coincident-peak demand for the "peak" portion, while some studies weight the Peak and Average loads based on the system coincident load factor and others give equal weight to energy usage and peak demand.

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

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

**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?**

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

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

| Class | OAG Traditional BIP | Seelye Modified BIP |
|---|---|---|
| Residential | 3.08% | 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. <u>Distribution</u>**

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

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

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

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

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

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

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

A. Possibly the best way to answer this question is by way of example. Consider two different electric utilities: one similar to 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:

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

[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(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 feet$^{0.5}$ = 1 $^{0.5}$ = 1, such that the cost for one foot becomes $0.75697. This is the zero-intercept used by Mr. Seelye.

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

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

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

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

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

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

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

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

A. Mr. Seelye classifies distribution plant as follows:

| Account | Percentage | |
|---|---|---|
| | Customer | 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

[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.

## GLENN A. WATKINS

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

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

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

### II. Transportation Regulation

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

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

### III. Insurance Studies

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

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

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

# GLENN A. WATKINS

## IV. Anti-Trust and Commercial Business Damage Litigation

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

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

## MEMBERSHIPS AND CERTIFICATIONS

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

**EXPERT TESTIMONY
PROVIDED BY
GLENN A. WATKINS**

| YEAR | CASE NAME | PRE-FILED | JURISDICTION | DOCKET NO. | SUBJECT OF TESTIMONY |
|---|---|---|---|---|---|
| 1985 | SAVANNAH ELECT. & PWR CO. | YES | GA. PSC | 3523U | SALES FORECAST, RATE DESIGN ISSUES |
| 1990 | CENTRAL MAINE PWR CO. | YES | ME. PUC | 89-68 | MARGINAL COST OF SERVICE |
| 1990 | COMMONWEALTH GAS SERVICES ( Columbia Gas) | YES | VA. SCC | PUE900034 | CLASS COST OF SERVICE |
| 1990 | WARNER FRUEHAUF | NO | U.S. BANKRUPTCY CT. | n/a | VALUE OF STOCK, COST OF CAPITAL |
| 1991 | W. VA. WATER | YES | WVA PSC | 91-140-W-42T | RATE DESIGN |
| 1992 | S.C. WORKERS COMPENSATION | YES | SC DEPT OF INSUR | 92-034 | INTERNAL RATE OF RETURN |
| 1992 | GRASS v. ATLAS PLUMBING, et.al. | NO | RICHMOND CIRCUT CT | n/a | DAMAGES, BREACH OF COVENANT NOT TO COMPETE (PROFFERED TEST) |
| 1992 | VIRGINIA NATURAL GAS | YES | VA SCC | PUE920031 | JURISDICTIONAL & CLASS COST OF SERVICE |
| 1992 | ALLSTATE INSURANCE COMPANY (DIRECT) | YES | N.J. DEPT OF INSUR | INS 06174-92 | COST ALLOCATIONS, PROFITABILITY |
| 1992 | ALLSTATE INSURANCE COMPANY (REBUTTAL) | YES | N.J. DEPT OF INSUR | INS 06174-92 | COST ALLOCATIONS, PROFITABILITY |
| 1993 | MOUNTAIN FORD v FORD MOTOR COMPANY | NO | FEDERAL DISTRICT CT | n/a | VEHICLE ALLOCATIONS, INVENTORY LEVELS, INCREMENTAL PROFIT, & DAMAGES |
| 1993 | SOUTH WEST GAS CO. | YES | AZ. CORP COMM | U-1551-92-253 | DIRECT: CLASS COST ALLOCATIONS |
| 1993 | SOUTH WEST GAS CO. | YES | AZ. CORP COMM | U-1551-92-253 | SURREBUTTAL: CLASS COST ALLOCATIONS |
| 1993 | POTOMAC EDISON CO. | YES | VA. SCC | PUE930033 | COST ALLOCATIONS,RATE DESIGN |
| 1995 | VIRGINIA AMERICAN WATER CO. | YES | VA. SCC | PUE950003 | JURISDICTIONAL ALLOCATIONS |
| 1995 | NEW JERSEY AMERICAN WATER COMPANY | YES | N.J. B.P.U. | WR95040185 | COST ALLOCATIONS,RATE DESIGN |
| 1995 | PIEDMONT NATURAL GAS COMPANY | YES | S.C. P.S.C. | 95-715-G | COST ALLOCATIONS,RATE DESIGN,WEATHER NORMALIZATION |
| 1995 | CYCLE WORLD v. HONDA MOTOR CO. | NO | VA. DMV | None | MARKET PERFORMANCE, FINANCIAL IMPACT OF NEW DEALER |
| 1996 | HOUSE BILL # 1513 | NO | VA. GEN'L ASSEMBLY | N/A | WATER / WASTEWATER CONNECTION FEES |
| 1996 | VIRGINIA AMERICAN WATER CO. | YES | VA. SCC | PUE950003 | JURISDICTIONAL ALLOCATIONS |
| 1996 | ELIZABETHTOWN WATER CO. | YES | N.J. B.P.U. | WR95110557 | COST ALLOCATIONS,RATE DESIGN |
| 1996 | ELIZABETHTOWN WATER CO. | NO | N.J. B.P.U. | WR95110557 | SURREBUTTAL COST ALLOCATIONS,RATE DESIGN |
| 1996 | SOUTH JERSEY GAS CO. | YES | N.J. B.P.U. | GR96010032 | CLASS COST OF SERVICE |
| 1996 | VIRGINIA LIABILITY INSURANCE COMPETITION | YES | VA. SCC | INS960164 | COST ALLOCATIONS, INSURANCE PROFITABILITY |
| 1996 | SOUTH JERSEY GAS CO. | YES | N.J. B.P.U. | GR96010032 | REBUTTAL - CLASS COST OF SERVICE |
| 1996 | HOUSE BILL # 1513 | NO | VA. GEN'L ASSEMBLY | N/A | WATER / WASTEWATER CONNECTION FEES |
| 1997 | NISSAN v. CRUMPLER NISSAN | NO | VA. DMV | None | MARKET DETERMINATION & PERFORMANCE |
| 1997 | PHILADELPHIA SUBURBAN WATER CO. (DIRECT) | YES | PA. PUC | R-00973952 | COST ALLOCATIONS,RATE DESIGN,RATE DISCOUNTS |
| 1997 | PHILADELPHIA SUBURBAN WATER CO. (REBUTTAL) | YES | PA. PUC | R-00973952 | COST ALLOCATIONS,RATE DESIGN,RATE DISCOUNTS |
| 1997 | PHILADELPHIA SUBURBAN WATER CO. (SURREBUTTAL) | YES | PA. PUC | R-00973952 | COST ALLOCATIONS,RATE DESIGN,RATE DISCOUNTS |
| 1997 | VIRGINIA AMERICAN WATER CO. | YES | VA. SCC | PUE970523 | JURISDICTIONAL/CLASS ALLOCATIONS |
| 1998 | VIRGINIA ELECTRIC POWER COMPANY | YES | VA. SCC | PUE960296 | CLASS COST OF SERVICE and TIME DIFFERENTIATED FUEL COSTS |
| 1998 | NEW JERSEY AMERICAN WATER COMPANY | YES | N.J. B.P.U. | WR98010015 | CLASS COST OF SERVICE,RATE DESIGN, REVENUES |
| 1998 | AMERICAN ELECTRIC POWER COMPANY | YES | VA. SCC | PUE960296 | CLASS COST OF SERVICE and TIME DIFFERENTIATED FUEL COSTS |
| 1998 | FREEMAN WRONGFUL DEATH | YES | FIEDERAL DISTRICT CT. | | LOST INCOME, WORK EXPECTANCY |
| 1998 | EASTERN MAINE ELECTRIC COOPERATIVE | YES | MAINE PUC | 98-596 | REVENUE REQUIREMENT |
| 1998 | CREDIT LIFE/AH RATE FILING | YES | VA. SCC | | PRIMA FACIA RATES, LEVEL OF COMPETITION |
| 1999 | CREDIT LIFE & A&H LEGISLATION | NO | VA. GEN'L ASSEMBLY | N/A | COST ALLOCATIONS, INSURANCE PROFITABILITY |
| 1999 | MILLER VOLKSWAGEN v. VOLKSWAGEN oF AMERICA | YES | VA. DMV | None | VEHICLE ALLOCATIONS/CSI |
| 1999 | COLUMBIA GAS of VIRGINIA | YES | VA. SCC | PUE980287 | RATE STRUCTURE |
| 1999 | NCCI (WORKERS COMPENSATION INSURANCE) | YES | VA. SCC | INS990165 | WORKERS COMPENSATION RATES |
| 1999 | ROANOKE GAS | YES | VA. SCC | PUE980626 | Rate Design/ Weather Norm |
| 2000 | PERSON-SMITH v. DOMINION REALITY | NO | RICHMOND CIRCUIT | n/a | LOST INCOME |
| 2000 | CREDIT LIFE/AH RATE FILING | YES | VA. SCC | | PRIMA FACIA RATES, LEVEL OF COMPETITION |
| 2000 | UNITED CITIES GAS | YESW | VA. SCC | | Cost Allocations/ Rate Design |
| 2001 | VERMONT WORKERS COMPENSATION RATE CASE | YES | VT. INSURANCE COMM. | n/a | WORKERS COMPENSATION RATES |
| 2001 | SERRA CHEVROLET v. GENERAL MOTORS CORP. | NO | ALABAMA CIRCUIT CT. | 98-2089 | ECONOMIC DAMAGES |
| 2001 | VIRGINIA POWER ELECTRIC RESTRUCTURING | YES | VA. SCC | PUE000584 | RATE Design (UNBUNDLING) |
| 2001 | AMERICAN ELECTRIC POWER RESTRUCTURING | YES | VA. SCC | PUE010011 | RATE Design (UNBUNDLING) |
| 2001 | NCCI (WORKERS COMPENSATION INSURANCE) | YES | VA. SCC | INS010190 | WORKERS COMPENSATION RATES |
| 2002 | PHILADELPHIA SUBURBAN WATER CO. (DIRECT) | YES | PA. PUC | R00016750 | COST ALLOCATIONS AND RATE DESIGN |
| 2002 | HAROLD MORRIS PERSONAL INJURY | YES | FED. DIST CT (RICHMOND) | n/a | LOST WAGES |
| 2002 | PIEDMONT NATURAL GAS | YES | S.C. PSC | 2002-63-G | REVENUE RQMT, COST OF CAPITAL |
| 2002 | VIRGINIA AMERICAN WATER COMPANY | YES | VA. SCC | PUE-2002-00375 | JURISDICTIONAL/CLASS ALLOCATIONS |
| 2002 | ROANOKE GAS COMPANY | YES | VA. SCC | PUE-2002-00373 | WEATHER NORMALIZATION RIDER |
| 2002 | SOUTH CAROLINA ELECTRIC & GAS (ELECTRIC) | YES | S.C. PSC | 2002-223-E | REVENUE RQMT. |
| 2003 | NCCI (WORKERS COMPENSATION INSURANCE) | YES | VA. SCC | INS-2003-00157 | WORKERS COMPENSATION RATES |
| 2003 | CREDIT LIFE/AH RATE FILING | YES | VA. SCC | | PRIMA FACIA RATES, LEVEL OF COMPETITION |
| 2003 | ROANOKE GAS | YES | VA. SCC | PUE-2003-00425 | WEATHER NORMALIZATION ADJUSTMENT RIDER |

**EXPERT TESTIMONY**
**PROVIDED BY**
**GLENN A. WATKINS**

| 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 | 2004-5-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 Facie Rates | YES | VA SCC | INS-2006-00013 | Market Structure |
| 2006 | Columbia Gas of Virginia | YES | VA SCC | PUE-2005-00098 | Revenue Requirements/ Alt. Regulation Plan |
| 2006 | PPL Gas | YES | PA. PUC | R-00061398 | COST ALLOCATIONS/ RATE DESIGN |
| 2006 | NCCI (WORKERS COMPENSATION INSURANCE) | YES | VA SCC | INS-2006-00197 | WORKERS COMPENSATION RATES |
| 2007 | Level of Private Pass. Auto Competition | YES | Ma. Dept of Insur | N/A | Private Pass Auto level of competition |
| 2007 | WASHINGTON GAS LIGHT | YES | VA SCC | PUE-2006-00059 | Cost Allocations/ Rate Design/ Alt Regulation Plan |
| 2007 | Valley Energy | YES | PA. PUC | R-00072349 | Cost of Capital/Rate Design |
| 2007 | Wellsboro Electric | YES | PA. PUC | R-00072350 | Cost of Capital/Rate Design |
| 2007 | Citizens' Electric Of Lewisburg, Pa | YES | PA. PUC | R-00072348 | Cost of Capital/Rate Design |
| 2007 | NCCI (WORKERS COMPENSATION INSURANCE) | YES | VA SCC | INS-2007-00224 | WORKERS COMPENSATION RATES |
| 2007 | Georgia Power | YES | Ga.PSC | 25060-U | Cost Allocations/Rate Design |
| 2008 | Columbia Gas of Pennsylvania | YES | PA. PUC | R-2008-2011621 | COST ALLOCATIONS/ RATE DESIGN |
| 2008 | Greenway Toll Road Investigation | YES | VA. GENERAL ASSEMBLY | N/A | Affiliate Transactions |
| 2008 | Puget Sound Energy (Electric) | YES | Wa. UTC | UE-072300 | Cost Allocations/Rate Design |
| 2008 | Puget Sound Energy (Gas) | YES | Wa. UTC | UE-072301 | Cost Allocations/Rate Design |
| 2008 | Blue Grass Electric Cooperative | YES | Ky PSC | 2008-00011 | Cost Allocations/Rate Design |
| 2008 | Columbia Gas of Ohio | YES | OH PUC | 08-72-GA-AIR, et. a | Cost Allocations/Rate Design |
| 2008 | Virginia Natural Gas | YES | Va SCC | PUE-2008-00060 | Natl Gas Conservation/ Revenue Decoupling |
| 2008 | Equitable Natural Gas | YES | PA. PUC | R-2008-2029325 | Cost Allocations/Rate Design/ Discounted Rates |
| 2008 | LG&E (Electric) | YES | Ky PSC | 2008-000252 | Cost Allocations/Rate Design/ Weather Normalization |
| 2008 | LG&E (Natural Gas) | YES | Ky PSC | 2008-000252 | Cost Allocations/Rate Design |
| 2008 | Kentucky Utilities | YES | Ky PSC | 2008-00251 | Cost Allocations/Rate Design/ Weather Normalization |
| 2008 | Pike County Natural Gas | YES | PA. PUC | R-2008-2046520 | Cost Allocations/Rate Design |
| 2008 | Pike County Electric | YES | PA. PUC | R-2008-2046518 | Cost Allocations/Rate Design |
| 2008 | Newtown Artesian Water | YES | PA. PUC | R-2008-2042293 | Revenue Requirement |
| 2009 | Leesburg Water & Sewer | YES | Va. Circuit Ct. | Civil Action 42736 | Revenue Requirement/ Excess Rates |
| 2009 | Central Penn Gas, Inc. | YES | PA. PUC | R-02008-2079675 | Cost Allocation/Rate Design |
| 2009 | Penn Natural Gas, Inc. | YES | PA. PUC | R-2008-2079660 | Cost Allocation/Rate Design |
| 2009 | Credit Life/ A&H ratemaking | YES | Va. SCC | n/a | Market Structure and Availability |
| 2009 | Fairfax County v. City of Falls Church Virginia | YES | Fairfax Circuit Ct. ( Va.) | CL-2008-16114 | Water Revenue Requirement |
| 2009 | Avista Utilities ( Electric) | YES | Wa. UTC | UE-090134 | Electric rate Design |
| 2009 | Avista Utilities ( Gas) | YES | Wa. UTC | UE-090135 | Gas Rate design |
| 2009 | Columbia Gas of Kentuky | YES | Ky PSC | 2009-00141 | Cost Allocations/Rate Design |
| 2009 | NCCI (Workers Compensation Rates) | YES | VA SCC | INS-2009-00142 | Workers Compensation Rates |
| 2009 | Duke Energy of Kentucky (Gas) | YES | Ky. PSC | 2009-00202 | Rate Design |
| 2009 | Duke Energy Carolinas (Electric) | YES | NC UC | E-7 Sub 909 | Cost Allocations/Rate Design |
| 2009 | PacifiCorp | YES | Wa. UTC | UE-090205 | Rate Design/Low Income |
| 2009 | Puget Sound Energy (Electric) | YES | Wa. UTC | UE-090704 | Cost Allocations/Rate Design |
| 2009 | Puget Sound Energy (Gas) | YES | Wa. UTC | UG-090705 | Cost Allocations/Rate Design |
| 2010 | Aqua Virginia, Inc. | YES | VA SCC | PUE-2009-00059 | Rate Design |
| 2010 | Philadelphia Gas Works | YES | PA. PUC | R-2009-2139884 | Cost Allocations/Rate Design |

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

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 | $183,196,129 | $54,631,912 | 77.9 | 85.6 | Base | 100.00% | 0.00% | $54,631,912 | $0 |
| Trimble County 1 | Coal | 586 | 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 | 493 | 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 | $72,507,881 | $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 | $93,964,084 | $29,847,094 | 38.7 | 84.7 | Intermediate | 38.70% | 61.30% | $11,550,825 | $18,296,269 |
| Green River 4 | Coal | 114 | 396,032 | 15 | $44,909,090 | $9,568,636 | 31.9 | 85.9 | Intermediate | 31.90% | 68.10% | $3,052,395 | $6,516,241 |
| Green River 3 | Coal | 75 | 226,460 | 16 | $20,882,040 | $4,223,762 | 21.2 | 83 | Intermediate | 21.20% | 78.80% | $895,438 | $3,328,324 |
| Brown 3 | Coal | 446 | 1,834,351 | 17 | $167,769,218 | $61,483,147 | 52.9 | 81.3 | Intermediate | 52.90% | 47.10% | $32,524,585 | $28,958,562 |
| Brown 2 | Coal | 180 | 627,235 | 18 | $51,604,493 | $19,960,742 | 37.7 | 86 | Intermediate | 37.70% | 62.30% | $7,525,200 | $12,435,542 |
| Brown 1 | Coal | 114 | 289,333 | 19 | $58,239,565 | $19,914,445 | 41 | 83.4 | Intermediate | 41.00% | 59.00% | $8,164,922 | $11,749,523 |
| Tyrone 3 | Coal | 75 | 68,321 | | $26,123,876 | $8,142,131 | 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 | $36,379,638 | $23,135,828 | 1.4 | 88 | Peak | 0.00% | 100.00% | $0 | $23,135,828 |
| Brown 9 | Gas,Oil | 126 | 1,524 | 29 | $48,505,028 | $26,291,775 | 1 | 85.7 | Peak | 0.00% | 100.00% | $0 | $26,291,775 |
| Brown 10 | Gas,Oil | 126 | 2,504 | 30 | $29,531,409 | $16,272,357 | 0.8 | 85.7 | Peak | 0.00% | 100.00% | $0 | $16,272,357 |
| Brown 11 | Gas,Oil | 126 | 4,493 | 31 | $44,435,742 | $27,303,037 | 0.5 | 89.1 | Peak | 0.00% | 100.00% | $0 | $27,303,037 |
| Brown 5 | Gas | 123 | 2,592 | 32 | $47,749,126 | $35,132,623 | 1.9 | 89.1 | Peak | 0.00% | 100.00% | $0 | $35,132,623 |
| Paddys Run 13 | Gas | 178 | 1,262 | 33 | $64,913,860 | $49,849,554 | 10.3 | 88.6 | Peak | 0.00% | 100.00% | $0 | $49,849,554 |
| Paddys Run 11 | Gas | 16 | 20 | 34 | $1,609,957 | ($28,342) | 0.1 | 50 | Peak | 0.00% | 100.00% | $-0 | ($28,342) |
| Cane Run 11 | Gas,Oil | 16 | 212 | 35 | $3,249,070 | $1,357,866 | 0.1 | 50 | Peak | 0.00% | 100.00% | $0 | $1,357,866 |
| Paddys Run 12 | Gas | 33 | 0 | 36 | $3,183,011 | ($213,388) | 0.1 | 50 | Peak | 0.00% | 100.00% | $-0 | ($213,388) |
| Zorn 1 | Gas | 18 | 231 | 37 | $1,899,048 | ($31,433) | 0.1 | 50 | Peak | 0.00% | 100.00% | $-0 | ($31,433) |
| Haefling 1-3 | Gas,Oil | 63 | -439 | 38 | $5,695,570 | $1,417,461 | 0.2 | 50 | Peak | 0.00% | 100.00% | $0 | $1,417,461 |
| Dix Dam 1-3 | Hydro | 27 | 56,130 | - | $12,391,689 | $3,980,168 | 28.8 | none | Hydro | 100.00% | 0.00% | $3,980,168 | $0 |
| Ohio Falls 1-8 | Hydro | 86 | 230,869 | - | $41,596,196 | $33,670,611 | 68.3 | none | Hydro | 100.00% | 0.00% | $33,670,611 | $0 |
| 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

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

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% |
| Pad 1P | 0.5219315 | 77046467 | 8.37% |
| Pad 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 | | $1,160,847,393 | $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 | $523,084 |
| | 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 | $6,167,674 | $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 | ($545,180) | ($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) | $681,891 |
| Total | Operating Expenses | | $992,161,332 | $391,009,550 | $128,797,310 | $7,417,111 | $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 | $13,354,064 | $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 | $8,786,064 | $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 | $1,813,148 | $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 | $369,563,054 | $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 | $289,969,815 | $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** | **$34,794,525** | **$661,786,392** | **$273,819,687** | **$36,016,860** | **$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** | **$22,460,568** | **$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 | $177,451,083 | $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 | $276 | $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 | | $34,059,459 | $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 | $84,436 | $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 | $394,332 | $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 | $21,742,408 | $6,023,521 | $332,386 | $3,757,853 | $1,188,243 | $166,490 | $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 | $1,689,293 | $57,193 | $1,601,779 | $82,784 | $21,326 | $22,102 | $11,632 | $1,939 | $4,983 |
| | **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 | $5,128,832 | $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 | ($1,896,800) | ($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 | $1,458,895 | $713,282 | $190,271 | $11,029 | $232,279 | $82,609 | $11,028 | $132,053 | $56,012 | $14,602 | $13,729 |
| 926 | EMPLOYEE BENEFITS | 66 | $33,258,029 | $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** | | $84,473,636 | $36,741,738 | $9,649,866 | $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 | $114,918,728 | $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 | $11,628,139 | $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 | $58,549,217 | $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
(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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Income Taxes | | | | | | | | | | | | |
| | State & Federal Income Taxes | | $72,859,576 | $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 | 583,081 | $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 | 6,707,991,967 | 1,975,198,498 | 141,711,283 | 3,683,924,566 | 1,617,468,927 | 214,625,644 | 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 | 3,389,538,468 | 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 | 2,950 | 82,620 | 4,270 | 1,100 | 1,140 | 600 | 100 | 256 |
| 7 | Street Lighting | 43,956,498 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 43,956,498 |
| 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) | 610,782 | 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 | 526,900 | 420,100 | 79,637 | 292 | 8,224 | 0 | 49 | 0 | 0 | 0 | 18,598 |
| 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 | 159,267,514 | 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 | 3,372,521,863 | 1,450,723,591 | 382,661,629 | 27,986,159 | 560,449,403 | 235,492,033 | 30,820,687 | 364,177,692 | 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) | (20,583,558) | 705,842 | (323,355) | (5,071,242) | (3,629,267) | (708,186) | (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% | 0.3345% | 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) | 3,694,628 | 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 | 584,301 | 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 | 2,373,158 | 204,055 | 3,249,500 | 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) | 945,383,672 | 627,921,666 | 137,056,662 | 8,906,167 | 87,385,837 | 25,258,991 | 4,043,344 | 49,559,248 | 0 | 0 | 14,261,758 |
| 40 | Temperature Normalization Revenues | 2,988,578 | 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) | (931,556) | 3,132,208 | 3,532,765 | 0 | 927,987 |
| 43 | FAC Roll-In | (3,710,704) | (1,339,973) | (396,233) | (33,684) | 39,974 | (296,317) | (993) | (539,386) | (694,223) | (387,783) | (72,086) |
| 44 | Interruptible Credit Allocator | 1,601,642,287 | 801,355,196 | 174,213,519 | 19,167,275 | 244,300,313 | 104,376,219 | 10,695,968 | 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 | 107,897,035 | 32,985,640 | 6,845,722 |
| 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 | 216,508 | 67,582 | 2,710 | 2,978 | 0 | 0 |
| 49 | Remove ECR Revenues | 92,931,133 | 34,626,991 | 11,982,292 | 648,858 | 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 | 10,176,265 | 4,884,714 | 1,308,727 | 1,382,335 |
| 51 | Gross Production Plant | 2,373,889,077 | 903,370,639 | 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 | 159,267,514 | 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 | 110,425,531 | 33,791,061 | 4,955,377 | 53,997,797 | 14,703 | 442 | 108,957,931 |
| 54 | Total Prod.,Trans., Distrib Plant | 4,017,258,557 | 1,792,843,074 | 466,278,259 | 33,506,032 | 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 | 68,631,768 | 5,326,549 | 53,961,859 | 18,398,762 | 2,549,762 | 29,633,780 | 0 | 0 | 6,882,097 |
| 56 | Gross Intangible Plant | 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 |
| 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 | 36,016,660 | 446,324,186 | 190,412,136 | 50,192,225 | 130,693,167 |
| 58 | Dist. Underground Lines Gross Plant | 125,419,549 | 70,330,623 | 17,633,724 | 1,394,270 | 16,831,591 | 6,860,209 | 745,114 | 11,026,468 | 0 | 0 | 1,598,551 |
| 59 | Gross General Plant | 100,246,736 | 44,738,636 | 11,635,515 | 836,110 | 15,918,733 | 6,588,563 | 866,633 | 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 | 115,288 | 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 | 3,093,647 | 877,786 | 63,584 | 1,629,319 | 714,888 | 94,655 | 1,176,677 | 561,564 | 150,391 | 58,508 |
| 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 | 47,793 | 13,587 | 1,019 | 24,766 | 10,839 | 1,418 | 17,779 | 8,733 | 2,280 | 830 |
| 64 | Labor Accts 581-586 | 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 | 19,268,204 | 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 | 8,217,576 | 476,338 | 10,031,631 | 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 | 8,440,770 | 79,061,152 | 37,659,883 | 9,741,731 | 5,187,116 |
| 68 | Dist. Lines Gross Plant | 606,971,916 | 368,598,374 | 86,265,512 | 6,720,818 | 69,793,450 | 25,258,891 | 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 | 26,298,098 | 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 | 258,778,603 | 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 | 3,634,858 |
| 72 | Total Labor | 115,102,647 | 56,179,615 | 14,974,214 | 874,454 | 18,348,728 | 6,562,743 | 875,562 | 10,499,009 | 4,454,604 | 1,161,789 | 1,172,028 |
| 73 | Distribution O&M | 35,765,798 | 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 | 151,765,498 | 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 | 137,056,662 | 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 | 760,604 | 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 | 91,538,912 | 6,215,941 | 152,090,411 | 63,594,192 | 8,453,436 | 104,083,342 | 50,026,079 | 12,939,943 | 6,430,415 |
| 79 | Steam Production Plant | 1,913,147,131 | 728,037,946 | 201,744,621 | 18,627,241 | 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 | 25,258,991 | 2,724,676 | 40,559,248 | 0 | 0 | 6,952,663 |
| 84 | Dist Secondary Lines | 117,706,566 | 85,369,354 | 17,164,733 | 1,629,047 | 11,445,249 | 0 | 570,199 | 0 | 0 | 0 | 1,527,985 |
| 85 | Dist Transformers | 258,778,603 | 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 | 236,772,815 | 100,732,884 | 10,322,615 | 152,046,238 | 66,869,716 | 19,860,971 | 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) | (1,036,911) | (305,029) | (21,684) | (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 | 306,153 | 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% | 1.8980% | 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% | 0.0426% |
| 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 | | | | | | | | | | | |

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% |
| Alliant 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% |
| Hawlian 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% | 9.7% | 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.

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% |