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Issues:	Rate Design
Witness:	Maurice Brubaker
Type of Exhibit:	Direct Testimony
Sponsoring Party:	Missouri Industrial Energy Consumers and Midwest Energy Consumers Group
Case No.:	ER-2012-0174
Date Testimony Prepared:	August 16, 2012

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	**Case No. ER-2012-0174** Tracking No. YE-2012-0404

Direct Testimony and Schedules of

Maurice Brubaker

On behalf of

Missouri Industrial Energy Consumers
and
Midwest Energy Consumer's Group

August 16, 2012

BRUBAKER & ASSOCIATES, INC.

Project 9593

BEFORE THE PUBLIC SERVICE
COMMISSION OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	)	**Case No. ER-2012-0174** Tracking No. YE-2012-0404

STATE OF MISSOURI	)	
	)	**SS**
COUNTY OF ST. LOUIS	)	

Affidavit of Maurice Brubaker

Maurice Brubaker, being first duly sworn, on his oath states:

1. My name is Maurice Brubaker. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017. We have been retained by Missouri Industrial Energy Consumers and Midwest Energy Consumer's Group in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes is my direct testimony and schedules which were prepared in written form for introduction into evidence in the Missouri Public Service Commission's Case No. ER-2012-0174.

3. I hereby swear and affirm that the testimony and schedules are true and correct and that they show the matters and things that they purport to show.

M E Brubaker

Maurice Brubaker

Subscribed and sworn to before me this 15th day of August, 2012.

TAMMY S. KLOSSNER
Notary Public - Notary Seal
STATE OF MISSOURI
St. Charles County
My Commission Expires: Mar. 14, 2015
Commission # 11024862

Tammy S Klossner

Notary Public

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Direct Testimony of Maurice Brubaker

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Direct Testimony of Maurice Brubaker

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Maurice Brubaker. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and President of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of Missouri Industrial Energy Consumers ("MIEC") and Midwest Energy Consumer's Group ("MECG"). These companies purchase substantial amounts of electricity from Kansas City Power & Light Company ("KCPL") and the outcome of this proceeding will have an impact on their cost of electricity.

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A The purpose of my testimony is to present the results of a class cost of service study for KCPL, to explain how the study should be used, to recommend an appropriate allocation of any rate increase, and to make rate design recommendations.

Q HOW IS YOUR TESTIMONY ORGANIZED?

A First, I present an overview of cost of service principles and concepts. This includes a description of how electricity is produced and distributed as well as a description of the various functions that are involved; namely, generation, transmission and distribution. This is followed by a discussion of the typical classification of these functionalized costs into demand-related costs, energy-related costs and customer-related costs.

With this as a background, I then explain the various factors which should be considered in determining how to allocate these functionalized and classified costs among customer classes.

Finally, I present the results of the detailed cost of service analysis for KCPL. This cost study indicates how individual customer class revenues compare to the costs incurred in providing service to them. This analysis and interpretation is then followed by recommendations with respect to the alignment of class revenues with class costs. I conclude by addressing rate design issues.

Summary

Q PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS.

A My testimony and recommendations may be summarized as follows:

1. Class cost of service is the starting point and most important guideline for establishing the level of rates charged to customers.

2. KCPL exhibits significant summer peak demands as compared to demands in other months.

3. There are two generally accepted methods for allocating generation and transmission fixed costs that would apply to KCPL. These are the coincident peak methodology and the average and excess ("A&E") methodology.

4. The A&E methodology appropriately considers both class maximum demands and class load factor, as well as diversity between class peaks and the system peak.

5. In order to better reflect cost-causation, I have changed KCPL's submitted cost of service methodology in two respects:

   (1) KCPL has used an obscure and inappropriate method to allocate generation fixed costs, which I will address in my rebuttal testimony. I have, instead, applied main-stream methods that this Commission has previously endorsed.

   (2) KCPL allocates the margin earned from off-system sales on a demand basis. I have changed the allocation to reflect the more appropriate energy-based allocation which the Commission has previously approved for this purpose.

6. The results of my class cost of service study, incorporating the change in methodology that I have applied, are summarized on Schedule MEB-COS-4. Schedule MEB-COS-5 shows the adjustments required to move each class to its cost of service on a revenue neutral basis at present rates.

7. A modest realignment of class revenues to move them closer to costs should be implemented, as presented on Schedule MEB-COS-6.

8. Schedules MEB-COS-7 and MEB-COS-8 show my recommended adjustments to the design of the Large Power Service ("LPS") and Large General Service ("LGS") rates, respectively.

COST OF SERVICE PROCEDURES

Overview

Q PLEASE DESCRIBE THE COST ALLOCATION PROCESS.

A The objective of *cost allocation* is to determine what proportion of the utility's total revenue requirement should be recovered from each customer class. As an aid to this determination, cost of service studies are usually performed to determine the portions of the total costs that are incurred to serve each customer class. The cost of service study identifies the cost responsibility of the class and provides the foundation for revenue allocation and rate design. For many regulators, cost-based rates are an expressed goal. To better interpret cost allocation and cost of service studies, it is important to understand the production and delivery of electricity.

Electricity Fundamentals

Q IS ELECTRICITY SERVICE LIKE ANY OTHER GOODS OR SERVICES?

A No. Electricity is different from most other goods or services purchased by consumers. For example:

- It cannot be stored; must be delivered as produced;
- It must be delivered to the customer's home or place of business;
- The delivery occurs instantaneously when and in the amount needed by the customer; and
- Both the total quantity used (energy or kWh) by a customer <u>and</u> the rate of use (demand or kW) are important.

These unique characteristics differentiate electric utilities from other service-related industries.

The service provided by electric utilities is multi-dimensional. First, unlike most vital services, electricity must be delivered at the place of consumption – homes, schools, businesses, factories – because this is where the lights, appliances, machines, air conditioning, etc. are located. Thus, every utility must provide a path through which electricity can be delivered regardless of the customer's **demand** and **energy** requirements at any point in time.

Even at the same location, electricity may be used in a variety of applications. Homeowners, for example, use electricity for lighting, air conditioning, perhaps heating, and to operate various appliances. At any instant, several appliances may be operating (e.g., lights, refrigerator, TV, air conditioning, etc.). Which appliances are used and when reflects the second dimension of utility service – the rate of electricity use or **demand**. The demand imposed by customers is an especially important characteristic because the maximum demands determine how much capacity the utility is obligated to provide.

Generating units, transmission lines and substations and distribution lines and substations are rated according to the maximum demand that can safely be imposed on them. (They are not rated according to average annual demand; that is, the amount of energy consumed during the year divided by 8,760 hours.) On a hot summer afternoon when customers demand 2,000 MW of electricity, the utility must have at least 2,000 MW of generation, plus additional capacity to provide adequate reserves, so that when a consumer flips the switch, the lights turn on, the machines operate and air conditioning systems cool our homes, schools, offices, and factories.

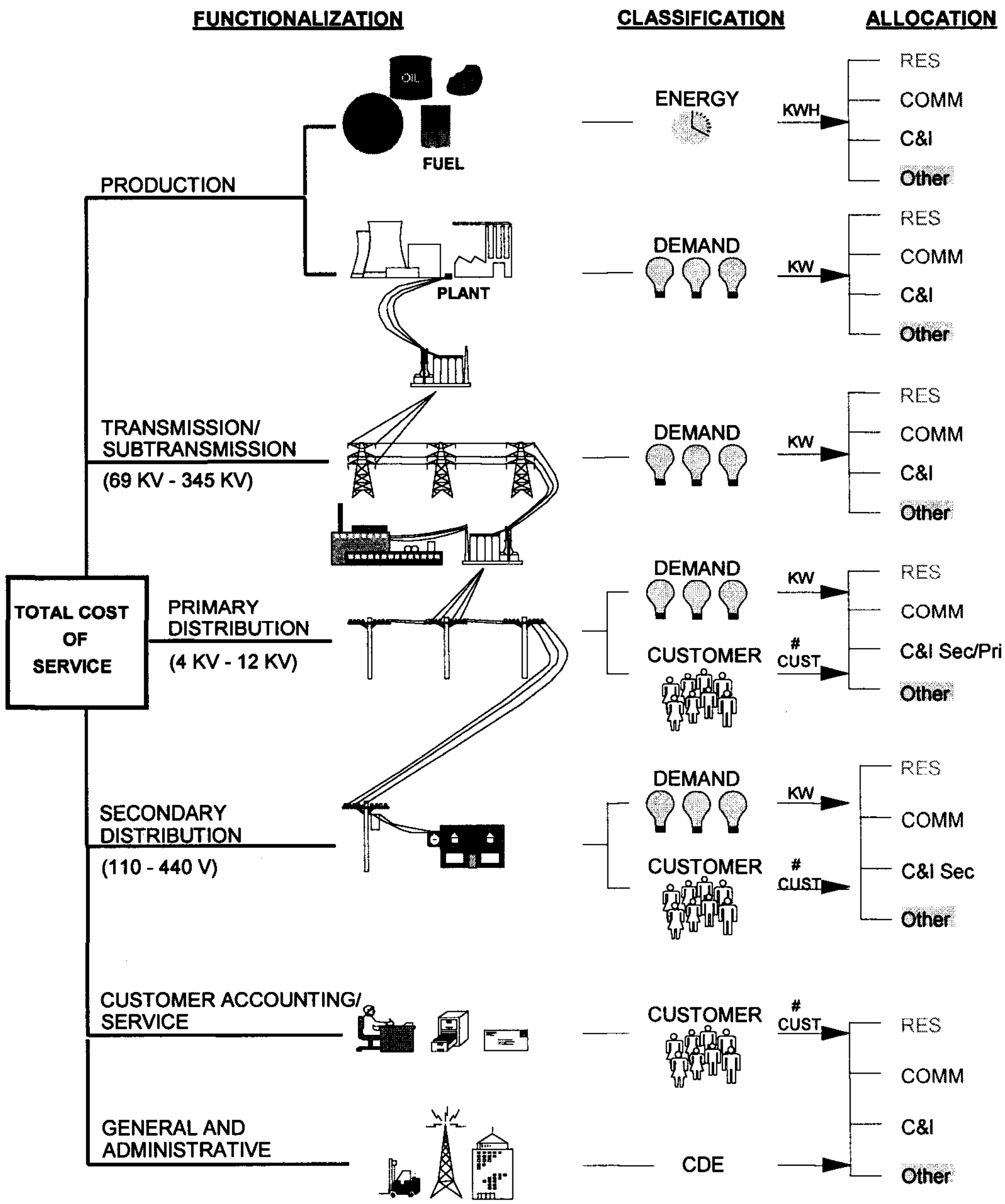
Satisfying customers' demand for electricity over time – providing **energy** – is the third dimension of utility service. It is also the dimension with which many people are most familiar, because people often think of electricity simply in terms of kWhs. To see one reason why this isn't so, consider a more familiar commodity – tomatoes, for example.

The tomatoes we buy at the supermarket for about $2.00 a pound might originally come from Florida where they are bought for about 30¢ a pound. In addition to the cost of buying them at the point of production, there is the cost of bringing them to the state of Missouri and distributing them in bulk to local wholesalers. The cost of transportation, insurance, handling and warehousing must be added to the original 30¢ a pound. Then they are distributed to neighborhood stores, which adds more handling costs as well as the store's own costs of light, heat, personnel and rent. Shoppers can then purchase as many or few tomatoes as they desire at their convenience. In addition, there are losses from spoilage and damage in handling. These "line losses" represent an additional cost which must be recovered in the final price. What we are really paying for at the store is not only the vegetable itself, but the <u>service</u> of having it available in convenient amounts and locations. If we took the time and trouble (and expense) to go down to the wholesale produce distributor, the price would be less. If we could arrange to buy them in bulk in Florida, they would be even cheaper.

As illustrated in Figure 1, electric utilities are similar, except that in most cases (including Missouri), a single company handles everything from production on down through wholesale (bulk and area transmission) and retail (distribution to homes and stores). The crucial difference is that, unlike producers and distributors of tomatoes, electric utilities have an obligation to provide continuous reliable service. The obligation is assumed in return for the exclusive right to serve all customers located within its territorial franchise. In addition to satisfying the energy (or kWh) requirements of its customers, the obligation to serve means that the utility must also provide the necessary facilities to attach customers to the grid (so that service can be used at the point where it is to be consumed) and these facilities must be responsive to changes in the kilowatt demands whenever they occur.

Figure 1

PRODUCTION AND DELIVERY OF ELECTRICITY



A CLOSER LOOK AT THE COST OF SERVICE STUDY

Q PLEASE EXPLAIN HOW A COST OF SERVICE STUDY IS PREPARED.

A To the extent possible, the unique characteristics that differentiate electric utilities from other service-related industries should be recognized in determining the cost of providing service to each of the various customer classes. The basic procedure for conducting a class cost of service study is simple. In an allocated cost of service study, we identify the different types of costs (**functionalization**), determine their primary causative factors (**classification**) and then apportion each item of cost among the various rate classes (**allocation**). Adding up the individual pieces gives the total cost for each customer class.

Functionalization

Q PLEASE EXPLAIN FUNCTIONALIZATION.

A Identifying the different levels of operation is a process referred to as **functionalization**. The utility's investment and expenses are separated by function (production, transmission, etc.). To a large extent, this is done in accordance with the Uniform System of Accounts.

Referring to Figure 1, at the top level there is generation. The next level is the extra high voltage transmission and subtransmission system (69,000 volts to 345,000 volts). Then the voltage is stepped down to primary voltage levels of distribution – 4,160 to 12,000 volts. Finally, the voltage is stepped down by pole transformers at the "secondary" level to 110-440 volts used to serve homes, barbershops, light manufacturing and the like. Additional investment and expenses are required to serve customers at secondary voltages, compared to the cost of serving customers at higher voltage.

Each additional transformation, thus, requires additional investment, additional expenses and results in some additional electrical losses. To say that "a kilowatthour is a kilowatthour" is like saying that "a tomato is a tomato." It's true in one sense, but when you buy a kWh at home you're not only buying the energy itself but also the service of having it delivered right to your doorstep in convenient form. Those who buy at the bulk or wholesale level – like some of the Large Power Service customers – pay less because some of the expenses to the utility are avoided. (Actually, the expenses are borne by the customer who must invest in his own transformers and other equipment, or pay separately for some services.)

Classification

Q WHAT IS CLASSIFICATION?

A Once the costs have been functionalized, the next step is to identify the primary causative factor (or factors). This step is referred to as **classification**. Costs are classified as demand-related, energy-related or customer-related.

Looking at the production function, the amount of production plant capacity required is primarily determined by the peak rate of usage during the year. If the utility anticipates a peak demand of 2,000 MW – it must install and/or contract for enough generating capacity to meet that anticipated demand (plus some reserve to compensate for variations in load and capacity that is temporarily unavailable).

There will be many hours during the day or during the year when not all of this generating capacity will be needed. Nevertheless, it must be in place to meet the peak demands on the system. Thus, production plant investment is usually classified to demand. **Regardless of how production plant investment is classified, the associated capital costs** (which include return on investment, depreciation, fixed operation and maintenance ("O&M") expenses, taxes and insurance) **are fixed;** that is, **<u>they do not vary with the amount of kWhs generated and sold</u>**. These fixed costs are determined by the amount of capacity (i.e., kilowatts) which the utility must install to satisfy its obligation-to-serve requirement.

On the other hand, it is easy to see that the amount of fuel burned – and therefore the amount of fuel expense – is closely related to the amount of energy (number of kWhs) that customers use. Therefore, fuel expense is an energy-related cost.

Most other O&M expenses are fixed and therefore are classified as demand-related. Variable O&M expenses are classified as energy-related. Demand-related and energy-related types of operating costs are not impacted by the number of customers served.

Customer-related costs are the third major category. Obvious examples of customer-related costs include the investment in meters and service drops (the line from the pole to the customer's facility or house). Along with meter reading, posting accounts and rendering bills, these "customer costs" may be several dollars per customer, per month. Less obvious examples of customer-related costs may include the investment in other distribution accounts.

A certain portion of the cost of the distribution system – poles, wires and transformers – is required simply to attach customers to the system, regardless of their demand or energy requirements. This minimum or "skeleton" distribution system may also be considered a customer-related cost since it depends primarily on the number of customers, rather than demand or energy usage.

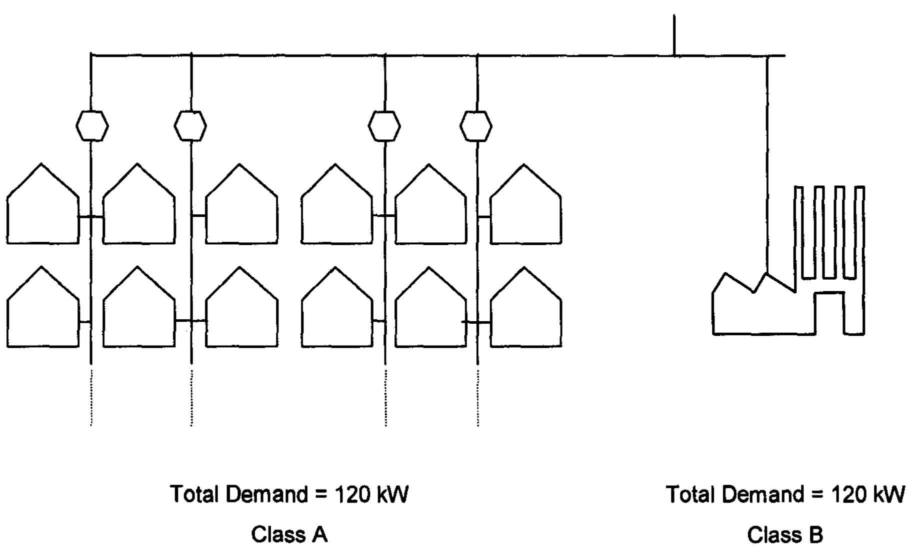
Figure 2, as an example, shows the distribution network for a utility with two customer classes, A and B. The physical distribution network necessary to attach

Class A is designed to serve 12 customers, each with a 10-kilowatt load, having a total demand of 120 kW. This is the same total demand as is imposed by Class B, which consists of a single customer. Clearly, a much more extensive distribution system is required to attach the multitude of small customers (Class A), than to attach the single larger customer (Class B), despite the fact that the total demand of each customer class is the same.

Even though some additional customers can be attached without additional investment in some areas of the system, it is obvious that attaching a large number of customers requires investment in facilities, not only initially but on a continuing basis as a result of the need for maintenance and repair.

To the extent that the distribution system components must be sized to accommodate additional load beyond the minimum, the balance is a demand-related cost. Thus, the distribution system is classified as both demand-related and customer-related.

Figure 2
<u>Classification of Distribution Investment</u>



Demand vs. Energy Costs

Q WHAT IS THE DISTINCTION BETWEEN DEMAND-RELATED COSTS AND ENERGY-RELATED COSTS?

A The difference between demand-related and energy-related costs explains the fallacy of the argument that "a kilowatthour is a kilowatthour." For example, Figure 3 compares the electrical requirements of two customers, A and B, each using 100-watt light bulbs.

Customer A turns on all five of his/her 100-watt light bulbs for two hours. Customer B, by contrast, turns on two light bulbs for five hours. Both customers use the same amount of energy – 1,000 watthours or 1 kWh. However, Customer A utilized electric power at a higher rate, 500 watts per hour or 0.5 kW, than Customer B who demanded only 200 watts per hour or 0.2 kW.

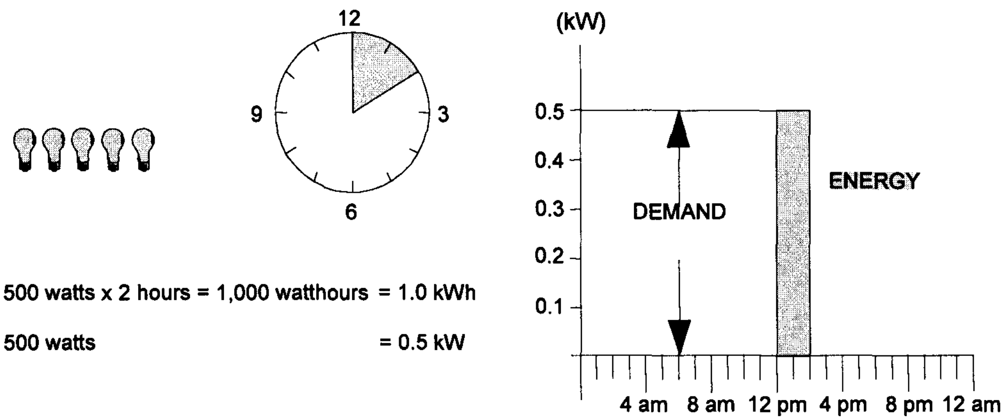
Although both customers had precisely the same kWh energy usage, Customer A's kW demand was 2.5 times Customer B's. Therefore, the utility must install 2.5 times as much generating capacity for Customer A as for Customer B. The cost of serving Customer A, therefore, is much higher.

Q DOES THIS HAVE ANYTHING TO DO WITH THE CONCEPT OF LOAD FACTOR?

A Yes. Load factor is an expression of how uniformly a customer uses energy. In our example of the light bulbs, the load factor of Customer B would be higher than the load factor of Customer A because the use of electricity was spread over a longer period of time, and the number of kWhs used for each kilowatt of demand imposed on the system is much greater in the case of Customer B.

Figure 3
DEMAND VS. ENERGY

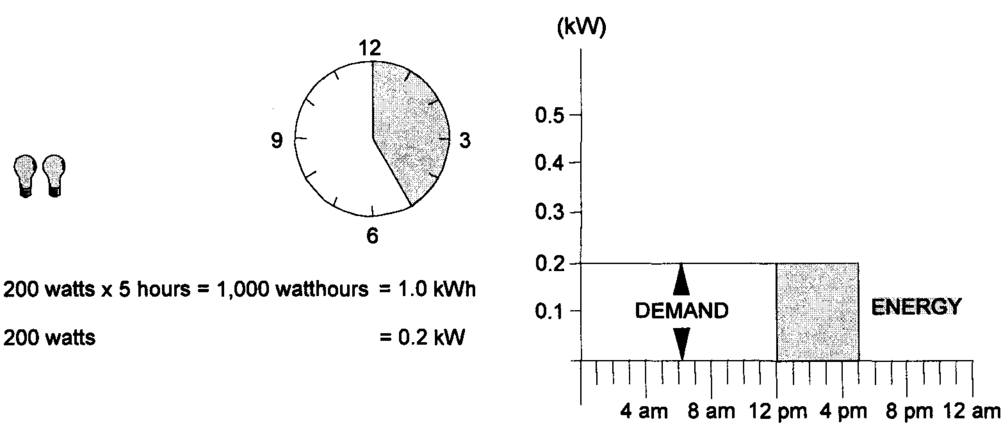
CUSTOMER A



ENERGY: 500 watts x 2 hours = 1,000 watthours = 1.0 kWh

DEMAND: 500 watts = 0.5 kW

CUSTOMER B



ENERGY: 200 watts x 5 hours = 1,000 watthours = 1.0 kWh

DEMAND: 200 watts = 0.2 kW

Mathematically, load factor is the average rate of use divided by the peak rate of use. A customer with a higher load factor is less expensive to serve, on a per kWh basis, than a customer with a low load factor, irrespective of size.

Consider also the analogy of a rental car which costs $40/day and 20¢/mile. If Customer A drives only 20 miles a day, the average cost will be $2.20/mile. But for Customer B, who drives 200 miles a day, spreading the daily rental charge over the total mileage gives an average cost of 40¢/mile. For both customers, the fixed cost rate (daily charge) and variable cost rate (mileage charge) are identical, but the average total cost per mile will differ depending on how intensively the car is used. Likewise, the average cost per kWh will depend on how intensively the generating plant is used. A low load factor indicates that the capacity is idle much of the time; a high load factor indicates a more steady rate of usage. Since industrial customers generally have higher load factors than residential or commercial customers, they are less costly to serve on a per-kWh basis. Again, we can say that "a kilowatthour is a kilowatthour" as to energy content, but there may be a big difference in how much generating plant investment is required to convert the raw fuel into electric energy.

Allocation

Q WHAT IS ALLOCATION?

A The final step in the cost of service analysis is the **allocation** of the costs to the customer classes. Demand, energy and customer allocation factors are developed to apportion the costs among the customer classes. Each factor measures the customer class's contribution to the system total cost.

For example, we have already determined that the amount of fuel expense on the system is a function of the energy required by customers. In order to allocate this expense among classes, we must determine how much each class contributes to the total kWh consumption and we must recognize the line losses associated with transporting and distributing the kWh. These contributions, expressed in percentage terms, are then multiplied by the expense to determine how much expense should be attributed to each class. For demand-related costs, we construct an allocation factor by looking at the important class demands.

Utility System Characteristics

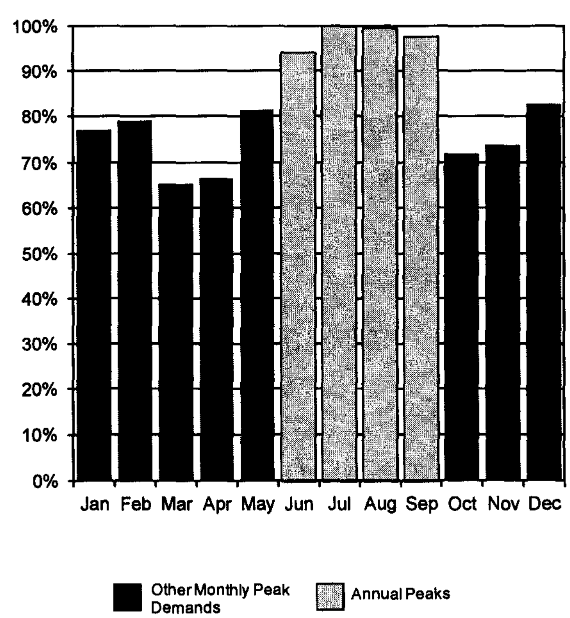
Q WHAT IS THE IMPORTANCE OF UTILITY SYSTEM LOAD CHARACTERISTICS?

A Utility system load characteristics are an important factor in determining the specific method which should be employed to allocate fixed or demand-related costs on a utility system. The most important characteristic is the annual load pattern of the utility. These characteristics for KCPL's Missouri jurisdiction are shown on Schedule MEB-COS-1. For convenience, it is also shown here as Figure 4.

Figure 4

KANSAS CITY POWER & LIGHT COMPANY

Analysis of KCP&L's (Missouri) Monthly Peak Demands
as a Percent of the Annual System Peak
For the Test Year Ended September 30, 2011



This shows the monthly system peak demands for the test year used in the study. The highlighted bar shows the month in which the highest peak occurred.

This analysis shows that summer peaks dominate the KCPL system. (This same information is presented in tabular form on Schedule MEB-COS-2.) This clearly shows that the system peak occurred in July, and was substantially higher than the monthly peaks occurring in most other months. The peaks in June, August and September were 5.7%, 0.3%, and 2.3%, respectively, lower than the annual peak.

Q **WHAT CRITERIA SHOULD BE USED TO DETERMINE AN APPROPRIATE METHOD FOR ALLOCATING PRODUCTION AND TRANSMISSION CAPACITY COSTS AMONG THE VARIOUS CUSTOMER CLASSES?**

A The specific allocation method should be consistent with the principle of cost-causation; that is, the allocation should reflect the contribution of each customer class to the demands that caused the utility to incur capacity costs.

Q **WHAT FACTORS CAUSE ELECTRIC UTILITIES TO INCUR PRODUCTION AND TRANSMISSION CAPACITY COSTS?**

A As discussed previously, production and transmission plant must be sized to meet the maximum demand imposed on these facilities. Thus, an appropriate allocation method should accurately reflect the characteristics of the loads served by the utility. For example, if a utility has a high summer peak relative to the demands in other seasons, then production and transmission capacity costs should be allocated relative to each customer class's contribution to the summer peak demands. If a utility has predominant peaks in both the summer and winter periods, then an appropriate allocation method would be based on the demands imposed during both the summer and winter peak periods. For a utility with a very high load factor and/or a non-seasonal load pattern, then demands in all months may be important.

Q **WHAT DO THESE CONSIDERATIONS MEAN IN THE CONTEXT OF THE KCPL SYSTEM?**

A As noted, the KCPL load pattern has predominant summer peaks. This means that these demands should be the primary ones used in the allocation of generation and transmission costs. Demands in other months are of much less significance, do not compel the addition of generation capacity to serve them and should not be used in determining the allocation of costs.

Q **WHAT SPECIFIC RECOMMENDATIONS DO YOU HAVE?**

A The two most predominantly used allocation methods in the industry are the coincident peak method and the A&E demand method.

The coincident method utilizes the demands of customer classes occurring at the time of the system peak or peaks selected for allocation. In the case of KCPL, this would be one or more peaks occurring during the summer.

Q **WHAT IS THE A&E METHOD?**

A The A&E method is one of a family of methods which incorporates a consideration of both the maximum rate of use (demand) and the duration of use (energy). As the name implies, A&E makes a conceptual split of the system into an "average" component and an "excess" component. The "average" demand is simply the total kWh usage divided by the total number of hours in the year. This is the amount of capacity that would be required to produce the energy if it were taken at the same demand rate each hour. The system "excess" demand is the difference between the system peak demand and the system average demand.

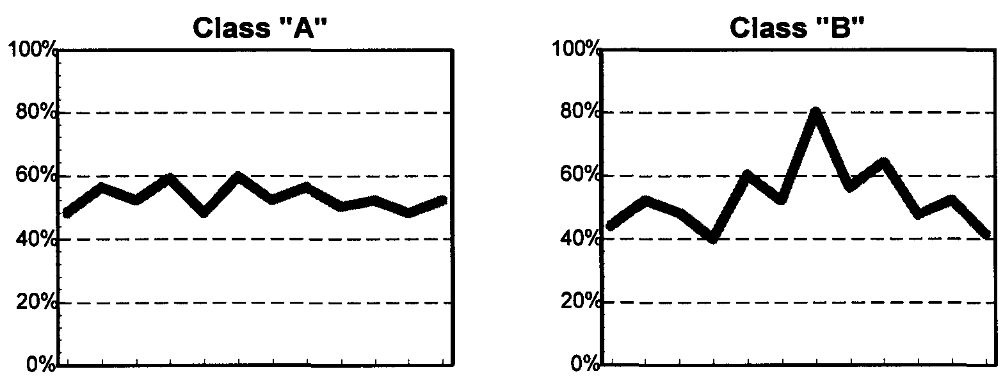
Under the A&E method, the average demand is allocated to classes in proportion to their average demand (energy usage). The difference between the system average demand and the system peak(s) is then allocated to customer classes on the basis of a measure that represents their "peaking" or variability in usage.[1]

Q WHAT DO YOU MEAN BY VARIABILITY IN USAGE?

A As an example, Figure 5 shows two classes that have different monthly usage patterns.

Figure 5

<u>Load Patterns</u>



Both classes use the same total amount of energy and, therefore, have the same average demand. Class B, though, has a much greater maximum demand[2] than

[1] <u>NARUC Electric Utility Cost Allocation Manual</u>, 1992, page 81.

[2] During any specified time period (e.g., month, year), the maximum demand of a class, regardless of when it occurs, is called the non-coincident peak demand.

Class A. The greater maximum demand imposes greater costs on the utility system. This is because the utility must provide sufficient capacity to meet the projected maximum demands of its customers. There may also be higher costs due to the greater variability of usage of some classes. This variability requires that a utility cycle its generating units in order to match output with demand on a real time basis. The stress of cycling generating units up and down causes wear and tear on the equipment, resulting in higher maintenance cost.

Thus, the excess component of the A&E method is an attempt to allocate the additional capacity requirements of the system (measured by the system excess) in proportion to the "peakiness" of the customer classes (measured by the class excess demands).

Q WHAT DEMAND ALLOCATION METHODOLOGY DO YOU RECOMMEND FOR GENERATION AND TRANSMISSION?

A First, in order to reflect cost-causation the methodology must give predominant weight to loads occurring during the summer months. Loads during these months (the peak loads) are the primary driver which has and continues to cause the utility to expand its generation and transmission capacity, and therefore should be given predominant weight in the allocation of capacity costs.

Either a coincident peak study, using the demands during the summer (peak) months, or a version of an A&E cost of service study that uses class non-coincident peak loads occurring during the summer, would be most appropriate to reflect these characteristics. The results should be similar as long as only summer period peak loads are used. I will make my recommendations based on the A&E method. It considers the maximum class demands during the critical time periods, and is less susceptible to variations in the absolute hour in which peaks occur – producing a somewhat more stable result over time.

Based on test year load characteristics, I believe the most appropriate A&E allocation would be using the two or three highest system peaks. However, the allocation factors for all classes are very close to the A&E-4NCP allocation factors.

Schedule MEB-COS-3 shows the derivation of the A&E demand allocation factor for generation using the four annual class non-coincident peaks, and page 1 of my MEB-COS-Appendix shows the derivation of the A&E-2NCP allocation factor.

Q REFERRING TO SCHEDULE MEB-COS-3, PLEASE EXPLAIN THE DEVELOPMENT OF THE A&E ALLOCATION FACTOR.

A Line 2 shows the average of the four non-coincident peaks for each class. Line 3 shows the annual amount of energy required by each class. Line 4 is the average demand, in kilowatts, which is determined by dividing the annual energy in line 3 by the number of hours (8,760) in a year. Line 5 shows the percentage relationship between the average demand for each class and the total system.

The excess demand, shown on line 6, is equal to the non-coincident peak demand shown on line 2 minus the average demand that is shown on line 4. Line 7 shows the excess demand percentage, which is a relationship among the excess demand of each customer class and the total excess demand for all classes.

Finally, line 10 presents the composite A&E allocation factor. It is determined by weighting the average demand responsibility of each class (which is the same as each class's energy allocation factor) by the system load factor, and weighting the excess demand factor by the quantity one minus the system load factor.

Making the Cost of Service Study – Summary

Q PLEASE SUMMARIZE THE PROCESS AND THE RESULTS OF A COST OF SERVICE ANALYSIS.

A As previously discussed, the cost of service procedure involves three steps:

1. Functionalization – Identify the different functional "levels" of the system;
2. Classification – Determine, for each functional type, the primary cause or causes (customer, demand or energy) of that cost being incurred; and
3. Allocation – Calculate the class proportional responsibilities for each type of cost and spread the cost among classes.

Q WHERE ARE YOUR COST OF SERVICE RESULTS PRESENTED?

A The results are presented in Schedule MEB-COS-4, which reflects results at present rates.

Q REFERRING TO SCHEDULE MEB-COS-4, PLEASE EXPLAIN THE ORGANIZATION AND WHAT IS SHOWN.

A Schedule MEB-COS-4 is a summary of the key elements and the results of the class cost of service study. The top section of the schedule shows the revenues, expenses and operating income based on an A&E-4NCP cost of service study.

The next section shows the major elements of rate base, and the rate of return at present rates for each customer class based on this cost of service study.

Q DID KCPL SUBMIT A CLASS COST OF SERVICE STUDY?

A Yes. KCPL submitted a class cost of service study. This study bases the allocation of generation costs on an obscure and inappropriate allocation method. KCPL's method is not grounded in appropriate cost-causation principles, and should not be accepted. I will address this proposed methodology in more detail in my rebuttal testimony.

Q HAVE YOU USED ITS STUDY?

A I have used the study framework as a basis for preparing my cost of service study. As explained below, I have developed a cost of service study using a different allocation for generation fixed costs, and also a different allocation of the margin on off-system sales.

Q HAVE YOU PREPARED ANY COST OF SERVICE STUDIES BESIDES THE A&E-4NCP STUDY PRESENTED IN SCHEDULE MEB-COS-4?

A Yes. I have prepared studies based on A&E-2NCP, and also 4CP methodologies. The derivation of the generation capacity allocation factor and the results of each cost of service study are presented in the Appendix to my schedules.

Q OTHER THAN THE USE OF A DIFFERENT ALLOCATION FOR GENERATION FIXED COSTS, HOW DO YOUR STUDIES DIFFER FROM THE ONE PRESENTED BY KCPL?

A There also is a difference in the allocation of the margin on off-system sales.

Q WHAT IS THE ISSUE WITH RESPECT TO THE ALLOCATION OF OFF-SYSTEM SALES?

A KCPL has allocated the margin from off-system sales on the basis of the allocation of steam fixed generation plant.

The more traditional approach is to allocate the revenues from off-system sales to customer classes on the basis of class kWh requirements. This would make the allocation of the revenues consistent with the allocation of the underlying costs. (This method was recently adopted in a KCPL rate case, Case No. ER-2006-0314, and re-affirmed in Ameren Missouri's rate case, Case No. ER-2010-0036).

Q HOW DID YOU USE KCPL'S COST OF SERVICE MODEL IN PRODUCING YOUR CLASS COST OF SERVICE STUDY?

A It was the starting point. The results of KCPL's allocation first were replicated by utilizing the data contained in its cost of service model. Many of KCPL's allocation factors and functionalizations and classifications have been utilized. The principal areas where I depart from KCPL and use a different approach were incorporated into the allocations. They have previously been explained in this testimony.

I disagree with KCPL's allocation of certain DSM costs on a production demand basis, but have not made a change in the attached COS studies because all of the relevant costs could not be identified. I will address this issue in my rebuttal testimony.

Adjustment of Class Revenues

Q WHAT SHOULD BE THE PRIMARY BASIS FOR ESTABLISHING CLASS REVENUE REQUIREMENTS AND DESIGNING RATES?

A Cost should be the primary factor used in both steps.

Just as cost of service is used to establish a utility's total revenue requirement, it should also be the primary basis used to establish the revenues collected from each customer class and to design rate schedules.

Factors such as simplicity, gradualism and ease of administration may also be taken into account, but the basic starting point and guideline throughout the process should be cost of service. To the extent practicable, rate schedules should be structured and designed to reflect the important cost-causative features of the service provided, and to collect the appropriate cost from the customers within each class or rate schedule, based upon the individual load patterns exhibited by those customers.

Electric rates also play a role in economic development, both with respect to job creation and job retention. This is particularly true in the case of industries where electricity is one of the largest components of the cost of production.

Q WHAT IS THE BASIS FOR YOUR RECOMMENDATION THAT COST BE USED AS THE PRIMARY FACTOR FOR THESE PURPOSES?

A The basic reasons for using cost as the primary factor are equity, conservation, and engineering efficiency (cost-minimization).

Q PLEASE EXPLAIN HOW EQUITY IS ACHIEVED BY BASING RATES ON COST.

A When rates are based on cost, each customer pays what it costs the utility to provide service to that customer; no more and no less. If rates are based on anything other than cost factors, then some customers will pay the costs attributable to providing service to other customers – which is inherently inequitable.

Q HOW DO COST-BASED RATES FURTHER THE GOAL OF CONSERVATION?

A Conservation occurs when wasteful, inefficient use is discouraged or minimized. Only when rates are based on costs do customers receive a balanced price signal upon which to make their electric consumption decisions. If rates are not based on costs, then customers who are not paying their full costs may be mislead into using electricity inefficiently in response to the distorted rate design signals they receive.

Q WILL COST-BASED RATES ASSIST IN THE DEVELOPMENT OF COST-EFFECTIVE DEMAND-SIDE MANAGEMENT ("DSM") PROGRAMS?

A Yes. The success of DSM (both energy efficiency and demand response programs) depends, to a large extent, on customer receptivity. There are many actions that can be taken by consumers to reduce their electricity requirements. A major element in a customer's decision-making process is the amount of reduction that can be achieved in the electric bill as a result of DSM activities. If the bill received by a customer is subsidized by other customers; that is, the bill is determined using rates which are below cost, that customer will have less reason to engage in DSM activities than when the bill reflects the actual cost of the electric service provided.

For example, assume that the relevant cost to produce and deliver energy is 8¢ per kWh. If a customer has an opportunity to install energy efficiency or DSM equipment that would allow the customer to reduce energy use or demand, the customer will be much more likely to make that investment if the price of electricity equals the cost of electricity, i.e., 8¢ per kWh, than if the customer is receiving a subsidized rate of 6¢ per kWh.

Q HOW DO COST-BASED RATES ACHIEVE THE COST-MINIMIZATION OBJECTIVE?

A When the rates are designed so that the energy costs, demand costs and customer costs are properly reflected in the energy, demand and customer components of the rate schedules, respectively, customers are provided with the proper incentives to minimize their costs, which will in turn minimize the costs to the utility.

If a utility attempts to extract a disproportionate share of revenues from a class that has alternatives available (such as producing products at other locations where costs are lower), then the utility will be faced with the situation where it must discount the rates or lose the load, either in part or in total. To the extent that the load could have been served more economically by the utility, then either the other customers of the utility or the stockholders (or some combination of both) will be worse off than if the rates were properly designed on the basis of cost.

From a rate design perspective, overpricing the energy portion of the rate and underpricing the fixed components of the rate (such as customer and demand charges) will result in a disproportionate share of revenues being collected from large customers and high load factor customers. To the extent that these customers may have lower cost alternatives than do the smaller or the low load factor customers, the same problems noted above are created.

Revenue Allocation

Q PLEASE REFER AGAIN TO SCHEDULE MEB-COS-4 AND SUMMARIZE THE RESULTS OF YOUR CLASS COST OF SERVICE STUDY.

A As indicated on line 0400 of Schedule MEB-COS-4, movement of all classes to cost of service will require an increase to the Residential class and a decrease to all other classes.

Q **WHAT ADJUSTMENTS TO REVENUES WOULD BE REQUIRED AT PRESENT RATES TO MOVE ALL CLASSES TO COST OF SERVICE?**

A This is shown on Schedule MEB-COS-5. The first five columns summarize the results of the cost of service study at present rates, and are taken from Schedule MEB-COS-4. The remaining columns of Schedule MEB-COS-5 determine the amount of increase or decrease, on a revenue neutral basis, required to move each customer class to the average rate of return at current revenue levels. That is, it shows the amount of increase or decrease required to have every class yield the same rate of return, before considering any overall increase in revenues. Note that the Residential class would require an increase of about $51 million, or 18.5%, in order to move to cost of service. All other classes would require a corresponding decrease. The decreases range from about 21% for the Lighting class to 8.5% for the Large Power Service class.

Q **HOW DOES KCPL PROPOSE TO ADJUST REVENUES?**

A KCPL proposes essentially an equal percentage across-the-board increase.

Q **WOULD KCPL'S ALLOCATION MOVE CLASS RATES CLOSER TO COST OF SERVICE?**

A No. KCPL's allocation would essentially maintain the status quo in which the Residential class is below cost of service, and other classes are above cost of service.

Q **DO YOU HAVE AN ALTERNATIVE RECOMMENDATION FOR ALLOCATION OF KCPL'S REVENUE REQUIREMENT?**

A Yes. I will focus on adjustments to be made on a revenue neutral basis at present rates. After having made my recommended revenue neutral adjustments at present rates, any overall change in revenues allowed to KCPL can then be applied on an equal percentage across-the-board basis to these adjusted class revenues.

Q **PLEASE EXPLAIN YOUR SPECIFIC PROPOSAL.**

A My specific proposal is shown on Schedule MEB-COS-6. Column 1 shows class revenues at current rates. Column 2 shows my proposed cost of service adjustment. This adjustment moves classes roughly 25% of the way toward cost of service. This 25% movement was selected because it makes a reasonable step in the right direction without imposing too disruptive of a revenue increase on the Residential class. An overall revenue-neutral increase of about 4.6% on the Residential class is a relatively modest step, but at least it is a step in the right direction.

While some will want to talk about the impact on the Residential class of this increase, it is also important not to lose sight of the fact that by not moving all the way to cost of service, the other customer classes are continuing to bear more of the burden of the revenue responsibility than they should. My recommendation of moving 25% of the way toward cost of service, which limits the Residential class revenue-neutral increase to 4.6% (as compared to the 18.5% increase required to move all the way to cost of service) is relatively moderate, and must be considered in light of the fact that other classes are being asked to continue to provide part of the revenue responsibility that rightly should be shouldered by the Residential class.

Analysis of Large Customer Rates

Q WHAT IS THE STRUCTURE OF THE TARIFFS APPLICABLE TO KCPL'S LARGEST CUSTOMERS?

A The LGS and LPS tariffs consist of a series of charges differentiated by voltage level. There are separate charges for service at secondary voltage, service at primary voltage, service at substation voltage, and service at transmission voltage. The rates charged at the higher voltage levels are lower than the rates charged at the lower voltage levels in order to recognize differences in cost of service.

At each voltage level, the rate consists of customer charges, facilities charges, charges for reactive power, demand charges and energy charges. Demand charges and energy charges also are seasonally differentiated, with summer charges being applied during the four consecutive months beginning May 16 and ending September 15.

Q WHAT IS THE STRUCTURE OF THE DEMAND CHARGES?

A In addition to being seasonally differentiated, the demand charges at each voltage level consist of multiple block charges.

Q WHAT IS THE STRUCTURE OF THE ENERGY CHARGES?

A The energy charges are structured as three "hours use" blocks. The three blocks consist of the first 180 hours use of the billing demand, the next 180 hours use of the billing demand and the tail block is for consumption in excess of 360 hours use of the billing demand.

These are what are known as hours use, or load factor based charges. The rates decrease as the hours use increases to recognize the spreading of fixed costs over more kilowatthours as the number of hours use, or load factor, increases. This structure also recognizes that energy consumed in the high load factor block likely will be off-peak or at times when energy costs are lower than during on-peak periods.

Q **PLEASE EXPLAIN HOW THE HOURS USE FUNCTION WORKS.**

A The number of kWh to be billed in each hours use block is determined by the customer's billing demand and the amount of kWh purchased.

A customer operating basically one shift (eight hours a day for five days a week) would have usage in the range of 180 kWh per kW of billing demand.[3] A customer operating two shifts would utilize approximately twice that much energy, and therefore use an additional 180 or so kWh per kW of demand, thereby filling up both the first and second blocks.

Thus, it is reasonable to consider the first block as being primarily the daytime on-peak hours, the second block for early morning, evening and/or weekend hours, and the third block for additional use in weekend and nighttime hours. Given these considerations, it is appropriate that the energy charges for the initial hours use blocks be higher than for the third hours use block in order to collect more fixed costs during the on-peak and shoulder periods.

Q **CAN YOU ILLUSTRATE WITH AN EXAMPLE OF HOW THE RATE WORKS?**

A Yes. Assume that a customer has a 1,000 kW billing demand, and uses 500,000 kWh in a month. This customer would be using 500 kWh per kW,[4] or 500 kWh for each kW of demand. To apply the rate, the 1,000 kW of demand would be multiplied times 180 kWh per kW, which is the size of the first block, and would result in 180,000

[3]8 hours/day x 5 days per week x 4.33 weeks per month = 173 hours
[4]500,000 ÷ 1,000 kW = 500 kWh/kW

kWh being priced out at the first block. The customer would also fully utilize the second block, so 180,000 kWh would go in it as well. The remaining 140,000 kWh[5] would be billed in the third, or high load factor block.

Q WHAT IS THE LEVEL OF THE ENERGY CHARGES FOR THE HIGH LOAD FACTOR (OVER 360 HOURS USE) BLOCK UNDER CURRENT TARIFFS?

A The charges vary slightly by voltage level and by season, but range from approximately 2.4¢/kWh to 2.6¢/kWh in LPS and from 3.1¢/kWh to 4.3¢/kWh for LGS.

Q DO YOU AGREE WITH THE LEVEL OF THE OFF-PEAK ENERGY CHARGES IN THE CURRENT TARIFFS?

A No, I do not. I believe the high load factor block energy charges collect more fixed costs than is appropriate.

Q PLEASE EXPLAIN.

A I have analyzed KCPL's current rate case filing and its claims for costs. KCPL's calculated average variable costs (See Schedule PMN-3, page 2) are less than 1.8¢/kWh. The energy charges in the high load factor block of KCPL's current LGS and LPS tariffs are substantially higher, as previously noted. Since KCPL proposes an essentially equal percentage increase to collect its requested revenue increase, these relationships would be perpetuated.

[5] 500,000 - 180,000 - 180,000 = 140,000 kWh

Q WHAT DO YOU CONCLUDE FROM THIS REVIEW?

A Based on the level of the average variable costs and also the avoided energy costs, it is clear that the off-peak energy charges are collecting more costs than appropriate.

Q WHAT SHOULD BE THE LEVEL OF THE OFF-PEAK ENERGY CHARGE?

A Recognizing that most of the fixed costs should be collected from use during the on-peak period and that consumption in the high load factor block occurs mostly during evening and weekend periods when KCPL's energy costs would be lower than they are during the on-peak periods, it is reasonable that the high load factor energy block be at a level approximating the utility's average variable costs.

This structure would collect more costs through demand charges and provide better price signals to customers. It would also be a more equitable rate because it will charge high load factor and low load factor customers more appropriately. This structure also would improve the stability of KCPL's earnings. Because customer demands are generally more stable than their energy purchases, this rate design would make KCPL's revenue collection and earnings less volatile.

Q HOW DO YOU PROPOSE TO ADJUST THE LGS AND LPS RATES IN THIS CASE?

A In the interest of gradualism, my proposal is to maintain the energy charges for the high load factor (over 360 hours use per month, or over a 50% load factor) block at their current levels, increase the middle blocks (hours use from 181 to 360) by three quarters of the average percentage increase, and to collect the balance of the revenue requirement for the tariff by applying a uniform percentage increase to the remaining charges in the tariff. This includes the customer charge, the reactive demand charge, the facilities charges, the demand charges and the initial block energy charges.

Q HAVE YOU PREPARED AN ILLUSTRATION OF THIS RATE DESIGN?

A Yes. This appears on Schedules MEB-COS-7 and MEB-COS-8 attached to my testimony.

Q PLEASE EXPLAIN SCHEDULE MEB-COS-7.

A The first two pages contain a summary of the rate values for the LPS rate. The first column is present rates, the second is KCPL's proposed rates and the third is my proposal at the level of KCPL's proposed increase. The first column of the detail sheets for this schedule (pages 3-8) shows the billing units for each block of each voltage level of the LPS rate. The next two columns show the current rates and resulting revenues by block. The middle two columns show KCPL's proposed rates and the resulting revenues.

The final two columns show the rate based on KCPL's proposed increase to the LPS class, but with my rate design proposal.

Schedule MEB-COS-8 shows the same information for the LGS rate.

Q HOW WOULD THE RATES BE DESIGNED TO MATCH WHATEVER AMOUNT OF INCREASE THE COMMISSION AWARDS TO KCPL IN THIS CASE?

A First, the amount of additional revenue to be collected from the LPS and LGS tariffs would be determined. The increase for the middle block energy charges would be equal to the overall percentage increase times 75%. The high load factor energy blocks would not change. The balance of the increased revenue from each tariff would be collected by uniformly increasing all of the remaining charges in the tariff.

Q **IN ADDITION TO ITS PROPOSAL FOR AN EQUAL PERCENTAGE ACROSS-THE-BOARD INCREASE, HAS KCPL PROPOSED ANY NEW RATES OR RATE DESIGN?**

A No, it has not. It seems content to simply percentage up all of the charges. KCPL should be examining the tariff schedules and attempting to move the rate elements closer to cost of service, to enhance the price signals given to customers.

Q **IS THERE ANYTHING ELSE THAT KCPL SHOULD BE DOING?**

A Yes. KCPL should be working with its larger customers, especially those who have unique load patterns and abilities to curtail load, to determine what rate or contract features would be appropriate to meet the needs of these customers, which may be different from what is contained in the standard tariffs.

Q **DO THESE CUSTOMERS OFFER BENEFITS TO KCPL AND ITS OTHER RATEPAYERS?**

A Yes. In many cases, these customers have unique load characteristics which allow KCPL to reduce its peak demand or to otherwise improve its overall load factor. For instance, some large customers have significant abilities to interrupt load. By making effective use of the interruptible nature of these customers, KCPL should be better able to reduce its annual peak and thereby reduce its overall revenue requirement. Other customers may offer other features. By providing tailored opportunities to these customers, KCPL should be able to increase its overall load factor and reduce its overall operating costs.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Appendix A

Qualifications of Maurice Brubaker

Q **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A Maurice Brubaker. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q **PLEASE STATE YOUR OCCUPATION.**

A I am a consultant in the field of public utility regulation and President of the firm of Brubaker & Associates, Inc. (BAI), energy, economic and regulatory consultants.

Q **PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

A I was graduated from the University of Missouri in 1965, with a Bachelor's Degree in Electrical Engineering. Subsequent to graduation I was employed by the Utilities Section of the Engineering and Technology Division of Esso Research and Engineering Corporation of Morristown, New Jersey, a subsidiary of Standard Oil of New Jersey.

In the Fall of 1965, I enrolled in the Graduate School of Business at Washington University in St. Louis, Missouri. I was graduated in June of 1967 with the Degree of Master of Business Administration. My major field was finance.

From March of 1966 until March of 1970, I was employed by Emerson Electric Company in St. Louis. During this time I pursued the Degree of Master of Science in Engineering at Washington University, which I received in June, 1970.

In March of 1970, I joined the firm of Drazen Associates, Inc., of St. Louis, Missouri. Since that time I have been engaged in the preparation of numerous studies relating to electric, gas, and water utilities. These studies have included analyses of the cost to serve various types of customers, the design of rates for utility services, cost forecasts, cogeneration rates and determinations of rate base and operating income. I have also addressed utility resource planning principles and plans, reviewed capacity additions to determine whether or not they were used and useful, addressed demand-side management issues independently and as part of least cost planning, and have reviewed utility determinations of the need for capacity additions and/or purchased power to determine the consistency of such plans with least cost planning principles. I have also testified about the prudency of the actions undertaken by utilities to meet the needs of their customers in the wholesale power markets and have recommended disallowances of costs where such actions were deemed imprudent.

I have testified before the Federal Energy Regulatory Commission (FERC), various courts and legislatures, and the state regulatory commissions of Alabama, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Georgia, Guam, Hawaii, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Missouri, Nevada, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, South Dakota, Texas, Utah, Virginia, West Virginia, Wisconsin and Wyoming.

The firm of Drazen-Brubaker & Associates, Inc. was incorporated in 1972 and assumed the utility rate and economic consulting activities of Drazen Associates, Inc., founded in 1937. In April, 1995 the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and staff. Our staff includes consultants with backgrounds in accounting, engineering, economics, mathematics, computer science and business.

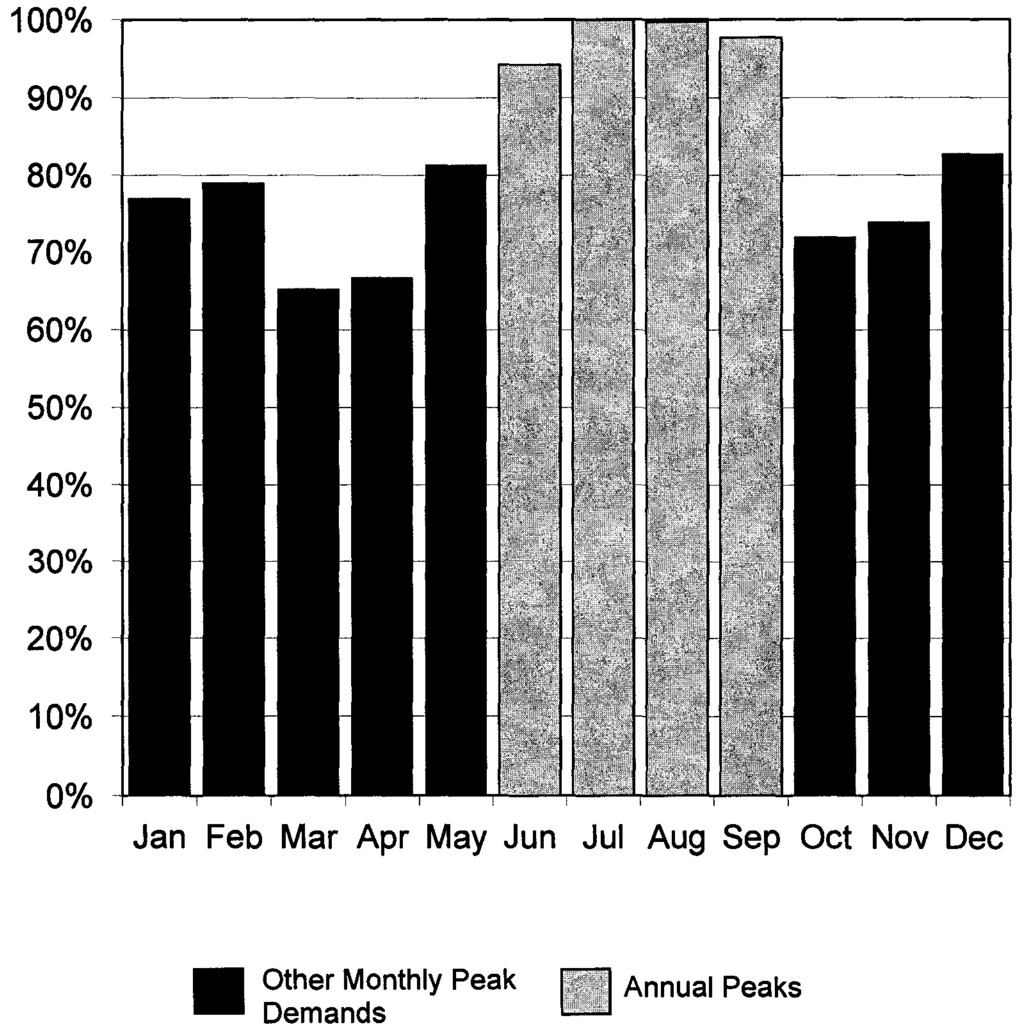
Brubaker & Associates, Inc. and its predecessor firm has participated in over 700 major utility rate and other cases and statewide generic investigations before utility regulatory commissions in 40 states, involving electric, gas, water, and steam rates and other issues. Cases in which the firm has been involved have included more than 80 of the 100 largest electric utilities and over 30 gas distribution companies and pipelines.

An increasing portion of the firm's activities is concentrated in the areas of competitive procurement. While the firm has always assisted its clients in negotiating contracts for utility services in the regulated environment, increasingly there are opportunities for certain customers to acquire power on a competitive basis from a supplier other than its traditional electric utility. The firm assists clients in identifying and evaluating purchased power options, conducts RFPs and negotiates with suppliers for the acquisition and delivery of supplies. We have prepared option studies and/or conducted RFPs for competitive acquisition of power supply for industrial and other end-use customers throughout the Unites States and in Canada, involving total needs in excess of 3,000 megawatts. The firm is also an associate member of the Electric Reliability Council of Texas and a licensed electricity aggregator in the State of Texas.

In addition to our main office in St. Louis, the firm has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

KANSAS CITY POWER & LIGHT COMPANY

Analysis of KCP&L's (Missouri) Monthly Peak Demands as a Percent of the Annual System Peak For the Test Year Ended September 30, 2011



Schedule MEB-COS-1

KANSAS CITY POWER & LIGHT COMPANY

Analysis of KCP&L's Monthly Peak Demands
as a Percent of the Annual System Peak
(Weather Normalized and with Losses)
For the Test Year Ended September 30, 2011

Line	Description	Total Company MW	Percent
		(1)	(2)
1	January	1,491	77.0
2	February	1,531	79.1
3	March	1,264	65.3
4	April	1,292	66.7
5	May	1,576	81.4
6	June	1,825	94.3
7	July	1,936	100.0
8	August	1,930	99.7
9	September	1,892	97.7
10	October	1,393	72.0
11	November	1,431	73.9
12	December	1,603	82.8

Source: KCPL Allocators MO Rev 2-23-12.xls

KANSAS CITY POWER & LIGHT COMPANY

Development of
Average and Excess Demand Allocator
Based on 4 Non-Coincident Peaks
For the Test Year Ended September 30, 2011

Line	Description	Missouri Retail (1)	Residential (2)	Small General Service (3)	Medium General Service (4)	Large General Service (5)	Large Power Service (6)	Other Lighting (7)
1	Missouri System Peak	1,935,936						
2	Avg of 4 Highest Monthly NCP Values	2,075,278	909,823	99,070	248,770	458,018	349,270	10,327
3	Energy Sales with Losses - MWh	9,045,302	2,742,028	438,496	1,154,656	2,362,973	2,256,681	90,467
4	Average Demand - kW	1,032,569	313,017	50,057	131,810	269,746	257,612	10,327
5	Average Demand - Percent	1.000000	0.303144	0.048478	0.127653	0.261238	0.249487	0.010002
6	Class Excess Demand - kW	1,042,709	596,806	49,013	116,960	188,272	91,658	-
7	Class Excess Demand - Percent	1.000000	0.572361	0.047006	0.112169	0.180561	0.087903	-
	Allocator:							
8	Annual Load Factor * Average Demand	0.533369	0.161688	0.025857	0.068086	0.139336	0.133068	0.005335
9	(1-LF) * Excess Demand	0.466631	0.267081	0.021934	0.052342	0.084255	0.041018	-
10	Average and Excess Demand Allocator	1.000000	0.428769	0.047791	0.120428	0.223591	0.174087	0.005335

Notes:
Line 4 equals Line 3 ÷ 8.760
Line 6 equals Line 2- Line 4

System Annual Load Factor	53.34%
1 - Load Factor	46.66%

Source: KCPL Allocators MO Rev 2-23-12.xls

KANSAS CITY POWER & LIGHT COMPANY
2012 RATE CASE - Direct Filing
COST OF SERVICE - Missouri Jurisdiction
TY 9/30/11; Update TBD; K&M 8/31/12

LINE NO.	DESCRIPTION	MISSOURI RETAIL	RESIDENTIAL	SMALL GEN. SERVICE	MEDIUM GEN. SERVICE	LARGE GEN. SERVICE	LARGE PWR SERVICE	TOTAL LIGHTING
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
0010	**SCHEDULE 1 - SUMMARY OF OPERATING INC & RATE BASE**							
0020								
0030	OPERATING REVENUE							
0040	RETAIL SALES REVENUE	699,636,961	259,806,177	47,984,116	94,385,415	163,335,353	125,295,179	8,830,722
0050	OTHER OPERATING REVENUE	49,051,908	16,338,152	2,431,778	6,215,310	12,358,095	11,198,781	509,791
0060	TOTAL OPERATING REVENUE	748,688,868	276,144,329	50,415,894	100,600,724	175,693,449	136,493,960	9,340,513
0070								
0080	OPERATING EXPENSES							
0090	FUEL	124,790,618	37,864,453	6,039,546	15,954,515	32,485,423	31,219,978	1,226,703
0100	PURCHASED POWER	24,345,430	7,532,510	1,189,362	3,103,358	6,331,380	5,935,822	252,997
0110	OTHER OPERATION & MAINTENANCE EXPENSES	296,422,803	141,948,864	17,504,188	33,592,326	57,195,075	43,250,875	2,931,474
0120	DEPRECIATION EXPENSES (AFTER CLEARINGS)	98,902,485	45,782,454	5,205,803	12,270,616	20,107,468	14,399,244	1,136,901
0130	AMORTIZATION EXPENSES	11,107,955	5,029,084	577,748	1,368,163	2,331,161	1,700,207	101,591
0140	TAXES OTHER THAN INCOME TAXES	48,547,311	22,398,032	2,620,817	5,909,919	9,926,489	7,216,700	475,351
0150	CURRENT INCOME TAXES	9,814,637	(14,163,992)	4,314,307	5,312,330	8,310,307	5,122,449	919,236
0160	DEFERRED INCOME TAXES	16,774,160	7,764,140	894,261	2,057,055	3,433,924	2,460,231	164,549
0170	TOTAL ELECTRIC OPERATING EXPENSES	630,705,397	254,155,547	38,346,032	79,568,282	140,121,226	111,305,506	7,208,803
0180								
0190	NET ELECTRIC OPERATING INCOME	117,983,472	21,988,782	12,069,862	21,032,442	35,572,222	25,188,454	2,131,710
0200								
0210	RATE BASE							
0220	TOTAL ELECTRIC PLANT	4,283,301,236	1,969,597,302	227,185,954	524,796,965	882,601,664	637,971,746	41,147,604
0230	LESS: ACCUM. PROV. FOR DEPREC	1,816,407,425	849,076,656	99,278,733	215,962,686	364,918,001	265,975,605	21,195,743
0240	NET PLANT	2,466,893,811	1,120,520,646	127,907,221	308,834,279	517,683,663	371,996,141	19,951,861
0250	PLUS:							
0260	CASH WORKING CAPITAL	(47,690,286)	(20,661,956)	(2,879,418)	(6,108,950)	(10,196,019)	(7,329,713)	(514,230)
0270	MATERIALS & SUPPLIES	51,855,549	23,275,090	2,661,497	6,363,892	10,998,444	8,114,521	442,103
0280	PREPAYMENTS	5,522,723	2,448,419	275,545	661,673	1,191,827	909,286	35,973
0290	FUEL INVENTORY	66,901,141	20,299,403	3,237,844	8,553,329	17,415,667	16,737,253	657,644
0300	REGULATORY ASSETS	121,304,313	49,640,766	6,355,804	14,798,626	27,677,305	21,599,867	1,231,946
0310	LESS:							
0320	CUSTOMER ADVANCES FOR CONSTRUCTION	158,781	88,149	10,508	20,915	24,434	11,469	3,306
0330	CUSTOMER DEPOSITS	4,192,439	2,179,087	1,607,581	335,161	65,338	5,272	0
0340	DEFERRED INCOME TAXES	485,201,862	223,111,153	25,735,068	59,447,713	99,978,952	72,267,875	4,661,100
0350	DEFERRED GAIN ON SO2 EMISSIONS ALLOWANCI	45,275,933	13,725,121	2,194,878	5,779,590	11,827,778	11,295,737	452,829
0360	DEFERRED GAIN(LOSS) EMISSIONS ALLOWANCE	2,121	643	103	271	554	529	21
0370	TOTAL RATE BASE	2,129,956,114	956,418,216	108,010,356	267,519,198	452,873,831	328,446,472	16,688,042
0380								
0390	RATE OF RETURN	5.539%	2.299%	11.175%	7.862%	7.855%	7.669%	12.774%
0400	RELATIVE RATE OF RETURN	1.00	0.42	2.02	1.42	1.42	1.38	2.31

Notes:
Production Plant and Expense Allocated using A&E-4NCP.
Margin on Sales Revenue Allocated on Energy.

Schedule MEB-COS-4

KANSAS CITY POWER & LIGHT COMPANY

Class Cost of Service Study Results
and Revenue Adjustments to Move Each Class to Cost of Service
Using Modified ECOS at Present Rates
($ in Thousands)

Line	Rate Class	Current Revenues (1)	Current Rate Base (2)	Net Operating Income (3)	Earned ROR (4)	Indexed ROR (5)	Income @ Current ROR (6)	Difference in Income (7)	Revenue Increase (8)	Percentage Increase (9)
1	Residential	$ 276,144	$ 956,418	$ 21,989	2.299%	42	$ 52,978	$ 30,990	$ 51,154	18.5%
2	Small General Service	50,416	108,010	12,070	11.175%	202	5,983	(6,087)	(10,047)	-19.9%
3	Medium General Service	100,601	267,519	21,032	7.862%	142	14,819	(6,214)	(10,257)	-10.2%
4	Large General Service	175,693	452,874	35,572	7.855%	142	25,086	(10,486)	(17,310)	-9.9%
5	Large Power Service	136,494	328,446	25,188	7.669%	138	18,193	(6,995)	(11,546)	-8.5%
6	Total Lighting	9,341	16,688	2,132	12.774%	231	924	(1,207)	(1,993)	-21.3%
7	Total	$ 748,689	$ 2,129,956	$ 117,983	5.539%	100	$ 117,983	$ 0	$ 0	0.0%

Source: Schedule MEB-COS-4

KANSAS CITY POWER & LIGHT COMPANY

Recommended Cost of Service Adjustments
Using Modified ECOS at Present Rates
($ in Millions)

Line	Rate Class	Current Revenues (1)	Move 25% Toward Cost Of Service (2)	Adjusted Current Revenue (3)	Percent of Adjusted Current Revenue (4)
1	Residential	$ 276.1	$ 12.8	$ 288.9	38.59%
2	Small General Service	50.4	(2.5)	47.9	6.40%
3	Medium General Service	100.6	(2.6)	98.0	13.09%
4	Large General Service	175.7	(4.3)	171.4	22.89%
5	Large Power Service	136.5	(2.9)	133.6	17.85%
6	Total Lighting	9.3	(0.5)	8.8	1.18%
7	Subtotal	$ 748.7	$ -	$ 748.7	100.00%

MO LARGE POWER SERVICE

SUMMARY OF PROPOSAL SCENARIO

*** Equal Percent Increase to All Rate Components except**
Energy 181-360 Hours Use -- use 75% of Average Increase
Energy over 360 Hours Use -- use Current Rates
Rates Designed to Achieve KCP&L's Proposed Increase.

INPUT FOR MODEL			
Cust Chg	**Current Rates**	**Rates With Increase**	**Proposed Rates**
A: CUSTOMER CHARGE			
	811.13	933.14	972.18
		-	-
	-	-	-
B: FACILITIES CHARGE			
SECONDARY:	2.716	3.125	3.255
PRIMARY:	2.252	2.591	2.699
SUBSTATION VOLTAGE	0.679	0.781	0.814
TRANSM VOLTAGE	-	-	-
C: DEMAND CHARGE			
SECONDARY-SUMMER:			
First 2443 kw	10.539	12.124	12.631
Next 2443 kw	8.430	9.698	10.104
Next 2443 kw	7.062	8.124	8.464
All kw over 7329 kw	5.155	5.930	6.179
SECONDARY-WINTER			
First 2443 kw	7.164	8.242	8.586
Next 2443 kw	5.590	6.431	6.700
Next 2443 kw	4.932	5.674	5.911
All kw over 7329 kw	3.796	4.367	4.550
PRIMARY-SUMMER			
First 2500 kw	10.297	11.846	12.341
Next 2500 kw	8.238	9.477	9.874
Next 2500 kw	6.900	7.938	8.270
All kw over 7500 kw	5.037	5.795	6.037
PRIMARY-WINTER			
First 2500 kw	6.999	8.052	8.389
Next 2500 kw	5.463	6.285	6.548
Next 2500 kw	4.819	5.544	5.776
All kw over 7500 kw	3.710	4.268	4.447
SUBSTATION-SUMMER			
First 2530 kw	10.174	11.704	12.194
Next 2530 kw	8.139	9.363	9.755
Next 2530 kw	6.818	7.844	8.172
All kw over 7590 kw	4.978	5.727	5.966
SUBSTATION-WINTER			
First 2530 kw	6.917	7.957	8.290
Next 2530 kw	5.398	6.210	6.470
Next 2530 kw	4.763	5.479	5.709
All kw over 7590 kw	3.666	4.217	4.394
TRANSMISSION-SUMMER			
First 2553 kw	10.086	11.603	12.089
Next 2553 kw	8.067	9.280	9.669
Next 2553 kw	6.756	7.772	8.097
All kw over 7659 kw	4.933	5.675	5.912
TRANSMISSION-WINTER			
First 2553 kw	6.854	7.885	8.215
Next 2553 kw	5.350	6.155	6.412
Next 2553 kw	4.720	5.430	5.657
All kw over 7659 kw	3.633	4.179	4.354

MO LARGE POWER SERVICE

SUMMARY OF PROPOSAL SCENARIO

*** Equal Percent Increase to All Rate Components except**
Energy 181-360 Hours Use -- use 75% of Average Increase
Energy over 360 Hours Use -- use Current Rates
Rates Designed to Achieve KCP&L's Proposed Increase.

INPUT FOR MODEL			
Cust Chg	**Current Rates**	**Rates With Increase**	**Proposed Rates**
D: ENERGY CHARGE			
SECONDARY-SUMMER:			
0-180 hrs use per month	0.06599	0.07592	0.07909
181-360 hrs use per month	0.04444	0.05112	0.04945
361+ hrs use per month	0.02566	0.02952	0.02566
SECONDARY-WINTER:			
0-180 hrs use per month	0.05594	0.06435	0.06705
181-360 hrs use per month	0.04043	0.04651	0.04499
361+ hrs use per month	0.02541	0.02923	0.02541
PRIMARY-SUMMER:			
0-180 hrs use per month	0.06448	0.07418	0.07728
181-360 hrs use per month	0.04344	0.04997	0.04834
361+ hrs use per month	0.02507	0.02884	0.02507
PRIMARY-WINTER:			
0-180 hrs use per month	0.05467	0.06289	0.06552
181-360 hrs use per month	0.03950	0.04544	0.04396
361+ hrs use per month	0.02484	0.02858	0.02484
SUBSTATION-SUMMER			
0-180 hrs use per month	0.06373	0.07332	0.07638
181-360 hrs use per month	0.04293	0.04939	0.04777
361+ hrs use per month	0.02477	0.02850	0.02477
SUBSTATION-WINTER			
0-180 hrs use per month	0.05403	0.06216	0.06476
181-360 hrs use per month	0.03904	0.04491	0.04344
361+ hrs use per month	0.02454	0.02823	0.02454
TRANSMISSION-SUMMER			
0-180 hrs use per month	0.06316	0.07266	0.07570
181-360 hrs use per month	0.04254	0.04894	0.04734
361+ hrs use per month	0.02456	0.02825	0.02456
TRANSMISSION-WINTER			
0-180 hrs use per month	0.05354	0.06159	0.06417
181-360 hrs use per month	0.03869	0.04451	0.04305
361+ hrs use per month	0.02431	0.02797	0.02431
E: REACTIVE DEMAND ADJUSTMENT	0.682	0.782	0.817
[redacted]	100.00%	[redacted]	[redacted]
[redacted]	100.00%	[redacted]	[redacted]
[redacted]	100.00%	[redacted]	[redacted]
[redacted]	100.00%	[redacted]	[redacted]
[redacted]	0.00%	[redacted]	[redacted]
[redacted]	11.3%	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]
Revenue	$127,310,955		$146,460,285
Change in Revenue			$19,149,330
Design Revenue per Revenue Summary			$19,149,337
			($8)

MO LARGE POWER
SECONDARY VOLTAGE - LPGSS

* Equal Percent Increase to All Rate Components except
Energy 181-360 Hours Use -- use 75% of Average Increase
Energy over 360 Hours Use -- use Current Rates
Rates Designed to Achieve KCP&L's Proposed Increase.

SUMMER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATES W/RATE DESIGN Rate	RATES W/RATE DESIGN Revenue
A: CUSTOMER CHARGE							
	112.6	$811.13	$91,364	933.14	$105,107	$972.18	$109,504
	-	$0.00	$0	-	$0	$0.00	$0
	-	$0.00	$0	-	$0	$0.00	$0
	113		$91,364		$105,107		$109,504
B: FACILITIES CHARGE	268,599.3	$2.716	$729,516	$3.125	$839,373	$3.255	$874,291
C: DEMAND CHARGE							
First 2443 kw	213,450.8	$10.539	$2,249,558	$12.124	$2,587,877	$12.631	$2,696,097
Next 2443 kw	57,948.0	$8.430	$488,502	$9.698	$561,980	$10.104	$585,507
Next 2443 kw	21,587.7	$7.062	$152,453	$8.124	$175,379	$8.464	$182,719
Over 7329 kw	2,789.0	$5.155	$14,377	$5.930	$16,539	$6.179	$17,233
	295,776		$2,904,889		$3,341,775		$3,481,555
D: ENERGY CHARGE							
0-180 hrs use per month	53,146,926.4	$0.06599	$3,507,166	$0.07592	$4,034,915	$0.07909	$4,203,390
181-360 hrs use per month	52,791,754.2	$0.04444	$2,346,066	$0.05112	$2,698,714	$0.04945	$2,610,552
361+ hrs use per month	53,792,219.1	$0.02566	$1,380,308	$0.02952	$1,587,946	$0.02566	$1,380,308
	159,730,900		$7,233,540		$8,321,575		$8,194,251
E: REACTIVE DEMAND ADJUSTMENT	2,517.5	$0.6820	$1,717	$0.7820	$1,969	$0.8170	$2,057
F: MANUAL BILL USAGE/REVENUE	-		-		$0		$0
REVENUE			$10,961,026		$12,609,799		$12,661,658
c/kwh			$0.0686		$0.0789		$0.0793
OVERALL CHANGE (%)	*2626*				15.04%		15.52%
used to reference avg customer	*1,418,094*						

WINTER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATES W/RATE DESIGN Rate	RATES W/RATE DESIGN Revenue
A: CUSTOMER CHARGE							
	271.4	$811.13	$220,110	933.14	$253,219	$972.18	$263,813
	-	$0.00	$0	-	$0	$0.00	$0
	-	$0.00	$0	-	$0	$0.00	$0
	271		$220,110		$253,219		$263,813
B: FACILITIES CHARGE	644,333.7	$2.716	$1,750,010	$3.125	$2,013,543	$3.255	$2,097,306
C: DEMAND CHARGE							
First 2443 kw	394,205.2	$7.164	$2,824,086	$8.242	$3,249,039	$8.586	$3,384,646
Next 2443 kw	87,205.0	$5.590	$487,476	$6.431	$560,815	$6.700	$584,273
Next 2443 kw	14,441.3	$4.932	$71,224	$5.674	$81,940	$5.911	$85,362
Over 7329 kw	-	$3.796	$0	$4.367	$0	$4.550	$0
	495,851		$3,382,786		$3,891,794		$4,054,282
D: ENERGY CHARGE							
0-180 hrs use per month	87,853,750.4	$0.05594	$4,914,539	$0.06435	$5,653,389	$0.06705	$5,890,594
181-360 hrs use per month	86,402,157.8	$0.04043	$3,493,239	$0.04651	$4,018,564	$0.04499	$3,887,233
361+ hrs use per month	86,376,877.1	$0.02541	$2,194,836	$0.02923	$2,524,796	$0.02541	$2,194,836
	260,632,785		$10,602,614		$12,196,749		$11,972,663
E: REACTIVE DEMAND ADJUSTMENT	5,152.5	$0.6820	$3,514	$0.7820	$4,029	$0.8170	$4,210
F: MANUAL BILL USAGE/REVENUE	-		-		$0		$0
REVENUE			$15,959,035		$18,359,335		$18,392,274
c/kwh			$0.0612		$0.0704		$0.0706
OVERALL CHANGE (%)	*1827*				15.04%		15.25%
used to reference avg customer	*960,461*						

	BILLING UNITS	PRESENT RATES Revenue	PROPOSED RATES Revenue	RATES W/RATE DESIGN Revenue
ANNUAL	420,363,685	$26,920,061	$30,969,133	$31,053,932
c/kwh		$0.0640	$0.0737	$0.0739
OVERALL CHANGE (%)			15.04%	15.36%
Winter Price Below Summer (SUM-WIN)/SUM		10.8%	10.8%	11.0%

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MO LARGE POWER
PRIMARY VOLTAGE - LPGSP

*** Equal Percent Increase to All Rate Components except**
Energy 181-360 Hours Use -- use 75% of Average Increase
Energy over 360 Hours Use -- use Current Rates
Rates Designed to Achieve KCP&L's Proposed Increase.

SUMMER

	BILLING UNITS	PRESENT RATES		PROPOSED RATES		RATES W/RATE DESIGN	
		Rate	Revenue	Rate	Revenue	Rate	Revenue
A: CUSTOMER CHARGE							
	111.9	$811.13	$90,760	933.14	$104,412	972.18	$108,781
	-	$0.00	$0	-	$0	-	$0
	-	$0.00	$0	-	$0	-	$0
	112		$90,760		$104,412		$108,781
B: FACILITIES CHARGE	557,676.1	$2.252	$1,255,887	$2.591	$1,444,939	$2.699	$1,505,168
C: DEMAND CHARGE							
First 2500 kw	285,690.3	$10.297	$2,941,753	$11.846	$3,384,288	$12.341	$3,525,704
Next 2500 kw	142,587.5	$8.238	$1,174,636	$9.477	$1,351,301	$9.874	$1,407,909
Next 2500 kw	69,629.0	$6.900	$480,440	$7.938	$552,715	$8.270	$575,832
Over 7500 kw	94,509.0	$5.037	$476,042	$5.795	$547,680	$6.037	$570,551
	592,416		$5,072,871		$5,835,984		$6,079,996
D: ENERGY CHARGE							
0-180 hrs use per month	106,447,261.6	$0.06448	$6,863,719	$0.07418	$7,896,258	$0.07728	$8,226,244
181-360 hrs use per month	104,801,872.1	$0.04344	$4,552,593	$0.04997	$5,236,950	$0.04834	$5,066,122
361+ hrs use per month	97,259,267.9	$0.02507	$2,438,290	$0.02884	$2,804,957	$0.02507	$2,438,290
	308,508,402		$13,854,603		$15,938,165		$15,730,657
E: REACTIVE DEMAND ADJUSTMENT	43,036	$0.682	$29,351	$0.782	$33,654	$0.817	$35,160
E: MANUAL BILL USAGE/REVENUE	4,045,717		$291,532		$335,382		$335,382
REVENUE			$20,595,002		$23,692,536		$23,795,143
c/kwh			$0.0659		$0.0758		$0.0761
OVERALL CHANGE (%)	*5294*				15.04%		15.54%
used to reference avg customer	*2,793,318*						

WINTER

	BILLING UNITS	PRESENT RATES		PROPOSED RATES		RATES W/RATE DESIGN	
		Rate	Revenue	Rate	Revenue	Rate	Revenue
A: CUSTOMER CHARGE							
	282.1	$811.13	$228,825	933.14	$263,245	$972.18	$274,258
	-	$0.00	$0	-	$0	$0.00	$0
	-	$0.00	$0	-	$0	$0.00	$0
	282		$228,825		$263,245		$274,258
B: FACILITIES CHARGE	1,404,516.9	$2.252	$3,162,972	$2.591	$3,639,103	$2.699	$3,790,791
C: DEMAND CHARGE							
First 2500 kw	545,593.7	$6.999	$3,818,610	$8.052	$4,393,120	$8.389	$4,576,985
Next 2500 kw	221,180.5	$5.463	$1,208,309	$6.285	$1,390,120	$6.548	$1,448,290
Next 2500 kw	114,215.0	$4.819	$550,402	$5.544	$633,208	$5.776	$659,706
Over 7500 kw	128,285.0	$3.710	$475,937	$4.268	$547,520	$4.447	$570,483
	1,009,274		$6,053,259		$6,963,968		$7,255,465
D: ENERGY CHARGE							
0-180 hrs use per month	181,035,238.4	$0.05467	$9,897,196	$0.06289	$11,385,306	$0.06552	$11,861,429
181-360 hrs use per month	178,452,696.8	$0.03950	$7,048,882	$0.04544	$8,108,891	$0.04396	$7,844,781
361+ hrs use per month	169,405,160.1	$0.02484	$4,208,024	$0.02858	$4,841,599	$0.02484	$4,208,024
	528,893,095		$21,154,102		$24,335,796		$23,914,234
E: REACTIVE DEMAND ADJUSTMENT	92,659	$0.682	$63,193	$0.782	$72,459	$0.817	$75,702
E: MANUAL BILL USAGE/REVENUE	9,518,505		$621,523		$715,008		$715,008
REVENUE			$31,283,874		$35,989,580		$36,025,459
c/kwh			$0.0581		$0.0668		$0.0669
OVERALL CHANGE (%)	*3578*				15.04%		15.16%
used to reference avg customer	*1,874,799*						

ANNUAL	850,965,719	$51,878,877	$59,682,116	$59,820,602
c/kwh		$0.0610	$0.0701	$0.0703
OVERALL CHANGE (%)			15.04%	15.31%
Winter Price Below Summer (SUM-WIN)/SUM		11.8%	11.8%	12.1%

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MO LARGE POWER
SUBSTATION VOLTAGE - LPGSSS

*** Equal Percent Increase to All Rate Components except**
Energy 181-360 Hours Use -- use 75% of Average Increase
Energy over 360 Hours Use -- use Current Rates
Rates Designed to Achieve KCP&L's Proposed Increase.

SUMMER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATES W/RATE DESIGN Rate	RATES W/RATE DESIGN Revenue
A: CUSTOMER CHARGE							
	10.3	$811.13	$8,345	933.14	$9,600	$972.18	$10,002
	-	$0.00	$0	-	$0	$0.00	$0
	-	$0.00	$0	-	$0	$0.00	$0
	10		$8,345		$9,600		$10,002
B: FACILITIES CHARGE	229,511.9	$0.679	$155,839	$0.781	$179,249	$0.814	$186,823
C: DEMAND CHARGE							
First 2530 kw	30,565.4	$10.174	$310,972	$11.704	$357,737	$12.194	$372,714
Next 2530 kw	28,681.9	$8.139	$233,442	$9.363	$268,549	$9.755	$279,792
Next 2530 kw	20,250.5	$6.818	$138,068	$7.844	$158,845	$8.172	$165,487
Over 7590 kw	181,247.2	$4.978	$902,248	$5.727	$1,038,003	$5.966	$1,081,321
	260,745		$1,584,731		$1,823,134		$1,899,315
D: ENERGY CHARGE							
0-180 hrs use per month	46,934,106.7	$0.06373	$2,991,111	$0.07332	$3,441,209	$0.07638	$3,584,827
181-360 hrs use per month	46,934,106.7	$0.04293	$2,014,881	$0.04939	$2,318,076	$0.04777	$2,242,042
361+ hrs use per month	48,907,839.0	$0.02477	$1,211,447	$0.02850	$1,393,873	$0.02477	$1,211,447
	142,776,052		$6,217,439		$7,153,158		$7,038,317
E: REACTIVE DEMAND ADJUSTMENT	22,039	$0.682	$15,030	$0.782	$17,234	$0.817	$18,006
REVENUE			$7,981,384		$9,182,375		$9,152,461
c/kwh			$0.0559		$0.0643		$0.0641
OVERALL CHANGE (%)	*25345*				15.05%		14.67%
used to reference avg customer	*13,878,185*						

WINTER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATES W/RATE DESIGN Rate	RATES W/RATE DESIGN Revenue
A: CUSTOMER CHARGE							
	25.7	$811.13	$20,856	933.14	$23,993	$972.18	$24,997
	-	$0.00	$0	-	$0	$0.00	$0
	-	$0.00	$0	-	$0	$0.00	$0
	26		$20,856		$23,993		$24,997
B: FACILITIES CHARGE	574,894.1	$0.679	$390,353	$0.781	$448,992	$0.814	$467,964
C: DEMAND CHARGE							
First 2530 kw	60,514.6	$6.917	$418,580	$7.957	$481,515	$8.290	$501,666
Next 2530 kw	53,853.1	$5.398	$290,699	$6.210	$334,427	$6.470	$348,429
Next 2530 kw	40,469.5	$4.763	$192,756	$5.479	$221,732	$5.709	$231,040
Over 7590 kw	318,085.8	$3.666	$1,166,103	$4.217	$1,341,368	$4.394	$1,397,669
	472,923		$2,068,137		$2,379,042		$2,478,805
D: ENERGY CHARGE							
0-180 hrs use per month	85,126,133.3	$0.05403	$4,599,365	$0.06216	$5,291,440	$0.06476	$5,512,768
181-360 hrs use per month	85,126,133.3	$0.03904	$3,323,324	$0.04491	$3,823,015	$0.04344	$3,697,879
361+ hrs use per month	86,549,765.5	$0.02454	$2,123,931	$0.02823	$2,443,300	$0.02454	$2,123,931
	256,802,032		$10,046,620		$11,557,755		$11,334,579
E: REACTIVE DEMAND ADJUSTMENT	22,455	$0.682	$15,315	$0.782	$17,560	$0.817	$18,346
REVENUE			$12,541,281		$14,427,343		$14,324,690
c/kwh			$0.0488		$0.0562		$0.0558
OVERALL CHANGE (%)	*18393*				15.04%		14.22%
used to reference avg customer	*9,987,557*						

	BILLING UNITS	PRESENT RATES Revenue	PROPOSED RATES Revenue	RATES W/RATE DESIGN Revenue
ANNUAL	399,578,085	$20,522,665	$23,609,718	$23,477,151
c/kwh		$0.0514	$0.0591	$0.0588
OVERALL CHANGE (%)			15.04%	14.40%
Winter Price Below Summer (SUM-WIN)/SUM		12.6%	12.6%	13.0%

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MO LARGE POWER
TRANSMISSION VOLTAGE - LPGSTR

* Equal Percent Increase to All Rate Components except
Energy 181-360 Hours Use -- use 75% of Average Increase
Energy over 360 Hours Use -- use Current Rates
Rates Designed to Achieve KCP&L's Proposed Increase.

SUMMER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATES W/RATE DESIGN Rate	RATES W/RATE DESIGN Revenue
A: CUSTOMER CHARGE							
	6.7	$811.13	$5,441	933.14	$6,259	$972.18	$6,521
	-	$0.00	$0	-	$0	$0.00	$0
	-	$0.00	$0	-	$0	$0.00	$0
	7		$5,441		$6,259		$6,521
B: FACILITIES CHARGE	64,262	$0.000	$0	$0.000	$0	$0.000	$0
C: DEMAND CHARGE							
First 2553 kw	14,828.0	$10.086	$149,555	$11.603	$172,049	$12.089	$179,256
Next 2553 kw	10,217.3	$8.067	$82,423	$9.280	$94,817	$9.669	$98,791
Next 2553 kw	10,217.3	$6.756	$69,028	$7.772	$79,409	$8.097	$82,730
Over 7659 kw	33,027.1	$4.933	$162,923	$5.675	$187,429	$5.912	$195,256
	68,290		$463,930		$533,704		$556,033
D: ENERGY CHARGE							
0-180 hrs use per month	12,292,161.4	$0.06316	$776,373	$0.07266	$893,148	$0.07570	$930,517
181-360 hrs use per month	11,778,738.2	$0.04254	$501,068	$0.04894	$576,451	$0.04734	$557,605
361+ hrs use per month	7,663,893.9	$0.02456	$188,225	$0.02825	$216,505	$0.02456	$188,225
	31,734,794		$1,465,666		$1,686,105		$1,676,347
E: REACTIVE DEMAND ADJUSTMENT	5,239	$0.682	$3,573	$0.782	$4,097	$0.817	$4,280
REVENUE			$1,938,609		$2,230,165		$2,243,181
c/kwh			$0.0611		$0.0703		$0.0707
OVERALL CHANGE (%)	*10181*				15.04%		15.71%
used to reference avg customer	*4,731,327*						

WINTER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATES W/RATE DESIGN Rate	RATES W/RATE DESIGN Revenue
A: CUSTOMER CHARGE							
	17.3	$811.13	$14,027	933.14	$16,136	$972.18	$16,812
	-	$0.00	$0	-	$0	$0.00	$0
	-	$0.00	$0	-	$0	$0.00	$0
	17		$14,027		$16,136		$16,812
B: FACILITIES CHARGE	160,186	$0.000	$0	$0.000	$0	$0.000	$0
C: DEMAND CHARGE							
First 2553 kw	39,471.0	$6.854	$270,534	$7.885	$311,229	$8.215	$324,254
Next 2553 kw	20,826.7	$5.350	$111,423	$6.155	$128,188	$6.412	$133,541
Next 2553 kw	20,418.7	$4.720	$96,376	$5.430	$110,873	$5.657	$115,508
Over 7659 kw	48,366.9	$3.633	$175,717	$4.179	$202,125	$4.354	$210,589
	129,083		$654,050		$752,416		$783,893
D: ENERGY CHARGE							
0-180 hrs use per month	23,232,675.3	$0.05354	$1,243,877	$0.06159	$1,430,900	$0.06417	$1,490,841
181-360 hrs use per month	22,336,426.5	$0.03869	$864,196	$0.04451	$994,194	$0.04305	$961,583
361+ hrs use per month	16,468,915.5	$0.02431	$400,359	$0.02797	$460,636	$0.02431	$400,359
	62,038,017		$2,508,433		$2,885,730		$2,852,783
E: REACTIVE DEMAND ADJUSTMENT	5,866	$0.682	$4,001	$0.782	$4,587	$0.817	$4,793
REVENUE			$3,180,510		$3,658,870		$3,658,280
c/kwh			$0.0513		$0.0590		$0.0590
OVERALL CHANGE (%)	*7465*				15.04%		15.02%
used to reference avg customer	*3,587,542*						

	BILLING UNITS	PRESENT RATES Revenue	PROPOSED RATES Revenue	RATES W/RATE DESIGN Revenue
ANNUAL	93,772,811	$5,119,119	$5,889,034	$5,901,461
c/kwh		$0.0546	$0.0628	$0.0629
OVERALL CHANGE (%)			15.04%	15.28%
Winter Price Below Summer (SUM-WIN)/SUM		16.1%	16.1%	16.6%

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MO LARGE POWER
TRANSMISSION VOLTAGE - OFF PEAK - LPSTRO

*** Equal Percent Increase to All Rate Components except**
Energy 181-360 Hours Use -- use 75% of Average Increase
Energy over 360 Hours Use -- use Current Rates
Rates Designed to Achieve KCP&L's Proposed Increase.

SUMMER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATES W/RATE DESIGN Rate	RATES W/RATE DESIGN Revenue
A: CUSTOMER CHARGE							
	7.2	811.13	$5,821	933.14	$6,696	972.18	$6,976
	-	-	$0	-	$0	-	$0
	-	-	$0	-	$0	-	$0
	7		$5,821		$6,696		$6,976
B: FACILITIES CHARGE	87,908	$0.000	$0	$0.000	$0	$0.000	$0
C: DEMAND CHARGE							
First 2553 kw	20,470.5	$10.086	$206,465	$11.603	$237,519	$12.089	$247,468
Next 2553 kw	14,442.6	$8.067	$116,508	$9.280	$134,027	$9.669	$139,646
Next 2553 kw	10,253.2	$6.756	$69,270	$7.772	$79,688	$8.097	$83,020
Over 7659 kw	42,295.9	$4.933	$208,645	$5.675	$240,029	$5.912	$250,053
	87,462		$600,890		$691,263		$720,186
D: ENERGY CHARGE							
0-180 hrs use per month	15,743,183.2	$0.06316	$994,339	$0.07266	$1,143,900	$0.07570	$1,191,759
181-360 hrs use per month	15,743,183.2	$0.04254	$669,715	$0.04894	$770,471	$0.04734	$745,282
361+ hrs use per month	23,457,687.4	$0.02456	$576,121	$0.02825	$662,680	$0.02456	$576,121
	54,944,054		$2,240,175		$2,577,051		$2,513,162
E: REACTIVE DEMAND ADJUSTMENT	3,566	$0.682	$2,432	$0.782	$2,788	$0.817	$2,913
REVENUE			$2,849,318		$3,277,799		$3,243,238
c/kwh			$0.0519		$0.0597		$0.0590
OVERALL CHANGE (%)	*12188*				15.04%		13.83%
used to reference avg customer	*7,656,577*						

WINTER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATES W/RATE DESIGN Rate	RATES W/RATE DESIGN Revenue
A: CUSTOMER CHARGE							
	16.8	811.13	$13,646	933.14	$15,699	972.18	$16,356
	-	-	$0	-	$0	-	$0
	-	-	$0	-	$0	-	$0
	17		$13,646		$15,699		$16,356
B: FACILITIES CHARGE	208,407	$0.000	$0	$0.000	$0	$0.000	$0
C: DEMAND CHARGE							
First 2553 kw	40,801.5	$6.854	$279,654	$7.885	$321,720	$8.215	$335,184
Next 2553 kw	25,280.4	$5.350	$135,250	$6.155	$155,601	$6.412	$162,098
Next 2553 kw	15,276.8	$4.720	$72,107	$5.430	$82,953	$5.657	$86,421
Over 7659 kw	50,268.1	$3.633	$182,624	$4.179	$210,071	$4.354	$218,868
	131,627		$669,634		$770,344		$802,571
D: ENERGY CHARGE							
0-180 hrs use per month	23,692,836.8	$0.05354	$1,268,514	$0.06159	$1,459,242	$0.06417	$1,520,369
181-360 hrs use per month	23,692,836.8	$0.03869	$916,676	$0.04451	$1,054,568	$0.04305	$1,019,977
361+ hrs use per month	36,065,772.7	$0.02431	$876,759	$0.02797	$1,008,760	$0.02431	$876,759
	83,451,446		$3,061,949		$3,522,570		$3,417,105
E: REACTIVE DEMAND ADJUSTMENT	4,009	$0.682	$2,734	$0.782	$3,135	$0.817	$3,276
REVENUE			$3,747,964		$4,311,748		$4,239,307
c/kwh			$0.0449		$0.0517		$0.0508
OVERALL CHANGE (%)	*7824*				15.04%		13.11%
used to reference avg customer	*4,960,280*						

	BILLING UNITS	PRESENT RATES Revenue	PROPOSED RATES Revenue	RATES W/RATE DESIGN Revenue
ANNUAL	138,395,500	$6,597,282	$7,589,547	$7,482,545
c/kwh		$0.0477	$0.0548	$0.0541
OVERALL CHANGE (%)			15.04%	13.42%
Winter Price Below Summer (SUM-WIN)/SUM		13.4%	13.4%	13.9%

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MO LARGE POWER
PRIMARY VOLTAGE, OFF PEAK - LPGSPO

* Equal Percent Increase to All Rate Components except
Energy 181-360 Hours Use -- use 75% of Average Increase
Energy over 360 Hours Use -- use Current Rates
Rates Designed to Achieve KCP&L's Proposed Increase.

SUMMER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATES W/RATE DESIGN Rate	RATES W/RATE DESIGN Revenue
A: CUSTOMER CHARGE							
	34.2	$811.13	$27,723	$933.14	$31,893	$972.18	$33,227
	-	$0.00	$0	$0.00	$0	$0.00	$0
	-	$0.00	$0	$0.00	$0	$0.00	$0
	34		$27,723		$31,893		$33,227
B: FACILITIES CHARGE	172,417.8	$2.252	$388,285	$2.591	$446,735	$2.699	$465,356
C: DEMAND CHARGE							
First 2500 kw	81,013.6	$10.297	$834,197	$11.846	$959,687	$12.341	$999,789
Next 2500 kw	45,449.1	$8.238	$374,410	$9.477	$430,721	$9.874	$448,764
Next 2500 kw	27,357.1	$6.900	$188,764	$7.938	$217,161	$8.270	$226,243
Over 7500 kw	26,637.7	$5.037	$134,174	$5.795	$154,366	$6.037	$160,812
	180,458		$1,531,545		$1,761,934		$1,835,608
D: ENERGY CHARGE							
0-180 hrs use per month	32,186,301.6	$0.06448	$2,075,373	$0.07418	$2,387,580	$0.07728	$2,487,357
181-360 hrs use per month	31,799,860.6	$0.04344	$1,381,386	$0.04997	$1,589,039	$0.04834	$1,537,205
361+ hrs use per month	30,861,531.4	$0.02507	$773,699	$0.02884	$890,047	$0.02507	$773,699
	94,847,694		$4,230,457		$4,866,665		$4,798,261
E: REACTIVE DEMAND ADJUSTMENT	17,553	$0.682	$11,971	$0.782	$13,727	$0.817	$14,341
F: MANUAL BILL USAGE/REVENUE	3,481,018		$239,640		$275,685		$275,685
REVENUE			$6,429,621		$7,396,639		$7,422,478
c/kwh			0.0654		0.0752		0.0755
OVERALL CHANGE (%)	*5280*				15.04%		15.44%
used to reference avg customer	*2,775,129*						

WINTER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATES W/RATE DESIGN Rate	RATES W/RATE DESIGN Revenue
A: CUSTOMER CHARGE							
	84.8	$811.13	$68,802	$933.14	$79,151	$972.18	$82,462
	-	$0.00	$0	$0.00	$0	$0.00	$0
	-	$0.00	$0	$0.00	$0	$0.00	$0
	85		$68,802		$79,151		$82,462
B: FACILITIES CHARGE	414,204.2	$2.252	$932,788	$2.591	$1,073,203	$2.699	$1,117,937
C: DEMAND CHARGE							
First 2500 kw	152,795.4	$6.999	$1,069,415	$8.052	$1,230,309	$8.389	$1,281,801
Next 2500 kw	71,483.9	$5.463	$390,517	$6.285	$449,276	$6.548	$468,077
Next 2500 kw	33,815.9	$4.819	$162,959	$5.544	$187,475	$5.776	$195,321
Over 7500 kw	46,611.3	$3.710	$172,928	$4.268	$198,937	$4.447	$207,280
	304,706		$1,795,818		$2,065,997		$2,152,478
D: ENERGY CHARGE							
0-180 hrs use per month	53,996,438.4	$0.05467	$2,951,985	$0.06289	$3,395,836	$0.06552	$3,537,847
181-360 hrs use per month	52,832,412.3	$0.03950	$2,086,880	$0.04544	$2,400,705	$0.04396	$2,322,513
361+ hrs use per month	59,229,242.6	$0.02484	$1,471,254	$0.02858	$1,692,772	$0.02484	$1,471,254
	166,058,093		$6,510,120		$7,489,313		$7,331,614
E: REACTIVE DEMAND ADJUSTMENT	37,871	$0.682	$25,828	$0.782	$29,615	$0.817	$30,940
F: MANUAL BILL USAGE/REVENUE	8,247,046		$509,975		$586,682		$586,682
REVENUE			$9,843,331		$11,323,961		$11,302,115
c/kwh			$0.0565		$0.0650		$0.0648
OVERALL CHANGE (%)	*3592*				15.04%		14.82%
used to reference avg customer	*1,957,719*						
ANNUAL	272,633,851		$16,272,952		$18,720,600		$18,724,593
c/kwh			$0.0597		$0.0687		$0.0687
OVERALL CHANGE (%)					15.04%		15.07%
Winter Price Below Summer (SUM-WIN)/SUM			13.6%		13.6%		14.1%

	BILLING UNITS	PRESENT RATES Revenue	PROPOSED RATES Revenue	RATES W/RATE DESIGN Revenue
SUMMER TOTAL (ALL RATES)	792,541,895	$47,905,641	$55,111,512	$55,274,922
WINTER TOTAL (ALL RATES)	1,357,875,470	$72,808,032	$83,759,089	$83,702,817
GRAND TOTAL (ANNUAL - ALL RATES)	**2,150,417,364**	**$127,310,955**	**$146,460,148**	**$146,460,286**
c/kwh Summer		**$0.0604**	**$0.0695**	**$0.0697**
c/kwh Winter		**$0.0536**	**$0.0617**	**$0.0616**
c/kwh Annual		**$0.0592**	**$0.0681**	**$0.0681**
Winter Price Below Summer (SUM-WIN)/SUM		**11.3%**	**11.3%**	**11.6%**
OVERALL CHANGE (%)			**15.041%**	**15.041%**

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MO LARGE GENERAL SERVICE
SUMMARY OF PROPOSAL SCENARIO
*** Equal Percent Increase to All Rate Components except**
Energy 181-360 Hours Use -- use 75% of Average Increase
Energy over 360 Hours Use -- use Current Rates
Rates Designed to Achieve KCP&L's Proposed Increase.

INPUT FOR MODEL			
Cust Chg	**Current Rates**	**Rates With Increase**	**Proposed Rates**
A: CUSTOMER CHARGE			
0-24 KW	91.02	104.71	107.78
25-199 KW	91.02	104.71	107.78
200-999 KW	91.02	104.71	107.78
1001+ KW	777.15	894.04	920.25
Separately Metered Space Heat	2.09	2.40	2.47
B: FACILITIES CHARGE			
SECONDARY:	2.604	2.996	3.084
PRIMARY:	2.159	2.484	2.557
C: DEMAND CHARGE			
SECONDARY-SUMMER:	5.200	5.982	6.158
SECONDARY-WINTER	2.798	3.219	3.313
PRIMARY-SUMMER	5.081	5.845	6.017
PRIMARY-WINTER	2.735	3.146	3.239
SECONDARY-WINTER - ELEC ONLY	2.591	2.981	3.068
PRIMARY-WINTER - ELEC ONLY	2.530	2.911	2.996
D: ENERGY CHARGE			
SECONDARY-SUMMER:			
0-180 hrs use per month	0.07637	0.08786	0.09043
181-360 hrs use per month	0.05665	0.06517	0.06304
361+ hrs use per month	0.04260	0.04901	0.04260
SECONDARY-WINTER:			
0-180 hrs use per month	0.07017	0.08072	0.08309
181-360 hrs use per month	0.04355	0.05010	0.04846
361+ hrs use per month	0.03580	0.04118	0.03580
PRIMARY-SUMMER:			
0-180 hrs use per month	0.07466	0.08589	0.08841
181-360 hrs use per month	0.05530	0.06362	0.06154
361+ hrs use per month	0.04160	0.04786	0.04160
PRIMARY-WINTER:			
0-180 hrs use per month	0.06857	0.07888	0.08120
181-360 hrs use per month	0.04251	0.04890	0.04731
361+ hrs use per month	0.03510	0.04038	0.03510
SECONDARY-WINTER - ALL ELECTRIC			
0-180 hrs use per month	0.06120	0.07041	0.07247
181-360 hrs use per month	0.03752	0.04316	0.04175
361+ hrs use per month	0.03140	0.03611	0.03140
PRIMARY-WINTER - ALL ELECTRIC		-	
0-180 hrs use per month	0.05992	0.06893	0.07095
181-360 hrs use per month	0.03669	0.04221	0.04083
361+ hrs use per month	0.03080	0.03543	0.03080
E: SEPARATELY METERED S/H-WINTER			
SECONDARY	0.04721	0.05431	0.05590
PRIMARY	0.00000	-	-
F: REACTIVE DEMAND ADJUSTMENT	0.653	0.751	0.773
[redacted]	100.00%	[redacted]	[redacted]
[redacted]	100.00%	[redacted]	[redacted]
[redacted]	0.00%	[redacted]	[redacted]
[redacted]	100.00%	[redacted]	[redacted]
[redacted]	100.00%	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]
[redacted]	0.00%	[redacted]	[redacted]
[redacted]	28.0%	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]
Revenue	$164,291,222		$189,005,410
Change in Revenue			$24,714,188
Design Revenue per Revenue Summary			$24,711,683
			$2,504

MO LARGE GENERAL
SECONDARY VOLTAGE - LGSS

*** Equal Percent Increase to All Rate Components except**
Energy 181-360 Hours Use -- use 75% of Average Increase
Energy over 360 Hours Use -- use Current Rates
Rates Designed to Achieve KCP&L's Proposed Increase.

SUMMER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATES W/RATE DESIGN Rate	RATES W/RATE DESIGN Revenue
25-199 KW	-	$91.02	$0	$104.71	$0 NC	$107.78	$0
200-999 KW	2,351.1	$91.02	$214,001	$104.71	$246,189	$107.78	$253,407
1001+ KW	93.4	$777.15	$72,621	$894.04	$83,544	$920.25	$85,993
Separately Metered Space Heat	-	$2.09	$0	$2.40	$0	$2.47	$0
	2,445		$286,622		$329,732		$339,400
B: FACILITIES CHARGE	1,094,490.8	$2.604	$2,850,054	$2.996	$3,279,094	$3.084	$3,375,410
C: DEMAND CHARGE	1,113,160.9	$5.200	$5,788,437	$5.982	$6,658,929	$6.158	$6,854,845
D: ENERGY CHARGE							
0-180 hrs use per month	190,727,153.9	$0.0764	$14,565,833	$0.08786	$16,757,288	$0.09043	$17,247,457
181-360 hrs use per month	153,242,558.8	$0.0567	$8,681,191	$0.06517	$9,986,818	$0.06304	$9,660,411
361+ hrs use per month	74,331,905.5	$0.0426	$3,166,539	$0.04901	$3,643,007	$0.04260	$3,166,539
	418,301,618		$26,413,563		$30,387,112		$30,074,407
E: SEPARATELY METERED SPACE HEAT	-	$0.0472	$0	$0.05431	$0	$0.05590	$0
F: REACTIVE DEMAND ADJUSTMENT	-	$0.653	$0	$0.751	$0	$0.773	$0
MANUAL BILLS	-		$0		$0		$0
REVENUE			$35,338,676		$40,654,867		$40,644,061
c/kwh			$0.0845		$0.0972		$0.0972
FLUCTUATION (%)					15.04%		15.01%
used to reference avg customer	*171,113*						

WINTER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATES W/RATE DESIGN Rate	RATES W/RATE DESIGN Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$91.02	$0	$104.71	$0	107.78	$0
25-199 KW	-	$91.02	$0	$104.71	$0	107.78	$0
200-999 KW	5,686.8	$91.02	$517,609	$104.71	$595,461	107.78	$612,919
1001+ KW	211.2	$777.15	$164,131	$894.04	$188,818	920.25	$194,354
Separately Metered Space Heat	-	$2.09	$0	$2.40	$0	2.47	$0
	5,898		$681,740		$784,279		$807,273
B: FACILITIES CHARGE	2,585,448.8	$2.604	$6,732,509	$2.996	$7,746,004	$3.084	$7,973,524
C: DEMAND CHARGE	1,917,697.8	$2.798	$5,365,718	$3.219	$6,173,069	$3.313	$6,353,333
D: ENERGY CHARGE							
0-180 hrs use per month	313,999,870.2	$0.0702	$22,033,371	$0.08072	$25,346,070	$0.08309	$26,090,249
181-360 hrs use per month	248,658,627.3	$0.0436	$10,829,083	$0.05010	$12,457,797	$0.04846	$12,049,997
361+ hrs use per month	117,402,221.7	$0.0358	$4,203,000	$0.04118	$4,834,623	$0.03580	$4,203,000
	680,060,719		$37,065,454		$42,638,490		$42,343,246
E: SEPARATELY METERED SPACE HEAT	-	$0.0472	$0	$0.05431	$0	$0.05590	$0
F: REACTIVE DEMAND ADJUSTMENT	2,060	$0.653	$1,345	$0.751	$1,547	$0.773	$1,593
MANUAL BILLS	2,816,716.0		$214,132		$246,340		$246,340
REVENUE			$50,060,898		$57,589,730		$57,725,308
c/kwh			$0.0736		$0.0847		$0.0849
FLUCTUATION (%)					15.04%		15.31%
used to reference avg customer	*115,782*						
ANNUAL ENERGY/REVENUE	1,101,179,053		$85,399,574		$98,244,598		$98,369,369
c/kwh			$0.0776		$0.0892		$0.0893
FLUCTUATION (%)					15.04%		15.19%
Winter Price Below Summer (SUM-WIN)/SUM			12.9%		12.9%		12.6%

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MO LARGE GENERAL
PRIMARY VOLTAGE - LGSP

*** Equal Percent Increase to All Rate Components except**
Energy 181-360 Hours Use -- use 75% of Average Increase
Energy over 360 Hours Use -- use Current Rates
Rates Designed to Achieve KCP&L's Proposed Increase.

SUMMER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATES W/RATE DESIGN Rate	RATES W/RATE DESIGN Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$91.02	$0	$104.71	$0	$107.78	$0
25-199 KW	-	$91.02	$0	$104.71	$0	$107.78	$0
200-999 KW	195.0	$91.02	$17,746	$104.71	$20,415	$107.78	$21,013
1001+ KW	61.5	$777.15	$47,773	$894.04	$54,958	$920.25	$56,570
Separately Metered Space Heat	-	$2.09	$0	$2.40	$0	$2.47	$0
	256		$65,519		$75,373		$77,583
B: FACILITIES CHARGE	217,109.4	$2.159	$468,739	$2.484	$539,300	$2.557	$555,149
C: DEMAND CHARGE	215,373.5	$5.081	$1,094,313	$5.845	$1,258,858	$6.017	$1,295,902
D: ENERGY CHARGE							
0-180 hrs use per month	37,215,734.7	$0.0747	$2,778,527	$0.08589	$3,196,459	$0.08841	$3,290,243
181-360 hrs use per month	28,452,913.8	$0.0553	$1,573,446	$0.06362	$1,810,174	$0.06154	$1,750,992
361+ hrs use per month	11,975,565.7	$0.0416	$498,184	$0.04786	$573,151	$0.04160	$498,184
	77,644,214		$4,850,156		$5,579,784		$5,539,419
E: SEPARATELY METERED SPACE HEAT	-	$0.0000	$0	$0.00000	$0	$0.00000	$0
F: REACTIVE DEMAND ADJUSTMENT	19,995	$0.653	$13,057	$0.751	$15,016	$0.773	$15,456
MANUAL BILLS	-		$0		$0		$0
REVENUE			$6,491,784		$7,468,331		$7,483,509
c/kwh			$0.0836		$0.0962		$0.0964
FLUCTUATION (%)					15.04%		15.28%
used to reference avg customer	*302,781*						

WINTER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATES W/RATE DESIGN Rate	RATES W/RATE DESIGN Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$91.02	$0	$104.71	$0	$107.78	$0
25-199 KW	-	$91.02	$0	$104.71	$0	$107.78	$0
200-999 KW	476.5	$91.02	$43,371	$104.71	$49,894	$107.78	$51,357
1001+ KW	141.9	$777.15	$110,280	$894.04	$126,867	$920.25	$130,587
Separately Metered Space Heat	-	$2.09	$0	$2.40	$0	$2.47	$0
	618		$153,651		$176,762		$181,944
B: FACILITIES CHARGE	520,207.7	$2.159	$1,123,128	$2.484	$1,292,196	$2.557	$1,330,171
C: DEMAND CHARGE	375,983.6	$2.735	$1,028,315	$3.146	$1,182,844	$3.239	$1,217,811
D: ENERGY CHARGE							
0-180 hrs use per month	65,215,477.8	$0.0686	$4,471,825	$0.07888	$5,144,197	$0.08120	$5,295,497
181-360 hrs use per month	49,093,759.6	$0.0425	$2,086,976	$0.04890	$2,400,685	$0.04731	$2,322,626
361+ hrs use per month	19,088,824.8	$0.0351	$670,018	$0.04038	$770,807	$0.03510	$670,018
	133,398,062		$7,228,819		$8,315,688		$8,288,140
E: SEPARATELY METERED SPACE HEAT	-	$0.0000	$0	$0.00000	$0	$0.00000	$0
F: REACTIVE DEMAND ADJUSTMENT	39,460	$0.653	$25,767	$0.751	$29,634	$0.773	$30,502
MANUAL BILLS	1,977,540.0		$420,752		$484,038		$484,038
REVENUE			$9,980,432		$11,481,163		$11,532,607
c/kwh			$0.0748		$0.0861		$0.0865
FLUCTUATION (%)					15.04%		15.55%
used to reference avg customer	*215,714*						
ANNUAL ENERGY/REVENUE	213,019,816		$16,472,216		$18,949,495		$19,016,116
c/kwh			$0.0773		$0.0890		$0.0893
FLUCTUATION (%)					15.04%		15.44%
Winter Price Below Summer (SUM-WIN)/SUM			10.5%		10.5%		10.3%

SUMMER TOTAL (LGSS/LGSP)	495,945,832	$41,830,460	$48,123,199	$48,127,570
WINTER TOTAL (LGSS/LGSP)	813,458,781	$60,041,331	$69,070,893	$69,257,915
GRAND TOTAL (ANNUAL-LGSS/LGSP)	**1,314,198,870**	**$101,871,790**	**$117,194,092**	**$117,385,484**
c/kwh		**$0.0775**	**$0.0892**	**$0.0893**
OVERAL CHANGE (%)			**15.04%**	**15.23%**

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MO LARGE GENERAL
SECONDARY VOLTAGE, ALL ELECTRIC (ONE METER) - LGSSA

*** Equal Percent Increase to All Rate Components except**
Energy 181-360 Hours Use -- use 75% of Average Increase
Energy over 360 Hours Use -- use Current Rates
Rates Designed to Achieve KCP&L's Proposed Increase.

SUMMER

	BILLING UNITS	PRESENT RATES		PROPOSED RATES		RATES W/RATE DESIGN	
		Rate	Revenue	Rate	Revenue	Rate	Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$91.02	$0	$104.71	$0	$107.78	$0
25-199 KW	-	$91.02	$0	$104.71	$0	$107.78	$0
200-999 KW	528.1	$91.02	$48,063	$104.71	$55,292	$107.78	$56,914
1001+ KW	163.5	$777.15	$127,081	$894.04	$146,195	$920.25	$150,481
Separately Metered Space Heat	-	$2.09	$0	$2.40	$0	$2.47	$0
	692		$175,144		$201,487		$207,394
B: FACILITIES CHARGE	541,732.6	$2.604	$1,410,672	$2.996	$1,623,031	$3.084	$1,670,703
C: DEMAND CHARGE	496,711.6	$5.200	$2,582,900	$5.982	$2,971,329	$6.158	$3,058,750
D: ENERGY CHARGE							
0-180 hrs use per month	87,664,673.3	$0.0764	$6,694,951	$0.08786	$7,702,218	$0.09043	$7,927,516
181-360 hrs use per month	80,638,900.7	$0.0567	$4,568,194	$0.06517	$5,255,237	$0.06304	$5,083,476
361+ hrs use per month	47,042,429.8	$0.0426	$2,004,008	$0.04901	$2,305,549	$0.04260	$2,004,008
	215,346,004		$13,267,152		$15,263,005		$15,015,000
E: SEPARATELY METERED SPACE HEAT	-	$0.0472	$0	$0.05431	$0	$0.05590	$0
F: REACTIVE DEMAND ADJUSTMENT	3,198	$0.653	$2,088	$0.751	$2,401	$0.773	$2,472
MANUAL BILLS	3,458,714.2		$263,589		$303,237		$303,237
REVENUE			$17,701,546		$20,364,490		$20,257,556
c/kwh			$0.0822		$0.0946		$0.0941
FLUCTUATION (%)					15.04%		14.44%
used to reference avg customer	*311,385*						

WINTER

	BILLING UNITS	PRESENT RATES		PROPOSED RATES		RATES W/RATE DESIGN	
		Rate	Revenue	Rate	Revenue	Rate	Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$91.02	$0	$104.71	$0	$107.78	$0
25-199 KW	-	$91.02	$0	$104.71	$0	$107.78	$0
200-999 KW	1,392.4	$91.02	$126,739	$104.71	$145,801	$107.78	$150,076
1001+ KW	438.5	$777.15	$340,781	$894.04	$392,037	$920.25	$403,531
Separately Metered Space Heat	-	$2.09	$0	$2.40	$0	$2.47	$0
	1,831		$467,520		$537,839		$553,607
B: FACILITIES CHARGE	1,438,104.6	$2.604	$3,744,825	$2.996	$4,308,562	$3.084	$4,435,115
C: DEMAND CHARGE	1,065,538.4	$2.591	$2,760,810	$2.981	$3,176,370	$3.068	$3,269,072
D: ENERGY CHARGE							
0-180 hrs use per month	188,044,009.8	$0.0612	$11,508,293	$0.07041	$13,240,179	$0.07247	$13,627,549
181-360 hrs use per month	168,838,480.0	$0.0375	$6,334,820	$0.04316	$7,287,069	$0.04175	$7,049,007
361+ hrs use per month	94,112,123.7	$0.0314	$2,955,121	$0.03611	$3,398,389	$0.03140	$2,955,121
	450,994,613		$20,798,234		$23,925,636		$23,631,677
E: SEPARATELY METERED SPACE HEAT	-	$0.0472	$0	$0.05431	$0	$0.05590	$0
F: REACTIVE DEMAND ADJUSTMENT	3,854	$0.653	$2,517	$0.751	$2,894	$0.773	$2,979
MANUAL BILLS	9,212,798.8		$547,402		$629,739		$629,739
REVENUE			$28,321,308		$32,581,041		$32,522,189
c/kwh			$0.0628		$0.0722		$0.0721
FLUCTUATION (%)					15.04%		14.83%
used to reference avg customer	*246,320*						
ANNUAL ENERGY/REVENUE	679,012,130		$46,022,853		$52,945,530		$52,779,745
c/kwh			$0.0678		$0.0780		$0.0777
FLUCTUATION (%)					15.04%		14.68%
Winter Price Below Summer (SUM-WIN)/SUM			23.6%		23.6%		23.3%

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MO LARGE GENERAL
PRIMARY VOLTAGE, ALL ELECTRIC (ONE METER) - LGSPA

*** Equal Percent Increase to All Rate Components except**
Energy 181-360 Hours Use -- use 75% of Average Increase
Energy over 360 Hours Use -- use Current Rates
Rates Designed to Achieve KCP&L's Proposed Increase.

SUMMER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATES W/RATE DESIGN Rate	RATES W/RATE DESIGN Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$91.02	$0	$104.71	$0	$107.78	$0
25-199 KW	-	$91.02	$0	$104.71	$0	$107.78	$0
200-999 KW	6.6	$91.02	$597	$104.71	$687	$107.78	$707
1001+ KW	39.4	$777.15	$30,583	$894.04	$35,183	$920.25	$36,214
Separately Metered Space Heat	-	$2.09	$0	$2.40	$0	$2.47	$0
	46		$31,180		$35,869		$36,921
B: FACILITIES CHARGE	156,596.8	$2.159	$338,092	$2.484	$388,986	$2.557	$400,418
C: DEMAND CHARGE	130,188.2	$5.081	$661,486	$5.845	$760,950	$6.017	$783,342
D: ENERGY CHARGE							
0-180 hrs use per month	23,433,876.2	$0.0747	$1,749,573	$0.08589	$2,012,736	$0.08841	$2,071,789
181-360 hrs use per month	20,686,240.2	$0.0553	$1,143,949	$0.06362	$1,316,059	$0.06154	$1,273,031
361+ hrs use per month	14,669,645.4	$0.0416	$610,257	$0.04786	$702,089	$0.04160	$610,257
	58,789,762		$3,503,780		$4,030,883		$3,955,077
E: SEPARATELY METERED SPACE HEAT	-	$0.0000	$0	$0.00000	$0	$0.00000	$0
F: REACTIVE DEMAND ADJUSTMENT	8,184	$0.653	$5,344	$0.751	$6,146	$0.773	$6,326
REVENUE			$4,539,882		$5,222,836		$5,182,085
c/kwh			$0.0772		$0.0888		$0.0881
FLUCTUATION (%)					15.04%		14.15%
used to reference avg customer	*1,280,514*						

WINTER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATES W/RATE DESIGN Rate	RATES W/RATE DESIGN Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$91.02	$0	$104.71	$0	$107.78	$0
25-199 KW	-	$91.02	$0	$104.71	$0	$107.78	$0
200-999 KW	16.3	$91.02	$1,480	$104.71	$1,703	$107.78	$1,753
1001+ KW	103.5	$777.15	$80,435	$894.04	$92,533	$920.25	$95,246
Separately Metered Space Heat	-	$2.09	$0	$2.40	$0	$2.47	$0
	120		$81,915		$94,236		$96,999
B: FACILITIES CHARGE	406,785.4	$2.159	$878,250	$2.484	$1,010,455	$2.557	$1,040,150
C: DEMAND CHARGE	288,505.4	$2.530	$729,919	$2.911	$839,839	$2.996	$864,362
D: ENERGY CHARGE							
0-180 hrs use per month	51,761,577.6	$0.0599	$3,101,554	$0.06893	$3,567,926	$0.07095	$3,672,484
181-360 hrs use per month	43,188,016.5	$0.0367	$1,584,568	$0.04221	$1,822,966	$0.04083	$1,763,367
361+ hrs use per month	27,977,790.9	$0.0308	$861,716	$0.03543	$991,253	$0.03080	$861,716
	122,927,385		$5,547,838		$6,382,145		$6,297,567
E: SEPARATELY METERED SPACE HEAT	-	$0.0000	$0	$0.00000	$0	$0.00000	$0
F: REACTIVE DEMAND ADJUSTMENT	12,396	$0.653	$8,095	$0.751	$9,309	$0.773	$9,582
REVENUE			$7,246,016		$8,335,984		$8,308,660
c/kwh			$0.0589		$0.0678		$0.0676
FLUCTUATION (%)					15.04%		-0.33%
used to reference avg customer	*1,026,413*						

	BILLING UNITS	PRESENT RATES Revenue	PROPOSED RATES Revenue	RATES W/RATE DESIGN Revenue
ANNUAL ENERGY/REVENUE	181,717,147	$11,785,898	$13,558,820	$13,490,745
c/kwh		$0.0649	$0.0746	$0.0742
FLUCTUATION (%)			15.04%	14.47%
Winter Price Below Summer (SUM-WIN)/SUM		23.7%	23.7%	23.3%

SUMMER TOTAL (LGSSA/LGSPA)	274,135,766	$22,241,428	$25,587,325	$25,439,641
WINTER TOTAL (LGSSA/LGSPA)	573,921,999	$35,567,324	$40,917,025	$40,830,848
GRAND TOTAL (ANNUAL-LGSSA/LGSPA)	**860,729,277**	**57,808,751**	**66,504,350**	**66,270,489**
c/kwh		**$0.0672**	**$0.0773**	**$0.0770**
OVERALL WINTER ENERGY CHANGE			**13.07%**	**11.97%**
OVERAL CHANGE (%)			**15.04%**	**14.64%**

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MO LARGE GENERAL
SECONDARY VOLTAGE, SPACE HEAT (TWO METER) - LGSSH

* **Equal Percent Increase to All Rate Components except**
Energy 181-360 Hours Use -- use 75% of Average Increase
Energy over 360 Hours Use -- use Current Rates
Rates Designed to Achieve KCP&L's Proposed Increase.

SUMMER

	BILLING UNITS	PRESENT RATES		PROPOSED RATES		RATES W/RATE DESIGN	
		Rate	Revenue	Rate	Revenue	Rate	Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$91.02	$0	$104.71	$0	$107.78	$0
25-199 KW	-	$91.02	$0	$104.71	$0	$107.78	$0
200-999 KW	133.3	$91.02	$12,130	$104.71	$13,954	$107.78	$14,363
1001+ KW	16.1	$777.15	$12,506	$894.04	$14,387	$920.25	$14,809
Separately Metered Space Heat	149.4	$2.09	$312	$2.40	$358	$2.47	$369
	299		$24,948		$28,699		$29,541
B: FACILITIES CHARGE	73,158.9	$2.604	$190,506	$2.996	$219,184	$3.084	$225,622
C: DEMAND CHARGE	56,820.4	$5.200	$295,466	$5.982	$339,900	$6.158	$349,900
D: ENERGY CHARGE							
0-180 hrs use per month	9,512,614.7	$0.0764	$726,478	$0.08786	$835,778	$0.09043	$860,226
181-360 hrs use per month	7,977,947.6	$0.0567	$451,951	$0.06517	$519,923	$0.06304	$502,930
361+ hrs use per month	3,892,872.6	$0.0426	$165,836	$0.04901	$190,790	$0.04260	$165,836
	21,383,435		$1,344,265		$1,546,491		$1,528,992
E: SEPARATELY METERED SPACE HEAT	-	$0.0000	$0	$0.00000	$0	$0.00000	$0
F: REACTIVE DEMAND ADJUSTMENT	-	$0.653	$0	$0.751	$0	$0.773	$0
MANUAL BILLS	-		$0		$0		$0
REVENUE			$1,855,185		$2,134,274		$2,134,055
c/kwh			$0.0868		$0.0998		$0.0998
FLUCTUATION (%)					15.04%		15.03%
used to reference avg customer	*71,586*						

WINTER

	BILLING UNITS	PRESENT RATES		PROPOSED RATES		RATES W/RATE DESIGN	
		Rate	Revenue	Rate	Revenue	Rate	Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$91.02	$0	$104.71	$0	$107.78	$0
25-199 KW	-	$91.02	$0	$104.71	$0	$107.78	$0
200-999 KW	261.5	$91.02	$23,806	$104.71	$27,387	$107.78	$28,190
1001+ KW	31.5	$777.15	$24,500	$894.04	$28,185	$920.25	$29,011
Separately Metered Space Heat	293.1	$2.09	$613	$2.40	$703	$2.47	$724
	586		$48,918		$56,275		$57,925
B: FACILITIES CHARGE	147,486.2	$2.604	$384,054	$2.996	$441,869	$3.084	$454,847
C: DEMAND CHARGE	117,344.7	$2.798	$328,330	$3.219	$377,732	$3.313	$388,763
D: ENERGY CHARGE							
0-180 hrs use per month	9,238,165.6	$0.0702	$648,242	$0.08072	$745,705	$0.08309	$767,599
181-360 hrs use per month	7,651,218.7	$0.0436	$333,211	$0.05010	$383,326	$0.04846	$370,778
361+ hrs use per month	3,594,582.4	$0.0358	$128,686	$0.04118	$148,025	$0.03580	$128,686
	20,483,967		$1,110,139		$1,277,056		$1,267,063
E: SEPARATELY METERED SPACE HEAT	18,725,990.7	$0.0472	$884,054	$0.05431	$1,017,009	$0.05590	$1,046,783
F: REACTIVE DEMAND ADJUSTMENT	-	$0.653	$0	$0.751	$0	$0.773	$0
MANUAL BILLS	-		$0		$0		$0
REVENUE			$2,755,496		$3,169,940		$3,215,381
c/kwh			$0.0703		$0.0808		$0.0820
FLUCTUATION (%)					15.04%		16.69%
used to reference avg customer	*69,894*						
	63,895						
ANNUAL ENERGY/REVENUE	60,593,392		$4,610,681		$5,304,214		$5,349,436
c/kwh			$0.0761		$0.0875		$0.0883
FLUCTUATION (%)					15.04%		16.02%
Winter Price Below Summer (SUM-WIN)/SUM			19.0%		19.0%		17.8%

SUMMER TOTAL (ALL RATES)	791,465,033	$65,927,072	$75,844,798	$75,701,266
WINTER TOTAL (ALL RATES)	1,426,590,737	$98,364,150	$113,157,858	$113,304,144
GRAND TOTAL (ANNUAL - ALL RATES)	**2,218,055,770**	**$164,291,222**	**$189,002,656**	**$189,005,410**
c/kwh Summer		**$0.0833**	**$0.0958**	**$0.0956**
c/kwh Winter		**$0.0690**	**$0.0793**	**$0.0794**
c/kwh Annual		**$0.0741**	**$0.0852**	**$0.0852**
Winter Price Below Summer (SUM-WIN)/SUM		**17.2%**	**17.2%**	**17.0%**
OVERALL CHANGE (%)			**15.041%**	**15.04%**

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KANSAS CITY POWER & LIGHT COMPANY

Development of
Average and Excess Demand Allocator
Based on 2 Non-Coincident Peaks
For the Test Year Ended September 30, 2011

Line	Description	Missouri Retail	Residential	Small General Service	Medium General Service	Large General Service	Large Power Service	Other Lighting
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Missouri System Peak	1,935,936						
2	Avg of 2 Highest Monthly NCP Values	2,103,286	921,755	101,680	252,647	456,503	360,373	10,327
3	Energy Sales with Losses - MWh	9,045,302	2,742,028	438,496	1,154,656	2,362,973	2,256,681	90,467
4	Average Demand - kW	1,032,569	313,017	50,057	131,810	269,746	257,612	10,327
5	Average Demand - Percent	1.000000	0.303144	0.048478	0.127653	0.261238	0.249487	0.010002
6	Class Excess Demand - kW	1,070,717	608,738	51,624	120,837	186,758	102,761	-
7	Class Excess Demand - Percent	1.000000	0.568533	0.048214	0.112856	0.174423	0.095974	-
	Allocator:							
8	Annual Load Factor * Average Demand	0.533369	0.161688	0.025857	0.068086	0.139336	0.133068	0.005335
9	(1-LF) * Excess Demand	0.466631	0.265295	0.022498	0.052662	0.081391	0.044785	-
10	Average and Excess Demand Allocator	1.000000	0.426983	0.048355	0.120748	0.220727	0.177853	0.005335

Notes:
Line 4 equals Line 3 ÷ 8.760
Line 6 equals Line 2- Line 4

System Annual Load Factor	53.34%
1 - Load Factor	46.66%

Source: KCPL Allocators MO Rev 2-23-12.xls

KANSAS CITY POWER & LIGHT COMPANY
2012 RATE CASE - Direct Filing
COST OF SERVICE - Missouri Jurisdiction
TY 9/30/11; Update TBD; K&M 8/31/12

LINE NO.	DESCRIPTION	MISSOURI RETAIL	RESIDENTIAL	SMALL GEN. SERVICE	MEDIUM GEN. SERVICE	LARGE GEN. SERVICE	LARGE PWR SERVICE	TOTAL LIGHTING
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
0010	**SCHEDULE 1 - SUMMARY OF OPERATING INC & RATE BASE**							
0020								
0030	OPERATING REVENUE							
0040	RETAIL SALES REVENUE	699,636,961	259,806,177	47,984,116	94,385,415	163,335,353	125,295,179	8,830,722
0050	OTHER OPERATING REVENUE	49,051,908	16,329,418	2,434,535	6,216,876	12,344,090	11,217,197	509,791
0060	TOTAL OPERATING REVENUE	748,688,868	276,135,595	50,418,651	100,602,291	175,679,443	136,512,376	9,340,513
0070								
0080	OPERATING EXPENSES							
0090	FUEL	124,790,618	37,864,453	6,039,546	15,954,515	32,485,423	31,219,978	1,226,703
0100	PURCHASED POWER	24,345,430	7,532,510	1,189,362	3,103,358	6,331,380	5,935,822	252,997
0110	OTHER OPERATION & MAINTENANCE EXPENSES	296,422,803	141,654,003	17,597,268	33,645,212	56,722,253	43,872,592	2,931,474
0120	DEPRECIATION EXPENSES (AFTER CLEARINGS)	98,902,485	45,666,301	5,242,470	12,291,449	19,921,212	14,644,153	1,136,901
0130	AMORTIZATION EXPENSES	11,107,955	5,014,606	582,318	1,370,759	2,307,944	1,730,736	101,591
0140	TAXES OTHER THAN INCOME TAXES	48,547,311	22,339,405	2,639,325	5,920,435	9,832,477	7,340,318	475,351
0150	CURRENT INCOME TAXES	9,814,637	(13,928,675)	4,240,023	5,270,124	8,687,647	4,626,281	919,236
0160	DEFERRED INCOME TAXES	16,774,160	7,743,972	900,628	2,060,672	3,401,583	2,502,755	164,549
0170	TOTAL ELECTRIC OPERATING EXPENSES	630,705,397	253,886,575	38,430,940	79,616,525	139,689,919	111,872,634	7,208,803
0180								
0190	NET ELECTRIC OPERATING INCOME	117,983,472	22,249,019	11,987,711	20,985,766	35,989,524	24,639,741	2,131,710
0200								
0210	RATE BASE							
0220	TOTAL ELECTRIC PLANT	4,283,301,236	1,964,397,645	228,827,359	525,729,570	874,263,795	648,935,262	41,147,604
0230	LESS: ACCUM. PROV. FOR DEPREC	1,816,407,425	846,786,584	100,001,653	216,373,431	361,245,774	270,804,240	21,195,743
0240	NET PLANT	2,466,893,811	1,117,611,062	128,825,706	309,356,139	513,018,021	378,131,022	19,951,861
0250	PLUS:							
0260	CASH WORKING CAPITAL	(47,690,286)	(20,624,749)	(2,891,164)	(6,115,624)	(10,136,357)	(7,408,163)	(514,230)
0270	MATERIALS & SUPPLIES	51,855,549	23,203,426	2,684,120	6,376,746	10,883,528	8,265,625	442,103
0280	PREPAYMENTS	5,522,723	2,439,595	278,331	663,255	1,177,677	927,891	35,973
0290	FUEL INVENTORY	66,901,141	20,299,403	3,237,844	8,553,329	17,415,667	16,737,253	657,644
0300	REGULATORY ASSETS	121,304,313	49,534,547	6,389,335	14,817,677	27,506,978	21,823,831	1,231,946
0310	LESS:							
0320	CUSTOMER ADVANCES FOR CONSTRUCTION	158,781	88,149	10,508	20,915	24,434	11,469	3,306
0330	CUSTOMER DEPOSITS	4,192,439	2,179,087	1,607,581	335,161	65,338	5,272	0
0340	DEFERRED INCOME TAXES	485,201,862	222,522,149	25,921,002	59,553,357	99,034,459	73,509,795	4,661,100
0350	DEFERRED GAIN ON SO2 EMISSIONS ALLOWANCI	45,275,933	13,725,121	2,194,878	5,779,590	11,827,778	11,295,737	452,829
0360	DEFERRED GAIN(LOSS) EMISSIONS ALLOWANCE	2,121	643	103	271	554	529	21
0370	TOTAL RATE BASE	2,129,956,114	953,948,135	108,790,100	267,962,229	448,912,952	333,654,656	16,688,042
0380								
0390	RATE OF RETURN	5.539%	2.332%	11.019%	7.832%	8.017%	7.385%	12.774%
0400	RELATIVE RATE OF RETURN	1.00	0.42	1.99	1.41	1.45	1.33	2.31

Notes:
Production Plant and Expense Allocated using A&E-2NCP.
Margin on Sales Revenue Allocated on Energy.

KANSAS CITY POWER & LIGHT COMPANY

Development of
4 CP Demand Allocator
For the Test Year Ended September 30, 2011

Line	Description	Missouri Retail	Residential	Small General Service	Medium General Service	Large General Service	Large Power Service	Other Lighting
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	4 CP Demand - kW	1,874,930	764,709	96,422	238,198	434,373	341,228	-
2	4 CP Demand - Percent	1.000000	0.407860	0.051427	0.127044	0.231674	0.181995	-

Source: KCPL Allocators MO Rev 2-23-12.xls

KANSAS CITY POWER & LIGHT COMPANY
2012 RATE CASE - Direct Filing
COST OF SERVICE - Missouri Jurisdiction
TY 9/30/11; Update TBD; K&M 8/31/12

LINE NO.	DESCRIPTION	MISSOURI RETAIL	RESIDENTIAL	SMALL GEN. SERVICE	MEDIUM GEN. SERVICE	LARGE GEN. SERVICE	LARGE PWR SERVICE	TOTAL LIGHTING
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
0010	SCHEDULE 1 - SUMMARY OF OPERATING INC & RATE BASE							
0020								
0030	OPERATING REVENUE							
0040	RETAIL SALES REVENUE	699,636,961	259,806,177	47,984,116	94,385,415	163,335,353	125,295,179	8,830,722
0050	OTHER OPERATING REVENUE	49,051,908	16,235,912	2,449,557	6,247,662	12,397,619	11,237,452	483,706
0060	TOTAL OPERATING REVENUE	748,688,868	276,042,088	50,433,673	100,633,076	175,732,972	136,532,631	9,314,428
0070								
0080	OPERATING EXPENSES							
0090	FUEL	124,790,618	37,864,453	6,039,546	15,954,515	32,485,423	31,219,978	1,226,703
0100	PURCHASED POWER	24,345,430	7,532,510	1,189,362	3,103,358	6,331,380	5,935,822	252,997
0110	OTHER OPERATION & MAINTENANCE EXPENSES	296,422,803	138,497,223	18,104,409	34,684,530	58,529,382	44,556,408	2,050,851
0120	DEPRECIATION EXPENSES (AFTER CLEARINGS)	98,902,485	44,422,768	5,442,245	12,700,862	20,633,084	14,913,525	790,001
0130	AMORTIZATION EXPENSES	11,107,955	4,859,597	607,221	1,421,794	2,396,680	1,764,314	58,350
0140	TAXES OTHER THAN INCOME TAXES	48,547,311	21,711,736	2,740,161	6,127,084	10,191,792	7,476,282	300,255
0150	CURRENT INCOME TAXES	9,814,637	(11,409,371)	3,835,294	4,440,685	7,245,448	4,080,554	1,622,027
0160	DEFERRED INCOME TAXES	16,774,160	7,528,052	935,316	2,131,761	3,525,189	2,549,527	104,315
0170	TOTAL ELECTRIC OPERATING EXPENSES	630,705,397	251,006,968	38,893,552	80,564,588	141,338,378	112,496,410	6,405,501
0180								
0190	NET ELECTRIC OPERATING INCOME	117,983,472	25,035,121	11,540,121	20,068,488	34,394,594	24,036,221	2,908,927
0200								
0210	RATE BASE							
0220	TOTAL ELECTRIC PLANT	4,283,301,236	1,908,730,137	237,770,413	544,057,180	906,131,191	660,993,855	25,618,459
0230	LESS: ACCUM. PROV. FOR DEPREC	1,816,407,425	822,269,077	103,940,421	224,445,416	375,281,054	276,115,177	14,356,280
0240	NET PLANT	2,466,893,811	1,086,461,060	133,829,992	319,611,764	530,850,136	384,878,678	11,262,180
0250	PLUS:							
0260	CASH WORKING CAPITAL	(47,690,286)	(20,226,415)	(2,955,156)	(6,246,769)	(10,364,387)	(7,494,449)	(403,109)
0270	MATERIALS & SUPPLIES	51,855,549	22,436,190	2,807,377	6,629,346	11,322,739	8,431,823	228,073
0280	PREPAYMENTS	5,522,723	2,345,128	293,507	694,357	1,231,756	948,354	9,620
0290	FUEL INVENTORY	66,901,141	20,299,403	3,237,844	8,553,329	17,415,667	16,737,253	657,644
0300	REGULATORY ASSETS	121,304,313	48,397,367	6,572,024	15,192,075	28,157,967	22,070,165	914,716
0310	LESS:							
0320	CUSTOMER ADVANCES FOR CONSTRUCTION	158,781	88,149	10,508	20,915	24,434	11,469	3,306
0330	CUSTOMER DEPOSITS	4,192,439	2,179,087	1,607,581	335,161	65,338	5,272	0
0340	DEFERRED INCOME TAXES	485,201,862	216,216,270	26,934,049	61,629,463	102,644,320	74,875,763	2,901,996
0350	DEFERRED GAIN ON SO2 EMISSIONS ALLOWANCI	45,275,933	13,725,121	2,194,878	5,779,590	11,827,778	11,295,737	452,829
0360	DEFERRED GAIN(LOSS) EMISSIONS ALLOWANCE	2,121	643	103	271	554	529	21
0370	TOTAL RATE BASE	2,129,956,114	927,503,463	113,038,469	276,668,702	464,051,457	339,383,052	9,310,972
0380								
0390	RATE OF RETURN	5.539%	2.699%	10.209%	7.254%	7.412%	7.082%	31.242%
0400	RELATIVE RATE OF RETURN	1.00	0.49	1.84	1.31	1.34	1.28	5.64

Notes:
Production Plant and Expense Allocated using 4CP.
Margin on Sales Revenue Allocated on Energy.