COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF KENTUCKY UTILITIES FOR AN ADJUSTMENT OF ITS ELECTRIC BASE RATES	)) CASE NO. 2012-00221)

PREPARED DIRECT TESTIMONY AND SCHEDULES

OF

GLENN A. WATKINS

ON BEHALF OF THE

KENTUCKY OFFICE OF THE ATTORNEY GENERAL

OCTOBER 3, 2012

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glenn A. Watkins. My business address is 9030 Stony Point Parkway, Suite 580, Richmond, VA 23235.

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, Delaware, 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 Utilities ("KU" or "Company") proposed electric cost of service study (CCOSS), proposed distribution of revenues by class, and residential electric 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. ELECTRIC CLASS COST OF SERVICE

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

A. First, I note that there are two general types of cost of service studies used for public utility ratemaking: marginal cost studies; and embedded, fully allocated cost studies. 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 or gas 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 LG&E's CCOSS.

A. The process in which I conducted my analysis in this case was identical to how I evaluate all CCOSSs. First, I reviewed the structure and organization of the Company's CCOSS sponsored by Mr. Conroy. 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. Conroy'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. Conroy's CCOSS to be mathematically accurate.

Q. DID YOUR EXAMINATION RESULT IN ANY DIFFERENCES OF OPINION OR DISAGREEMENTS WITH THE ASSUMPTIONS AND METHODOLOGIES USED BY MR. CONROY AS THEY RELATE TO KU's ELECTRIC COST ALLOCATIONS?

A. Yes. There are two material differences of opinion between my electric cost allocation study and that performed by Mr. Conroy. These differences relate to the classification and ultimate allocation of generation and distribution plant. However, it is important to note two significant points as they relate to Mr. Conroy's and my electric CCOSSs.

With regard to generation plant, my difference of opinion is by and large purely academic in nature. That is, while I do not agree with the naming convention Mr. Conroy claims to have used to classify and allocate generation plant, his ultimate allocation of this plant to various classes is not unreasonable, and fairly reflects cost causation across classes.

With regard to the classification of distribution plant, I do have numerous concerns with the data utilized by Mr. Conroy as well as with the mathematical methods he employed to classify this plant between customer-related and demand-related costs.

With the above exceptions outlined, my ultimate electric CCOSS findings (rates of return at current rates) are not significantly different than those calculated by Mr. Conroy. A comparison of Mr. Conroy's and my class rates of return at current rates are shown below:

Class	Class ROR At Current Rates	
	Conroy	Watkins
Residential	3.97%	5.55%
General Service	8.72%	9.68%
All Electric Schools	7.25%	5.47%
PS-Secondary	10.51%	8.03%
PS-Primary	8.52%	7.39%
TOD-Secondary	5.83%	2.67%
TOD-Primary	5.89%	3.73%
RTS	6.06%	5.21%
FLS Transmission	-1.59%	-2.18%
Street Lighting	7.13%	8.33%
Lighting Energy	3.38%	0.01%
Traffic Signals	8.24%	7.32%
Total Company	6.02%	6.02%

A. Generation

Q. YOU INDICATE THAT ONE OF THE DIFFERENCES OF OPINION WITH MR. CONROY IS THE NAMING CONVENTION HE CLAIMS TO USE TO ASSIGN GENERATION-RELATED COSTS TO INDIVIDUAL CLASSES. WHAT NAMING CONVENTION DID MR. CONROY USE WITH RESPECT TO GENERATION COST ALLOCATIONS?

A. Mr. Conroy refers to his approach as a time-differentiated "Modified Base-Intermediate-Peak" approach.

Q. 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, the investments in production facilities reflect joint costs; i.e., facilities 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 nor does it consider the reasons that cause the current mix and level of generation facilities. This may have severe consequences because a utility's planning decisions regarding the amount and type of generation capacity to build and install is predicated not only on the maximum system load, but also on how customers demand electricity throughout the year, i.e., load duration. To illustrate, if a utility had a peak load of 15,000 MW and its actual optimal generation mix included an assortment of nuclear, coal, hydro, combined cycle and combustion turbine units, the total cost of capacity is significantly higher than if the utility only had to consider meeting 15,000 MW for 1 hour of the year. This is because the utility would install the cheapest type of plant, (i.e., peaker units) if it only had to consider one hour a year.

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

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

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

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

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

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 an equal weighting of "peak" and average class loads, while some studies weight the peak and average loads based on the system coincident load factor.[1]

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.

[1] It is generally agreed that the use of system coincident peak demands is an appropriate measure for assigning the "peak" portion of generation facilities under the P&A method.

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 generation resources to the same degree, at the same times. Mechanically, the A&E method weights average and excess demands based on the 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 as well as subjective planning criteria.

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.[2] In my opinion, the BIP method is an excellent cost allocation approach for many utilities as it captures the actual differences in the capacity/energy trade-off that exist across a utility's generation mix. The BIP method may not be appropriate for utilities that purchase the majority of their energy needs or for utilities with an inefficient mix of generating resources.

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

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

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 cost-causation and utilization of a utility's facilities. Individual generating unit investments 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 and coal 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 however, would be astronomical; i.e., variable fuel costs would be exceptionally expensive. This situation would result in a higher overall cost to serve customers than what actually exists. The 1-CP and seasonal CP methods totally ignore this very important fact.

Q. MR. CONROY 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. Conroy's Modified BIP method does not follow the generally accepted BIP approach, and in fact, I have never seen Mr. Conroy's method used in any other cases or for utilities other than KU and LG&E. However, I would be reluctant to say his approach is totally unreasonable.

Whereas Mr. Conroy's Modified BIP method does allocate a portion of generation facilities based on energy (34.35%) and a portion on peak demands (32.39% on winter peak and 33.26% on summer peak), his approach does not reflect the actual mix of supply resources utilized by KU. At this point, it should be noted that LG&E's and KU's generation resources are centrally dispatched. Both Mr. Conroy 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 LG&E and KU and not the individual legal ownership of these plants for booking purposes.

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

Mr. Conroy's approach ignores the actual supply-side characteristics of KU's and LG&E's combined generation portfolio because it only considers relative differences in system usages and demands. In fact, given KU's and LG&E's retail customers combined usages and demand profiles, Mr. Conroy's approach would classify a utility's generation investment exactly the same regardless of its actual portfolio mix of plants. Mr. Conroy's classification would be identical if the Companies' 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 given system's generation resources.

Q. PLEASE EXPLAIN THE ACTUAL COMPOSITION OF KU's AND LG&E's COMBINED GENERATION RESOURCES.

A. The Companies combined generation capacity is about 9,500 MW. The following is a summary of this generation portfolio by fuel type:

Fuel	MW Capacity	% Of Total
Coal	7,016	74%
Gas/Oil	2,487	26%
Hydro	19	<1%
Total	9,492	100%

As can be seen above, about 74% of the Companies' generation comes from very low running cost coal plants. Furthermore, the combined LG&E and KU peak native load is about 6,200 MW, which is lower than the capacity of the combined Companies coal plants. This is especially relevant for cost allocation purposes since these 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. CONROY'S COST ALLOCATION METHODOLOGY REFLECT THE FACT THAT KU'S AND LG&E's COMBINED GENERATION PORTFOLIO IS COMPRISED PRIMARILY OF BASE LOAD UNITS?

A. No.

Q. DID YOU CONDUCT AN ANALYSIS OF KU'S AND LG&E's COMBINED GENERATION FACILITIES UTILIZING THE INDUSTRY ACCEPTED BIP APPROACH?

A. Yes.

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.[3] With this information, I was able to separate each generation unit into Base, 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 the Companies' Hydro facilities

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[3] 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.

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:	74.51%
Demand-related:	25.49%

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

A. Individual class rates of return utilizing the traditional BIP classification method, compared to Mr. Conroy'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 adjustments to distribution plant allocations which are explained later in my testimony:

Class	OAG Traditional BIP	Conroy Modified BIP
Residential	4.74%	3.97%
General Service	9.52%	8.72%
All Electric Schools	7.04%	7.25%
PS-Secondary	9.24%	10.51%
PS-Primary	8.63%	8.52%
TOD-Secondary	3.51%	5.83%
TOD-Primary	4.62%	5.89%
RTS	5.21%	6.06%
FLS Transmission	-2.18%	-1.59%
Street Lighting	7.05%	7.13%
Lighting Energy	0.06%	3.38%
Traffic Signals	5.76%	8.24%
Total Company	6.02%	6.02%

B. Distribution

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

A. Mr. Conroy 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. Conroy'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 PHRASE "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 DISTRIBUTION PLANT SOMETIMES CLASSIFIED AS PARTIALLY CUSTOMER-RELATED AND PARTIALLY DEMAND-RELATED?

A. Even though investment is made in distribution plant and equipment to meet the energy needs of its customers at their required power levels, there may be considerable differences in both customer densities and the mix of customers throughout a utility's service area. As a hypothetical, suppose a utility serves both an urban area and a rural area. In this situation, many customers' electrical needs are served with relatively few miles of conductors, few poles, etc. in the urban area, while many more miles of conductors, more poles, etc. are required to serve the requirements of relatively few customers in the rural area. If the distribution of classes of customers (class customer mix) is relatively similar in both the rural and urban areas, there is no need to consider customer counts (number of customers) within the allocation process, because all classes use the utility's joint distribution facilities proportionately across the service area. However, if the customer mix is such that Commercial and Industrial customers are predominately clustered in the urban area, while the rural portion of the service territory consists almost entirely of Residential customers, it may be unreasonable to allocate the total Company's investment based only on demand; i.e., a large investment in many miles of line is required to serve predominately Residential customers in the rural area while the Commercial and Industrial electrical needs are met with much fewer miles of lines in the urban area. Under this circumstance, an allocation of costs based on a weighting of customers and demand can be considered equitable and appropriate.

Q. PLEASE PROVIDE AN EXAMPLE THAT ILLUSTRATES THE CONCEPTS OF DENSITY AND CLASS CUSTOMER MIX AS THEY RELATE TO COST ALLOCATIONS.

A. As a starting point, it is important to understand absolute and relative class relationships of an electric utility's number of customers, energy requirements, and maximum loads (demands). In terms of simple customer counts, the number of Residential accounts make-up the overwhelming majority of any retail electric utility's number of customers. However, because Residential customers tend to be small volume users compared to Commercial and Industrial customers, the Residential class is responsible for a significantly smaller percentage of total KWH energy supplied or peak loads on the system. For example, in KU's system, the following characteristics are exhibited:

Category	Percentage of Total Jurisdictional Distribution System Customers	KWH	Peak Demand
Residential	61%	33%	40%
Comm./Ind. Secondary Voltage	13%	31%	31%
Comm./Ind. Primary/Transmission Voltage	1%	35%	<1%
Lighting	25%	1%	28%
	100%		

While the table above shows the relative class differences between number of customers, energy usage, and peak demands, the following table illustrates the absolute size differences between KU's different types of customers:

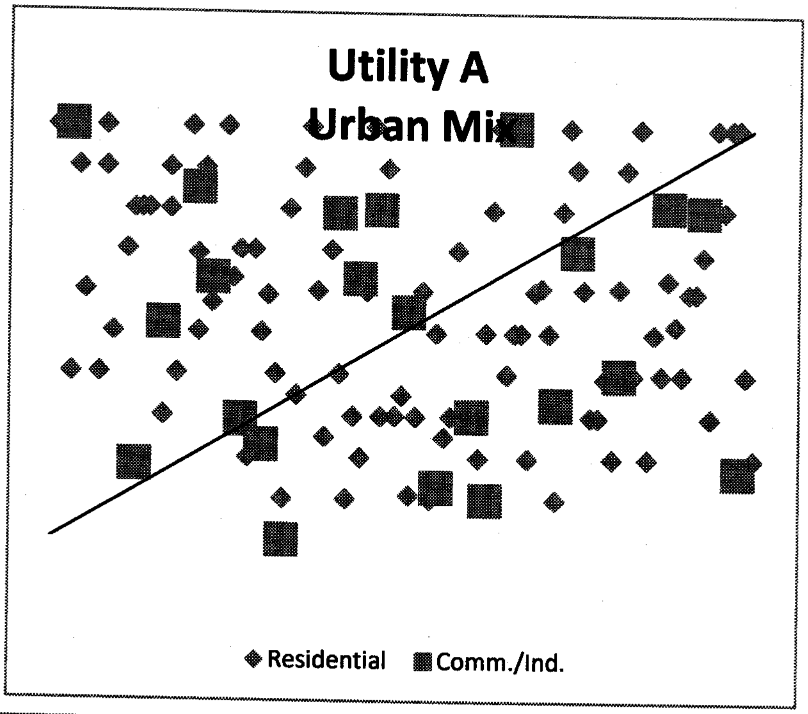
Category	Average Annual KWH Per Customer (KWH)
Residential	15,314
Comm./Ind. Secondary Voltage	68,372
Comm./Ind. Primary/Transmission Voltage	13,304,133

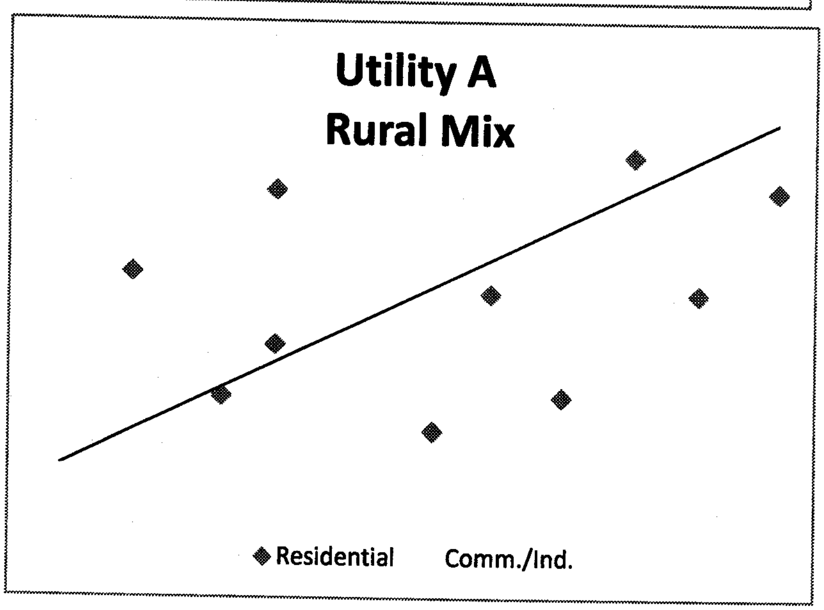
With the above relationships explained, in order to understand the concepts of density and class customer mix, consider examples of two hypothetical electric utilities each of which are comprised of only two distribution lines: one line serving a densely populated area (urban) and another line serving a sparsely populated area (rural). Furthermore, for simplicity and explanatory purposes, assume there are only two classes of customers for each utility: Residential and Commercial/Industrial with the following characteristics:

	Absolute			Relative	
Class	Number of Customers	Peak Load	Peak Load Per Customer	Number of Customers	Peak Load
Residential	110	550	5	83%	33%
Comm./Ind.	22	1,100	50	17%	67%
Total	132	1,650	--	100%	100%

Utility A:

For Utility A, assume all non-Residential customers are located on the urban (densely populated) distribution line such that the rural line only serves Residential customers as shown graphically below:



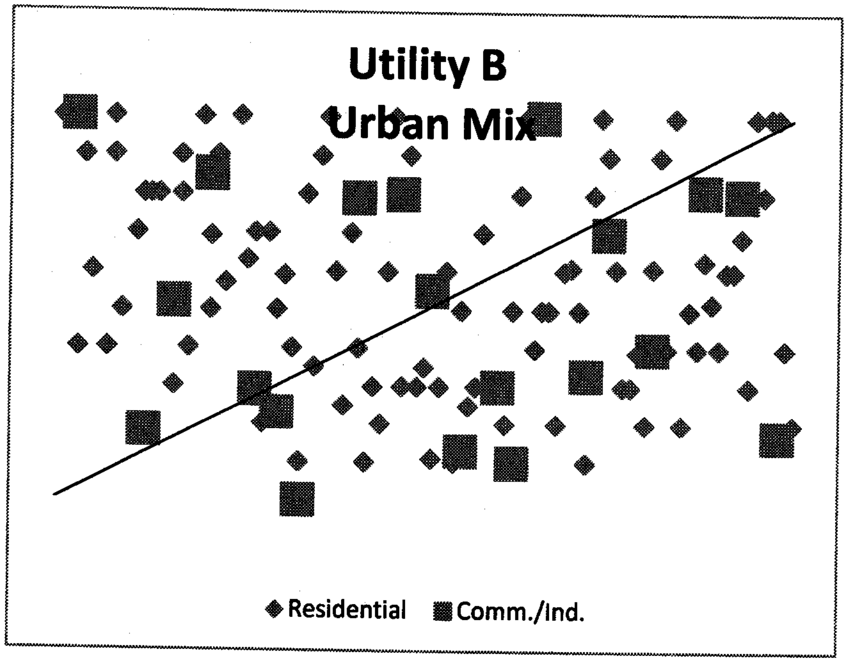


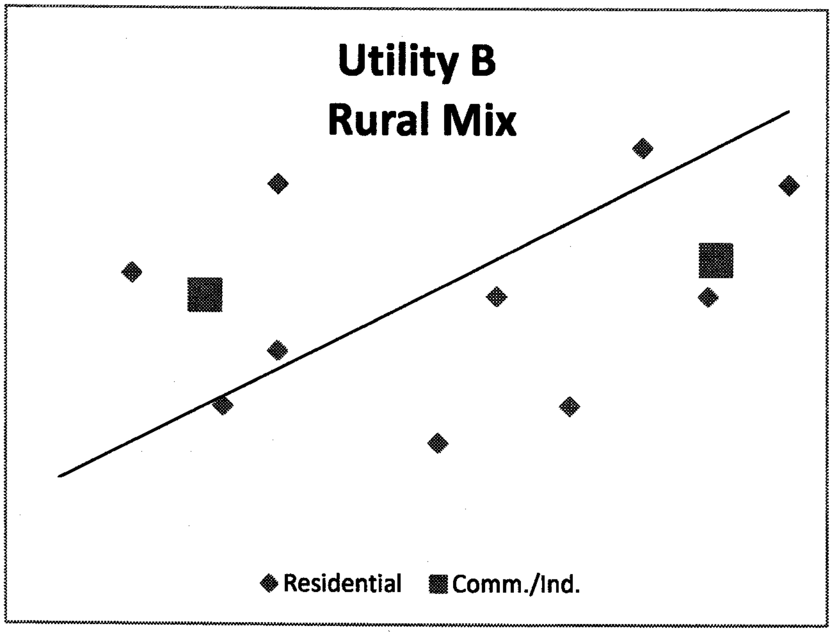
Because the urban line is much shorter in total distance, yet, serves the majority of customers (and loads) <u>and</u> many more miles of line are required to serve relatively few Residential only customers in rural areas, it would be unfair, and inconsistent with cost causation to allocate total system line costs only on utilization (KW) because non-Residential customers arguably do not cause costs to be incurred for the rural portion of the system. As such, some weighting of relative number of customers and utilization is appropriate to allocate total system line costs.

<u>Utility B</u>:

For Utility B, assume that the relative mix of customers is evenly distributed between the urban and rural lines. In other words, this utility's configuration of customers is as follows:

	Number of Customers			
	Urban Line		Rural Line	
Class	Amount	Percent	Amount	Percent
Residential	100	83%	10	83%
Comm./Ind.	20	17%	2	17%
Total	120	100%	12	100%





As can be seen in the above table and charts, the relative imposition of costs across the two classes for Utility B is the same for the urban and rural lines. That is, while there are more absolute Residential customers than Commercial/Industrial on both the urban and rural lines, the proportion (mix) of customers is the same. As such, an allocation of total system lines costs based on utilization (maximum loads) is appropriate such that no consideration of customer counts is needed or desired.

Q. DOES THE CLASSIFICATION OF DISTRIBUTION PLANT INVESTMENT AS PARTIALLY CUSTOMER-RELATED AND PARTIALLY DEMAND-RELATED REFLECT ANY RELATIVE COST (PER MILE) DIFFERENCES BETWEEN URBAN AND RURAL AREAS?

A. No. It is generally more expensive to install a mile of distribution circuit in an urban area than in a rural area. However, although this cost difference may be substantial, this cost difference is usually ignored due to record keeping limitations, in that all costs are simply assumed to be uniform (averaged) across the rural and urban portions of a service area.

Q. DO YOUR EXAMPLES DISCUSSED ABOVE IMPLY THAT IT COSTS MORE TO SERVE RURAL CUSTOMERS THAN URBAN CUSTOMERS AND THAT PERHAPS A UTILITY'S RURAL CUSTOMERS SHOULD PAY MORE PER UNIT THAN URBAN CUSTOMERS?

A. While it is possible that it technically costs more to serve a rural customer versus an urban customer, regulatory policy in the United States has universally been not to price discriminate based on customer densities, urban versus rural, or other geographic differences. Rather, regulatory policy has been such that classes of customers with similar usage and/or load characteristics are established for pricing purposes. In fact, during my 30 plus years practicing utility costing and pricing across the Country, I have not seen a rate structure that discriminates based on customer densities or other geographic characteristics.

Q. IS THERE ACADEMIC SUPPORT FOR YOUR EXPLANATION AND CONCEPTS REGARDING CUSTOMER DENSITIES AND CLASS CUSTOMER MIXES?

A. Yes. In the well known and often referenced, treatise Principles of Public Utility Rates, Professor James Bonbright states that there:

> is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customers per linear mile or per square mile). Our casual empiricism is supported by a more systematic regression analysis in (Lessels, 1980) where no statistical association was found between distribution costs and number of customers. Thus, if the company's entire service area stays fixed, an increase in number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system.[4]

Q. BEFORE WE CONTINUE, IS KU's DISTRIBUTION SYSTEM COMPRISED OF VARIOUS SUB-SYSTEMS?

A. Yes. As is the case with virtually every electric utility, KU's overall distribution system is comprised of a primary voltage system and a secondary voltage system. The

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[4] Bonbright, Principles of Public Utility Rates, Second Edition, page 491.

primary system operates at higher voltage levels than the secondary system and generally consists of plant and equipment between the substations and transformers. The lower voltage secondary system can be thought of as operating downstream from the primary system and delivers electricity to small end-users.

Q. BRIEFLY DESCRIBE THE TYPES OF INVESTMENT (EQUIPMENT) UTILIZED IN KU's DISTRIBUTION SYSTEM.

A. For accounting purposes, KU's distribution plant is grouped into various accounts. These accounts include: Land and Land Rights (Account 360); Structures and Improvements (Account 361); Station Equipment (Account 362); Poles, Towers and Fixtures (Account 364); Overhead Conductors (Account 365); Underground Conduit (Account 366); Underground Conductors (Account 367); Line Transformers (Account 368); Meters (Account 370); Area Lighting (Account 371) and Street Lighting (Account 373).

Q. WHAT RELATIVE CUSTOMER/DEMAND PERCENTAGES DID MR. CONROY USE IN THIS CASE?

A. The following are Mr. Conroy's customer/demand percentages used for each distribution plant account:

KU Classification of Distribution Plant

Account	(1) Total Gross Plant ($000)	(2) Percent Customer ($000)	(3) Customer Allocation (1) x (2) ($000)
Overhead Lines	537,135,305	54.57%	293,114,736
Underground Lines	141,341,084	75.21%	106,302,629
Total	678,476,389	58.90%	399,417,365

As can be seen above, Mr. Conroy's classification allocates 54.57% of its Overhead lines (poles plus conductors) based on number of customers and 75.21% of Underground lines (conduit and conductors) on a customer count basis. On a collective basis, Mr. Conroy allocates about 59% of these distribution costs (plant and expenses) based on number of customers and about 38% of its costs based on utilization and relative size (demand). In other words, about 59% of KU's investment in joint distribution lines is allocated to classes based on customer counts regardless of size, utilization, or demands placed upon the KU system.

Q. HAVE YOU CONDUCTED ANY ANALYSES TO DETERMINE IF A CLASSIFICATION OF DISTRIBUTION PLANT AS PARTIALLY CUSTOMER-RELATED IS APPROPRIATE FOR KU?

A. Yes, I have.

Q. PLEASE EXPLAIN.

A. Mr. Conroy has made an *a priori* assumption that it is appropriate to allocate a portion of its distribution plant based on customer counts and a portion based on demand levels. As indicated earlier, the only reason why it may be appropriate to allocate a portion of distribution plant expenses based on number of customers, rather than utilization, is due to the possibility that the mix of customer classes varies significantly across the urban and rural portions of a service territory. In this regard, I evaluated this assumption by conducting an analysis of the distribution, or mix, of KU's customer classes across its service area. I analyzed KU's customer densities and mix because KU is more rural than LG&E and Mr. Conroy utilized the same data and results for classifying KU's and LG&E's distribution plant; i.e., Mr. Conroy's classifications of distribution lines is the same for KU and LG&E.

Through discovery, the Company provided a data base of the number of customers by rate schedule for each postal zip-code within its service area. I then evaluated the mix of customers by rate class for each postal zip-code within the KU service area. In order to evaluate whether any differences exist in the distribution of customers across rural, suburban, and urban areas, I calculated the number of total KU customers per square mile for each non-Post Office Box ("P.O. Box") zip-code to serve as a measure of density for relatively small geographic areas. I was then able to readily compare KU's mix of customers by rate class throughout its service area and delineate between very rural (sparsely populated) to very urban (densely populated) areas. As a further refinement, I also evaluated the distribution of customers on a stratified basis. That is, for each rate class I separated small geographical areas (zip codes) into five separate strata (lowest to highest customer densities). I examined each stratum (by rate class) to determine if any significant differences in customer mix occur within each stratum.

This analysis of the distribution of the various customer classes by density provided a basis to determine whether: (a) utilization alone (demand) is an appropriate (and fair) method to allocate distribution costs; or, (b) whether a weighting of customers and utilization (demand) is appropriate in order to reasonably reflect the imposition or causation of costs.

If there is any basis for a customer classification of distribution plant, this analysis should show a negative correlation between the Residential customer mix (Residential percentage of total customers) and density across the KU service area. In other words, the percentage of Residential customers (by zip-code) should decline as customer density per square mile increases from the most rural areas to the most urban areas of KU's service territory. Similarly, if Mr. Conroy's assumption is correct, we should see a distinct positive correlation between non-Residential customer mixes and customer densities by zip-code. A summary of the approach and data utilized for this analysis is provided below:

			Percent of Total Distribution Customers[5]			
Class	Customers Per Sq. Mile (Density)	Count Of Zip Codes	Avg.	Std. Deviation	Number	% of Class
Residential						
Strata 1	.03 Min to 7.17 Max	67	63.5%	14.2%	12,452	3.0%
Strata 2	7.19 Min to 13.77 Max	67	65.6%	6.8%	37,435	9.1%
Strata 3	13.83 Min to 33.64 Max	67	66.0%	6.8%	79,477	19.3%
Strata 4	33.68 Min to 3994.81 Max	67	77.0%	11.1%	282,414	68.6%
Total		268			411,778	100%
Non-Residential						
Strata 1	.03 Min to 7.17 Max	67	18.0%	12.3%	3,529	4.1%
Strata 2	7.19 Min to 13.77 Max	67	18.0%	4.4%	10,265	11.9%
Strata 3	13.83 Min to 33.64 Max	67	18.0%	4.8%	21,672	25.1%
Strata 4	33.68 Min to 3994.81 Max	67	13.9%	7.1%	50,920	58.9%
Total		268			86,386	100%

[5] Excludes Lighting.

Q. WHAT ARE YOUR FINDINGS AS A RESULT OF THIS ANALYSIS?

A. KU's customers are dispersed in a reasonably proportional manner throughout its service area. That is, there are no distinct differences in the mix of customers (by class) across the rural and urban portions of KU's service area. The relationship of Residential customers relative to non-Residential customers is relatively constant throughout KU's service area. While the rural areas of KU's service area are comprised mainly of Residential customers, this relationship also remains true for the more dense population areas of KU's territory as well. More importantly, in the less dense portions of KU's service territory (rural areas), KU serves a proportionate number of non-Residential customers.

In summary, each customer class is represented in a reasonably proportional manner in both rural and urban areas within KU's service area. As a result, it cannot be said that the less populated portions of KU's service area (which require significant investment to serve few customers) are dedicated to any one class of customers. As such, KU's distribution plant and expenses should be assigned to classes based only on utilization and any consideration of customer counts is improper for the allocation of distribution plant, as such, this study indicates that KU's distribution plant should be classified as 100% demand-related.

Q. DOES THE NARUC ELECTRIC COST ALLOCATION MANUAL INDICATE IF AN *A PRIORI* ASSUMPTION IS APPROPRIATE REGARDING WHETHER DISTRIBUTION COSTS MUST BE CLASSIFIED AS PARTIALLY CUSTOMER-RELATED AND PARTIALLY DEMAND-RELATED?

A. No. In fact, the NARUC Manual (published in 1992) states the following:

> To ensure that costs are properly allocated, the analyst must first classify each account as demand-related, customer-related, or a combination of both. The classification depends upon the analyst's evaluation of how the costs in these accounts were incurred. In making this determination, supporting data may be more important than theoretical considerations.
>
> Allocating costs to the appropriate groups in a cost study requires a special analysis of the nature of distribution plant and expenses. (page 89)

Q. HAS NARUC PROVIDED MORE RECENT GUIDANCE CONCERNING THE CLASSIFICATION OF DISTRIBUTION PLANT THAN WHAT WAS PUBLISHED IN THE 1992 NARUC ELECTRIC COST ALLOCATION MANUAL?

A. Yes. The 1992 NARUC Manual was written in an era when all retail utility services were bundled (generation, transmission and distribution). Subsequent to the unbundling of retail rates in the mid to late 1990's by several state jurisdictions, NARUC commissioned a study to examine the costing and pricing of electric distribution service in further detail. In December 2000, NARUC published a report entitled: <u>Charging For Distribution Services: Issues in Rate Design</u>. As part of the Executive Summary this report states:

> The usefulness of cost analyses of the distribution system in designing rate structures and setting rate levels depends in large measure upon the manner in which the studies are undertaken. Cost studies (both marginal and embedded) are intended, among other things, to determine the nature and causes of costs, so that they can then be reformulated into rates that cost-causers can pay. Such studies must of necessity rely on a host of simplifying assumptions in order to produce workable results; this is especially true of embedded cost studies. Moreover, it is often the case that many of the costs (*e.g.*, administrative and general) that distribution rates recover are not caused by provision of distribution service, but are assigned to it arbitrarily. Too great dependence on cost studies is to be captured by their underlying assumptions and methodological flaws. Utilities and commissions should be cautious before adopting a particular method on the basis of what may be a superficial appeal. More important, however, is the concern that a costing method, once adopted, becomes the predominant and unchallenged determinant of rate design. (page 67)

With specific regard to classification and allocation of certain distribution plant (poles, wires and transformers), Chapter IV of this report is devoted to the costing of distribution services. With respect to embedded cost analyses this updated NARUC report states:

> There are a number of methods for differentiating between the customer and demand components of embedded distribution plant. The most common method used is the basic customer method, which classifies all poles, wires, and transformers as demand-related and meters, meter-reading, and billing as customer-related. This general approach is used in more than thirty states. A variation is to treat poles, wires, and transformers as energy-related driven by kilowatt-hour sales but, though it

> has obvious appeal, only a small number of jurisdictions have gone this route.
>
> Two other approaches sometimes used are the minimum size and zero-intercept methods. The minimum size method operates, as its name implies, on the assumption that there is a minimum-size distribution system capable of serving customers minimum requirements. The costs of this hypothetical system are, so the argument goes, driven not by customer demand but rather by numbers of customers, and therefore they are considered customer costs. The demand-related cost portion then is the difference between total distribution investment and the customer-related costs. The zero-intercept approach is a variation on the minimum size. Here the idea is to identify that portion of plant that is necessary to give customers access but which is incapable of serving any level of demand. The logic is that the costs of this system, because it can serve no demand and thus is not demand-related, are necessarily customer-related. However, the distinction between customer and demand costs is not always clear, insofar as the number of customers on a system (or particular area of a system) will have impacts on the total demand on the system, to the extent that their demand is coincident with the relevant peak (system, areal, substation, etc.).
>
> Any approach to classifying costs has virtues and vices. The first potential pitfall lies in the assumptions, explicit and implicit, that a method is built upon. In the basic customer method, it is the *a priori* classification of expenditures (which may or may not be reasonable). In the case of the minimum-size and zero-intercept methods, the threshold assumption is that there is some portion of the system whose costs are unrelated to demand (or to energy for that matter). From one perspective, this notion has a certain intuitive appeal these are the lowest costs that must be incurred before any or some minimal amount of power can be delivered but from another viewpoint it seems absurd, since in the absence of any demand no such system would be built at all. Moreover, firms in competitive markets do not indeed, cannot price their products according to such methods: they recover their costs through the sale of goods and services, not merely by charging for the ability to consume, or access. (pages 29 & 30)

In summary, when all of the facts and guidelines are known, it is clear to me that: (a) data and analysis specific to each utility is more appropriate and preferred over an *a priori* assumption that distribution plant must be partially customer-related; and, (b) many (if not most) state regulatory commissions endorse a method in which all distribution plant from substations through line transformers is classified and allocated based solely on demand. A copy of the entire Chapter (IV) from the 2000 NARUC Publication discussing costing studies is provided in my Schedule GAW-3.

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

A. Mr. Conroy 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. Conroy's reference to his proposed classifications as a "zero-intercept" derived study, and I also disagree with his approaches.

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,[6] 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:

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

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[6] 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. Conroy's method presented in his Conroy Exhibits C5, C6, and C7. Mr. Conroy 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 24 of his direct testimony, Mr. Conroy states:

> "the feet of conductor and number of transformers on KU's system are not uniformly distributed over all sizes of wire and transformer. For this reason, it was necessary to use a weighted regression analysis in the determination of the zero intercept."

It is interesting that Mr. Conroy 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 when a classification study is found to be appropriate.

To understand the bias in Mr. Conroy's "weighted regression analysis," we must fully understand the mathematical model he derives. Using Overhead Conductors as an example, consider Mr. Conroy's analysis presented in his Exhibit C5. Although not shown in his exhibit, Mr. Conroy's equation for Overhead Conductors is:

$$(\text{cost per foot x feet}^{0.5}) = 0 + 0.8901(\text{feet}^{0.5}) + 0.0040\ (\text{size x feet}^{0.5})$$

Notice that the equation's true intercept is forced to zero. However, if size is set to zero, the second term [0.0040(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 $0.8901. This is the zero-intercept used by Mr. Conroy.

To illustrate the bias in Mr. Conroy'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 statistically correct and industry 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. Conroy'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. Conroy's approach would result in a zero cost per foot of $1.9815 as compared to the industry accepted cost per foot of $1.75.

Q. DO YOU HAVE OTHER CONCERNS REGARDING MR. CONROY'S ZERO-INTERCEPT ANALYSES USED TO CLASSIFY DISTRIBUTION PLANT?

A. Yes. The data utilized by Mr. Conroy to conduct his statistical (zero-intercept) analyses is so questionable that no credibility can be given to any results obtained, regardless of the specific method utilized. My first concern relates to the accuracy of the data used by Mr. Conroy. To illustrate, consider Mr. Conroy's data used for Account No. 365, Overhead Conductors, as shown in Conroy Exhibit C5. Mr. Conroy's database indicates that the LGE/KU distribution systems are comprised of 97,432,621 linear feet of Overhead Conductors. Of this amount, Mr. Conroy's data includes 0.3 million linear feet of #8 wire, 15.0 million linear feet of #6 wire, and 11.5 million linear feet of #4 wire. These wire sizes are extremely small and not typically utilized to carry current throughout a primary or secondary distribution system. Indeed, these wires are smaller than most residential service lines. I cannot be certain if such small wires are actually installed within the Companies distribution system, but if they are, they are almost certainly ground wires or individual customer service lines.[7] My next data concern relates to the average cost per linear foot calculated and used by Mr. Conroy in his analysis. For example, and again referring to Conroy Exhibit C5, consider his average cost for small conductors. We see that his database utilizes an average cost of #1 conductor of $6.81 per foot while his calculated average cost of much larger 1/0 and 2/0 conductors are only $4.72 and $1.05, respectively. In other words, as conductor sizes increase, the average cost decreases. Finally, the database and mix of conductors used by Mr. Conroy in this case are much different than the data used in prior LG&E/KU cases. My Schedule GAW-4 provides the data utilized by the Company in the 2009 case. As can be seen by comparing these two data sets, the amounts and mix of plant (conductors) is vastly different between these two cases. For example, the following is a sample comparison of various size conductors utilized in this case to those utilized for the same purpose during the 2010 case:

Overhead Conductor Quantity
(Linear Feet)

Conductor Size	Current Case	2009 Case
#2	9,402,756	971,519
#1	115,720	88,940
1/0	247,264	39,898
2/0	648,440	713,507
3/0	2,032,233	1,954,687
Sum of All Wires in Data Base	97,430,621	4,699,122

Q. ARE THERE ANY OTHER DEFICIENCIES IN THE ZERO-INTERCEPT DATA UTILIZED BY MR. CONROY?

A. Yes. When a zero-intercept or minimum-size study is performed for Overhead or Underground Conductors, it is important to identify and state the various sizes of conductors on a circuit foot, not linear foot, basis. This is because all electric distribution

7 The maximum capacity of #8 wire is only 100 amps, #6 is 140 amps, and #4 wire is 180 amps: less than a modern single-family home service circuit panel.

systems are comprised of both single-phase and multi-phase (3-phase) circuits. While some single-phase circuits are comprised of only two wires, current practices are to generally install three-wire single-phase circuits, while virtually all three-phase circuits require four conductors. Furthermore, three-phase circuits tend to be comprised of larger size conductors. Most important is the fact that the analyst is attempting to estimate the theoretical cost per foot of zero size circuit which would be comprised of only two wires. When historical data is stated only on a linear foot basis it is impossible to estimate the cost of a zero size circuit.

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

A. Yes. I question why the data Mr. Conroy used for his Overhead Conductors (Account 365) and Underground Conductors (Account 367) analyses are exactly the same for LG&E and KU, and different for Line Transformers (Account 368). The data used for the analyses clearly should be different between LG&E and KU, and in fact, were different in the LG&E/KU 2008 rate case.

Q. WHAT ARE YOUR RECOMMENDATIONS CONCERNING THE CLASSIFICATION OF DISTRIBUTION PLANT IN THIS CASE?

A. Based on my customer density/mix analysis of KU's distribution system, it is entirely likely that all of KU's distribution system should be classified as 100% demand-related. Furthermore, I completely disagree with the analyses performed by Mr. Conroy. In this regard, I have conducted my CCOSS utilizing a 100% demand classification of distribution plant. In this way, we can test and evaluate the sensitivity of various distribution plant classifications and their effects on class rates of return.

Q. WHAT ARE THE CCOSS RESULTS UTILIZING THE INDUSTRY ACCEPTED BIP APPROACH TO ALLOCATE GENERATION PLANT AND ALSO CLASSIFIES DISTRIBUTION PLANT AS 100% DEMAND-RELATED?

A. The following provides a summary of my CCOSS results at current rates as well as a comparison to those obtained by Mr. Conroy:

	ROR At Current Rates		
Class	Watkins CCOSS	Conroy CCOSS	Average Results
Residential	5.55%	3.97%	4.76%
General Service	9.68%	8.72%	9.20%
All Electric Schools	5.47%	7.25%	6.36%
PS-Secondary	8.03%	10.51%	9.27%
PS-Primary	7.39%	8.52%	7.96%
TOD-Secondary	2.67%	5.83%	4.25%
TOD-Primary	3.73%	5.89%	4.81%
RTS	5.21%	6.06%	5.64%
FLS Transmission	-2.18%	-1.59%	-1.89%
Street Lighting	8.33%	7.13%	7.73%
Lighting Energy	0.01%	3.38%	1.70%
Traffic Signals	7.32%	8.24%	7.78%
Total Company	6.02%	6.02%	6.02%

As can be seen above, in a relative sense, my class rates of return at current rates are generally consistent with those obtained by Mr. Conroy. That is, the classes that are earning at, below, or above, the system average ROR are generally consistent across both studies. The details of my CCOSS are presented in my Schedule GAW-5.

III. ELECTRIC CLASS REVENUE INCREASE DISTRIBUTION

Q. HOW DOES MR. CONROY PROPOSE TO ASSIGN KU's PROPOSED OVERALL $81.5 MILLION INCREASE IN SALES REVENUE ACROSS RATE CLASSES?

A. In general, Mr. Conroy proposes to assign somewhat larger percentage increases to those classes whose ROR's at current rates are below the system average ROR and somewhat smaller percentage increases to those classes whose ROR's are greater than the system average ROR. A summary of Mr. Conroy's proposed class increases is as follows:

KU Proposed Revenue Increases

Class	Percent Increase	Percent of System Avg.
Residential	8.03%	124%
General Service	4.97%	77%
All Electric Schools	5.81%	90%
PS-Secondary	1.96%	30%
PS-Primary	5.23%	81%
TOD-Secondary	6.59%	102%
TOD-Primary	6.62%	102%
RTS	6.50%	100%
FLS Transmission	6.25%	96%
Street Lighting	5.41%	83%
Lighting Energy	5.42%	84%
Traffic Signals	5.40%	83%
Total System	6.49%	100%

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

A. In general, yes. My only exception is the Fluctuating Load ("FLS") class. While both Mr. Conroy's and my CCOSS studies indicate that this class is achieving an ROR well below the system average ROR, Mr. Conroy proposes a smaller percentage increase than the system average. Given the size and magnitude of KU's proposed increase, I recommend that the FLS class be increased at 125% of the overall system-wide percentage increase. Furthermore, because of the absolute size of the Residential class, I recommend that the additional revenue collected from the FLS class be credited to the Residential increase.

Q. **SHOULD THE COMMISSION AUTHORIZE AN OVERALL INCREASE LESS THAN THE 6.49% REQUESTED BY KU, HOW SHOULD THE FINAL INCREASE BE ASSIGNED TO INDIVIDUAL CLASSES?**

A. I recommend that any reduction in the overall increase be scaled-back in proportion to the Company's proposed class increases with the adjustment to the FLS class noted above.

IV. RESIDENTIAL RATE DESIGN

Q. DOES KU PROPOSE ANY SIGNIFICANT INCREASES TO ITS ELECTRIC RESIDENTIAL CUSTOMER CHARGE?

A. Yes. KU proposes to significantly increase its Residential customer charge from \$8.50 to \$13.00 per month which represents a 53% increase.

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

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

Q. WHY DOES KU DESIRE MORE RESIDENTIAL REVENUE 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. OTHER THAN DECOUPLING THE LINK BETWEEN PROFITABILITY AND VOLUMETRIC SALES, DOES MR. CONROY PROVIDE OTHER JUSTIFICATIONS FOR HIS PROPOSAL TO COLLECT SUBSTANTIALLY MORE OF ITS RESIDENTIAL RATE REVENUES FROM FIXED MONTHLY CHARGES?

A. Yes. Mr. Conroy claims that 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. 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.[8] 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

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

that receive more benefits should pay more in total than those who receive fewer benefits. With respect to electric and natural gas usage, the volume of consumption is the most direct, and in my opinion the best indicator of benefits received, such that volumetric pricing promotes the fairest pricing mechanism to customers and to the utility.

The above philosophy is, and has been, the belief of economists, regulators, and the marketplace for many years. As an illustration, consider utility industry pricing in its infancy (1800s). In the beginning, customers paid a fixed monthly fee and consumed as much of the utility commodity/service as they desired (usually water). It soon became apparent that the fixed monthly fee rate schedule was inefficient and unfair. Utilities soon began metering their commodity/service and charging only for the amount actually consumed. In this way, consumers receiving more benefits from the utility than others paid more in total for the utility service because they used more of the commodity.

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

Accordingly, the position of Mr. Conroy 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. DOES KU's PROPOSAL TO COLLECT A SUBSTANTIALLY GREATER PORTION OF ITS RESIDENTIAL REVENUES AND FROM FIXED MONTHLY CUSTOMER CHARGES COMPORT WITH PROPER RATEMAKING PRINCIPLES?

A. No. Perhaps the most highly regarded, and certainly the most commonly used reference to ratemaking principles is Dr. James Bonbright's treatise entitled Principles of

Public Utility Rates. With regard to the collection of revenue solely (or largely) through a fixed customer charge, Dr. Bonbright states:

> . . . there remains a choice as to the unit of service to which the uniform rate shall be applied. Among a variety of alternatives, three receive closest consideration: a uniform charge per customer; a uniform charge per unit of energy (kilowatt-hour); and a uniform charge per unit of the customer's maximum monthly kilowatt demand.
>
> **Uniformity of charge per customer (say, $10 per month for any desired quantity of service) has charm in avoiding metering costs. Nevertheless, it is soon rejected because of its utter failure to recognize either cost differences or value-of-service differences between large and small customers.** [Page 396] **[Emphasis added].**

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

A. Yes. Retail electric competition for electric generation services exists in several states. Invariably, customer choice for generation supply is volumetrically priced. However, competition for electric generation alone does not necessarily provide a good apples-to-apples comparison with the bundled services provided by KU.

Texas has implemented total retail electric competition for most of the State's 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 competitive electric service provider in Texas has a volumetric component within their rate structure. With regard to Residential fixed monthly customer charges, there are two different pricing structures: those with traditional fixed monthly customer charges (regardless of consumption); and, those that have a minimum bill amount. The following is a summary of the current rate structures regarding customer charges for the 28 providers that offer competitive Residential electric service in Texas:

	Number Of Providers	Percentage Of Providers
Fixed charge waived with usage threshold	21	75%
Traditional fixed monthly customer charge	7	25%
Total	28	100%

Of the 7 providers that utilize a traditional fixed monthly customer charge, the average customer charge is $6.94 per month. Regarding the 21 competitive providers that waive a fixed fee with a minimum threshold of usage, the average customer charge is $9.14 per month. The details supporting these amounts are provided in my Exhibit No. GAW-6.

From this data, 25% of the providers have maintained the traditional fixed monthly customer charge, and 75% of the providers waive any fixed fees once a minimum level of consumption (KWH) is achieved.[9]

When prices for a service similar to KU's 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. CONROY 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. CONROY'S CUSTOMER COST ANALYSIS?

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[9] As indicated in the notes to Exhibit No. GAW-6 customer charges are waived with minimum monthly usages ranging from of 500 KWH to 2,000 KWH.

A. No.

Q. PLEASE EXPLAIN.

A. Mr. Conroy estimates KU's monthly electric Residential customer "cost" to be $18.82. However, Mr. Conroy'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 FOR ELECTRIC SERVICE?

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 Schedule GAW-7. This study indicates a monthly KU customer cost of $4.29 per month.

Q. WHAT IS YOUR RECOMMENDATION REGARDING KU's RESIDENTIAL CUSTOMER CHARGE?

A. Although my customer cost analysis indicates that a reduction to KU's electric customer charge is warranted, in the interest of gradualism and rate continuity I recommend that KU's current Residential electric customer charge be maintained at the current level of $8.50 per month.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

BACKGROUND & EXPERIENCE PROFILE

GLENN A. WATKINS

VICE PRESIDENT/SENIOR ECONOMIST
TECHNICAL ASSOCIATES, INC.

EDUCATION

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

POSITIONS

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

EXPERIENCE

I. Public Utility Regulation

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

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

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

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

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

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

II. Transportation Regulation

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

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

III. Insurance Studies

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

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

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

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

GLENN A. WATKINS

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**

PDF	YEAR	CASE NAME	JURISDICTION	DOCKET NO.	SUBJECT OF TESTIMONY
Yes	1985	SAVANNAH ELECT. & PWR CO.	GA. PSC	3523U	SALES FORECAST, RATE DESIGN ISSUES
Yes	1990	CENTRAL MAINE PWR CO.	ME. PUC	89-68	MARGINAL COST OF SERVICE
Yes	1990	COMMONWEALTH GAS SERVICES (Columbia Gas)	VA. SCC	PUE900034	CLASS COST OF SERVICE
No	1990	WARNER FRUEHAUF	U.S. BANKRUPTCY CT.	n/a	VALUE OF STOCK, COST OF CAPITAL
Yes	1991	W. VA. WATER	WVA PSC	91-140-W-42T	RATE DESIGN
Yes	1992	S.C. WORKERS COMPENSATION	SC DEPT OF INSUR	92-034	INTERNAL RATE OF RETURN
No	1992	GRASS v. ATLAS PLUMBING, et.al.	RICHMOND CIRCUT CT	n/a	DAMAGES, BREACH OF COVENANT NOT TO COMPETE (PROFFERED TEST)
Yes	1992	VIRGINIA NATURAL GAS	VA SCC	PUE920031	JURISDICTIONAL & CLASS COST OF SERVICE
Yes	1992	ALLSTATE INSURANCE COMPANY (DIRECT)	N.J. DEPT OF INSUR	INS 06174-92	COST ALLOCATIONS, PROFITABILITY
Yes	1992	ALLSTATE INSURANCE COMPANY (REBUTTAL)	N.J. DEPT OF INSUR	INS 06174-92	COST ALLOCATIONS, PROFITABILITY
No	1993	MOUNTAIN FORD v FORD MOTOR COMPANY	FEDERAL DISTRICT CT	n/a	VEHICLE ALLOCATIONS, INVENTORY LEVELS, INCREMENTAL PROFIT, & DAMAGES
No	1993	SOUTH WEST GAS CO.	AZ. CORP COMM	U-1551-92-253	DIRECT: CLASS COST ALLOCATIONS
Yes	1993	SOUTH WEST GAS CO.	AZ. CORP COMM	U-1551-92-253	SURREBUTTAL: CLASS COST ALLOCATIONS
Yes	1993	POTOMAC EDISON CO.	VA. SCC	PUE930033	COST ALLOCATIONS,RATE DESIGN
Yes	1995	VIRGINIA AMERICAN WATER CO.	VA. SCC	PUE950003	JURISDICTIONAL ALLOCATIONS
Yes	1995	NEW JERSEY AMERICAN WATER COMPANY	N.J. B.P.U.	WR95040165	COST ALLOCATIONS,RATE DESIGN
Yes	1995	PIEDMONT NATURAL GAS COMPANY	S.C. P.S.C.	95-715-G	COST ALLOCATIONS,RATE DESIGN,WEATHER NORMALIZATION
Yes	1995	CYCLE WORLD v. HONDA MOTOR CO.	VA. DMV	None	MARKET PERFORMANCE, FINANCIAL IMPACT OF NEW DEALER
No	1996	HOUSE BILL # 1513	VA. GEN'L ASSEMBLY	N/A	WATER / WASTEWATER CONNECTION FEES
Yes	1996	VIRGINIA AMERICAN WATER CO.	VA. SCC	PUE950003	JURISDICTIONAL ALLOCATIONS
Yes	1996	ELIZABETHTOWN WATER CO.	N.J. B.P.U.	WR95110557	COST ALLOCATIONS,RATE DESIGN
Yes	1996	ELIZABETHTOWN WATER CO.	N.J. B.P.U.	WR95110557	SURREBUTTAL COST ALLOCATIONS,RATE DESIGN
Yes	1996	SOUTH JERSEY GAS CO.	N.J. B.P.U.	GR96010032	CLASS COST OF SERVICE
Yes	1996	VIRGINIA LIABILITY INSURANCE COMPETITION	VA. SCC	INS960164	COST ALLOCATIONS, INSURANCE PROFITABILITY
Yes	1996	SOUTH JERSEY GAS CO.	N.J. B.P.U.	GR96010032	REBUTTAL - CLASS COST OF SERVICE
No	1996	HOUSE BILL # 1513	VA. GEN'L ASSEMBLY	N/A	WATER / WASTEWATER CONNECTION FEES
No	1997	NISSAN v. CRUMPLER NISSAN	VA. DMV	None	MARKET DETERMINATION & PERFORMANCE
Yes	1997	PHILADELPHIA SUBURBAN WATER CO. (DIRECT)	PA. PUC	R-00973952	COST ALLOCATIONS,RATE DESIGN,RATE DISCOUNTS
Yes	1997	PHILADELPHIA SUBURBAN WATER CO. (REBUTTAL)	PA. PUC	R-00973952	COST ALLOCATIONS,RATE DESIGN,RATE DISCOUNTS
Yes	1997	PHILADELPHIA SUBURBAN WATER CO. (SURREBUTT/	PA. PUC	R-00973952	COST ALLOCATIONS,RATE DESIGN,RATE DISCOUNTS
Yes	1997	VIRGINIA AMERICAN WATER CO.	VA. SCC	PUE970523	JURISDICTIONAL/CLASS ALLOCATIONS
Yes	1998	VIRGINIA ELECTRIC POWER COMPANY	VA. SCC	PUE960296	CLASS COST OF SERVICE and TIME DIFFERENTIATED FUEL COSTS
Yes	1998	NEW JERSEY AMERICAN WATER COMPANY	N.J. B.P.U.	WR98010015	CLASS COST OF SERVICE,RATE DESIGN, REVENUES
Yes	1998	AMERICAN ELECTRIC POWER COMPANY	VA. SCC	PUE960296	CLASS COST OF SERVICE and TIME DIFFERENTIATED FUEL COSTS
No	1998	FREEMAN WRONGFUL DEATH	FfEDERAL DISTRICT CT.		LOST INCOME, WORK EXPECTANCY
Yes	1998	EASTERN MAINE ELECTRIC COOPERATIVE	MAINE PUC	98-596	REVENUE REQUIREMENT
Yes	1998	CREDIT LIFE/AH RATE FILING	VA. SCC		PRIMA FACIA RATES, LEVEL OF COMPETITION
Yes	1999	CREDIT LIFE & A&H LEGISLATION	VA. GEN'L ASSEMBLY	N/A	COST ALLOCATIONS, INSURANCE PROFITABILITY
Yes	1999	MILLER VOLKSWAGEN v. VOLKSWAGEN oF AMERICA	VA. DMV	None	VEHICLE ALLOCATIONS/CSI
Yes	1999	COLUMBIA GAS of VIRGINIA	VA. SCC	PUE980287	RATE STRUCTURE
Yes	1999	NCCI (WORKERS COMPENSATION INSURANCE)	VA. SCC	INS990165	WORKERS COMPENSATION RATES
No	1999	ROANOKE GAS	VA. SCC	PUE980626	Rate Design/ Weather Norm
Yes	2000	PERSON-SMITH v. DOMINION REALITY	RICHMOND CIRCUIT	n/a	LOST INCOME
Yes	2000	CREDIT LIFE/AH RATE FILING	VA. SCC		PRIMA FACIA RATES, LEVEL OF COMPETITION
No	2000	UNITED CITIES GAS	VA. SCC		Cost Allocations/ Rate Design
Yes	2001	VERMONT WORKERS COMPENSATION RATE CASE	VT. INSURANCE COMM.	n/a	WORKERS COMPENSATION RATES
No	2001	SERRA CHEVROLET v. GENERAL MOTORS CORP.	ALABAMA CIRCUIT CT.	98-2089	ECONOMIC DAMAGES
Yes	2001	VIRGINIA POWER ELECTRIC RESTRUCTURING	VA. SCC	PUE000584	RATE Design (UNBUNDLING)
No	2001	AMERICAN ELECTRIC POWER RESTRUCTURING	VA. SCC	PUE010011	RATE Design (UNBUNDLING)
Yes	2001	NCCI (WORKERS COMPENSATION INSURANCE)	VA. SCC	INS010190	WORKERS COMPENSATION RATES
Yes	2002	PHILADELPHIA SUBURBAN WATER CO. (DIRECT)	PA. PUC	R00016750	COST ALLOCATIONS AND RATE DESIGN
Yes	2002	HAROLD MORRIS PERSONAL INJURY	FED. DIST CT (RICHMOND)	n/a	LOST WAGES
Yes	2002	PIEDMONT NATURAL GAS	S.C. PSC	2002-63-G	REVENUE RQMT, COST OF CAPITAL
Yes	2002	VIRGINIA AMERICAN WATER COMPANY	VA. SCC	PUE-2002-00375	JURISDICTIONAL/CLASS ALLOCATIONS
Yes	2002	ROANOKE GAS COMPANY	VA. SCC	PUE-2002-00373	WEATHER NORMALIZATION RIDER
Yes	2002	SOUTH CAROLINA ELECTRIC & GAS (ELECTRIC)	S.C. PSC	2002-223-E	REVENUE RQMT.
Yes	2003	NCCI (WORKERS COMPENSATION INSURANCE)	VA. SCC	INS-2003-00157	WORKERS COMPENSATION RATES
Yes	2003	CREDIT LIFE/AH RATE FILING	VA. SCC		PRIMA FACIA RATES, LEVEL OF COMPETITION
Yes	2003	ROANOKE GAS	VA. SCC	PUE-2003-00425	WEATHER NORMALIZATION ADJUSTMENT RIDER
Yes	2003	SOUTHWESTERN VIRGINIA GAS CO.	VA. SCC	PUE-2003-00426	WEATHER NORMALIZATION ADJUSTMENT RIDER
Yes	2004	SOUTH CAROLINA PIPELINE COMPANY	S.C. PSC	2004-6-G	COST OF GAS AND INTERUPT. SALES PROGRAM
Yes	2004	VIRGINIA AMERICAN WATER COMPANY	VA. SCC	PUE-2003-00539	JURISDICTIONAL/CLASS ALLOCATIONS
Yes	2004	SCE&G FUEL CONTRACT	S.C. PSC	2004-126-E	GAS CONTRACT FOR COMBINED CYCLE PLANT

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

PDF	YEAR	CASE NAME	JURISDICTION	DOCKET NO.	SUBJECT OF TESTIMONY
Yes	2004	WASHINGTON GAS LIGHT	VA. SCC	PUE-2003-00603	RATE DESIGN/ WNA RIDER
Yes	2004	ATMOS ENERGY	VA. SCC	PUE-2003-00507	RATE DESIGN/ WNA RIDER
Yes	2004	SCE&G RATE CASE (ELECTRIC)	S.C. PSC	2004-178-E	COST OF CAPITAL/ REV RQMT.
No	2004	MEDICAL MALPRACTICE LEGISLATION	VA. GENERAL ASSEMBLY	N/A	INDUSTRY RESTRUTURE/ PROFITABILITY
Yes	2004	ATLAS HONDA v. HONDA MOTOR CO.	VA. DMV	None	NEW DEALER PROTEST
Yes	2004	NCCI (WORKERS COMPENSATION INSURANCE)	VA. SCC	INS-2004-00124	WORKERS COMPENSATION RATES
Yes	2004	NATIONAL FUEL GAS DISTRIBUTION	PA. PUC	R00049656	COST ALLOCATIONS/ RATE DESIGN
Yes	2005	WASHINGTON GAS LIGHT	VA SCC	PUE-2005-00010	WEATHER NORMALIZATION ADJUSTMENT RIDER
No	2005	Serra Chevrolet	US Federal Ct.	CV-01-P-2682-S	Dealer incremental profits and costs
No	2005	NEWTOWN ARTESIAN WATER	PA. PUC		REV. RQMT./ RATE STRUCTURE
No	2005	CITY OF BETHLEHEM WATER RATE CASE	PA. PUC		REV. RQMT./ RATE STRUCTURE
Yes	2005	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	INS-2005-00159	WORKERS COMPENSATION RATES
Yes	2005	Virginia Natural Gas	VA SCC	PUE-2005-00057	Revenue Requirement/ Alt. Regulation Plan
Yes	2006	Olathe Hyundai v. Hyundai Motors of America	KS DMV	None	Dealer impact analysis
Yes	2006	Virginia Credit Life & A&H Prima Facia Rates	VA SCC	INS-2006-00013	Market Structure
Yes	2006	Columbia Gas of Virginia	VA SCC	PUE-2005-00098	Revenue Requirements/ Alt. Regulation Plan
Yes	2006	PPL Gas	PA. PUC	R-00061398	COST ALLOCATIONS/ RATE DESIGN
Yes	2006	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	INS-2006-00197	WORKERS COMPENSATION RATES
Yes	2007	Level of Private Pass. Auto Competition	Ma. Dept of Insur	N/A	Private Pass Auto level of competition
Yes	2007	WASHINGTON GAS LIGHT	VA SCC	PUE-2006-00059	Cost Allocations/ Rate Design/ Alt Regulation Plan
Yes	2007	Valley Energy	PA. PUC	R-00072349	Cost of Capital/Rate Design
Yes	2007	Wellsboro Electric	PA. PUC	R-00072350	Cost of Capital/Rate Design
Yes	2007	Citizens' Electric Of Lewisburg, Pa	PA. PUC	R-00072348	Cost of Capital/Rate Design
Yes	2007	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	INS-2007-00224	WORKERS COMPENSATION RATES
Yes	2007	Georgia Power	Ga.PSC	25060-U	Cost Allocations/Rate Design
Yes	2008	Columbia Gas of Pennsylvania	PA. PUC	R-2008-2011621	COST ALLOCATIONS/ RATE DESIGN
Yes	2008	Greenway Toll Road Investigation	VA. GENERAL ASSEMBLY	N/A	Affiliate Transactions
Yes	2008	Puget Sound Energy (Electric)	Wa. UTC	UE-072300	Cost Allocations/Rate Design
Yes	2008	Puget Sound Energy (Gas)	Wa. UTC	UE-072301	Cost Allocations/Rate Design
Yes	2008	Blue Grass Electric Cooperative	Ky PSC	2008-00011	Cost Allocations/Rate Design
Yes	2008	Columbia Gas of Ohio	OH PUC	08-72-GA-AIR, et. al	Cost Allocations/Rate Design
Yes	2008	Virginia Natural Gas	Va SCC	PUE-2008-00060	Natl Gas Conservation/ Revenue Decoupling
Yes	2008	Equitable Natural Gas	PA. PUC	R-2008-2029325	Cost Allocations/Rate Design/ Discounted Rates
Yes	2008	LG&E (Electric)	Ky PSC	2008-000252	Cost Allocations/Rate Design/ Weather Normalization
Yes	2008	LG&E (Natural Gas)	Ky PSC	2008-000252	Cost Allocations/Rate Design
Yes	2008	Kentucky Utilities	Ky PSC	2008-00251	Cost Allocations/Rate Design/ Weather Normalization
Yes	2008	Pike County Natural Gas	PA. PUC	R-2008-2046520	Cost Allocations/Rate Design
Yes	2008	Pike County Electric	PA. PUC	R-2008-2046518	Cost Allocations/Rate Design
Yes	2008	Newtown Artesian Water	PA. PUC	R-2008-2042293	Revenue Requirement
Yes	2009	Leesburg Water & Sewer	Va. Circuit Ct.	Civil Action 42736	Revenue Requirement/ Excess Rates
Yes	2009	Central Penn Gas, Inc.	PA. PUC	R-02008-2079675	Cost Allocation/Rate Design
Yes	2009	Penn Natural Gas, Inc.	PA. PUC	R-2008-2079660	Cost Allocation/Rate Design
Yes	2009	Credit Life/ A&H ratemaking	Va. SCC	n/a	Market Structure and Availability
Yes	2009	Fairfax County v. City of Falls Church Virginia	Fairfax Circuit Ct. (Va.)	CL-2008-16114	Water Revenue Requirement
Yes	2009	Avista Utilities (Electric)	Wa. UTC	UE-090134	Electric rate Design
Yes	2009	Avista Utilities (Gas)	Wa. UTC	UE-090135	Gas Rate design
Yes	2009	Columbia Gas of Kentuky	Ky PSC	2009-00141	Cost Allocations/Rate Design
Yes	2009	NCCI (Workers Compensation Rates)	VA SCC	INS-2009-00142	Workers Compensation Rates
Yes	2009	Duke Energy of Kentucky (Gas)	Ky. PSC	2009-00202	Rate Design
Yes	2009	Duke Energy Carolinas (Electric)	NC UC	E-7 Sub 909	Cost Allocations/Rate Design
Yes	2009	PacifiCorp	Wa. UTC	UE-090205	Rate Design/Low Income
Yes	2009	Puget Sound Energy (Electric)	Wa. UTC	UE-090704	Cost Allocations/Rate Design
Yes	2009	Puget Sound Energy (Gas)	Wa. UTC	UG-090705	Cost Allocations/Rate Design
Yes	2009	United Water of Pennsylvania	PA PUC	2009-212287	Cost Allocations/Rate Design
Yes	2010	Aqua Virginia, Inc.	VA SCC	PUE-2009-00059	Rate Design
Yes	2010	Kentucky Utilities	Ky PSC	2009-00548	Cost Allocations/Rate Design/ Weather Normalization
Yes	2010	LG&E (Electric)	Ky PSC	2009-00549	Cost Allocations/Rate Design
Yes	2010	LG&E (Natural Gas)	Ky PSC	2009-00549	Cost Allocations/Rate Design/ Weather Normalization
Yes	2010	Philadelphia Gas Works	PA PUC	2009-2139884	Cost Allocations/Rate Design
Yes	2010	Columbia Gas of Pennsylvania	PA PUC	2009-2149262	Cost Allocations/Rate Design
Yes	2010	PPL Electric Company	PA PUC	2010-2161694	Cost Allocations/Rate Design
Yes	2010	York Water Company	PA PUC	2010-2157140	Cost Allocations/Rate Design
Yes	2010	Valley Energy, Inc.	PA PUC	2010-2174470	Cost of Capital/Revenue Requirement/Rate Design

EXPERT TESTIMONY
PROVIDED BY
GLENN A. WATKINS

PDF	YEAR	CASE NAME	JURISDICTION	DOCKET NO.	SUBJECT OF TESTIMONY
Yes	2010	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	INS-2010-00126	WORKERS COMPENSATION RATES
Yes	2010	Columbia Gas of Virginia	VA SCC	PUE-2010-00017	Cost of Capital/Revenue Requirement/Rate Design
Yes	2010	Georgia Power Company	GA PSC	Docket No. 31958	Cost Allocations/Rate Design
Yes	2010	City of Lancaster, Bureau of Water	PA PUC	R-2010-2179103	Cost of Capital
Yes	2011	Columbia Gas of Pennsylvania	PA PUC	R-2010-2215623	Cost Allocations/Rate Design
Yes	2011	Owen Electric Cooperative	KY PSC	PUE-2011-00037	Rate Design
Yes	2011	Virginia Natural Gas	VA SCC	PUE-2010-00142	Pipeline Prudency/Cost Allocations/Rate Design
Yes	2011	United Water of Pennsylvania	PA PUC	2011-2232985	Cost Allocations/Rate Design
Yes	2011	PPL Electric Company (Remand)	PA PUC	2010-2161694	Negotiated Industrial Rate
Yes	2011	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	2011-00163	WORKERS COMPENSATION RATES
Yes	2011	Artesian Water Company	DE PSC	11-207	Cost Allocations/Rate Design
Yes	2011	Arizona-American Water Company	AZ. CORP COMM	W-01303A-10-0448	Excess Capacity/Need For Facilities
Yes	2012	Tidewater Utilities, Inc.	DE PSC	11-397	Cost of Capital/Revenue Requirement/Rate Design
	2012	PPL Electric	PA PUC	R-2012-2290597	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 & LG&E
Test Year Generation Statistics

Generating Unit	Fuel	Generator Nameplate (MW)	Net MWH Produced	Generation Order	Total Gross Investment	Total Net Investment	Capacity Factor Net	Capacity Factor Gross		Net Investment Energy	Net Investment Demand
Ghent 2	Coal	556	3,341,264	3	$273,472,042	$83,388,818	68.60%	74.64%	Base	$83,388,818	$0
Ghent 1	Coal	557	3,282,901	7	$457,703,835	$271,488,089	67.28%	72.69%	Base	$271,488,089	$0
Trimble County 1	Coal	566	3,308,126	2	$515,981,742	$278,424,714	66.72%	72.77%	Base	$278,424,714	$0
Mill Creek 4	Coal	544	3,150,394	6	$510,585,061	$228,578,983	66.11%	72.35%	Base	$228,578,983	$0
Mill Creek 1	Coal	356	2,053,056	4	$171,459,453	$52,146,990	65.83%	73.35%	Base	$52,146,990	$0
Trimble County 2	Coal	838	4,740,434	1	$1,019,959,483	$906,947,029	64.58%	69.84%	Base	$906,947,029	$0
Ghent 3	Coal	557	2,940,071	8	$778,865,366	$477,834,135	60.26%	66.46%	Base	$477,834,135	$0
Ghent 4	Coal	556	2,801,767	11	$426,413,546	$238,401,985	57.52%	63.51%	Base	$238,401,985	$0
Cane Run 4	Coal	164	807,948	24	$82,888,694	$16,703,463	56.24%	61.59%	Base	$16,703,463	$0
Mill Creek 2	Coal	356	1,734,022	5	$132,002,570	$40,056,311	55.60%	62.98%	Base	$40,056,311	$0
Mill Creek 3	Coal	463	2,051,810	10	$284,377,385	$122,639,799	50.59%	55.30%	Intermediate	$62,041,669	$60,598,130
Green River 4	Coal	114	501,882	9	$46,859,950	$8,588,941	50.26%	54.36%	Intermediate	$4,316,505	$4,272,436
Cane Run 5	Coal	209	905,328	18	$97,221,510	$23,631,839	49.45%	53.91%	Intermediate	$11,685,656	$11,946,183
Green River 3	Coal	75	320,975	23	$27,716,488	$10,089,303	48.85%	53.38%	Intermediate	$4,929,093	$5,160,210
Cane Run 6	Coal	272	1,138,782	21	$153,644,905	$56,407,604	47.79%	52.62%	Intermediate	$26,959,090	$29,448,514
Brown 2	Coal	180	581,164	25	$59,125,163	$28,891,106	36.86%	41.34%	Intermediate	$10,648,447	$18,242,659
Brown 3	Coal	464	1,298,614	27	$617,105,989	$469,702,193	31.95%	36.04%	Intermediate	$150,065,404	$319,636,789
Brown 1	Coal	114	275,317	32	$76,780,399	$36,383,634	27.57%	33.21%	Intermediate	$10,030,675	$26,352,959
Trimble County 6	Gas	199	93,551	13	$62,918,755	$46,166,154	5.37%	5.44%	Peak	$0	$46,166,154
Trimble County 7	Gas	199	91,965	14	$54,236,860	$39,700,952	5.28%	5.35%	Peak	$0	$39,700,952
Trimble County 9	Gas	199	85,420	16	$54,028,301	$39,977,482	4.90%	4.99%	Peak	$0	$39,977,482
Trimble County 5	Gas	199	62,572	12	$66,804,468	$48,361,256	3.59%	3.68%	Peak	$0	$48,361,256
Trimble County 8	Gas	199	61,973	15	$53,873,686	$39,444,963	3.56%	3.62%	Peak	$0	$39,444,963
Trimble County 10	Gas	199	53,035	17	$60,462,097	$45,235,631	3.04%	3.09%	Peak	$0	$45,235,631
Brown 7	Gas,Oil	177	34,745	20	$60,225,468	$43,404,094	2.24%	2.38%	Peak	$0	$43,404,094
Paddys Run 13	Gas	178	31,743	22	$65,720,461	$45,252,606	2.04%	2.06%	Peak	$0	$45,252,606
Brown 6	Gas,Oil	177	30,756	19	$64,812,407	$50,236,200	1.98%	2.13%	Peak	$0	$50,236,200
Brown 9	Gas,Oil	126	3,807	28	$48,713,646	$23,411,374	0.34%	0.53%	Peak	$0	$23,411,374
Brown 5	Gas	123	3,196	26	$49,685,284	$33,734,583	0.30%	0.50%	Peak	$0	$33,734,583
Brown 11	Gas,Oil	126	2,890	31	$44,740,278	$24,255,858	0.26%	0.41%	Peak	$0	$24,255,858
Brown 8	Gas,Oil	126	2,436	30	$37,227,939	$21,396,169	0.22%	0.36%	Peak	$0	$21,396,169
Brown 10	Gas,Oil	126	1,568	29	$30,167,921	$15,175,125	0.14%	0.29%	Peak	$0	$15,175,125
Cane Run 11	Gas,Oil	16	198	34	$3,557,311	$1,294,371	0.14%	0.14%	Peak	$0	$1,294,371
Haefling 1-3	Gas,Oil	21	169	37	$6,346,312	$2,227,070	0.09%	0.16%	Peak	$0	$2,227,070
Paddys Run 11	Gas	16	100	33	$1,609,957	($136,355)	0.07%	0.11%	Peak	$0	($136,355)
Zorn 1	Gas	18	(49)	36	$1,951,456	($99,370)	-0.03%	0.02%	Peak	$0	($99,370)
Paddys Run 12	Gas	33	(273)	35	$3,990,011	$419,642	-0.09%	0.00%	Peak	$0	$419,642
Tyrone 3	Coal	75	(1,477)		$28,798,957	$6,704,422	-0.22%	0.00%	Peak	$0	$6,704,422
Dix Dam 1-3	Hydro	9	82,033		$28,850,449	$20,621,308	34.68%	34.74%	Hydro	$20,621,308	$0
Ohio Falls 1-8	Hydro	10	185,569		$42,551,883	$33,455,820	24.63%	25.19%	Hydro	$33,455,820	$0
						$3,930,544,291				$2,928,724,184	$1,001,820,107
							Total System			74.51%	25.49%

Sources: Company responses to KU OAG 1-248, KU OAG 1-250, LG&E OAG 1-291, and LG&E OAG 1-293.

CHARGING FOR DISTRIBUTION UTILITY SERVICES: ISSUES IN RATE DESIGN

December 2000

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IV. THE COSTS OF DISTRIBUTION SERVICES

A first question to be answered when designing rates is what does it cost to provide the service? What are the causes and magnitudes of the relevant costs? It s helpful to observe that the costs recovered by distribution-level rates have historically extended far beyond the distribution system. Are there other costs, not directly related to distribution services, that distribution rates are expected to recover? What follow here are an overview of utility costing methodologies and a discussion of some practical considerations to keep in mind when determining rate structures.

A. Utility Plant Costing Methods

Utilities and regulatory commissions use a variety of methods for determining and allocating cost responsibility among customers and customer classes. There are two general types of cost study, embedded and marginal. Embedded, or fully distributed, seeks to identify and assign the historical, or accounting, costs that make up a utility s revenue requirement. Marginal, as the name connotes, aims at determining the change in total costs imposed on the system by a change in output (whether measured by kilowatt-hour, kilowatt, customer, customer group, or other relevant cost driver). Each commission around the country uses these studies in its own way to inform the rate design process; in the end, most commissions rely on embedded cost studies for ultimate allocations and price levels, constrained as they are by a legal requirement to set rates that offer the prudent utility a reasonable opportunity to earn a fair rate of return on its assets used in service to public.[33] The allocations, however, are often structured to reflect at least relative differences in the marginal costs of providing a company s various services.

1. Cost Causation

There is broad agreement in the literature that distribution investment is causally related to peak demand. Numbers of customers on the system and energy needs are also seen to drive costs, but there is less of a consensus on these points or on their implications for rate design. In addition, not all jurisdictions employ the same methods for analyzing the various cost components, and there is of course a wide range of views on their nature marginal, embedded, fixed, variable, joint, common,[34] etc. and thus on how they should be recovered in rates.

33. NARUC, p. 32.

34. The costs of multiple products or services supplied by the same plant or process are either common or joint. Common are those that generally do not vary with changes in output. The classic example is the president s desk, which is needed to run the firm as a whole but is incremental to the provision of no particular good or service. Another example is that of an airline flight, the majority of whose costs are incurred in a single lump and do not vary with the number of passengers carried. Put another way, common costs are those for which the unit of production (the single flight), which is the basis of cost incurrence, is larger than the unit of sale (a

(continued...)

Numbers of customers, usage, and demand, however, are only part of the story. Other factors also play an important role: geography (particularly population density), system design (*e.g.*, aerial versus underground lines), and the utility s business practices (for example, the extent of expenditures on billing, answering customers questions/complaints, etc.). The implications of such factors on rate design is unclear, however: one can charge for services on the basis of numbers of customers, usage, and demand, but not on the basis of other such factors.[35]

2. Embedded Costs

a. Cost Classification: Customers, Demand, and Energy

Traditionally, customer costs are those that are seen to vary with the number of customers on the system service drops (the line from the distribution radial to the home or business), meters, and billing and collection. Some utilities and jurisdictions also include some portion of the primary and secondary distribution plant (poles, wires, and transformers) in these costs, on the ground that they also are driven more by numbers of customers than by demand or energy. Similar reasoning leads to the designation of the costs of customer service and customer premises equipment as customer-related. But, since the system and its components are sized to serve a maximum level of anticipated demand, the notion that there are any customer costs (aside from perhaps metering and billing) that are not more properly categorized as demand can be challenged (see Subsections 3 and 4, below).

Utilities classify significant portions of their embedded distribution investment as demand-related, reasoning that it is designed and installed to serve a customer or group of customers according to their contribution to some peak load (system, substation, etc.). Substations are a typical example of such costs, but so too may be a significant portion of the wires and related facilities, since they are sized, at least in part, to serve a peak demand.

There are a number of methods for differentiating between the customer and demand components of embedded distribution plant. The most common method used is the basic customer method, which classifies all poles, wires, and transformers as demand-related and meters, meter-reading, and billing as customer-related. This general approach is used in more than thirty states. A

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34. (...continued)
single ticket to a single passenger). Kahn, Vol. I, p. 77. If services produced in common can be produced in varying proportions, it may then be possible to identify separate marginal production costs for each.

Products that are produced in fixed proportions (*e.g.*, cotton fiber and cottonseed oil, beef and hides, mutton and wool) are characterized by joint costs. For that aspect of their production process that is joint, the products have no separately identifiable marginal costs. *Id.*, p. 79. See also Bonbright, pp. 355-360.

35. These other cost factors can have huge effects on prices. Three distribution utilities in the American south, owned by the same holding company and using the same costing methodology, recently proposed new metering, customer service rates, and delivery rates. The rates, designed as a combination of monthly per-customer and per-kW of peak demand charges, vary from company to company by ratios ranging from 1.25 to 1.9.

variation is to treat poles, wires, and transformers as energy-related driven by kilowatt-hour sales but, though it has obvious appeal, only a small number of jurisdictions have gone this route.

Two other approaches sometimes used are the minimum size and zero-intercept methods. The minimum size method operates, as its name implies, on the assumption that there is a minimum-size distribution system capable of serving customers minimum requirements. The costs of this hypothetical system are, so the argument goes, driven not by customer demand but rather by numbers of customers, and therefore they are considered customer costs. The demand-related cost portion then is the difference between total distribution investment and the customer-related costs. The zero-intercept approach is a variation on the minimum size. Here the idea is to identify that portion of plant that is necessary to give customers access but which is incapable of serving any level of demand. The logic is that the costs of this system, because it can serve no demand and thus is not demand-related, are necessarily customer-related.[36] However, the distinction between customer and demand costs is not always clear, insofar as the number of customers on a system (or particular area of a system) will have impacts on the total demand on the system, to the extent that their demand is coincident with the relevant peak (system, areal, substation, etc.).

Any approach to classifying costs has virtues and vices. The first potential pitfall lies in the assumptions, explicit and implicit, that a method is built upon. In the basic customer method, it is the *a priori* classification of expenditures (which may or may not be reasonable). In the case of the minimum-size and zero-intercept methods, the threshold assumption is that there is some portion of the system whose costs are unrelated to demand (or to energy for that matter). From one perspective, this notion has a certain intuitive appeal these are the lowest costs that must be incurred before any or some minimal amount of power can be delivered but from another viewpoint it seems absurd, since in the absence of any demand no such system would be built at all. Moreover, firms in competitive markets do not indeed, cannot price their products according to such methods: they recover their costs through the sale of goods and services, not merely by charging for the ability to consume, or access.

Other assumptions are of a more technical nature. What constitutes the minimum system? What are the proper types of equipment to be modeled? What cost data are applicable (historical, current installations, etc.)? Doesn t the minimum system in fact include demand costs, since such a system can serve some amount of demand? The zero-intercept method attempts to model a system that has no demand-serving capability whatsoever, but what remains is not necessarily a system whose costs are driven any more by the number of customers than it is by geographical considerations, whose causative properties are neither squarely demand- nor customer-related. Does use of an abstract minimum system place a disproportionate share of the cost burden on

36. It is called zero-intercept because it relates installed cost to current carrying capacity or demand rating, creat[ing] a curve for various sizes of the equipment involved, using regression techniques, and extend[ing] the curve to a no-load intercept. NARUC, p. 92.

certain customers or classes, in certain cases even resulting in double-counting? The answers chosen to these and other questions will have impacts upon the respective assignments (by type and customer class) of costs.[37]

Historically, the investment decisions of system planners in vertically-integrated utilities were constrained by the least total cost objective: simply, that they would make that combination of investments that were expected, given their assessments of risk, to meet expected demand for service over some reasonable planning horizon. Given the inability to store electricity and the typical obligation to serve all customers *on demand*, a utility was required to have sufficient capacity available to meet peak demand. And, if its only obligation were to meet peak demand, then it would install only the most inexpensive capacity. However, it had also to serve energy needs at other times, and it is a general characteristic of electric generation technology that as capacity costs decrease variable operating costs increase. There is, therefore, a trade-off between capacity and energy costs that system planners considered when building (or purchasing) new capacity, if they hoped to minimize total costs. Put another way, significant portions of generating capacity were purchased not to meet demand, but to serve energy, when the fuel cost savings that the more expensive generation would produce were greater than the additional costs of that capacity. These incremental capacity costs were therefore correctly viewed as energy costs.

A similar kind of analysis can inform the design of distribution systems, as it also does transmission. The question is whether there is some amount of capacity in excess of the minimum needed to meet peak demand that can cost-effectively be installed. The additional capacity larger substations, conductors, transformers will reduce energy losses; if the cost of energy saved is greater than that of the additional capacity, then the investment will be cost-effective and should be made.[38] For the purposes of cost analysis and rate design, these kinds of distribution investments are rightly treated as energy-related.[39]

b. Cost Allocation

As a general matter, distribution facilities are designed and operated to serve localized area loads. Substations are designed to meet the maximum expected load of the distribution feeders radiating from them. The feeders are designed to meet at least the maximum expected loads at the primary

37. Sterzinger, George, The Customer Charge and Problems of Double Allocation of Costs, *Public Utilities Fortnightly*, July 2, 1981, p. 31; see also Bonbright, p. 347-348.

38. Losses vary with the square of the load. We note also that there is some minimum amount of losses that cannot be avoided, and that conductors must be sized such that the losses can be absorbed while still meeting peak load. To this degree, losses impose a capacity, rather than energy, cost.

39. An unhappy consequence of separating distribution and transmission planning from that of generation in restructured markets is the potential loss of this capacity-versus-energy consideration when making new investment. Certainly, without some sort of regulatory or legislative requirement, wires-only companies have no generation cost-savings motive to guide their planning decisions.

and secondary service levels. (As noted above, some investment in distribution capacity may be seen as reducing energy losses rather than serving peak demand.) For costing purposes it is the relevant subsystem s (substation, feeder, etc.?) peak that matters, but these peaks may or may not be coincident with each other or with the overall system s peak. There can be significant variation among them. Consequently, one practice is to allocate the costs of substations and primary feeders (which usually enjoy relatively high load factors) to customer class non-coincident peaks and to allocate secondary feeders and line transformers (with lower load factors) to the individual customer s maximum demand.[40] In addition, costs are allocated according to voltage level; customers taking service at higher levels are typically not assigned any of the costs of the lower-voltage systems that do not serve them. Costs are then allocated among customer rate groups (or classes) which requires, among other things, information and judgments about coincidence of demand when customers of different classes share facilities, as is often the case.

3. Marginal Costs

For the reasons stated earlier, it is the long-run marginal cost that is most relevant to designing rates. It can be described as the cost of that lumpy, geographically dispersed set of investments that a utility must make if demand continues to grow after the distribution system has initially been built out.

a. Demand and Energy

As already noted, the drivers of distribution costs are typically seen to be peak demand (itself driven by both customer demand and numbers of customers) and energy needs.[41] For the purposes of marginal cost analysis, it is also necessary to identify investments that are not made to serve incremental demands, but are made for some other purpose reliability, replacement of existing systems, etc. The costs of these investments are generally not included in marginal cost calculations, although, in certain cases, there may be legitimate arguments to the contrary.[42]

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40. Class non-coincident peak may not be the best measure of cost causation, since much of the system serves a variety of customer classes. Chernick, Paul, *From Here to Efficiency: Securing Demand-Management Resources*, Vol. 5, 1993, p. 81. Ideally, the object is to design rates that reflect the costs of customers contributions to the relevant peak.

41. It is worth noting that, in the short run, distribution costs vary more closely with numbers of customers than with load (except in capacity-constrained areas). For rate design, with its focus on the long run, this fact need not be a distraction. It does, however, have implications for setting revenue requirements. We address this question in Chapter V, below.

42. For instance, at the time that an investment to replace existing facilities (whose loads, let us say, are not expected to change over some extended period) is being contemplated, there are costs that can potentially be avoided. In the extreme, replacement would be unnecessary if all customers served by the facility were to decide to go off grid. Other, more likely alternatives involve combinations of end-use efficiency, distributed generation, and smaller, more efficient distribution technologies. On these bases, the marginal or, more reasonably, the larger

(continued...)

Many of the same cost classification and assignment questions that pervade embedded cost analyses also recur in marginal cost studies, although their answers have different analytical effects. Whereas an embedded cost study strives to identify and assign total historical costs to classes of service (on the basis of any of a number of principles, including cost causation and fairness), a marginal cost analysis aims to determine the cost consequences of changes in output and thus the value of resources that must be used to serve incremental demand. Therefore, costs that are unaffected by changes in output (which describes all common and many joint costs) are excluded from the costs under examination.[43]

The study period for a marginal cost analysis is forward-looking and should be of sufficient duration to assure that all incremental demand is related to the investments forecast to serve that demand: a mismatch of timing and investment could result in significantly over- or understated costs. Those incremental costs are then discounted to their present value and annualized over the planning horizon. This has the effect of smoothing out the lumpiness of investment in relation to changes in demand.[44] This analysis relates changes in total costs to changes in demand (aggregating demand increases caused by the addition of customers with those caused by increases in demand per customer).[45] Since new customers create additional demand, this approach is not unreasonable.

Even so, some jurisdictions consider certain costs customer-related and treat them separately for the purpose of marginal cost analysis. Customer premises equipment that which is dedicated specifically to individual customers and unrelated to variations in demand (meters and perhaps service drops) are probably the only distribution costs that can be directly assigned to customers (except in the cases of customers who have additional facilities transformers, wires, even

42. (...continued)
incremental costs of distribution can be calculated. If replacement of the particular component of the system is forecast for some time in the future, then its expected future costs would need to be discounted appropriately to yield a present-value incremental cost.

43. Because marginal cost is defined as the change in total cost arising from a change in output, all costs are, strictly speaking, included in the analysis. It just happens that most are netted out, to reveal those that are caused by the change in output. As a practical matter, however, an analyst may simply identify the costs that vary with output and exclude the rest. It is this second approach, however, that raises debates about the nature of costs and whether they should be included in the analysis. Are they joint or common? Do they vary with demand, energy, customers, or not at all? Resolving the issues usually requires large doses of judgment.

44. An alternative approach is to calculate the cost (savings) of advancing (deferring) by one year the planned stream of investments to meet the increment (decrement) in demand. This approach yields a cost that is equal to the value of the marginal investments for one year (which is the same as the economic carrying charge on those investments). This method is often used, for example, to determine an annual cost per kW of generating capacity.

45. For sizing much of the distribution system, demand is the critical factor. One customer contributing six kilowatts to peak demand has the same impact as two each contributing three kilowatts.

substations, dedicated solely to their needs).[46] Some jurisdictions also consider other facilities (line transformers, secondary level conductors) in some measure customer-related, but, to the extent that they are jointly-used to serve more than one customer, it may be difficult to establish that the addition or loss of any one customer will affect the costs of those facilities.[47] In any event, if some costs are deemed marginal customer costs (which means that they are avoidable only at the time of hook-up), it by no means follows that they should be recovered in recurring monthly fixed fees (see Section V.A.5., below).

Other approaches sometimes used to resolve the cost-causation question are the minimum system and zero intercept methods. Here, instead of using embedded cost data, the distribution system is modeled to determine the cost (in current dollars) of a hypothetical system that could serve all customers minimum demand or (in the case of zero-intercept) that could provide voltage but not power.[48] This cost would be deemed customer-related and separated from the total incremental cost previously determined, to identify the demand (or, more properly, the demand- and energy-related) portion. For the reasons stated earlier, we challenge the wisdom of these approaches.[49]

Other methodological difficulties may also arise. By definition, joint and common costs are not marginal, but occasionally they creep into the analysis, when, for example, they make use of what are in effect *average*, not *marginal*, investments and expenditures.[50] And, as with embedded costs, marginal costs are typically broken out by customer class. Here, again, the analysis requires

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46. After the meter, the customer service drop is typically seen as the least demand-related component of the system: it is sized to exceed any realistic maximum demand that the consumer might impose and it will last a very long time. However, although it is true that no investment would be made unless a customer were present, it is also true that the amount of the initial investment increases as the customer s forecasted load increases. Thus, customer investments can be seen as demand-related, as can investments farther up the system transformers, wires, and substations whose sizing depends on expected peak demand. Bouford, James D., Standardized Component Method for the Determination of Marginal and Avoided Demand Cost at the Distribution Level, Central Maine Power Company, (unpublished and undated), pp. 3-4.

47. NARUC, p. 136.

48. A handbook published by the National Economic Research Associates (NERA), which is often cited in support of the minimum system distribution cost classification, states that only the labor costs necessary to put together a minimum system and no conductor and transformer costs are customer-related. NERA, How To Quantify Marginal Costs: Topic 4, (prepared for the Electric Utility Rate Design Study, March 10, 1977), pp. 76.

49. California, for instance, has rejected the minimum system approach to marginal costs, favoring instead a method which uses the weighted average of the costs of continuing to serve existing customers and the costs of initiating service to new customers.

50. See, *e.g.*, NARUC, p. 127, which notes that, because calculating marginal distribution and customer costs can be difficult, it is still common for analysts to use some variation of a projected embedded methodology for these elements, rather than a strictly marginal approach. This tack is justified by the sweeping assumption that projected embedded distribution costs are a reasonable approximation of marginal costs. The assumption is, however, contestable. FERC accounting requirements, which form the basis of most embedded cost analyses, include in distribution certain, and often substantial, administrative and general (A&G) costs (Accounts 920 to 935). A&G is not caused by the provision of distribution service.

reasonable assessments of the coincidence of demand, when customers of different classes share facilities.

Another dimension of cost, and perhaps most revealing, is the geographic. There are several aspects to it. First are the topographical and meteorological characteristics of the area over which the distribution system is laid. Elevations, plant life, weather, soil conditions, and so on all have effects on costs. So too demography, which is captured partly by demand and numbers of customers, but also affecting costs is the density of customers in an area (sometimes expressed as customers per mile). These influences combine in assorted ways, with themselves but also with changes in load and rates of investment, to produce variations in costs from one area of the distribution system to another. It is not unusual to see marginal distribution costs varying greatly from one place to another, even when the distances between the different areas is comparatively short. Table 1 describes the significant variations in costs for incremental distribution investments in a large mid-western utility.

	Average System Marginal Costs per kW	Area Specific High-Low Marginal Costs per kW	Annual Cost @ 15% Capital Cost Recovery Factor	Average Marginal Costs per kWh @ 20% Load Factor[51]	High Marginal Costs per kWh @ 20% Load Factor
Transmission	$230	NA	$34	$0.02	$0.04
Distribution Lines	$960	$1,575 - 0	$140	$0.08	$0.135
Distribution Transformers	$60	$300 - 0	$9	$0.0015	$0.025
Total	$1,250	$1,875 - 0	$183	$.1015	$0.20

Table 1

Differentiating marginal costs along these lines will tell a utility where investment (whether in new facilities, end-use efficiency, or distributed generation) is needed and what the minimum value of that investment is. Whether for rate-making purposes this information is useful should distribution rates be geographically deaveraged ? is a tougher question. We take it up in Chapter V, below.

51. This is estimated load factor for the incremental distribution investment alone, not for the entire distribution system altogether. Incremental investment to meet peak needs typically manifests low load factors; 20% is a conservatively high estimate.

4. Key Concern in Determining Costs: Follow the Money

The occasionally technical and arcane matters taken up in embedded and marginal cost studies are, of course, important, but it is perhaps more important to bear in mind that, in rate design cases, what is fundamentally at issue is who should bear what revenue responsibilities. In the interplay between cost allocation and rate structures, the debate over money is played out. First is the question of what costs will be categorized as *distribution*, as opposed to transmission or generation in the case of vertically integrated utilities, or perhaps competitive services in other instances. This is no small matter, since significant portions of a firm s joint and common costs (typically, administrative and general) are often attributed to the distribution business, even though there is no causal relationship between them. Then there is the designation of a cost as either *customer* or *demand*, which will affect both how costs are divvied up among classes and who within each class will pay them (*i.e.*, both inter- and intra-class allocations). While there is a touch of cynicism in the observation that there is no shortage of academic arguments to justify particular outcomes, it is nevertheless largely true. Always be aware of the revenue effects of a particular rate structure. Who benefits, who loses? Fixed prices, because they recover revenues by customer rather than by usage, invariably shift a larger proportion of the system s costs to the lower-volume consumers (residential and small business). The positions that interested parties take with respect to rate design should, in part, be considered in light of their impacts on class revenue burdens and on the profitability of the utility. Here the admonition to be practical cannot be stressed enough. Seemingly small changes in a rate design can have very significant consequences for different customers.[52]

52. Consider the following example (the hypothetical rates cover distribution services only). A residential customer using 500 kWh per month and paying $0.05 per delivered kWh and a monthly customer charge of $5.00 sees a monthly bill of $30. If rates were revised so that residential customers paid a fixed charge of $20 per month plus $0.02 cents per kWh, a customer using 500 kWh would receive the same total bill of $30. For this customer, the rate redesign is revenue neutral. However, for a customer using 300 kWh/month, the monthly bill under the original rate structure is $20 and, under the new rates, is $26 a 30% increase, even though there is no change in usage. For a customer using 700 kWh/month, the original bill is $40 and the revised bill is $34, a 15% reduction.

Consider again the customer using 500 kWh/month. If, under the original rate structure, she reduced her electricity use to 300 kWh per month (whether by load reduction, demand-side management, the installation of a rooftop solar electric system, or some combination of these options), she would reduce her bill by $10. However, under the revised rate structure, she would only reduce her bill by $4.

Whether the impacts of a rate design change are immediate and substantial depends, of course, on a variety of factors. The extent to which class cost allocations are altered will determine whether particular customers total bills (all else being equal) will go up or down. Even those changes that are meant to be class revenue-neutral will affect individual customer bills: as already noted, shifts from usage-based to fixed charges recover disproportionately higher revenues from low-volume users and then, more subtly, there are the effects (both positive and negative) on bills and revenues that flow from demand responses to the changes in rate structure.

5. Usage Sensitivity: What s Avoidable?

a. Peak Demand and Sizing the Wires

Distribution investment is made to serve an expected level of demand over a period of time, often determined by the useful life of the equipment. To the extent that, once a network (or component of it) is built, there is excess capacity in it, the marginal cost of using that excess capacity will be quite low (possibly very close to zero, insofar as there is little in the way of variable cost). It is this phenomenon that the short-run marginal cost of delivering a kilowatt-hour is zero that underlies the argument that there should be no per-kilowatt-hour charge for doing so.

As peak load grows, it will press up against the capacity limits of the system. At the time of constraint, the marginal cost of delivering a kilowatt-hour is, in fact, significantly greater than zero: at a minimum it is the cost of the additional investment needed to carry that marginal kilowatt-hour to end-users.[53] At that point, presumably, the new investment is made, and it is sized to minimize the total costs of delivery over the long term and thus, as before, there is suddenly excess capacity causing once again the marginal cost to fall to almost zero.

This non-linearity of investment with demand is a characteristic of much of the distribution system, the closer one gets to the end-user. To the extent that there are not an infinite number of equipment sizes to enable precise matching of investment and demand, excess capacity is almost necessarily built into the system, from substation facilities to feeders, transformers, customer service drops. But this has less to do with the finitude of equipment options than it does with the least total cost planning objective (optimizing total construction and operations costs over the investment horizon). The analytical key is to view the system over a time period long enough to smooth out the lumpiness of investment in relation to changes in demand.[54]

What emerges from such analysis is the recognition that there are costs associated with load growth, savings generated by reductions in load growth, and savings flowing from reductions in existing load. These values, not necessarily equal to each other, reflect in part the fungibility of significant portions of the system (*e.g.*, substations and feeders). Capacity unused, or freed up, by one customer can be used by others.[55]

Sometimes cited as an interesting and somewhat anomalous characteristic of some distribution investment, specifically that closest to customers (such as the service drop) is its manifestation of positive marginal costs with load growth but seemingly zero marginal (or avoided) costs with load reductions. This is because, so the argument goes, load reduction makes no capacity available for

53. And it may indeed be greater, if the value to consumers of that marginal delivery is greater than the cost of the additional investment. See Appendix A.

54. The justification for analyzing costs over the long run, and for setting prices on that basis, is discussed in Appendix A.

55. Chernick, Vol. 5, p. 68.

alternative uses, that did not already exist. This not so, however, because the inability to re-use capacity does not mean that there is no value to not using it. At the very least, future replacement costs can be deferred and the equipment installed on replacement can be down-sized, thereby reducing costs for all users.[56]

The differences in costs and savings associated with load growth, reduced growth rates, and reductions in existing load may leave some room for debate about their implications for rate design; but, given the declining-cost nature of the distribution system, these differences will probably have less of an impact than will the need to recover an embedded revenue requirement. The critical point here is that distribution costs vary primarily with load over the longer term.

b. Energy: The Costs of Throughput

As discussed earlier, to the extent that distribution investments are made to offset energy needs, there are necessarily costs associated with avoiding those investments. Losses, heat build-up, frequency of overloads, etc., are aspects of energy use that affect distribution investment and operations; thus there are marginal energy costs in distribution. Whether avoiding those costs make alternatives to distribution cost-effective is an empirical question. But, for purposes of rate design, it is sufficient to say that these marginal costs should be understood and appropriately reflected in rates. They are unquestionably volumetric in nature.

B. Conclusion: The Costs of Distribution Services

Cost studies are intended to provide useful information about the causes and magnitudes of costs, to inform a rate design process that is guided by the general principle that those who cause a cost should pay that cost. However, the usual drivers ascribed to distribution costs (both embedded and marginal) describe only part of the story, and the force-fitting of square costs into round drivers can lead to rate designs that will not best promote long-run dynamic efficiency. This is especially true of embedded cost studies, in which a central objective is to assign or allocate costs to particular services or classes of customers, even though many of those costs cannot be assigned unequivocally according to the principle of causation. By their very nature, many utility costs are joint or common to two or more services; consequently there can be no unshakeable assertion that any one service in fact caused a cost and, therefore, that a particular rate element should recover it. And marginal cost studies often suffer from this deficiency as well. This means that regulators should be very careful before relying upon what are essentially (though not necessarily

56. *Id.*, pp. 68-71. Also affected is the magnitude and cost of over-sizing equipment in order to serve forecast demand. See also NERA, pp. 17-18.

unreasonable) arbitrary cost assignments for the purposes of designing rates.[57] Too great a dependence on cost studies is to be captured by their underlying assumptions and methodological flaws. Utilities and commissions should be cautious before adopting a particular method on the basis of what may be a superficial appeal. More important, however, is the concern that a costing method, once adopted, becomes the predominant and unchallenged determinant of rate design.

Marginal cost analysis demonstrates that distribution costs vary with load in the long run. This has important implications for rate design. Embedded cost analysis, though it relies on *a priori* assumptions about causes (and allocations therefore) of historical costs, is useful in rate design at least insofar as it informs the process of reconciling marginal cost-based rates with revenue requirements.[58] We recognize that there are honest disagreements over approaches to both kinds of analysis.[59] But what is important here is for regulators to be aware of the fundamental relationships between costs and demand for electric service, in order to devise rates that best serve the objectives they seek.

57. To ensure that [embedded distribution plant] costs are properly allocated, the analyst must first classify each account as demand-related, customer-related, or a combination of both. The classification depends upon the analyst s evaluation of how the costs in these accounts were incurred. NARUC, p. 89. Interestingly, the manual, in a table on page 34, acknowledges that there is an energy-related component to embedded distribution costs, but is otherwise silent on the question.

58. Bonbright, pp. 366-367. Bonbright expresses some skepticism as to the usefulness of most embedded cost studies for rate design, on the ground that they often ignore the relationship between cost causation and apportionment. One may suspect that the choice of [allocation] formula depends, not on principles of cost imputation but rather on types of apportionment which tend to justify whatever rate structure is advocated for non-cost reasons. *Id.*, p. 368.

59. See, *e.g.*, Chernick, Vol. 5, pp. 58-83, and NARUC, pp. 86-104 and 137-146.

Zero Intercept Analysis
Account 365 -- Overhead Conductor

October 31, 2009

Description	Size	Cost	Quantity	Avg Cost
#12 conductor	6.53	15.15	1,515.00	0.01
#8 conductor	16.51	24.24	1,212.00	0.02
#6 conductor	26.24	3,499.99	18,421.00	0.19
#4 conductor	41.74	21,484.56	89,519.00	0.24
#2 conductor	66.36	650,917.73	971,519.00	0.67
#1 conductor	83.69	116,511.40	88,940.00	1.31
1/0 conductor	105.6	55,059.24	39,898.00	1.38
2/0 conductor	133.1	1,027,450.08	713,507.00	1.44
3/0 conductor	167.8	3,127,499.20	1,954,687.00	1.6
4/0 conductor	211.6	182,934.90	112,230.00	1.63
266 MCM Conductor	266	519,829.20	288,794.00	1.8
266.8 MCM Conductor	266.8	37,486.55	20,263.00	1.85
300 MCM Conductor	300	34,118.49	9,557.00	3.57
350 MCM Conductor	350	3,076.00	769.00	4
397 MCM Conductor	397	228,295.60	265,460.00	0.86
500 MCM Conductor	500	52,201.45	7,511.00	6.95
556 MCM Conductor	556	6,433.00	919.00	7
750 MCM Conductor	750	5,745.00	766.00	7.5
795 MCM Conductor	795	452,816.00	113,204.00	4
954 MCM Conductor	954	1,600.00	100.00	16
1000 MCM Conductor	1000	5,478.05	331.00	16.55

Kentucky Utilities
Electric Cost of Service Study
(Rate Base)

Acct. No.	Account Description	Allocator		Total System	Residential Rate RS	Gen. Service GSS	All Elec. Schools AES	Secondary PS	Primary PS	Sec. TOD TODS	Pri. TOD TODP	Retail Trans. RTS	Fluc. Load FLS	Outdoor Ltng. St. and POL	Lighting Energy LE	Traffic TE
RATE BASE																
Plant-in-Service																
	Intangible Plant															
301.00	ORGANIZATION	54		$38,707	$15,034	$4,614	$330	$5,948	$1,298	$936	$6,459	$2,306	$738	$1,042	$0	$3
302.00	FRANCHISE AND CONSENTS	54		$55,919	$21,719	$6,665	$477	$8,593	$1,875	$1,352	$9,331	$3,331	$1,067	$1,505	$0	$4
303.00	SOFTWARE	54		$52,331,978	$20,325,780	$6,237,639	$446,097	$8,041,550	$1,754,617	$1,265,002	$8,732,656	$3,117,615	$998,318	$1,408,402	$112	$4,190
	Sub-total			$52,426,604	$20,362,533	$6,248,918	$446,904	$8,056,090	$1,757,790	$1,267,289	$8,748,446	$3,123,252	$1,000,123	$1,410,949	$112	$4,196
	Production Plant															
	Steam Production Generation		$3,105,688,242													
	Energy	1	74.5100%	$2,314,048,309	$773,163,344	$244,002,054	$20,320,783	$397,198,649	$84,704,808	$64,201,621	$462,704,188	$189,844,302	$61,701,654	$16,048,144	$5,219	$153,544
	Demand	30	25.4900%	$791,639,933	$315,164,515	$95,657,154	$5,462,573	$124,080,721	$31,417,335	$19,415,252	$129,156,101	$54,399,940	$16,856,402	$0	$0	$29,940
330	Hydro Baseload Generation		$24,836,524													
	Energy	1	74.5100%	$18,505,694	$6,183,071	$1,951,311	$162,507	$3,176,440	$677,393	$513,427	$3,700,295	$1,518,205	$493,435	$128,339	$42	$1,228
	Demand	30	25.4900%	$6,330,830	$2,520,405	$764,981	$43,685	$992,287	$251,248	$155,266	$1,032,875	$435,042	$134,802	$0	$0	$239
340	Other Production Generation		$459,827,511													
	Energy	1	74.5100%	$342,617,478	$114,474,393	$36,126,890	$3,008,691	$58,809,144	$12,541,375	$9,505,678	$68,507,879	$28,108,305	$9,135,533	$2,376,085	$773	$22,734
	Demand	30	25.4900%	$117,210,033	$46,683,188	$14,162,977	$808,787	$18,371,364	$4,651,644	$2,874,618	$19,122,824	$8,054,443	$2,495,755	$0	$0	$4,433
	Total Production Plant			$3,590,352,277	$1,258,168,915	$392,665,366	$29,807,026	$602,628,605	$134,243,803	$96,665,862	$684,224,162	$282,360,237	$90,817,581	$18,552,567	$6,033	$212,118
	Transmission Plant															
	KENTUCKY SYSTEM PROPERTY	51		$528,497,002	$185,201,464	$57,800,030	$4,387,571	$88,706,452	$19,760,581	$14,229,138	$100,717,253	$41,563,203	$13,368,276	$2,730,923	$888	$31,224
	VIRGINIA PROPERTY - 500 KV LINE	51		$7,504,808	$2,629,914	$820,777	$62,305	$1,259,657	$280,606	$202,058	$1,430,214	$590,209	$189,833	$38,780	$13	$443
	Total Transmission Plant			$536,001,810	$187,831,378	$58,620,807	$4,449,875	$89,966,109	$20,041,187	$14,431,196	$102,147,467	$42,153,412	$13,558,109	$2,769,703	$901	$31,667
	Distribution Plant															
360-362	TOTAL ACCTS 360-362	28		$146,452,780	$66,246,846	$20,310,035	$1,912,659	$22,427,370	$5,593,088	$3,317,316	$25,510,987	$0	$0	$1,128,501	$378	$5,600
364-365	OVERHEAD LINES															
	Primary		$456,565,009													
	Customer	19	0.0000%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Demand	28	100.0000%	$456,565,009	$206,523,849	$63,316,320	$5,962,894	$69,917,091	$17,436,392	$10,341,699	$79,530,234	$0	$0	$3,518,091	$1,180	$17,459
	Secondary		$80,570,296													
	Customer	18	0.0000%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Demand	29	100.0000%	$80,570,296	$55,185,189	$12,823,843	$752,949	$9,901,109	$0	$1,496,716	$0	$0	$0	$408,136	$137	$2,217
366-367	UNDERGROUND LINES															
	Primary		$120,139,922													
	Customer	19	0.0000%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Demand	28	100.0000%	$120,139,922	$54,344,417	$16,660,974	$1,569,016	$18,397,892	$4,588,190	$2,721,301	$20,927,482	$0	$0	$925,746	$310	$4,594
	Secondary		$21,201,162													
	Customer	18	0.0000%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Demand	29	100.0000%	$21,201,162	$14,521,358	$3,374,449	$198,130	$2,605,365	$0	$393,844	$0	$0	$0	$107,396	$36	$583
368	TRANSFORMERS - POWER POOL		$5,409,429													
	Customer	18	46.1100%	$2,494,288	$1,985,953	$388,151	$3,041	$26,613	$0	$648	$0	$0	$0	$89,498	$8	$378
	Demand	29	53.8900%	$2,915,141	$1,996,674	$463,984	$27,243	$358,235	$0	$54,153	$0	$0	$0	$14,767	$5	$80
368	TRANSFORMERS - ALL OTHER		$267,984,931													
	Customer	18	46.1100%	$123,567,866	$98,384,799	$19,229,111	$150,658	$1,318,430	$0	$32,100	$0	$0	$0	$4,433,738	$286	$18,744
	Demand	29	53.8900%	$144,417,065	$98,915,896	$22,985,913	$1,349,613	$17,747,100	$0	$2,682,767	$0	$0	$0	$731,557	$245	$3,974
369	SERVICES	27		$84,507,618	$40,175,956	$26,367,088	$125,854	$1,447,098	$0	$26,815	$0	$0	$0	$16,294,865	$1,053	$68,889
370	METERS	26		$66,969,753	$42,024,614	$15,321,350	$358,057	$4,495,796	$1,650,063	$169,046	$1,193,972	$1,624,029	$59,666	$0	$1,101	$72,058
371	CUSTOMER INSTALLATION	7		$17,384,575	$0	$0	$0	$0	$0	$0	$0	$0	$0	$17,384,575	$0	$0
373	STREET LIGHTING	7		$80,975,590	$0	$0	$0	$0	$0	$0	$0	$0	$0	$80,975,590	$0	$0
	Total Distribution Plant			$1,348,161,065	$680,305,552	$201,241,216	$12,409,914	$148,642,100	$29,267,733	$21,236,405	$127,162,675	$1,624,029	$59,666	$126,012,460	$4,737	$194,578

Kentucky Utilities
Electric Cost of Service Study
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Acct. No.	Account Description	Allocator	Total System	Residential Rate RS	Gen. Service GSS	All Elec. Schools AES	Secondary PS	Primary PS	Sec. TOD TODS	Pri. TOD TODP	Retail Trans. RTS	Fluc. Load FLS	Outdoor Ltng. St. and POL	Lighting Energy LE	Traffic TE
	General Plant														
	Total General Plant	54	$124,597,128	$48,393,619	$14,851,185	$1,062,113	$19,146,114	$4,177,565	$3,011,841	$20,791,567	$7,422,725	$2,376,895	$3,353,262	$266	$9,977
	TOTAL COMMON PLANT														
106	COMPLETED CONSTR NOT CLASSIFIED														
105	PLANT HELD FOR FUTURE USE	53	$722,727	$364,701	$107,882	$6,653	$79,685	$15,690	$11,384	$68,170	$871	$32	$67,553	$3	$104
	OTHER	53	$786,955	$397,111	$117,469	$7,244	$86,766	$17,084	$12,396	$74,228	$948	$35	$73,557	$3	$114
	Construction Work In Progress														
	CWIP Production	51	$229,805,038	$80,530,693	$25,133,043	$1,907,836	$38,572,006	$8,592,444	$6,187,221	$43,794,633	$18,072,824	$5,812,894	$1,187,481	$386	$13,577
	CWIP Transmission	52	$36,186,518	$12,680,859	$3,957,604	$300,420	$6,073,786	$1,353,019	$974,278	$6,896,173	$2,845,858	$915,334	$186,988	$61	$2,138
	CWIP Distribution Plant	53	$21,196,765	$10,696,257	$3,164,060	$195,118	$2,337,059	$460,168	$333,894	$1,999,344	$25,534	$938	$1,981,259	$74	$3,059
	CWIP General Plant	54	$12,374,679	$4,806,335	$1,474,983	$105,486	$1,901,545	$414,905	$299,129	$2,064,967	$737,207	$236,067	$333,038	$26	$991
	RWIP														
	Total CWIP		$299,563,000	$108,714,143	$33,729,691	$2,508,860	$48,884,395	$10,820,538	$7,794,521	$54,755,116	$21,681,423	$6,965,234	$3,688,765	$548	$19,765
	TOTAL PLANT-IN-SERVICE		$5,653,048,566	$2,195,823,809	$673,852,844	$48,189,729	$868,605,469	$189,620,851	$136,636,374	$943,216,715	$336,685,473	$107,812,442	$152,240,050	$12,053	$462,756
	TOTAL UTILITY PLANT		$5,952,611,566	$2,304,537,952	$707,582,535	$50,698,589	$917,489,865	$200,341,389	$144,430,896	$997,971,831	$358,366,896	$114,777,675	$155,928,816	$12,601	$472,521
Accumulated Reserve for Depreciation															
	Steam Production	79	$1,079,524,091	$378,298,158	$118,064,103	$8,962,185	$181,194,503	$40,363,565	$29,064,871	$205,728,132	$84,898,265	$27,306,448	$5,578,267	$1,814	$63,778
	Hydraulic Production	80	$6,757,630	$2,368,080	$739,060	$56,102	$1,134,246	$252,669	$181,941	$1,287,822	$531,448	$170,934	$34,919	$11	$399
	Other Production	81	$154,788,757	$54,242,700	$16,928,752	$1,285,053	$25,980,774	$5,787,575	$4,167,499	$29,498,556	$12,173,232	$3,915,365	$799,846	$260	$9,145
	Transmission - Kentucky System Property	52	$254,981,613	$89,353,332	$27,886,525	$2,116,852	$42,797,810	$9,533,800	$6,865,069	$48,592,608	$20,052,815	$6,449,733	$1,317,576	$428	$15,064
	Transmission - Virginia Property	52	$3,872,987	$1,357,213	$423,576	$32,153	$650,068	$144,812	$104,275	$738,087	$304,588	$97,967	$20,013	$7	$229
	Distribution	53	$525,543,760	$265,198,534	$78,448,390	$4,837,666	$57,944,062	$11,409,226	$8,278,432	$49,570,895	$633,083	$23,259	$49,122,515	$1,847	$75,851
	General Plant	54	$49,454,286	$19,208,082	$5,894,636	$421,567	$7,599,352	$1,658,132	$1,195,440	$8,252,454	$2,946,180	$943,422	$1,330,955	$105	$3,960
	Intangible Plant	54	$16,605,338	$6,449,526	$1,979,251	$141,550	$2,551,645	$556,753	$401,395	$2,770,939	$989,243	$316,774	$446,897	$35	$1,330
	TOTAL ACCUMULATED RESERVE FOR DEPRECIATION		$2,091,528,462	$816,475,625	$250,364,295	$17,853,128	$319,852,460	$69,706,532	$50,258,924	$346,439,492	$122,528,853	$39,223,901	$58,650,988	$4,508	$169,756
Net Utility Plant			$3,861,083,104	$1,488,062,327	$457,218,240	$32,845,461	$597,637,405	$130,634,857	$94,171,972	$651,532,339	$235,838,043	$75,553,774	$97,277,828	$8,093	$302,765
Rate Base Adjustments and Working Capital															
	Working Capital Assets														
	Cash Working Capital - Operation and Maintenance Expenses	67	$96,090,910	$36,088,977	$11,659,420	$861,379	$15,181,483	$3,235,831	$2,410,694	$17,026,586	$6,583,239	$2,121,990	$912,920	$229	$8,162
	Materials and Supplies	57	$115,098,215	$44,707,806	$13,719,900	$981,161	$17,685,137	$3,858,716	$2,781,968	$19,204,250	$6,855,044	$2,195,102	$3,099,665	$245	$9,218
	Prepayments	57	$6,567,467	$2,551,013	$782,853	$55,985	$1,009,108	$220,177	$158,738	$1,095,788	$391,147	$125,252	$176,866	$14	$526
	Sub-total		$217,756,592	$83,347,796	$26,162,173	$1,898,525	$33,875,728	$7,314,725	$5,351,400	$37,326,625	$13,829,429	$4,442,344	$4,189,451	$489	$17,907
Other Rate Base Items															
	Deferred Debits														
	Service Pension Cost														
	Total Production Plant	51	$294,093,013	$103,059,159	$32,164,014	$2,441,554	$49,362,527	$10,996,161	$7,918,096	$56,046,184	$23,128,698	$7,439,052	$1,519,678	$494	$17,375
	Total Transmission Plant	52	$33,496,412	$11,738,164	$3,663,396	$278,086	$5,622,261	$1,252,436	$901,850	$6,383,511	$2,634,297	$847,288	$173,087	$56	$1,979
	Total Distribution Plant	53	$102,688,559	$51,818,435	$15,328,414	$945,255	$11,321,973	$2,229,304	$1,617,563	$9,685,899	$123,701	$4,545	$9,598,288	$361	$14,821
	Total General Plant	54	$9,365,573	$3,637,596	$1,116,317	$79,836	$1,439,153	$314,014	$226,391	$1,562,837	$557,943	$178,664	$252,054	$20	$750
	Sub-total		$439,643,557	$170,253,354	$52,272,140	$3,744,731	$67,745,914	$14,791,936	$10,663,900	$73,678,431	$26,444,639	$8,469,548	$11,543,108	$931	$34,925
	Accumulated Deferred Investment Tax Credits														
	Production	51	$86,299,724	$30,242,055	$9,438,325	$716,458	$14,485,120	$3,226,759	$2,323,515	$16,446,396	$6,786,969	$2,182,942	$445,940	$145	$5,099
	Transmission														
	Transmission VA														
	Distribution VA														
	Distribution Plant KY, FERC & TN														
	General														
	Sub-total		$86,299,724	$30,242,055	$9,438,325	$716,458	$14,485,120	$3,226,759	$2,323,515	$16,446,396	$6,786,969	$2,182,942	$445,940	$145	$5,099
	Less:														
	Customer Advances	68	$2,936,189	$1,430,603	$416,212	$36,710	$436,317	$95,314	$64,713	$434,743	$0	$0	$21,462	$7	$108
	Asset Retirement Obligations	51	$49,440,753	$17,325,547	$5,407,177	$410,456	$8,298,465	$1,848,597	$1,331,132	$9,422,072	$3,888,226	$1,250,599	$255,477	$83	$2,921
	Sub-total		$52,376,942	$18,756,150	$5,823,389	$447,166	$8,734,782	$1,943,911	$1,395,845	$9,856,815	$3,888,226	$1,250,599	$276,939	$90	$3,029

Kentucky Utilities
Electric Cost of Service Study
(Rate Base)

Acct. No.	Account Description	Allocator	Total System	Residential Rate RS	Gen. Service GSS	All Elec. Schools AES	Secondary PS	Primary PS	Sec. TOD TODS	Pri. TOD TODP	Retail Trans. RTS	Fluc. Load FLS	Outdoor Ltng. St. and POL	Lighting Energy LE	Traffic TE
	Emission Allowance														
	Emission Allowance	51	$415,671	$145,664	$45,461	$3,451	$69,769	$15,542	$11,191	$79,216	$32,690	$10,514	$2,148	$1	$25
	Sub-total		$415,671	$145,664	$45,461	$3,451	$69,769	$15,542	$11,191	$79,216	$32,690	$10,514	$2,148	$1	$25
	TOTAL OTHER RATE BASE		$473,982,010	$181,884,923	$55,932,537	$4,017,474	$73,566,020	$16,090,326	$11,602,761	$80,347,228	$29,376,072	$9,412,406	$11,714,256	$987	$37,019
TOTAL RATE BASE			$3,500,935,144	$1,352,304,228	$415,892,019	$29,839,081	$540,617,087	$118,002,517	$85,151,304	$588,956,537	$212,580,328	$68,103,543	$89,203,439	$7,416	$277,644

Kentucky Utilities
Electric Cost of Service Study
(Expenses)

Acct. No.	Account Description	Allocator	Total System	Residential Rate RS	Gen. Service GSS	All Elec. Schools AES	Secondary PS	Primary PS	Sec. TOD TODS	Pri. TOD TODP	Retail Trans. RTS	Fluc. Load FLS	Outdoor Ltng. St. and POL	Lighting Energy LE	Traffic TE
O & M Expenses															
	Steam Production O&M														
500	OPERATION SUPERVISION & ENGINEERING	60	$5,020,059	$1,745,174	$545,659	$42,088	$845,863	$187,026	$135,864	$964,743	$397,714	$128,157	$27,458	$9	$303
501	FUEL	1	$420,872,445	$140,620,723	$44,378,391	$3,695,886	$72,241,347	$15,405,867	$11,676,806	$84,155,306	$34,528,335	$11,222,119	$2,918,790	$949	$27,926
502	STEAM EXPENSES-- Labor	51	$7,897,509	$2,767,528	$863,725	$65,565	$1,325,570	$295,289	$212,631	$1,505,052	$621,093	$199,767	$40,809	$13	$467
	STEAM EXPENSES— Other	51	$7,205,827	$2,525,142	$788,078	$59,823	$1,209,474	$269,427	$194,008	$1,373,236	$566,696	$182,271	$37,235	$12	$426
505	ELECTRIC EXPENSES-Labor	51	$5,503,565	$1,928,617	$601,907	$45,690	$923,755	$205,779	$148,177	$1,048,831	$432,823	$139,212	$28,439	$9	$325
	ELECTRIC EXPENSES-- Other	51	$696,653	$244,128	$76,191	$5,784	$116,931	$26,048	$18,757	$132,763	$54,788	$17,622	$3,600	$1	$41
506	MISC. STEAM POWER EXPENSES	51	$21,102,860	$7,395,086	$2,307,952	$175,195	$3,542,044	$789,039	$568,169	$4,021,635	$1,659,617	$533,795	$109,046	$35	$1,247
507	RENTS	51	$118,990	$41,698	$13,014	$988	$19,972	$4,449	$3,204	$22,676	$9,358	$3,010	$615	$0	$7
510	MAINTENANCE SUPERVISION & ENGINEERING	61	$6,590,708	$2,211,761	$697,280	$57,591	$1,129,015	$241,717	$182,367	$1,312,268	$538,684	$174,921	$44,657	$15	$433
511	MAINTENANCE OF STRUCTURES	51	$5,063,205	$1,774,301	$553,747	$42,035	$849,842	$189,314	$136,321	$964,910	$398,192	$128,073	$26,163	$9	$299
512	MAINTENANCE OF BOILER PLANT	1	$34,867,058	$11,649,684	$3,676,515	$306,185	$5,984,814	$1,276,295	$967,362	$6,971,822	$2,860,490	$929,693	$241,806	$79	$2,314
513	MAINTENANCE OF ELECTRIC PLANT	1	$11,091,401	$3,705,828	$1,169,520	$97,399	$1,903,802	$405,996	$307,723	$2,217,775	$909,937	$295,740	$76,920	$25	$736
514	MAINTENANCE OF MISC STEAM PLANT	1	$1,928,065	$644,200	$203,303	$16,931	$330,946	$70,576	$53,493	$385,525	$158,178	$51,410	$13,371	$4	$128
	Sub-total		$527,958,345	$177,253,869	$55,875,282	$4,611,160	$90,423,376	$19,366,822	$14,604,879	$105,076,542	$43,135,905	$14,005,790	$3,568,909	$1,161	$34,651
	Hydraulic Production O&M														
535	OPERATION SUPERVISION & ENGINEERING	62	$6,861	$2,404	$750	$57	$1,152	$257	$185	$1,308	$540	$174	$35	$0	$0
536	WATER FOR POWER														
537	HYDRAULIC EXPENSES														
538	ELECTRIC EXPENSES														
539	MISC. HYDRAULIC POWER EXPENSES	51	$38,553	$13,510	$4,216	$320	$6,471	$1,442	$1,038	$7,347	$3,032	$975	$199	$0	$2
540	RENTS														
541	MAINTENANCE SUPERVISION & ENGINEERING	63	$102,609	$34,757	$10,933	$887	$17,502	$3,779	$2,823	$20,245	$8,319	$2,696	$660	$0	$7
542	MAINTENANCE OF STRUCTURES	51	$146,078	$51,190	$15,976	$1,213	$24,519	$5,462	$3,933	$27,839	$11,488	$3,695	$755	$0	$9
543	MAINT. OF RESERVES, DAMS, AND WATERWAYS	51	$36,620	$12,833	$4,005	$304	$6,147	$1,369	$986	$6,979	$2,880	$926	$189	$0	$2
544	MAINTENANCE OF ELECTRIC PLANT	1	$79,975	$26,721	$8,433	$702	$13,727	$2,927	$2,219	$15,991	$6,561	$2,132	$555	$0	$5
545	MAINTENANCE OF MISC HYDRAULIC PLANT	1	$6,837	$2,284	$721	$60	$1,174	$250	$190	$1,367	$561	$182	$47	$0	$0
	Sub-total		$417,533	$143,700	$45,035	$3,543	$70,691	$15,486	$11,373	$81,075	$33,381	$10,781	$2,441	$1	$26
	Other Power Generation Operation Expense														
546	OPERATION SUPERVISION & ENGINEERING	51	$182,409	$63,922	$19,949	$1,514	$30,617	$6,820	$4,911	$34,762	$14,345	$4,614	$943	$0	$11
547	FUEL	1	$27,501,175	$9,188,616	$2,899,828	$241,501	$4,720,485	$1,006,669	$763,001	$5,498,981	$2,256,194	$733,290	$190,723	$62	$1,825
548	GENERATION EXPENSE	51	$267,069	$93,589	$29,208	$2,217	$44,827	$9,986	$7,191	$50,896	$21,003	$6,755	$1,380	$0	$16
549	MISC OTHER POWER GENERATION	51	$140,149	$49,112	$15,328	$1,164	$23,524	$5,240	$3,773	$26,709	$11,022	$3,545	$724	$0	$8
550	RENTS	51		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
551	MAINTENANCE SUPERVISION & ENGINEERING	51	$42,784	$14,993	$4,679	$355	$7,181	$1,600	$1,152	$8,153	$3,365	$1,082	$221	$0	$3
552	MAINTENANCE OF STRUCTURES	51	$228,539	$80,087	$24,995	$1,897	$38,360	$8,545	$6,153	$43,553	$17,973	$5,781	$1,181	$0	$14
553	MAINTENANCE OF GENERATING & ELEC PLANT	51	$1,363,702	$477,883	$149,144	$11,321	$228,893	$50,989	$36,716	$259,885	$107,247	$34,495	$7,047	$2	$81
554	MAINTENANCE OF MISC OTHER POWER GEN PLT	51	$196,771	$68,955	$21,520	$1,634	$33,027	$7,357	$5,298	$37,499	$15,475	$4,977	$1,017	$0	$12
	Sub-total		$29,922,598	$10,037,156	$3,164,652	$261,604	$5,126,912	$1,097,207	$828,194	$5,960,439	$2,446,625	$794,539	$203,236	$66	$1,968
	Other Power Supply Expense														
555	PURCHASED POWER														
	Demand	51	$7,557,848	$2,648,500	$826,578	$62,745	$1,268,559	$282,589	$203,486	$1,440,322	$594,381	$191,175	$39,054	$13	$447
	Energy	1	$82,502,853	$27,565,622	$8,699,415	$724,498	$14,161,339	$3,019,984	$2,288,983	$16,496,810	$6,768,526	$2,199,851	$572,165	$186	$5,474
555	PURCHASED POWER OPTIONS														
555	BROKERAGE FEES														
555	MISO TRANSMISSION EXPENSES														
556	SYSTEM CONTROL AND LOAD DISPATCH	51	$1,594,179	$558,649	$174,350	$13,235	$267,578	$59,607	$42,921	$303,807	$125,373	$40,325	$8,238	$3	$94
557	OTHER EXPENSES	51	$345,976	$121,241	$37,838	$2,872	$58,071	$12,936	$9,315	$65,934	$27,209	$8,751	$1,788	$1	$20
	Sub-total		$92,000,856	$30,894,012	$9,738,181	$803,350	$15,755,547	$3,375,116	$2,544,705	$18,306,873	$7,515,489	$2,440,102	$621,244	$202	$6,035
Transmission Expenses															
560	OPERATION SUPERVISION AND ENG	51	$1,203,373	$421,699	$131,609	$9,990	$201,982	$44,994	$32,399	$229,330	$94,638	$30,439	$6,218	$2	$71
561	LOAD DISPATCHING	51	$2,285,040	$800,748	$249,908	$18,970	$383,536	$85,438	$61,522	$435,467	$179,705	$57,800	$11,808	$4	$135
562	STATION EXPENSES	51	$619,141	$216,966	$67,713	$5,140	$103,921	$23,150	$16,670	$117,992	$48,692	$15,661	$3,199	$1	$37
563	OVERHEAD LINE EXPENSES	51	$391,173	$137,079	$42,781	$3,248	$65,657	$14,626	$10,532	$74,547	$30,763	$9,895	$2,021	$1	$23
565	TRANSMISSION OF ELECTRICITY BY OTHERS	51	$1,918,210	$672,199	$209,789	$15,925	$321,965	$71,722	$51,645	$365,559	$150,856	$48,521	$9,912	$3	$113
566	MISC. TRANSMISSION EXPENSES	51	$9,779,438	$3,427,013	$1,069,546	$81,189	$1,641,446	$365,655	$263,299	$1,863,697	$769,096	$247,370	$50,534	$16	$578
567	RENTS	51	$114,629	$40,169	$12,537	$952	$19,240	$4,286	$3,086	$21,845	$9,015	$2,900	$592	$0	$7
568	MAINTENACE SUPERVISION AND ENG														
569	STRUCTURES														
570	MAINT OF STATION EQUIPMENT	51	$1,568,775	$549,747	$171,572	$13,024	$263,314	$58,657	$42,237	$298,966	$123,375	$39,682	$8,106	$3	$93
571	MAINT OF OVERHEAD LINES	51	$3,755,066	$1,315,890	$410,680	$31,174	$630,275	$140,402	$101,101	$715,614	$295,314	$94,984	$19,404	$6	$222
572	UNDERGROUND LINES														
573	MISC PLANT	51	$546,407	$191,478	$59,759	$4,536	$91,713	$20,430	$14,711	$104,130	$42,972	$13,821	$2,823	$1	$32
575	MISO DAY 1&2 EXPENSE	51	$1,224,445	$429,083	$133,914	$10,165	$205,519	$45,782	$32,967	$233,346	$96,295	$30,972	$6,327	$2	$72
	Sub-total		$23,405,697	$8,202,070	$2,559,806	$194,314	$3,928,568	$875,142	$630,170	$4,460,494	$1,840,721	$592,045	$120,945	$39	$1,383
	Distribution Expense - Operating														
580	OPERATION SUPERVISION AND ENGI	64	$1,886,829	$1,030,940	$340,347	$16,351	$197,076	$51,235	$22,927	$155,163	$20,140	$740	$50,933	$16	$960
581	LOAD DISPATCHING	28	$705,213	$318,998	$97,799	$9,210	$107,994	$26,932	$15,974	$122,843	$0	$0	$5,434	$2	$27
582	STATION EXPENSES	28	$1,404,339	$635,242	$194,753	$18,341	$215,057	$53,632	$31,810	$244,625	$0	$0	$10,821	$4	$54
583	OVERHEAD LINE EXPENSES	55	$3,298,413	$1,607,069	$467,558	$41,239	$490,144	$107,073	$72,697	$488,375	$0	$0	$24,110	$8	$121
584	UNDERGROUND LINE EXPENSES	58	$255,302	$124,391	$36,190	$3,192	$37,938	$8,288	$5,627	$37,801	$0	$0	$1,866	$1	$9
585	STREET LIGHTING EXPENSE	15	$21,918	$0	$0	$0	$0	$0	$0	$0	$0	$0	$21,918	$0	$0
586	METER EXPENSES	26	$7,329,419	$4,599,330	$1,676,826	$39,187	$492,037	$180,589	$18,501	$130,673	$177,740	$6,530	$0	$120	$7,886

Kentucky Utilities
Electric Cost of Service Study
(Expenses)

Acct. No.	Account Description	Allocator	Total System	Residential Rate RS	Gen. Service GSS	All Elec. Schools AES	Secondary PS	Primary PS	Sec. TOD TODS	Pri. TOD TODP	Retail Trans. RTS	Fluc. Load FLS	Outdoor Ltng. St. and POL	Lighting Energy LE	Traffic TE
586	METER EXPENSES - LOAD MANAGEMENT														
587	CUSTOMER INSTALLATIONS EXPENSE	7	($70,814)	$-0	$-0	$-0	$-0	$-0	$-0	$-0	$-0	$-0	($70,814)	$-0	$-0
588	MISCELLANEOUS DISTRIBUTION EXP	53	$4,706,180	$2,374,820	$702,496	$43,321	$518,882	$102,168	$74,132	$443,901	$5,669	$208	$439,886	$17	$679
588	MISC DISTR EXP -- MAPPING														
589	RENTS	53	$10,707	$5,403	$1,598	$99	$1,181	$232	$169	$1,010	$13	$0	$1,001	$0	$2
590	MAINTENANCE SUPERVISION AND EN	65	$133,026	$64,943	$18,868	$1,653	$19,645	$4,298	$2,912	$19,598	$2	$0	$1,101	$0	$5
591	STRUCTURES														
592	MAINTENANCE OF STATION EQUIPMENT	28	$649,934	$293,993	$90,133	$8,488	$99,529	$24,821	$14,722	$113,214	$0	$0	$5,008	$2	$25
593	MAINTENANCE OF OVERHEAD LINES	55	$29,856,454	$14,546,994	$4,232,221	$373,286	$4,436,663	$969,195	$658,034	$4,420,657	$0	$0	$218,238	$73	$1,094
594	MAINTENANCE OF UNDERGROUND LINES	58	$476,335	$232,085	$67,522	$5,955	$70,783	$15,463	$10,498	$70,528	$0	$0	$3,482	$1	$17
595	MAINTENANCE OF LINE TRANSFORMER	70	$187,044	$137,709	$29,465	$1,047	$13,307	$0	$1,895	$0	$0	$0	$3,605	$0	$16
596	MAINTENANCE OF ST LIGHTS & SIG SYSTEMS														
597	MAINTENANCE OF METERS														
598	MISCELLANEOUS DISTRIBUTION EXPENSES	53	$127,093	$64,133	$18,971	$1,170	$14,013	$2,759	$2,002	$11,988	$153	$6	$11,879	$0	$18
	Sub-total		$50,977,392	$26,036,071	$7,974,745	$562,540	$6,714,248	$1,546,685	$931,899	$6,260,376	$203,716	$7,484	$728,469	$245	$10,913
	Customer Accounts Expense														
901	SUPERVISION/CUSTOMER ACCTS	6	$2,581,408	$1,674,842	$654,273	$25,500	$112,221	$5,917	$13,647	$16,535	$2,869	$199	$75,102	$4	$299
902	METER READING EXPENSES	6	$4,654,897	$3,020,141	$1,179,811	$45,983	$202,362	$10,670	$24,608	$29,817	$5,173	$359	$135,427	$7	$539
903	RECORDS AND COLLECTION	6	$13,547,808	$8,789,944	$3,433,772	$133,831	$588,961	$31,053	$71,621	$86,781	$15,056	$1,046	$394,154	$21	$1,568
904	UNCOLLECTIBLE ACCOUNTS	6	$5,121,451	$3,322,845	$1,298,062	$50,592	$222,644	$11,739	$27,075	$32,806	$5,692	$395	$149,001	$8	$593
905	MISC CUST ACCOUNTS	6	$709,907	$460,594	$179,930	$7,013	$30,862	$1,627	$3,753	$4,547	$789	$55	$20,654	$1	$82
	Sub-total		$26,615,471	$17,268,366	$6,745,848	$262,919	$1,157,050	$61,005	$140,703	$170,487	$29,578	$2,054	$774,338	$41	$3,081
	Customer Service & Information Expense														
907	SUPERVISION	6	$205,546	$133,360	$52,097	$2,030	$8,936	$471	$1,087	$1,317	$228	$16	$5,980	$0	$24
908	CUSTOMER ASSISTANCE EXPENSES	6	$13,664,342	$8,865,553	$3,463,308	$134,982	$594,028	$31,320	$72,237	$87,528	$15,186	$1,055	$397,544	$21	$1,582
908	CUSTOMER ASSISTANCE EXP-INCENTIVES														
909	INFORMATIONAL AND INSTRUCTIONAL	6	$148,605	$96,416	$37,665	$1,468	$6,460	$341	$786	$952	$165	$11	$4,323	$0	$17
909	INFORM AND INSTRUC -LOAD MGMT														
910	MISCELLANEOUS CUSTOMER SERVICE	6	$417,350	$270,781	$105,780	$4,123	$18,143	$957	$2,206	$2,673	$464	$32	$12,142	$1	$48
911	DEMONSTRATION AND SELLING EXP														
912	DEMONSTRATION AND SELLING EXP														
913	ADVERTISING EXPENSES	6	$22,672	$14,710	$5,746	$224	$986	$52	$120	$145	$25	$2	$660	$0	$3
915	MDSE-JOBBING-CONTRACT														
916	MISC SALES EXPENSE														
	Sub-total		$14,458,515	$9,380,820	$3,664,596	$142,827	$628,552	$33,140	$76,435	$92,615	$16,068	$1,116	$420,649	$22	$1,674
	General Expenses														
920	ADMIN. & GEN. SALARIES	66	$19,422,909	$8,484,975	$2,826,270	$176,869	$2,663,825	$572,091	$406,560	$2,771,624	$963,197	$301,503	$253,321	$57	$2,617
921	OFFICE SUPPLIES AND EXPENSES	66	$6,626,712	$2,894,905	$964,267	$60,344	$908,844	$195,186	$138,710	$945,623	$328,624	$102,867	$86,428	$19	$893
922	ADMINISTRATIVE EXPENSES TRANSFERRED	66	($2,579,862)	($1,127,023)	($375,401)	($23,493)	($353,825)	($75,988)	($54,002)	($368,143)	($127,937)	($40,047)	($33,648)	($8)	($348)
923	OUTSIDE SERVICES EMPLOYED	66	$7,878,029	$3,441,548	$1,146,349	$71,739	$1,080,461	$232,043	$164,903	$1,124,185	$390,678	$122,291	$102,748	$23	$1,061
924	PROPERTY INSURANCE	23	$3,722,836	$1,441,286	$442,531	$31,708	$573,809	$125,296	$90,329	$624,144	$224,127	$71,783	$97,520	$8	$296
925	INJURIES AND DAMAGES - INSURANCE	66	$3,166,637	$1,383,358	$460,784	$28,836	$434,300	$93,272	$66,284	$451,875	$157,036	$49,156	$41,300	$9	$427
926	EMPLOYEE BENEFITS	66	$35,853,084	$15,662,562	$5,217,060	$326,486	$4,917,201	$1,056,033	$750,476	$5,116,189	$1,777,982	$556,550	$467,609	$104	$4,831
928	REGULATORY COMMISSION FEES	23	$1,496,158	$579,234	$177,847	$12,743	$230,606	$50,355	$36,302	$250,835	$90,074	$28,849	$39,192	$3	$119
929	DUPLICATE CHARGES														
930	MISCELLANEOUS GENERAL EXPENSES	66	$3,577,675	$1,562,922	$520,595	$32,579	$490,673	$105,378	$74,888	$510,530	$177,420	$55,537	$46,661	$10	$482
931	RENTS AND LEASES	59	$2,113,482	$820,878	$251,914	$18,016	$324,766	$70,862	$51,088	$352,677	$125,908	$40,318	$56,880	$5	$169
932	MAINTENANCE OF GENERAL PLANT														
935	MAINTENANCE OF GENERAL PLANT	59	$11,753,914	$4,565,229	$1,400,992	$100,195	$1,806,155	$394,092	$284,123	$1,961,380	$700,225	$224,225	$316,331	$25	$941
	Sub-total		$93,031,574	$39,709,875	$13,033,208	$836,021	$13,076,818	$2,818,620	$2,009,661	$13,740,919	$4,807,334	$1,513,032	$1,474,343	$256	$11,488
	TOTAL O & M EXPENSES		$858,787,981	$318,925,939	$102,801,353	$7,678,278	$136,881,761	$29,189,224	$21,778,019	$154,149,819	$60,028,817	$19,366,944	$7,914,576	$2,033	$71,219
	TOTAL O&M EXPENSE Less PURCHASED POWER		$768,727,280	$288,711,816	$93,275,360	$6,891,035	$121,461,863	$25,886,651	$19,285,550	$136,212,688	$52,665,910	$16,975,918	$7,303,356	$1,834	$66,298
	Depreciation Expense														
	Steam Production	51	$98,366,735	$34,470,703	$10,758,056	$816,638	$16,510,527	$3,677,947	$2,648,405	$18,746,043	$7,735,969	$2,488,176	$508,294	$165	$5,812
	Hydraulic Production	51	$129,934	$45,533	$14,210	$1,079	$21,809	$4,858	$3,498	$24,762	$10,219	$3,287	$671	$0	$8
	Other Production	51	$14,936,094	$5,234,063	$1,633,513	$123,999	$2,506,973	$558,463	$402,136	$2,846,416	$1,174,637	$377,807	$77,180	$25	$882
	Transmission - Kentucky System Property	52	$9,156,938	$3,208,870	$1,001,465	$76,021	$1,536,961	$342,379	$246,539	$1,745,065	$720,140	$231,624	$47,317	$15	$541
	Transmission - Virginia Property	52	$133,401	$46,748	$14,590	$1,107	$22,391	$4,988	$3,592	$25,423	$10,491	$3,374	$689	$0	$8
	Distribution	53	$32,743,234	$16,522,806	$4,887,612	$301,404	$3,610,120	$710,835	$515,776	$3,088,442	$39,443	$1,449	$3,060,506	$115	$4,726
	General Plant	59	$5,699,724	$2,213,777	$679,371	$48,587	$875,843	$191,104	$137,777	$951,115	$339,554	$108,732	$153,396	$12	$456
	Intangible Plant	56	$6,534,688	$2,538,078	$778,893	$55,704	$1,004,147	$219,099	$157,961	$1,090,446	$389,296	$124,660	$175,867	$14	$523
	TOTAL DEPRECIATION EXPENSES		$167,700,748	$64,280,578	$19,767,710	$1,424,539	$26,088,772	$5,709,673	$4,115,684	$28,517,711	$10,419,749	$3,339,109	$4,023,921	$347	$12,956
	Other Expenses														
	Regulatory Credits and Accretion Expense														
	Production	51	($2,647,544)	($927,780)	($289,553)	($21,980)	($444,381)	($98,992)	($71,282)	($504,550)	($208,214)	($66,969)	($13,681)	($4)	($156)
	Transmission	52	($5,404)	($1,894)	($591)	($45)	($907)	($202)	($145)	($1,030)	($425)	($137)	($28)	($0)	($0)
	Distribution	53	($12,404)	($6,259)	($1,852)	($114)	($1,368)	($269)	($195)	($1,170)	($15)	($1)	($1,159)	($0)	($2)
	Property Taxes & Other	23	$17,000,077	$6,581,535	$2,020,787	$144,790	$2,620,261	$572,155	$412,481	$2,850,110	$1,023,461	$327,794	$445,317	$36	$1,349
	Other Taxes	23	$8,845,973	$3,424,695	$1,051,514	$75,341	$1,363,450	$297,721	$214,634	$1,483,052	$532,557	$170,567	$231,720	$19	$702
	Gain on Disposition of Allowances	1	($767)	($256)	($81)	($7)	($132)	($28)	($21)	($153)	($63)	($20)	($5)	($0)	($0)

Kentucky Utilities
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Acct. No.	Account Description	Allocator	Total System	Residential Rate RS	Gen. Service GSS	All Elec. Schools AES	Secondary PS	Primary PS	Sec. TOD TODS	Pri. TOD TODP	Retail Trans. RTS	Fluc. Load FLS	Outdoor Ltng. St. and POL	Lighting Energy LE	Traffic TE
	Interest	23	$59,882,590	$23,183,388	$7,118,199	$510,022	$9,229,843	$2,015,411	$1,452,958	$10,039,482	$3,605,130	$1,154,650	$1,568,626	$127	$4,754
	Other Expenses														
	Total Other Expenses		$83,062,521	$32,253,429	$9,898,423	$708,008	$12,766,767	$2,785,796	$2,008,429	$13,865,741	$4,952,431	$1,585,884	$2,230,791	$177	$6,647
TOTAL EXPENSES BEFORE INCOME TAX & PROFORMA ADJUSTMENTS			$1,109,551,250	$415,459,945	$132,467,486	$9,810,825	$175,737,300	$37,684,692	$27,902,131	$196,533,271	$75,400,997	$24,291,937	$14,169,287	$2,557	$90,822
Calculation of Taxable Income Before Proforma Adjustments															
	Total Operating Revenue		$1,342,076,920	$495,746,733	$187,157,042	$11,472,511	$229,350,647	$53,138,237	$26,333,984	$210,446,101	$89,022,911	$15,784,061	$23,512,840	$2,333	$109,519
	O&M Expenses		$858,787,981	$318,925,939	$102,801,353	$7,678,278	$136,881,761	$29,189,224	$21,778,019	$154,149,819	$60,028,817	$19,366,944	$7,914,575	$2,033	$71,219
	Depreciation Expense		$167,700,748	$64,280,578	$19,767,710	$1,424,539	$26,088,772	$5,709,673	$4,115,684	$28,517,711	$10,419,749	$3,339,109	$4,023,921	$347	$12,956
	Regulatory Credits & Accretion		($2,665,352)	($935,933)	($291,996)	($22,139)	($446,656)	($99,463)	($71,623)	($506,750)	($208,654)	($67,107)	($14,868)	($5)	($159)
	Property Taxes		$17,000,077	$6,581,535	$2,020,787	$144,790	$2,620,261	$572,155	$412,481	$2,850,110	$1,023,461	$327,794	$445,317	$36	$1,349
	Other Taxes		$8,845,973	$3,424,695	$1,051,514	$75,341	$1,363,450	$297,721	$214,634	$1,483,052	$532,557	$170,567	$231,720	$19	$702
	Gain/Disposition of Allowance		($767)	($256)	($81)	($7)	($132)	($28)	($21)	($153)	($63)	($20)	($5)	($0)	($0)
	Assignment of Curtailable Service Rider Avoided Cost	Dir	($5,672,873)					($70,827)		($190,332)		($5,411,714)			
	Allocation of Curtailable Service Rider Credits	88	$5,672,873	$2,258,461	$685,477	$39,145	$889,160	$225,136	$139,129	$925,530	$389,829	$120,793	$0	$0	$215
	Subtotal Expenses		$1,049,668,660	$394,535,019	$126,034,764	$9,339,947	$167,396,617	$35,823,589	$26,588,302	$187,228,986	$72,185,696	$17,846,365	$12,600,661	$2,430	$86,283
	Interest		$59,882,590	$23,183,388	$7,118,199	$510,022	$9,229,843	$2,015,411	$1,452,958	$10,039,482	$3,605,130	$1,154,650	$1,568,626	$127	$4,754
	Taxable Income		$232,525,670	$78,028,327	$54,004,079	$1,622,542	$52,724,187	$15,299,236	($1,707,277)	$13,177,633	$13,232,085	($3,216,954)	$9,343,554	($224)	$18,483
	Income Taxes Before Proforma Adjustments	Tax Income	$89,659,334	$30,086,862	$20,823,377	$625,634	$20,329,865	$5,899,217	($658,307)	$5,081,150	$5,102,146	($1,240,422)	$3,602,771	($86)	$7,127
Proforma Adjustments															
	Revenue Adjustments		($54,380,384)	($22,058,875)	($10,457,241)	($219,327)	($8,345,215)	($6,487,097)	$2,045,998	($2,598,523)	($4,440,930)	($1,545,131)	($283,241)	($37)	$9,234
	Proforma Expense Adjustments:														
	Eliminate mismatch in fuel cost recovery	2	($12,785,149)	($4,275,357)	($1,368,498)	($113,092)	($2,202,932)	($503,710)	($326,111)	($2,515,431)	($1,049,616)	($340,903)	($88,666)	($29)	($805)
	Remove ECR expenses	49	($9,309,387)	($3,527,954)	($1,641,706)	($78,630)	($1,743,615)	($433,824)	($138,668)	($1,036,325)	($436,180)	($107,761)	($164,054)	($7)	($664)
	Adjust base expenses for full year of ECR roll-in														
	Adjustment to reflect changes to FAC calculations	43	($2,614,696)	($799,275)	($284,366)	($25,067)	($468,460)	($139,321)	($60,973)	($490,795)	($246,570)	($81,125)	($18,596)	($6)	($142)
	Eliminate brokered sales expenses	2	($6,018)	($2,012)	($644)	($53)	($1,037)	($237)	($154)	($1,184)	($494)	($160)	($42)	($0)	($0)
	Eliminate DSM expenses	48	($13,589,518)	($10,081,286)	($2,740,196)	($34,141)	($465,083)	($85,849)	($61,808)	($121,155)	$-0	$-0	$-0	$-0	$-0
	Year end adjustment	86	($1,909,033)	($397,728)	$23,924	$41,176	($875,036)	$96,141	$65,172	($1,017,045)	$93,512	$0	$54,652	$0	$6,198
	Annualized depreciation expense under current rates	71	$712,846	$273,238	$84,027	$6,055	$110,896	$24,270	$17,495	$121,220	$44,291	$14,194	$17,104	$1	$55
	Labor adjustment	72	$2,883,454	$1,254,426	$416,741	$26,195	$397,242	$85,370	$60,706	$414,071	$144,069	$45,143	$39,102	$8	$383
	Pension & post retirement expense adjustment	72	($4,067,870)	($1,769,697)	($587,922)	($36,954)	($560,414)	($120,436)	($85,641)	($584,156)	($203,247)	($63,686)	($55,164)	($12)	($540)
	Property insurance expense adjustment	22	$1,079,050	$415,866	$127,778	$9,179	$167,021	$36,508	$26,318	$182,083	$65,909	$21,115	$27,186	$2	$85
	Remove out of period items	69	($475,875)	($183,816)	($56,531)	($4,056)	($73,485)	($16,040)	($11,574)	($80,056)	($28,896)	($9,257)	($12,125)	($1)	($38)
	Normalized storm damage expenses	39	($834,318)	($460,506)	($133,321)	($8,162)	($97,988)	($17,730)	($14,289)	($80,872)	$-0	$-0	($21,353)	($3)	($94)
	Eliminate advertising expenses	74	($808,453)	($296,767)	($113,580)	($6,954)	($139,063)	($32,200)	($15,772)	($126,669)	($53,651)	($9,222)	($14,506)	($1)	($67)
	Adjustment for transfer of ITO functions	52	($3,328,434)	($1,166,385)	($364,020)	($27,633)	($558,666)	($124,451)	($89,614)	($634,310)	($261,762)	($84,192)	($17,199)	($6)	($197)
	Amortization of rate case expenses	78	($25,313)	($9,400)	($3,030)	($226)	($4,035)	($860)	($642)	($4,544)	($1,769)	($571)	($233)	($0)	($2)
	Adjustment for injuries and damages FERC account 925	22	($1,233,028)	($475,209)	($146,012)	($10,489)	($190,854)	($41,718)	($30,074)	($208,065)	($75,314)	($24,128)	($31,065)	($3)	($97)
	MISO exit free regulatory asset amortization	52	($1,509,951)	($529,133)	($165,139)	($12,536)	($253,440)	($56,457)	($40,654)	($287,756)	($118,749)	($38,194)	($7,802)	($3)	($89)
	General Management Audit regulatory asset amortization	78	$47,507	$17,643	$5,687	$425	$7,572	$1,615	$1,205	$8,527	$3,321	$1,071	$438	$0	$4
	Subtotal Expense Adjustments		($47,774,186)	($22,013,354)	($8,946,809)	($274,963)	($6,951,379)	($1,328,929)	($705,079)	($6,462,462)	($2,125,146)	($677,676)	($292,323)	($57)	$3,990
	Net Adjustments before Tax		($6,606,198)	($45,521)	($3,510,432)	$55,636	($1,393,836)	($5,158,167)	$2,751,077	$3,863,939	($2,315,784)	($867,455)	$9,083	$20	$5,243
	Federal & State Income tax adjustment	Net Adj Before Tax	($2,427,596)	($16,728)	($1,289,987)	$20,445	($512,196)	($1,895,485)	$1,010,945	$1,419,891	($850,987)	($318,766)	$3,338	$7	$1,927
	Federal & Stae income tax interest adjustment	Tax Income	$145,218	$48,731	$33,727	$1,013	$32,928	$9,555	($1,066)	$8,230	$8,264	($2,009)	$5,835	($0)	$12
	Adjustment for tax basis depreciation reduction	Tax Income	($331,159)	($111,127)	($76,912)	($2,311)	($75,089)	($21,789)	$2,431	($18,767)	($18,845)	$4,582	($13,307)	$0	($26)
	Prior income tax true-ups & adjustments	Tax Income	($436,228)	($146,384)	($101,314)	($3,044)	($98,913)	($28,702)	$3,203	($24,722)	($24,824)	$6,035	($17,529)	$0	($35)
	Total Expense Adjustments		($50,823,951)	($22,238,862)	($8,381,295)	($258,860)	($7,604,649)	($3,265,350)	$310,434	($5,077,830)	($3,011,538)	($987,834)	($313,986)	($49)	$5,868
	Total Expenses After Adjustment		$1,088,504,043	$402,383,020	$138,476,846	$9,706,722	$180,121,833	$38,457,456	$26,240,430	$187,232,306	$74,276,304	$15,618,109	$15,889,446	$2,295	$99,277
	Net Operating Income After Adjustments														
	Total Proforma Rev		$1,287,696,536	$473,687,859	$176,699,801	$11,253,184	$221,005,432	$46,651,140	$28,379,982	$207,847,578	$84,581,981	$14,238,930	$23,229,600	$2,296	$118,753
	Total Proforma Operating Expenses		$1,088,504,043	$402,383,020	$138,476,846	$9,706,722	$180,121,833	$38,457,456	$26,240,430	$187,232,306	$74,276,304	$15,618,109	$15,889,446	$2,295	$99,277
	Net Operating Income After Adjustments		$199,192,493	$71,304,839	$38,222,955	$1,546,462	$40,883,599	$8,193,684	$2,139,552	$20,615,272	$10,305,677	($1,379,178)	$7,340,154	$1	$19,476
	Rate Base before Adjustments		$3,500,935,144	$1,352,304,228	$415,892,019	$29,839,081	$540,617,067	$118,002,517	$85,151,304	$588,956,537	$212,580,328	$68,103,543	$89,203,439	$7,416	$277,644
	ECR Plan Eliminations	51	($183,667,066)	($64,362,540)	($20,087,081)	($1,524,800)	($30,827,902)	($6,867,339)	($4,945,012)	($35,001,982)	($14,444,342)	($4,645,839)	($949,070)	($309)	($10,851)
	Adjustment to Depreciation reserve	71	($712,846)	($273,238)	($84,027)	($6,055)	($110,896)	($24,270)	($17,495)	($121,220)	($44,291)	($14,194)	($17,104)	($1)	($55)
	Adj to Cash Working Capital	87	($5,709,964)	($2,475,789)	($819,850)	($52,646)	($792,988)	($168,866)	($122,018)	($829,854)	($283,069)	($89,485)	($74,751)	($15)	($634)
	Adjusted Rated Base		$3,310,845,268	$1,285,192,661	$394,901,062	$28,255,580	$508,885,301	$110,942,042	$80,066,779	$553,003,481	$197,808,626	$63,354,025	$88,162,514	$7,091	$266,104
	ROR		6.02%	5.55%	9.68%	5.47%	8.03%	7.39%	2.67%	3.73%	5.21%	-2.18%	8.33%	0.01%	7.32%

Kentucky Utilities
Electric Cost of Service Study
(Labor)

Acct. No.	Account Description	Allocator	Total System	Residential Rate RS	Gen. Service GSS	All Elec. Schools AES	Secondary PS	Primary PS	Sec. TOD TODS	Pri. TOD TODP	Retail Trans. RTS	Fluc. Load FLS	Outdoor Ltng. St. and POL	Lighting Energy LE	Traffic TE
	Labor O & M Expenses														
Labor Expenses															
Steam Power Generation Operation Expenses															
500	OPERATION SUPERVISION & ENGINEERING	60	$4,189,374	$1,456,395	$455,367	$35,124	$705,895	$156,078	$113,382	$805,104	$331,903	$106,951	$22,915	$7	$253
501	FUEL	1	$3,035,692	$1,014,277	$320,095	$26,658	$521,066	$111,120	$84,223	$607,000	$249,048	$80,944	$21,053	$7	$201
502	STEAM EXPENSES	51	$7,897,509	$2,767,528	$863,725	$65,565	$1,325,570	$295,289	$212,631	$1,505,052	$621,093	$199,767	$40,809	$13	$467
505	ELECTRIC EXPENSES	51	$5,503,565	$1,928,617	$601,907	$45,690	$923,755	$205,779	$148,177	$1,048,831	$432,823	$139,212	$28,439	$9	$325
506	MISC. STEAM POWER EXPENSES	51	$1,311,016	$459,420	$143,382	$10,884	$220,050	$49,019	$35,298	$249,844	$103,104	$33,162	$6,774	$2	$77
507	RENTS														
	Total Steam Power Operation Expenses		$21,937,156	$7,626,237	$2,384,477	$183,921	$3,696,337	$817,286	$593,710	$4,215,831	$1,737,971	$560,035	$119,990	$39	$1,323
Steam Power Generation Maintenance Expenses															
510	MAINTENANCE SUPERVISION & ENGINEERING	61	$5,688,357	$1,908,943	$601,814	$49,706	$974,439	$208,623	$157,399	$1,132,602	$464,931	$150,972	$38,543	$13	$374
511	MAINTENANCE OF STRUCTURES	51	$989,589	$346,782	$108,228	$8,216	$166,099	$37,001	$26,643	$188,589	$77,825	$25,032	$5,114	$2	$58
512	MAINTENANCE OF BOILER PLANT	1	$7,837,920	$2,618,784	$826,460	$68,829	$1,345,353	$286,904	$217,458	$1,567,227	$643,022	$208,990	$54,357	$18	$520
513	MAINTENANCE OF ELECTRIC PLANT	1	$1,958,591	$654,399	$206,521	$17,199	$336,186	$71,693	$54,340	$391,629	$160,683	$52,224	$13,583	$4	$130
514	MAINTENANCE OF MISC STEAM PLANT	1	$192,076	$64,176	$20,253	$1,687	$32,969	$7,031	$5,329	$38,406	$15,758	$5,122	$1,332	$0	$13
	Total Steam Power Generation Maintenance Expense		$16,666,533	$5,593,084	$1,763,276	$145,637	$2,855,046	$611,252	$461,168	$3,318,453	$1,362,219	$442,339	$112,928	$37	$1,095
	Total Steam Power Generation Expense		$38,603,689	$13,219,320	$4,147,753	$329,558	$6,551,382	$1,428,538	$1,054,878	$7,534,284	$3,100,190	$1,002,374	$232,918	$76	$2,418
Hydraulic Power Generation Operation Expenses															
535	OPERATION SUPERVISION & ENGINEERING	62	$6,807	$2,385	$744	$57	$1,143	$255	$183	$1,297	$535	$172	$35	$0	$0
536	WATER FOR POWER														
537	HYDRAULIC EXPENSES														
538	ELECTRIC EXPENSES														
539	MISC. HYDRAULIC POWER EXPENSES	51	$4,595	$1,610	$503	$38	$771	$172	$124	$876	$361	$116	$24	$0	$0
540	RENTS														
	Total Hydraulic Power Operation Expenses		$11,402	$3,996	$1,247	$95	$1,914	$426	$307	$2,173	$897	$288	$59	$0	$1
Hydraulic Power Generation Maintenance Expenses															
541	MAINTENANCE SUPERVISION & ENGINEERING	63	$93,176	$31,562	$9,928	$806	$15,893	$3,431	$2,563	$18,383	$7,555	$2,448	$600	$0	$6
542	MAINTENANCE OF STRUCTURES	51	$19,320	$6,770	$2,113	$160	$3,243	$722	$520	$3,682	$1,519	$489	$100	$0	$1
543	MAINT. OF RESERVES, DAMS, AND WATERWAYS														
544	MAINTENANCE OF ELECTRIC PLANT	1	$45,888	$15,332	$4,839	$403	$7,877	$1,680	$1,273	$9,176	$3,765	$1,224	$318	$0	$3
545	MAINTENANCE OF MISC HYDRAULIC PLANT	1	$3,037	$1,015	$320	$27	$521	$111	$84	$607	$249	$81	$21	$0	$0
	Total Hydraulic Power Generation Maint. Expense		$161,421	$54,679	$17,200	$1,396	$27,534	$5,945	$4,441	$31,848	$13,088	$4,242	$1,039	$0	$10
	Total Hydraulic Power Generation Expense		$172,823	$58,675	$18,447	$1,490	$29,448	$6,371	$4,748	$34,021	$13,984	$4,530	$1,098	$0	$11
Other Power Generation Operation Expense															
546	OPERATION SUPERVISION & ENGINEERING	51	$173,570	$60,824	$18,983	$1,441	$29,133	$6,490	$4,673	$33,078	$13,650	$4,390	$897	$0	$10
547	FUEL														
548	GENERATION EXPENSE	51	$206,772	$72,459	$22,614	$1,717	$34,706	$7,731	$5,567	$39,405	$16,261	$5,230	$1,068	$0	$12
549	MISC OTHER POWER GENERATION	51	$18,378	$6,440	$2,010	$153	$3,085	$687	$495	$3,502	$1,445	$465	$95	$0	$1
550	RENTS														
	Total Other Power Generation Expenses		$398,720	$139,724	$43,607	$3,310	$66,924	$14,908	$10,735	$75,985	$31,357	$10,086	$2,060	$1	$24
Other Power Generation Maintenance Expense															
551	MAINTENANCE SUPERVISION & ENGINEERING	51	$35,796	$12,544	$3,915	$297	$6,008	$1,338	$964	$6,822	$2,815	$905	$185	$0	$2
552	MAINTENANCE OF STRUCTURES	51	$111,975	$39,239	$12,246	$930	$18,795	$4,187	$3,015	$21,339	$8,806	$2,832	$579	$0	$7
553	MAINTENANCE OF GENERATING & ELEC PLANT	51	$546,106	$191,372	$59,726	$4,534	$91,662	$20,419	$14,703	$104,073	$42,948	$13,814	$2,822	$1	$32
554	MAINTENANCE OF MISC OTHER POWER GEN PLT	51	$74,961	$26,269	$8,198	$622	$12,582	$2,803	$2,018	$14,286	$5,895	$1,896	$387	$0	$4
	Total Other Power Generation Maintenance Expense		$768,838	$269,424	$84,085	$6,383	$129,047	$28,747	$20,700	$146,520	$60,465	$19,448	$3,973	$1	$45
	Total Other Power Generation Expense		$1,167,558	$409,148	$127,692	$9,693	$195,971	$43,655	$31,435	$222,505	$91,822	$29,533	$6,033	$2	$69
	Total Production Expense		$39,944,070	$13,687,143	$4,293,892	$340,741	$6,776,801	$1,478,564	$1,091,061	$7,790,810	$3,205,996	$1,036,437	$240,049	$78	$2,498
Purchased Power															
555	PURCHASED POWER														
556	SYSTEM CONTROL AND LOAD DISPATCH	51	$1,475,083	$516,914	$161,325	$12,246	$247,588	$55,154	$39,715	$281,111	$116,007	$37,312	$7,622	$2	$87
557	OTHER EXPENSES														
	Total Purchased Power Labor		$1,475,083	$516,914	$161,325	$12,246	$247,588	$55,154	$39,715	$281,111	$116,007	$37,312	$7,622	$2	$87
Transmission Labor Expenses															
560	OPERATION SUPERVISION AND ENG	51	$1,045,952	$366,533	$114,392	$8,683	$175,560	$39,108	$28,161	$199,330	$82,258	$26,457	$5,405	$2	$62

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561	LOAD DISPATCHING	51	$2,129,244	$746,152	$232,869	$17,677	$357,386	$79,613	$57,327	$405,776	$167,453	$53,859	$11,003	$4	$126
562	STATION EXPENSES	51	$268,512	$94,095	$29,366	$2,229	$45,069	$10,040	$7,229	$51,171	$21,117	$8,792	$1,387	$0	$16
563	OVERHEAD LINE EXPENSES	51	$55,713	$19,524	$6,093	$463	$9,351	$2,083	$1,500	$10,617	$4,382	$1,409	$288	$0	$3
566	MISC. TRANSMISSION EXPENSES	51	$335,386	$117,529	$36,680	$2,784	$56,293	$12,540	$9,030	$63,916	$26,376	$8,484	$1,733	$1	$20
568	MAINTENANCE SUPERVISION AND ENG														
570	MAINT OF STATION EQUIPMENT	51	$559,103	$195,927	$61,147	$4,642	$93,844	$20,905	$15,053	$106,550	$43,970	$14,142	$2,889	$1	$33
571	MAINT OF OVERHEAD LINES	51	$177,051	$62,044	$19,364	$1,470	$29,717	$6,620	$4,767	$33,741	$13,924	$4,478	$915	$0	$10
572	UNDERGROUND LINES														
573	MISC PLANT	51	$88,167	$30,896	$9,643	$732	$14,799	$3,297	$2,374	$16,802	$6,934	$2,230	$456	$0	$5
	Total Transmission Labor Expenses		$4,659,128	$1,632,701	$509,554	$38,680	$782,019	$174,205	$125,441	$887,904	$366,413	$117,852	$24,075	$8	$275
Distribution Operation Labor Expense															
580	OPERATION SUPERVISION AND ENGI	64	$1,295,320	$707,747	$233,651	$11,225	$135,294	$35,173	$15,739	$106,520	$13,826	$508	$34,966	$11	$659
581	LOAD DISPATCHING	28	$717,346	$324,486	$99,481	$9,368	$109,852	$27,396	$16,249	$124,956	$0	$0	$5,528	$2	$27
582	STATION EXPENSES	28	$756,223	$342,072	$104,873	$9,876	$115,806	$28,880	$17,129	$131,728	$0	$0	$5,827	$2	$29
583	OVERHEAD LINE EXPENSES	55	$1,589,814	$774,607	$225,360	$19,877	$236,246	$51,608	$35,039	$235,394	$0	$0	$11,621	$4	$58
584	UNDERGROUND LINE EXPENSES	58	$95,744	$46,649	$13,572	$1,197	$14,228	$3,108	$2,110	$14,176	$0	$0	$700	$0	$4
585	STREET LIGHTING EXPENSE	15	$2,507	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,507	$0	$0
586	METER EXPENSES	26	$4,312,676	$2,706,275	$986,655	$23,058	$289,517	$106,260	$10,886	$76,889	$104,583	$3,842	$0	$71	$4,640
586	METER EXPENSES - LOAD MANAGEMENT														
587	CUSTOMER INSTALLATIONS EXPENSE	7	$1,631	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,631	$0	$0
588	MISCELLANEOUS DISTRIBUTION EXP	53	$2,617,399	$1,320,785	$390,702	$24,093	$288,582	$56,822	$41,230	$246,881	$3,153	$116	$244,648	$9	$378
589	RENTS														
	Total Distribution Operation Labor Expense		$11,388,660	$6,222,621	$2,054,293	$98,695	$1,189,526	$309,247	$138,383	$936,545	$121,562	$4,466	$307,427	$99	$5,795
Distribution Maintenance Labor Expense															
590	MAINTENANCE SUPERVISION AND EN	65	$83,850	$40,935	$11,893	$1,042	$12,383	$2,709	$1,836	$12,353	$1	$0	$694	$0	$3
591	MAINTENANCE OF STRUCTURES														
592	MAINTENANCE OF STATION EQUIPMENT	28	$330,041	$149,292	$45,770	$4,310	$50,542	$12,604	$7,476	$57,491	$0	$0	$2,543	$1	$13
593	MAINTENANCE OF OVERHEAD LINES	55	$6,250,997	$3,045,680	$886,093	$78,154	$928,897	$202,919	$137,771	$925,546	$0	$0	$45,692	$15	$229
594	MAINTENANCE OF UNDERGROUND LINES	58	$167,819	$81,767	$23,789	$2,098	$24,938	$5,448	$3,699	$24,848	$0	$0	$1,227	$0	$6
595	MAINTENANCE OF LINE TRANSFORMER	70	$68,342	$50,316	$10,766	$383	$4,862	$0	$692	$0	$0	$0	$1,317	$0	$6
596	MAINTENANCE OF ST LIGHTS & SIG SYSTEMS														
597	MAINTENANCE OF METERS														
598	MAINTENANCE OF MISC DISTR PLANT	53	$66,382	$33,498	$9,909	$611	$7,319	$1,441	$1,046	$6,261	$80	$3	$6,205	$0	$10
	Total Distribution Maintenance Labor Expense		$6,967,431	$3,401,487	$988,219	$86,599	$1,028,940	$225,121	$152,519	$1,026,499	$81	$3	$57,678	$17	$266
	Total Distribution Operation and Maintenance Labor Expenses		$18,356,091	$9,624,108	$3,042,512	$185,294	$2,218,466	$534,369	$290,902	$1,963,044	$121,643	$4,469	$365,105	$116	$6,062
	Transmission and Distribution Labor Expenses		$23,015,219	$11,256,809	$3,552,066	$223,974	$3,000,485	$708,574	$416,343	$2,850,948	$488,057	$122,321	$389,181	$124	$6,337
	Production, Transmission and Distribution Labor Expenses		$64,434,372	$25,460,866	$8,007,283	$576,961	$10,024,873	$2,242,292	$1,547,120	$10,922,869	$3,810,059	$1,196,070	$636,852	$205	$8,922
Customer Accounts Expense															
901	SUPERVISION/CUSTOMER ACCTS	6	$2,323,402	$1,507,445	$588,880	$22,952	$101,005	$5,325	$12,283	$14,883	$2,582	$179	$67,596	$4	$269
902	METER READING EXPENSES	6	$270,538	$175,528	$68,569	$2,672	$11,761	$620	$1,430	$1,733	$301	$21	$7,871	$0	$31
903	RECORDS AND COLLECTION	6	$8,203,410	$5,322,449	$2,079,203	$81,037	$356,625	$18,803	$43,367	$52,547	$9,117	$633	$238,666	$13	$950
904	UNCOLLECTIBLE ACCOUNTS														
905	MISC CUST ACCOUNTS	6	$426,247	$276,553	$108,035	$4,211	$18,530	$977	$2,253	$2,730	$474	$33	$12,401	$1	$49
	Total Customer Accounts Labor Expense		$11,223,597	$7,281,975	$2,844,687	$110,872	$487,921	$25,726	$59,334	$71,893	$12,473	$866	$326,534	$17	$1,299
Customer Service Expense															
907	SUPERVISION	6	$180,381	$117,033	$45,719	$1,782	$7,842	$413	$954	$1,155	$200	$14	$5,248	$0	$21
908	CUSTOMER ASSISTANCE EXPENSES	6	$1,275,796	$827,748	$323,358	$12,603	$55,462	$2,924	$6,745	$8,172	$1,418	$98	$37,117	$2	$148
908	CUSTOMER ASSISTANCE EXP-LOAD MGMT														
909	INFORMATIONAL AND INSTRUCTIONAL														
909	INFORM AND INSTRUC -LOAD MGMT														
910	MISCELLANEOUS CUSTOMER SERVICE														
911	DEMONSTRATION AND SELLING EXP														
912	DEMONSTRATION AND SELLING EXP														
913	WATER HEATER - HEAT PUMP PROGRAM														
915	MDSE-JOBBING-CONTRACT														
916	MISC SALES EXPENSE														
	Total Customer Service Labor Expense		$1,456,177	$944,781	$369,077	$14,385	$63,304	$3,338	$7,698	$9,328	$1,618	$112	$42,365	$2	$169
	Sub-Total Labor Exp		$77,114,146	$33,687,621	$11,221,047	$702,217	$10,576,099	$2,271,355	$1,614,151	$11,004,090	$3,824,151	$1,197,049	$1,005,751	$224	$10,390
Administrative and General Expense															
920	ADMIN. & GEN. SALARIES-	66	$19,421,711	$8,484,452	$2,826,095	$176,858	$2,663,661	$572,056	$406,535	$2,771,453	$963,138	$301,485	$253,305	$57	$2,617
921	OFFICE SUPPLIES AND EXPENSES	66	$34,619	$15,123	$5,037	$315	$4,748	$1,020	$725	$4,940	$1,717	$537	$452	$0	$5

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Electric Cost of Service Study
(Labor)

Acct. No.	Account Description	Allocator	Total System	Residential Rate RS	Gen. Service GSS	All Elec. Schools AES	Secondary PS	Primary PS	Sec. TOD TODS	Pri. TOD TODP	Retail Trans. RTS	Fluc. Load FLS	Outdoor Ltng. St. and POL	Lighting Energy LE	Traffic TE
922	ADMIN. EXPENSES TRANSFERRED - CREDIT	66	($1,884,219)	($823,129)	($274,177)	($17,158)	($258,418)	($55,499)	($39,440)	($268,876)	($93,440)	($29,249)	($24,575)	($5)	($254)
923	OUTSIDE SERVICES EMPLOYED														
924	PROPERTY INSURANCE														
925	INJURIES AND DAMAGES - INSURANCE	66	$795,436	$347,489	$115,746	$7,243	$109,093	$23,429	$16,650	$113,508	$39,446	$12,348	$10,374	$2	$107
926	EMPLOYEE BENEFITS	66	$34,920,650	$15,255,225	$5,081,380	$317,995	$4,789,319	$1,028,569	$730,958	$4,983,132	$1,731,742	$542,076	$455,448	$102	$4,705
928	REGULATORY COMMISSION FEES														
929	DUPLICATE CHARGES-CR														
930	MISCELLANEOUS GENERAL EXPENSES	66	$30,997	$13,541	$4,510	$282	$4,251	$913	$649	$4,423	$1,537	$481	$404	$0	$4
931	RENTS AND LEASES														
932	MAINTENANCE OF GENERAL PLANT														
935	MAINTENANCE OF GENERAL PLANT	59	$5,065,262	$1,967,352	$603,747	$43,178	$778,349	$169,831	$122,441	$845,242	$301,757	$96,628	$136,321	$11	$406
	Total Administrative and General Expense		$58,384,456	$25,260,054	$8,362,339	$528,714	$8,091,003	$1,740,319	$1,238,517	$8,453,823	$2,945,897	$924,306	$831,729	$166	$7,590
	Total Operation and Maintenance Expenses		$135,498,602	$58,947,675	$19,583,385	$1,230,931	$18,667,102	$4,011,674	$2,852,668	$19,457,912	$6,770,048	$2,121,355	$1,837,480	$390	$17,980
	Operation and Maintenance Expenses Less Purchase Power		**$135,498,602**	**$58,947,675**	**$19,583,385**	**$1,230,931**	**$18,667,102**	**$4,011,674**	**$2,852,668**	**$19,457,912**	**$6,770,048**	**$2,121,355**	**$1,837,480**	**$390**	**$17,980**

Kentucky Utilities
Electric Cost of Service Study
(Revenues)

Acct. No.	Account Description	Allocator	Total System	Residential Rate RS	Gen. Service GSS	All Elec. Schools AES	Secondary PS	Primary PS	Sec. TOD TODS	Pri. TOD TODP	Retail Trans. RTS	Fluc. Load FLS	Outdoor Ltng. St. and POL	Lighting Energy LE	Traffic TE
REVENUE															
	Sales	74	$1,291,701,071	$474,158,148	$181,472,282	$11,111,098	$222,187,654	$51,446,772	$25,199,769	$202,384,448	$85,720,555	$14,733,900	$23,177,212	$2,251	$106,981
	Franchise Fees and HEA														
	Accrued Revenues														
	Intercompany Sales	2	$22,834,450	$7,635,846	$2,444,156	$201,985	$3,934,466	$899,633	$582,438	$4,492,594	$1,874,628	$608,857	$158,359	$51	$1,438
	Off-System Sales	82	$5,895,029	$2,160,092	$662,785	$49,718	$953,024	$218,226	$145,031	$1,082,539	$455,186	$141,370	$26,723	$9	$325
	Brokered Sales	2	($294,880)	($98,608)	($31,563)	($2,608)	($50,809)	($11,618)	($7,522)	($58,017)	($24,209)	($7,863)	($2,045)	($1)	($19)
	LATE PAYMENT - DIRECT	76	$6,910,624	$5,226,739	$1,128,697	$5,854	$225,327	$29,221	$75,334	$179,921	$39,402	$0	$125	$0	$4
	RECONNECT CHARGES	83	$1,659,612	$1,505,487	$53,534	$662	$3,314	$63,195	$2,611	$98	$0	$126	$30,585	$0	$0
	OTHER SERVICE CHARGES	83	$547,025	$496,224	$17,645	$218	$1,092	$20,830	$860	$32	$0	$42	$10,081	$0	$0
	RENT FROM ELEC PROPERTY	22	$2,153,991	$830,149	$255,069	$18,324	$333,405	$72,878	$52,536	$363,472	$131,567	$42,149	$54,269	$5	$169
	TRANSMISSION SERVICE	52	$10,488,823	$3,675,603	$1,147,129	$87,078	$1,760,514	$392,179	$282,399	$1,998,886	$824,885	$265,314	$54,199	$18	$620
	TAX REMITTANCE COMPENSATION	85	$17,113	$6,282	$2,404	$147	$2,944	$682	$334	$2,681	$1,136	$195	$307	$0	$1
	RETURN CHECK CHARGES	83	$130,862	$118,709	$4,221	$52	$261	$4,983	$206	$8	$0	$10	$2,412	$0	$0
	OTHER MISC REVENUES	83	$22,525	$20,433	$727	$9	$45	$858	$35	$1	$0	$2	$415	$0	$0
	EXCESS FACILITIES CHARGES	83	$14,277	$12,951	$461	$6	$29	$544	$22	$1	$0	$1	$263	$0	$0
	FORFEITED REFUNDABLE ADVANCE	85	($3,602)	($1,322)	($506)	($31)	($620)	($143)	($70)	($564)	($239)	($41)	($65)	($0)	($0)
	Unbilled Revenue														
	TOTAL REVENUE		$1,342,076,920	$495,746,733	$187,157,042	$11,472,511	$229,350,647	$53,138,237	$26,333,984	$210,446,101	$89,022,911	$15,784,061	$23,512,840	$2,333	$109,519
ProForma Adjustments															
	Eliminate unbilled revenues	85	$5,107,000	$1,874,680	$717,487	$43,930	$876,464	$203,405	$99,632	$800,168	$338,913	$58,253	$91,636	$9	$423
	Eliminate accrued revenues	85	($8,438,658)	($3,097,666)	($1,185,555)	($72,589)	($1,451,548)	($336,101)	($164,630)	($1,322,174)	($560,011)	($96,256)	($151,416)	($15)	($699)
	Mismatch in fuel cost recovery	2	($9,156,061)	($3,061,789)	($980,047)	($80,991)	($1,577,625)	($360,731)	($233,544)	($1,801,421)	($751,680)	($244,137)	($63,498)	($21)	($577)
	Annualize FAC roll-in to base rates	43	$2,885,839	$882,160	$313,854	$27,666	$517,040	$153,768	$67,296	$541,691	$272,139	$89,538	$20,524	$6	$156
	Adjustment to reflect changes to FAC cε	43	($2,638,801)	($806,644)	($286,987)	($25,298)	($472,779)	($140,605)	($61,535)	($495,320)	($248,843)	($81,873)	($18,767)	($6)	($143)
	Eliminate ECR revenues	49	($14,710,734)	($5,574,888)	($2,594,231)	($124,251)	($2,755,268)	($685,530)	($219,124)	($1,637,606)	($689,254)	($170,284)	($259,239)	($11)	($1,049)
	Adjustment to reflect Full Year of ECR Roll-in														
	Remove off-system ECR revenues	82	($296,088)	($108,494)	($33,290)	($2,497)	($47,867)	($10,961)	($7,284)	($54,372)	($22,863)	($7,101)	($1,342)	($0)	($16)
	To adjust Off-system sales margins	82	($292,995)	($107,361)	($32,942)	($2,471)	($47,367)	($10,846)	($7,208)	($53,804)	($22,624)	($7,026)	($1,328)	($0)	($16)
	Eliminate brokered sales revenues	2	$294,881	$98,608	$31,564	$2,608	$50,809	$11,618	$7,522	$58,017	$24,209	$7,863	$2,045	$1	$19
	Eliminate DSM revenues	48	($15,401,724)	($11,425,658)	($3,105,609)	($38,694)	($527,104)	($97,298)	($70,050)	($137,311)	$-0	$-0	$-0	$-0	$-0
	Year End Adjustment	86	($3,407,542)	($709,927)	$42,703	$73,498	($1,561,902)	$171,608	$116,329	($1,815,382)	$166,915	$0	$97,552	$0	$11,064
	Customer rate switching adjustment	84	($8,348,788)	($30,891)	($3,346,954)	($20,438)	($1,353,663)	($5,386,209)	$2,518,028	$3,315,076	($2,949,246)	($1,094,561)	$0	$0	$70
	Remove out of period items	69	$23,287	$8,995	$2,766	$198	$3,596	$785	$566	$3,918	$1,414	$453	$593	$0	$2
	Subtotal		($54,380,384)	($22,058,875)	($10,457,241)	($219,327)	($8,345,215)	($6,487,097)	$2,045,998	($2,598,523)	($4,440,930)	($1,545,131)	($283,241)	($37)	$9,234
Total Revenue After Adjustments			$1,287,696,536	$473,687,859	$176,699,801	$11,253,184	$221,005,432	$46,651,140	$28,379,982	$207,847,578	$84,581,981	$14,238,930	$23,229,600	$2,296	$118,753

Kentucky Utilities
Electric Cost of Service Study
(Allocator Amounts)

Alloc.	Account Description		Total	Residential Rate RS	Gen. Service GSS	All Elec. Schools AES	Secondary PS	Primary PS	Sec. TOD TODS	Pri. TOD TODP	Retail Trans. RTS	Fluc. Load FLS	Outdoor Ltng. St. and POL	Lighting Energy LE	Traffic TE
1	Average Demand (Loss Adjusted) Adjusted For Rate Switching	Energy	2,199,392	734,855	231,912	19,314	377,518	80,508	61,021	439,778	180,438	58,644	15,253	5	146
2	Energy (Loss Adjusted) Before Rate Switching		19,319,457,805	6,460,431,335	2,067,918,123	170,892,344	3,328,818,666	761,148,808	492,781,255	3,801,032,523	1,586,059,250	515,132,956	133,982,265	43,528	1,216,752
3	Customers (Monthly Bills)		679,690	420,348	82,102	640	5,633	297	137	166	36	1	169,645	11	674
4	Customers (Monthly Bills)		679,690	420,348	82,102	640	5,633	297	137	166	36	1	169,645	11	674
5	Average Customers (Lighting = Lights)		679,690	420,348	82,102	640	5,633	297	137	166	36	1	169,645	11	674
6	Weighted Average Customers (Lighting =9 Lights per Cust)	Cust05	647,876	420,348	164,206	6,400	28,165	1,485	3,425	4,150	720	50	18,849	1	75
7	Street Lighting	Cust04	80,975,590	0	0	0	0	0	0	0	0	0	80,975,590	0	0
8	Average Customers	Cust01	679,690	420,348	82,102	640	5,633	297	137	166	36	1	169,645	11	674
9	Average Customers (Lighting = 9 Lights per Cust)	Cust06	528,286	420,348	82,102	640	5,633	297	137	166	36	1	18,849	1	75
10	Average Secondary Customers	Cust07	527,786	420,348	82,102	640	5,633	0	137	0	0	0	18,849	1	75
11	Average Primary Customers	Cust08	528,249	420,348	82,102	640	5,633	297	137	166	0	0	18,849	1	75
12	Year End Customers		679,917	419,902	82,069	643	5,627	298	137	167	35	1	170,307	11	720
13	Year End Customers (Lighting = Lights)		679,917	419,902	82,069	643	5,627	298	137	167	35	1	170,307	11	720
14	Weighted Year End Customers (Lighting =9 Lights per Cust)	YECust05	647,449	419,902	164,138	6,430	28,135	1,490	3,425	4,175	700	50	18,923	1	80
15	Street Lighting	YECust04	80,975,590	0	0	0	0	0	0	0	0	0	80,975,590	0	0
16	Year End Customers	YECust01	679,917	419,902	82,069	643	5,627	298	137	167	35	1	170,307	11	720
17	Year End Customers (Lighting = 9 Lights per Cust)	YECust06	527,883	419,902	82,069	643	5,627	298	137	167	35	1	18,923	1	80
18	Year End Secondary Customers	YECust07	527,382	419,902	82,069	643	5,627	0	137	0	0	0	18,923	1	80
19	Year End Primary Customers	YECust08	527,847	419,902	82,069	643	5,627	298	137	167	0	0	18,923	1	80
20	Maximum Class Non-Coincident Peak Demands (Adjusted)	NCP	4,319,251	1,750,711	536,735	50,546	592,690	147,809	87,667	674,181	276,057	172,874	29,823	10	148
21															
22	Net Utility Plant	UPT	3,861,083,104	1,488,062,327	457,218,240	32,845,461	597,637,405	130,634,857	94,171,972	651,532,339	235,838,043	75,553,774	97,277,828	8,093	302,765
23	Total Utility Plant	TUP	5,952,611,566	2,304,537,952	707,582,535	50,698,589	917,489,865	200,341,389	144,430,896	997,971,831	358,366,896	114,777,675	155,928,816	12,601	472,521
24															
25															
26	Meter Cost - Weighted Cost of Meters	C03	41,191,066	25,848,067	9,423,696	220,230	2,765,228	1,014,904	103,975	734,376	998,891	36,699	0	677	44,321
27	Customer Services - Weighted cost of Services	C02	261,984,004	124,550,403	81,741,213	390,162	4,486,183	0	83,129	0	0	0	50,516,086	3,263	213,565
28	Maximum Class Demands (Primary)	NCPP	3,870,320	1,750,711	536,735	50,546	592,690	147,809	87,667	674,181	0	0	29,823	10	148
29	Sum of the Individual Customer Demands (Secondary)	SICD	5,887,377	4,032,454	937,055	55,019	723,487	0	109,367	0	0	0	29,823	10	162
30	Summer Peak Period Demand Allocator	SCP	3,516,646	1,400,033	424,931	24,266	551,195	139,563	86,247	573,741	241,657	74,880	0	0	133
31	Winter Peak Period Demand Allocator	WCP	3,439,501	1,570,811	433,803	29,246	435,872	96,788	64,825	519,768	231,577	56,678	0	0	133
32															
33	Production Residual Winter Demand Allocator	PPWDRA	3,439,501	1,570,811	433,803	29,246	435,872	96,788	64,825	519,768	231,577	56,678	0	0	133
34	Production Winter Demand Allocator	PPWDA	3,439,501	1,570,811	433,803	29,246	435,872	96,788	64,825	519,768	231,577	56,678	0	0	133
35	Production Residual Summer Demand Allocator	PPSDRA	3,516,646	1,400,033	424,931	24,266	551,195	139,563	86,247	573,741	241,657	74,880	0	0	133
36	Production Summer Demand Allocator	PPSDA	3,516,646	1,400,033	424,931	24,266	551,195	139,563	86,247	573,741	241,657	74,880	0	0	133
37	Production Residual Summer Demand Allocator	PPSDRA	3,516,646	1,400,033	424,931	24,266	551,195	139,563	86,247	573,741	241,657	74,880	0	0	133
38	Production Summer Demand Total	PPSDT	3,516,646	1,400,033	424,931	24,266	551,195	139,563	86,247	573,741	241,657	74,880	0	0	133
39	Distribution Lines, Transformers & Services Plan)	SDALL	1,036,378,367	572,034,092	165,609,832	10,139,198	121,718,934	22,024,582	17,750,043	100,457,716	0	0	26,523,794	3,258	116,919
40															
41															
42															
43	FAC Roll-In	FAC01	(3,616,226)	(1,105,429)	(393,289)	(34,668)	(647,899)	(192,686)	(84,328)	(678,789)	(341,016)	(112,199)	(25,719)	(8)	(196)
44															
45															
46	Base Rate Revenue		1,257,574,176	458,005,465	182,158,458	10,668,266	221,396,753	51,224,549	22,889,891	184,047,357	79,886,044	24,102,240	23,087,333	2,255	105,565
47															
48	Remove DSM Revenues	DSM01	15,401,444	11,425,450	3,105,553	38,693	527,094	97,296	70,049	137,309	0	0	0	0	0
49	Remove ECR Revenues	ECRREV01	14,710,735	5,574,888	2,594,231	124,251	2,755,268	685,530	219,124	1,637,606	689,254	170,284	259,239	11	1,049
50															
51	Gross Production Plant		3,590,352,277	1,258,168,915	392,665,366	29,807,026	602,628,605	134,243,803	96,665,862	684,224,162	282,360,237	90,817,581	18,552,567	6,033	212,118
52	Gross Transmission Plant		536,001,810	187,831,378	58,620,807	4,449,875	89,966,109	20,041,187	14,431,196	102,147,467	42,153,412	13,558,109	2,769,703	901	31,667
53	Gross Distribution Plant		1,348,161,065	680,305,552	201,241,216	12,409,914	148,642,100	29,267,733	21,236,405	127,162,675	1,624,029	59,666	126,012,460	4,737	194,578
54	Total Prod.,Trans., Distrib Plant		5,474,515,152	2,126,305,845	652,527,389	46,666,815	841,236,814	183,552,723	132,333,463	913,534,304	326,137,678	104,435,357	147,334,730	11,671	438,363
55	Dist. Overhead Lines Gross Plant		537,135,305	261,709,038	76,140,163	6,715,644	79,818,200	17,436,392	11,838,415	79,530,234	0	0	3,926,227	1,317	19,676
56	Gross Intangible Plant		52,426,604	20,362,533	6,248,918	446,904	8,056,090	1,757,790	1,267,289	8,748,446	3,123,252	1,000,123	1,410,949	112	4,198
57	Gross Total Plant in Service		5,653,048,566	2,195,823,809	673,852,644	48,189,729	868,605,469	189,520,851	136,636,374	943,216,715	336,685,473	107,812,442	152,240,050	12,053	452,756
58	Dist. Underground Lines Gross Plant		141,341,084	68,865,775	20,035,423	1,767,146	21,003,257	4,588,190	3,115,145	20,927,482	0	0	1,033,142	346	5,178
59	Gross General Plant		124,597,128	48,393,619	14,851,185	1,062,113	19,146,114	4,177,565	3,011,841	20,791,567	7,422,725	2,376,895	3,353,262	266	9,977
60	Labor Accts 501-507		17,747,782	6,169,842	1,929,109	148,797	2,990,441	661,208	480,328	3,410,727	1,406,068	453,084	97,075	32	1,071
61	Labor Accts 511-514		10,978,176	3,684,141	1,161,463	95,930	1,880,607	402,629	303,770	2,185,851	897,288	291,367	74,385	24	721
62	Labor Accts 536-540		4,595	1,610	503	38	771	172	124	876	361	116	24	0	0
63	Labor Accts 542-545		66,245	23,117	7,272	590	11,641	2,513	1,878	13,465	5,533	1,793	439	0	4
64	Labor Accts 581-588		10,093,340	5,514,874	1,820,642	87,470	1,054,232	274,074	122,643	830,024	107,736	3,958	272,461	88	5,136
65	Labor Accts 591-598		6,883,581	3,360,552	976,327	85,557	1,016,557	222,412	150,684	1,014,146	80	3	56,984	17	263
66	Labor Accts 500-916		77,114,146	33,687,621	11,221,047	702,217	10,576,099	2,271,355	1,614,151	11,004,090	3,824,151	1,197,049	1,005,751	224	10,390
67	O&M less Purchased Power		768,727,280	288,711,816	93,275,360	6,891,035	121,451,863	25,886,651	19,285,550	136,212,688	52,665,910	16,975,918	7,303,356	1,834	65,298
68	Dist. Lines Gross Plant		678,476,389	330,574,813	96,175,586	8,482,789	100,821,457	22,024,582	14,953,560	100,457,716	0	0	4,959,369	1,663	24,853
69	Rate Base		3,500,935,144	1,352,304,228	415,892,019	29,839,081	540,617,087	118,002,517	85,151,304	588,956,537	212,580,328	68,103,543	89,203,439	7,416	277,644
70	Gross Transformer Plant		273,394,360	201,283,323	43,067,158	1,530,555	19,450,378	0	2,769,668	0	0	0	5,269,559	542	23,177
71	Depreciation Expense	DET	167,700,748	64,280,578	19,767,710	1,424,539	26,088,772	5,709,673	4,115,684	28,517,711	10,419,749	3,339,109	4,023,921	347	12,956
72	Total Labor	LBT	135,498,602	58,947,675	19,583,385	1,230,931	18,667,102	4,011,674	2,852,668	19,457,912	6,770,048	2,121,355	1,837,480	390	17,980
73															
74	Sales Revenue	R01	1,291,701,070	474,158,148	181,472,282	11,111,098	222,187,654	51,446,772	25,199,769	202,384,448	85,720,555	14,733,900	23,177,212	2,251	106,981
75															
76	Late Payment Revenue		6,910,624	5,226,739	1,128,697	5,854	225,327	29,221	75,334	179,921	39,402	0	125	0	4
77															
78	O&M Expenses	OMT	858,787,981	318,925,939	102,801,353	7,678,278	136,881,761	29,189,224	21,778,019	154,149,819	60,028,817	19,366,944	7,914,575	2,033	71,219

Kentucky Utilities
Electric Cost of Service Study
(Allocator Amounts)

Alloc.	Account Description		Total	Residential Rate RS	Gen. Service GSS	All Elec. Schools AES	Secondary PS	Primary PS	Sec. TOD TODS	Pri. TOD TODP	Retail Trans. RTS	Fluc. Load FLS	Outdoor Ltng. St. and POL	Lighting Energy LE	Traffic TE
79	Steam Production Plant		3,105,688,242	1,088,327,858	339,659,208	25,783,356	521,279,370	116,122,143	83,616,874	591,860,289	244,244,241	78,558,056	16,048,144	5,219	183,484
80	Hydro Production Plant		24,836,524	8,703,475	2,716,291	206,192	4,168,727	928,641	668,693	4,733,171	1,953,248	628,237	128,339	42	1,467
81	Other Production Plant		459,827,511	161,137,581	50,289,867	3,817,478	77,180,508	17,193,019	12,380,296	87,630,703	36,162,748	11,631,288	2,376,085	773	27,167
82	Off-System Sales	OSSALL	5,695,028	2,160,092	662,785	49,718	953,024	218,226	145,031	1,082,539	455,186	141,370	26,723	9	325
83	Misc. Service Revenue		1	1	0	0	0	0	0	0	0	0	0	0	0
84	Rate Switching Allocator		(8,348,788)	(30,891)	(3,346,954)	(20,438)	(1,353,863)	(5,388,209)	2,518,028	3,315,076	(2,949,246)	(1,094,561)	0	0	70
85	Billing Determinant Rev net of CSR & HEA		1,288,235,380	472,885,961	180,985,384	11,081,286	221,591,515	51,308,738	25,132,157	201,841,442	85,490,563	14,694,368	23,115,027	2,245	106,694
86	Year End Rev Adjustment		(3,407,542)	(709,927)	42,703	73,498	(1,561,902)	171,608	116,329	(1,815,382)	166,915	0	97,552	0	11,064
87	O&M less Fuel & Purchased Power		320,353,660	138,902,477	45,997,141	2,953,648	44,490,031	9,474,115	6,845,744	46,558,400	15,881,382	5,020,509	4,193,843	823	35,547
88	Intermediate & Peak Production Plant Allocated Amount		915,180,795	364,348,107	110,585,112	6,315,045	143,444,372	36,320,226	22,445,136	149,311,800	62,889,425	19,486,959	0	0	34,612

Kentucky Utilities
Electric Cost of Service Study
(Allocator Percentages)

Alloc.	Account Description		Total	Residential Rate RS	Gen. Service GSS	All Elec. Schools AES	Secondary PS	Primary PS	Sec. TOD TODS	Pri. TOD TODP	Retail Trans. RTS	Fluc. Load FLS	Outdoor Ltng. St. and POL	Lighting Energy LE	Traffic TE
1	Average Demand (Loss Adjusted) Adjusted For Rate Switching		100.0000%	33.4117%	10.5444%	0.8781%	17.1647%	3.6605%	2.7744%	19.9954%	8.2040%	2.6664%	0.6935%	0.0002%	0.0066%
2	Energy (Loss Adjusted) Before Rate Switching	0	100.0000%	33.4400%	10.7038%	0.8846%	17.2304%	3.9398%	2.5507%	19.6746%	8.2096%	2.6664%	0.6935%	0.0002%	0.0063%
3	Customers (Monthly Bills)		100.0000%	61.8441%	12.0793%	0.0942%	0.8288%	0.0437%	0.0202%	0.0244%	0.0053%	0.0001%	24.9592%	0.0016%	0.0992%
4	Customers (Monthly Bills)		100.0000%	61.8441%	12.0793%	0.0942%	0.8288%	0.0437%	0.0202%	0.0244%	0.0053%	0.0001%	24.9592%	0.0016%	0.0992%
5	Average Customers (Lighting = Lights)		100.0000%	61.8441%	12.0793%	0.0942%	0.8288%	0.0437%	0.0202%	0.0244%	0.0053%	0.0001%	24.9592%	0.0016%	0.0992%
6	Weighted Average Customers (Lighting =9 Lights per Cust)	Cust05	100.0000%	64.8809%	25.3456%	0.9878%	4.3473%	0.2292%	0.5287%	0.6406%	0.1111%	0.0077%	2.9094%	0.0002%	0.0116%
7	Street Lighting	Cust04	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%
8	Average Customers	Cust01	100.0000%	61.8441%	12.0793%	0.0942%	0.8288%	0.0437%	0.0202%	0.0244%	0.0053%	0.0001%	24.9592%	0.0016%	0.0992%
9	Average Customers (Lighting = 9 Lights per Cust)	Cust06	100.0000%	79.5683%	15.5412%	0.1211%	1.0663%	0.0562%	0.0259%	0.0314%	0.0068%	0.0002%	3.5680%	0.0002%	0.0142%
10	Average Secondary Customers	Cust07	100.0000%	79.6437%	15.5559%	0.1213%	1.0673%	0.0000%	0.0260%	0.0000%	0.0000%	0.0000%	3.5714%	0.0002%	0.0142%
11	Average Primary Customers	Cust08	100.0000%	79.5739%	15.5423%	0.1212%	1.0664%	0.0562%	0.0259%	0.0314%	0.0000%	0.0000%	3.5683%	0.0002%	0.0142%
12	Year End Customers		100.0000%	61.7578%	12.0704%	0.0946%	0.8276%	0.0438%	0.0201%	0.0246%	0.0051%	0.0001%	25.0482%	0.0016%	0.1059%
13	Year End Customers (Lighting = Lights)		100.0000%	61.7578%	12.0704%	0.0946%	0.8276%	0.0438%	0.0201%	0.0246%	0.0051%	0.0001%	25.0482%	0.0016%	0.1059%
14	Weighted Year End Customers (Lighting =9 Lights per Cust)	YECust05	100.0000%	64.8548%	25.3515%	0.9931%	4.3455%	0.2301%	0.5290%	0.6448%	0.1081%	0.0077%	2.9227%	0.0002%	0.0124%
15	Street Lighting	YECust04	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%
16	Year End Customers	YECust01	100.0000%	61.7578%	12.0704%	0.0946%	0.8276%	0.0438%	0.0201%	0.0246%	0.0051%	0.0001%	25.0482%	0.0016%	0.1059%
17	Year End Customers (Lighting = 9 Lights per Cust)	YECust06	100.0000%	79.5445%	15.5468%	0.1218%	1.0660%	0.0565%	0.0260%	0.0316%	0.0066%	0.0002%	3.5847%	0.0002%	0.0152%
18	Year End Secondary Customers	YECust07	100.0000%	79.6201%	15.5616%	0.1219%	1.0670%	0.0000%	0.0260%	0.0000%	0.0000%	0.0000%	3.5881%	0.0002%	0.0152%
19	Year End Primary Customers	YECust08	100.0000%	79.5499%	15.5479%	0.1218%	1.0660%	0.0565%	0.0260%	0.0316%	0.0000%	0.0000%	3.5849%	0.0002%	0.0152%
20	Maximum Class Non-Coincident Peak Demands (Adjusted)	NCP	100.0000%	40.5327%	12.4266%	1.1702%	13.7221%	3.4221%	2.0297%	15.6087%	6.3913%	4.0024%	0.6905%	0.0002%	0.0034%
21															
22	Net Utility Plant	SICD	100.0000%	38.5400%	11.8417%	0.8507%	15.4785%	3.3834%	2.4390%	16.8743%	6.1081%	1.9568%	2.5194%	0.0002%	0.0078%
23	Total Utility Plant	SCP	100.0000%	38.7147%	11.8869%	0.8517%	15.4132%	3.3656%	2.4263%	16.7653%	6.0203%	1.9282%	2.6195%	0.0002%	0.0079%
24															
25															
26	Meter Cost - Weighted Cost of Meters	PPWDRA	100.0000%	62.7516%	22.8780%	0.5347%	6.7132%	2.4639%	0.2524%	1.7829%	2.4250%	0.0891%	0.0000%	0.0016%	0.1076%
27	Customer Services - Weighted cost of Services		100.0000%	47.5412%	31.2008%	0.1489%	1.7124%	0.0000%	0.0317%	0.0000%	0.0000%	0.0000%	19.2821%	0.0012%	0.0815%
28	Maximum Class Demands (Primary)		100.0000%	45.2343%	13.8680%	1.3060%	15.3137%	3.8190%	2.2651%	17.4193%	0.0000%	0.0000%	0.7706%	0.0003%	0.0038%
29	Sum of the Individual Customer Demands (Secondary)		100.0000%	68.4932%	15.9163%	0.9345%	12.2888%	0.0000%	1.8577%	0.0000%	0.0000%	0.0000%	0.5066%	0.0002%	0.0028%
30	Summer Peak Period Demand Allocator	ERR	100.0000%	39.8116%	12.0834%	0.6900%	15.6739%	3.9686%	2.4525%	16.3150%	6.8718%	2.1293%	0.0000%	0.0000%	0.0038%
31	Winter Peak Period Demand Allocator	PPWDA	100.0000%	45.6697%	12.6124%	0.8503%	12.6725%	2.8140%	1.8847%	15.1117%	6.7329%	1.6479%	0.0000%	0.0000%	0.0039%
32															
33	Production Residual Winter Demand Allocator		100.0000%	45.6697%	12.6124%	0.8503%	12.6725%	2.8140%	1.8847%	15.1117%	6.7329%	1.6479%	0.0000%	0.0000%	0.0039%
34	Production Winter Demand Allocator		100.0000%	45.6697%	12.6124%	0.8503%	12.6725%	2.8140%	1.8847%	15.1117%	6.7329%	1.6479%	0.0000%	0.0000%	0.0039%
35	Production Residual Summer Demand Allocator		100.0000%	39.8116%	12.0834%	0.6900%	15.6739%	3.9686%	2.4525%	16.3150%	6.8718%	2.1293%	0.0000%	0.0000%	0.0038%
36	Production Summer Demand Allocator	PPSDT	100.0000%	39.8116%	12.0834%	0.6900%	15.6739%	3.9686%	2.4525%	16.3150%	6.8718%	2.1293%	0.0000%	0.0000%	0.0038%
37	Production Residual Summer Demand Allocator	PPSDA	100.0000%	39.8116%	12.0834%	0.6900%	15.6739%	3.9686%	2.4525%	16.3150%	6.8718%	2.1293%	0.0000%	0.0000%	0.0038%
38	Production Summer Demand Total	SDALL	100.0000%	39.8116%	12.0834%	0.6900%	15.6739%	3.9686%	2.4525%	16.3150%	6.8718%	2.1293%	0.0000%	0.0000%	0.0038%
39	Distribution Lines, Transformers & Services Plan)	:CRREV01	100.0000%	55.1955%	15.9797%	0.9783%	11.7446%	2.1251%	1.7127%	9.6932%	0.0000%	0.0000%	2.5593%	0.0003%	0.0113%
40															
41															
42															
43	FAC Roll-In	0	100.0000%	30.5686%	10.8757%	0.9587%	17.9164%	5.3284%	2.3319%	18.7706%	9.4302%	3.1027%	0.7112%	0.0002%	0.0054%
44															
45															
46	Base Rate Revenue	0	100.0000%	36.4198%	14.4849%	0.8483%	17.6051%	4.0733%	1.8202%	14.6351%	6.3524%	1.9166%	1.8359%	0.0002%	0.0084%
47															
48	Remove DSM Revenues	0	100.0000%	74.1843%	20.1640%	0.2512%	3.4224%	0.6317%	0.4548%	0.8915%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
49	Remove ECR Revenues	0 0 0	100.0000%	37.8967%	17.6350%	0.8446%	18.7296%	4.6601%	1.4896%	11.1320%	4.6854%	1.1575%	1.7622%	0.0001%	0.0071%
50															
51	Gross Production Plant	0 0 0	100.0000%	35.0430%	10.9367%	0.8302%	16.7847%	3.7390%	2.6924%	19.0573%	7.8644%	2.5295%	0.5167%	0.0002%	0.0059%
52	Gross Transmission Plant	0 0 0	100.0000%	35.0430%	10.9367%	0.8302%	16.7847%	3.7390%	2.6924%	19.0573%	7.8644%	2.5295%	0.5167%	0.0002%	0.0059%
53	Gross Distribution Plant	0 0 0	100.0000%	50.4617%	14.9271%	0.9205%	11.0255%	2.1709%	1.5752%	9.4323%	0.1205%	0.0044%	9.3470%	0.0004%	0.0144%
54	Total Prod.,Trans., Distrib Plant	0 0 0	100.0000%	38.8401%	11.9194%	0.8524%	15.3664%	3.3529%	2.4173%	16.6870%	5.9574%	1.9077%	2.6913%	0.0002%	0.0080%
55	Dist. Overhead Lines Gross Plant	0 0 0	100.0000%	48.7231%	14.1752%	1.2503%	14.8600%	3.2462%	2.2040%	14.8064%	0.0000%	0.0000%	0.7310%	0.0002%	0.0037%
56	Gross Intangible Plant	0 0 0	100.0000%	38.8401%	11.9194%	0.8524%	15.3664%	3.3529%	2.4173%	16.6870%	5.9574%	1.9077%	2.6913%	0.0002%	0.0080%
57	Gross Total Plant in Service	0 0 0	100.0000%	38.8432%	11.9202%	0.8525%	15.3653%	3.3525%	2.4170%	16.6851%	5.9558%	1.9072%	2.6931%	0.0002%	0.0080%
58	Dist. Underground Lines Gross Plant	0 0 0	100.0000%	48.7231%	14.1752%	1.2503%	14.8600%	3.2462%	2.2040%	14.8064%	0.0000%	0.0000%	0.7310%	0.0002%	0.0037%
59	Gross General Plant	0 0 0	100.0000%	38.8401%	11.9194%	0.8524%	15.3664%	3.3529%	2.4173%	16.6870%	5.9574%	1.9077%	2.6913%	0.0002%	0.0080%
60	Labor Accts 501-507	0 0 0	100.0000%	34.7640%	10.8696%	0.8384%	16.8497%	3.7256%	2.7064%	19.2178%	7.9225%	2.5529%	0.5470%	0.0002%	0.0060%
61	Labor Accts 511-514	0 0 0	100.0000%	33.5588%	10.5797%	0.8738%	17.1304%	3.6675%	2.7670%	19.9109%	8.1734%	2.6541%	0.6776%	0.0002%	0.0066%
62	Labor Accts 536-540	0 0 0	100.0000%	35.0430%	10.9367%	0.8302%	16.7847%	3.7390%	2.6924%	19.0573%	7.8644%	2.5295%	0.5167%	0.0002%	0.0059%
63	Labor Accts 542-545	0 0 0	100.0000%	33.8735%	10.6554%	0.8646%	17.0571%	3.6827%	2.7512%	19.7299%	8.1079%	2.6276%	0.6435%	0.0002%	0.0064%
64	Labor Accts 581-588	0 0 0	100.0000%	54.6387%	18.0381%	0.8666%	10.4448%	2.7154%	1.2151%	8.2235%	1.0674%	0.0392%	2.6994%	0.0009%	0.0509%
65	Labor Accts 591-598	0 0 0	100.0000%	48.8198%	14.1834%	1.2429%	14.7679%	3.2311%	2.1890%	14.7328%	0.0012%	0.0000%	0.8278%	0.0002%	0.0038%
66	Labor Accts 500-916	0 0 0	100.0000%	43.6854%	14.5512%	0.9106%	13.7149%	2.9454%	2.0932%	14.2699%	4.9591%	1.5523%	1.3042%	0.0003%	0.0135%
67	O&M less Purchased Power	DET 0 0	100.0000%	37.5571%	12.1337%	0.8964%	15.7991%	3.3675%	2.5088%	17.7192%	6.8511%	2.2083%	0.9501%	0.0002%	0.0085%
68	Dist. Lines Gross Plant	LBT 0 0	100.0000%	48.7231%	14.1752%	1.2503%	14.8600%	3.2462%	2.2040%	14.8064%	0.0000%	0.0000%	0.7310%	0.0002%	0.0037%
69	Rate Base	0 0 0	100.0000%	38.6269%	11.8795%	0.8523%	15.4421%	3.3706%	2.4322%	16.8228%	6.0721%	1.9453%	2.5480%	0.0002%	0.0079%
70	Gross Transformer Plant	R01 0 0	100.0000%	73.6238%	15.7528%	0.5598%	7.1144%	0.0000%	1.0131%	0.0000%	0.0000%	0.0000%	1.9275%	0.0002%	0.0085%
71	Depreciation Expense	0 0 0	100.0000%	38.3305%	11.7875%	0.8495%	15.5567%	3.4047%	2.4542%	17.0051%	6.2133%	1.9911%	2.3995%	0.0002%	0.0077%

Kentucky Utilities
Electric Cost of Service Study
(Allocator Percentages)

Alloc.	Account Description				Total	Residential Rate RS	Gen. Service GSS	All Elec. Schools AES	Secondary PS	Primary PS	Sec. TOD TODS	Pri. TOD TODP	Retail Trans. RTS	Fluc. Load FLS	Outdoor Ltng. St. and POL	Lighting Energy LE	Traffic TE
72	Total Labor	0	0	0	100.0000%	43.5043%	14.4528%	0.9084%	13.7766%	2.9607%	2.1053%	14.3602%	4.9964%	1.5656%	1.3561%	0.0003%	0.0133%
73																	
74	Sales Revenue	OMT	0	0	100.0000%	36.7080%	14.0491%	0.8602%	17.2012%	3.9829%	1.9509%	15.6681%	6.6363%	1.1407%	1.7943%	0.0002%	0.0083%
75																	
76	Late Payment Revenue	0	0	0	100.0000%	75.6334%	16.3328%	0.0847%	3.2606%	0.4228%	1.0901%	2.6035%	0.5702%	0.0000%	0.0018%	0.0000%	0.0001%
77																	
78	O&M Expenses	OSSALL	0	0	100.0000%	37.1367%	11.9705%	0.8941%	15.9389%	3.3989%	2.5359%	17.9497%	6.9899%	2.2551%	0.9216%	0.0002%	0.0083%
79	Steam Production Plant	0	0	0	100.0000%	35.0430%	10.9367%	0.8302%	16.7847%	3.7390%	2.6924%	19.0573%	7.8644%	2.5295%	0.5167%	0.0002%	0.0059%
80	Hydro Production Plant	0	0	0	100.0000%	35.0430%	10.9367%	0.8302%	16.7847%	3.7390%	2.6924%	19.0573%	7.8644%	2.5295%	0.5167%	0.0002%	0.0059%
81	Other Production Plant	0	0	0	100.0000%	35.0430%	10.9367%	0.8302%	16.7847%	3.7390%	2.6924%	19.0573%	7.8644%	2.5295%	0.5167%	0.0002%	0.0059%
82	Off-System Sales	0	0	0	100.0000%	36.6426%	11.2431%	0.8434%	16.1666%	3.7019%	2.4602%	18.3636%	7.7215%	2.3981%	0.4533%	0.0002%	0.0055%
83	Misc. Service Revenue	0	0	0	100.0000%	90.7132%	3.2257%	0.0399%	0.1997%	3.8078%	0.1573%	0.0059%	0.0000%	0.0076%	1.8429%	0.0000%	0.0000%
84	Rate Switching Allocator	0	0	0	100.0000%	0.3700%	40.0891%	0.2448%	16.2139%	64.5149%	-30.1604%	-39.7073%	35.3254%	13.1104%	-0.0000%	-0.0000%	-0.0008%
85	Billing Determinant Rev net of CSR & HEA	0	0	0	100.0000%	36.7080%	14.0491%	0.8602%	17.2012%	3.9829%	1.9509%	15.6681%	6.6363%	1.1407%	1.7943%	0.0002%	0.0083%
86	Year End Rev Adjustment	0	0	0	100.0000%	20.8340%	-1.2532%	-2.1569%	45.8366%	-5.0361%	-3.4139%	53.2754%	-4.8984%	-0.0000%	-2.8628%	-0.0000%	-0.3247%
87	O&M less Fuel & Purchased Power	0	0	0	100.0000%	43.3591%	14.3582%	0.9220%	13.8878%	2.9574%	2.1369%	14.5334%	4.9575%	1.5672%	1.3091%	0.0003%	0.0111%
88	Intermediate & Peak Production Plant Allocated Amount	0	0	0	100.0000%	39.8116%	12.0834%	0.6900%	15.6739%	3.9686%	2.4525%	16.3150%	6.8718%	2.1293%	0.0000%	0.0000%	0.0038%

Schedule GAW-6

KENTUCKY UTILITIES
Competitive Fixed Charges For Electric Residential Rates In Texas

COMPANY		MONTHLY CHARGE	
No Waiver of Customer Charge:			
1 Andeler		$3.95	
2 APG&E		$8.95	
3 CPL Retail		$4.97	
4 Direct Energy		$5.00	
5 Gexa		$4.79	
6 Smartcom	< 500 kwh	$12.95	
Smartcom	> 500 kwh	$9.95	
7 TriEagle		$4.95	
Customer Charge Waived w/Minimum Usage:			
8 4Change		$9.95	1/
9 Ambit Texas		$9.98	1/
10 Amigo - Plan 1		$9.95	1/
Amigo - Plan 2		$6.95	4/
11 APNA - Plan 1		$9.95	1/
APNA - Plan 2		$12.95	1/
12 Bounce		$6.95	1/
13 Brilliant		$10.99	1/
14 Cirro		$5.75	1/
15 Dynowatt		$6.95	1/
16 Infinite		$18.55	1/
17 Just Energy - Plan 1		$9.95	1/
Just Energy - Plan 2		$14.95	2/
18 Pennywise		$9.95	1/
19 Potentia		$9.99	1/
20 Southwest Power		$7.95	1/
21 Spark		$8.99	1/
22 Star		$4.99	3/
23 Stream	< 699 kwh	$9.95	1/
Stream	700-999 kwh	$4.95	1/
24 Tara		$6.95	4/
25 Texpo		$7.95	1/
26 TRUE		$9.95	1/
27 Veteran		$5.00	1/
28 YEP		$7.95	1/
AVERAGE: CUST. CHARGE WAIVED W/ MINIMUM USAGE		**$9.14**	
AVERAGE: NO WAIVER TO CUST. CHARGE W/ MINIMUM USAGE		**$6.94**	

1/ Waived if usage is at least 1,000 kwh.
2/ Waived if usage is at least 2,000 kwh.
3/ Waived if usage is at least 500 kwh.
4/ Waived if usage is at least 800 kwh.

Schedule GAW-7

Kentucky Utilities
Residential Electric Customer Costs

	Residential Amount	
Rate Base:		
Gross Plant		
Services	$40,175,956	
Meters	42,024,614	
Total	82,200,571	
Depreciation Reserve		
Services	27,620,164	1/
Meters	20,579,258	1/
Total	48,199,422	
Net Rate Base	34,001,148	
Operation & Maintenance Expenses		
Meter Operations	4,599,330	
Meter Maint.	0	
Meter Reading	3,020,141	
Records & Collections	8,789,944	
Misc. Customer Accts.	460,594	
Total	16,870,009	
Depreciation Expense		
Services	815,572	2/
Meters	962,364	2/
Total	1,777,936	
Revenue Requirement:		
Interest	629,021	
Equity Return	1,445,049	
Income Tax @ effective rate	906,876	
Revenue for Return	2,980,946	
Total Customer Revenue Requirement	21,628,892	
Number of Bills	5,044,176	
Monthly Cost	**$4.29**	

	Pct	Cost	Weighted Cost
Debt	50.00%	3.70%	1.85%
Equity	50.00%	8.50%	4.25%
Total	100.00%		6.10%

Effective Tax Rate

Tax	Taxable Income	
$89,659,334	$232,525,670	38.56%

1/ Calculated Per Company Response toOAG 1-273
2/ Calculated Per Mr. Spanos Depreciation rates Exhibit JJS-KU, Part III.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	)))	2012-00221

AFFIDAVIT OF GLENN A. WATKINS

Commonwealth of Virginia)

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

Glenn A. Watkins

SUBSCRIBED AND SWORN to before me this ____ day of ____________, 2012.

NOTARY PUBLIC

My Commission Expires: 10-31-14

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