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Issues: Class Cost of Service
Rate Design
Witness: Janice Pyatte
Sponsoring Party: MO PSC Staff
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Case No.: ER-2006-0314
Date Testimony Prepared: August 22, 2006

MISSOURI PUBLIC SERVICE COMMISSION

UTILITY OPERATIONS DIVISION

DIRECT TESTIMONY

OF

JANICE PYATTE

FILED
NOV 13 2006
Missouri Public Service Commission

KANSAS CITY POWER & LIGHT COMPANY

CASE NO. ER-2006-0314

Jefferson City, Missouri
August 2006

Staff Exhibit No. 128
Case No(s). ER-2006-0314
Date 10-16-06 Rptr KF

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Application of Kansas City Power & Light Company for Approval to Make Certain Changes in its Charges for Electric Service to Begin the Implementation of Its Regulatory Plan	)))))	Case No. ER-2006-0314

AFFIDAVIT OF JANICE PYATTE

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

Janice Pyatte, of lawful age, on her oath states: that she has participated in the preparation of the following Direct Testimony in question and answer form, consisting of 23 pages of Direct Testimony to be presented in the above case, that the answers in the following Direct Testimony were given by her; that she has knowledge of the matters set forth in such answers; and that such matters are true to the best of her knowledge and belief.

Janice Pyatte
Janice Pyatte

Subscribed and sworn to before me this 21st day of August, 2006.

Dawn L. Hake
Notary Public

NOTARY PUBLIC STATE OF MISSOURI NOTARY SEAL

DAWN L. HAKE
My Commission Expires
March 16, 2009
Cole County
Commission #05407643

My commission expires ____________

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Q. Please state your name and business address.

A. My name is Janice Pyatte and my business address is Missouri Public Service Commission, P. O. Box 360, Jefferson City, Missouri 65102.

Q. What is your present position with the Missouri Public Service Commission?

A. I am a Regulatory Economist in the Economic Analysis section of the Energy Department, Utility Operations Division.

Q. What is your educational background and work experience?

A. I completed a Bachelor of Arts degree in Economics at Western Washington State College in Bellingham, Washington and a Masters of Arts (A.M.) degree in Economics at Washington University in St. Louis, Missouri. I have been employed by the Missouri Public Service Commission (Commission) since June 1977. My primary role with the Missouri Public Service Commission Staff (Staff) has been to perform analysis in the areas of rate design, class cost of service, rate revenue, and billing units for the regulated electric utilities in Missouri. Schedule JP-1 contains a list of the cases in which I have filed testimony before the Commission.

Q. What is your work experience relating specifically to class cost of service and rate design for Kansas City Power & Light Company ("KCP&L" or "Company")?

A. I have participated in two investigations of KCP&L's class cost of service and rate design. The first was Case No.EO-78-161. The second was Case No.EO-94-199 *In the Investigation of the Customer Class Cost of Service and Comprehensive Rate Design Investigation of Kansas City Power and Light Company* ("KCP&L's Rate Design Case"). The latter KCP&L rate design case is of particular significance to the current case because the Missouri rate schedules that resulted from that case are still in effect today. Neither rate classes nor rate structures have changed since those tariffs became effective on July 9, 1996.

EXECUTIVE SUMMARY

Q. What is the purpose of your testimony?

A. I describe the Staff class cost of service ("CCOS") study being filed in this case. I also provide background material to assist those readers not familiar with electric class cost of service in general or with KCP&L's class cost of service and rate design in particular.

Q. How does your CCOS and rate design testimony relate to the testimony of other Staff witnesses?

A. Two additional Staff witness are filing direct testimony on the CCOS/Rate Design filing date. Staff witness James A. Busch's testimony presents the Staff's rate design recommendation in this case. Staff witness William L. McDuffey addresses miscellaneous tariff issues relating to KCP&L rules and regulations.

CLASS COST OF SERVICE

Q. What is the purpose of CCOS studies?

A. They are used to analyze the relationship between the costs an electric company incurs to serve each customer class and the revenues being generated by each class' tariffs (rates). The function of a class cost-of-service study is to measure the cost responsibility of each customer class as a whole. The results of this analysis can be expressed a number of ways: the most common being each class' realized rate of return; the second (which Staff prefers) is the change in class revenues that would be required to result in each class yielding the same rate of return to the company.

Q. How does a CCOS study relate to a Revenue Requirement study?

A. Conceptually, a CCOS study is an extension of the Revenue Requirement study (sometimes referred to as Cost of Service Study) that is filed by Staff in every major rate case. A Revenue Requirement study shows how <u>total</u> company costs are adjusted, if appropriate, and then allocated to the Missouri retail jurisdiction to determine the total amount of prudently-incurred costs that should be collected from the utility's Missouri customers through the utility's Missouri tariffs.

In a CCOS study, Missouri retail costs determined in a Revenue Requirement study are further allocated to classes of customers to determine the costs the utility incurs to serve specific types of customers.

Q. What decisions need to be made when planning for a CCOS study?

A. A number of decisions need to be made prior to conducting a CCOS study, decisions such as

(1) What time period (test year or study period) will be used for the study?

(2) What classes of customers will be analyzed?

(3) How long will it take to assemble Missouri accounting cost data for the test year?

(4) How long will it take to collect and assemble class level demand, energy, and revenue data?

(5) Will special studies of distribution costs and customer-related costs be required?

(6) Is enough time allowed in the procedural schedule for a CCOS study to be conducted?

Q. When was the planning done for the CCOS study filed by KCP&L in this case?

A. The planning for the CCOS study KCP&L filed in this case was done in Case No. EO-2005-0329 ("KCP&L Regulatory Plan"). The Stipulation and Agreement in that case specified that KCP&L would prepare and file a CCOS study in conjunction with its rate filing #1 (this case). Appendix I: *Requirements of the Missouri Class Cost of Service Study to be Provided with Rate Filing #1* specified important parameters of the Company's CCOS study:

- the accounting cost (rate base and expenses) data would be entirely historical; would cover the 12 months ending September 30, 2005 ("study period"); and would be split between jurisdictions by KCP&L;
- the rate of return used would be residually determined (i.e., the rate of return used in the study would be determined by equating study period costs with study period revenues);
- the customer classes would correspond to KCP&L's current Missouri rate schedules (i.e., Residential, Small General Service, Medium General Service, Large General Service, Large Power Service, and Lighting);
- the class energy, demand, load, and revenue data used would correspond to the specified classes and the specified study period;
- the class energy and demand data would be segregated by voltage level;

- class-level data would be weather-normalized but not adjusted for customer growth;
- KCP&L would perform a number of special studies of distribution costs; and
- KCP&L would perform a number of special studies of customer-related costs.

Q. Has KCP&L complied with the Regulatory Plan requirements of Appendix I?

A. Yes. KCP&L filed a revenue-neutral CCOS study on February 1, 2006 that is based upon Missouri jurisdictional costs through September 30, 2005. Staff was provided with the cost and load data specified in Appendix I. KCP&L also produced the special distribution and customer cost studies that were required.

Q. What is the rationale for using a different historical time period ("study period") for the CCOS study than the test year used in determining the Revenue Requirement?

A. The timing of the Company's Revenue Requirement (rate increase request) filing in this case (February 1, 2006) and the specified test year (12 months ending December 31, 2005) were too close in (calendar) time to allow for the use of 12 months of historical data in its initial filing. Therefore, KCP&L's Revenue Requirement filing was done using nine months of historical data and three months of forecasted data, with the expectation that parties would be provided supplemental information when historical data became available.

The parties involved in planning for the CCOS study chose, instead, to use the 12-month study period ending September 30, 2005 (three months prior to the Revenue Requirement test year) so that a Company CCOS filing, using totally historical data, could be done.

Q. How will any differences in the CCOS study period and the Revenue Requirement test year be reconciled in this case?

A. Instead of updating Staff's CCOS study to reconcile to the Revenue Requirement test year, Staff's rate design recommendations separately address both CCOS and Revenue Requirement issues:

- What changes should be made to the distribution of study period revenues collected by classes?
- How should any additional revenues that result from this case be collected from classes?

Q. What is the significance of residually determining the rate of return to be used in the CCOS study?

A. It means that the CCOS study will be revenue neutral; i.e., the total Missouri revenues generated by current rates exactly equals total Missouri costs. If one thinks of total Missouri revenues equal to costs as a pie of fixed size, then one class cannot get a smaller slice (decreased rates) without one or more other classes getting a larger slice (increased rates).

Q. What criteria were used to determine the customer classes to be analyzed in the CCOS studies?

A. Conceptually, each customer class is composed of individual customers whose cost of service is similar and who are (or should be) subject to the same rates. In most classes it is not possible to directly measure the cost of service for each individual customer. What is measurable, however, are <u>customer-related</u> factors such as energy usage, metered demand, and voltage level (who owns certain distribution facilities used by the customer), and <u>class-related</u> factors such as load shape (the pattern of class energy usage over time) and diversity (how coincident the class' peak is with the system peak). These factors were used to group customers who are likely to have similar costs. Classes need to be homogeneous in the statistical sense; namely, the variation in load and cost characteristics <u>among</u> the individuals within the class is smaller than the variation <u>between</u> classes.

Q. What classes of customers did the parties choose to analyze in their CCOS studies?

A. The customer classes chosen to be studied were:

- Residential ("RES")
- Small General Service ("Small GS" or "SGS"):
- Medium General Service ("Medium GS" or "MGS")
- Large General Service ("Large GS" or "LGS")
- Large Power Service ("Large PWR" or "LPS")
- Lighting

Since these customer classes correspond to KCP&L's current tariff classifications, it is also correct to refer to them as "rate" classes.

Q. Why were customer classes defined on the basis of their current rate schedule?

A. Which customers belong to the Residential class and the Lighting class are well defined. In KCP&L's specific situation, individual customers served on any of the non-residential, non-lighting rate schedules have other characteristics that result in similar costs:

- Small General Service: very small (under 25 kilowatt (kW)) commercial or industrial customer with low load factor (average demand divided by peak demand); almost always served at secondary voltage.
- Medium General Service: medium size (25 - 200 kW) commercial or industrial customer with moderate load factor; customer must have, or be willing to assume,

a 25 kW minimum demand; 99% are metered at secondary and 1% are metered at primary voltage.

- Large General Service: large size (200 - 1000 kW) commercial or industrial customer with higher load factor; customer must have, or be willing to assume, a 200 kW minimum demand; 88% are served at secondary and 12% are served at primary voltage.
- Large Power Service: very large size (1000+ kW) commercial or industrial customer with very high load factor; customer must have, or be willing to assume, a 1000 kW minimum demand; 16% are served at secondary, 55% at primary, 20% at substation and 9% are served at the transmission voltage level.

Q. Why weren't commercial customers and industrial customers analyzed separately?

A. "Commercial" and "industrial" are classifications that are not very useful for grouping customers by cost characteristics, even though they are important in the reporting of operating data to various federal agencies. The small general service, medium general service, large general service, and large power service rate classes each contain a mixture of both commercial and industrial customers.

Q. Why weren't customer classes defined by voltage level?

A. Voltage level is an important consideration in allocating distribution costs and correctly pricing any individual customer, but not when defining customer classes. For example, one distinguishing feature between KCP&L Large General Service customers is the voltage level (secondary or primary) at which electricity service is provided to the customer. Past load analysis shows that groups of primary and secondary customers of similar size display similar load shapes and thus similar time-of-use costs. The main cost differences between these groups of primary and secondary customers are those distribution costs associated with voltage level (i.e., losses and ownership of transformation equipment).

Current KCP&L rates were designed so that the rates paid by these customers should differ only by those costs associated with voltage level. Allocating costs to these customers as a single rate class in a class cost of service study, rather than as two distinct rate classes, will help maintain this feature of the current rate design.

Q. Is the Staff CCOS study filed in this case consistent with the parameters of Appendix I?

A. Yes, it is. Staff is presenting a revenue-neutral CCOS study based upon Missouri jurisdictional costs and class energy, demand, and load data for the 12 months ending September 30, 2005. It uses the results of KCP&L's special studies of distribution and customer-related costs. Staff has chosen to adopt KCP&L's functionalizations of costs.

However, there are two areas where Staff's CCOS study differs from that of KCP&L. One difference is the treatment of the Lighting class. The second difference is the format used in Staff's study.

Q. What is the difference between the Staff's and KCP&L's treatment of the Lighting class in Staff's CCOS study?

A. Staff chose not to study the costs of providing service to the Lighting class; KCP&L did. Staff's CCOS assumes that current Lighting class revenues are equal to its costs, i.e., the Lighting class is already providing the Company with the system average rate of return, so no changes to Lighting revenues are warranted.

Q. Why did Staff make this assumption?

A. It is difficult to accurately compute the cost of providing service to Lighting customers because of the uniqueness of their load pattern. These customers are either "on" at maximum load (during night-time hours) or "off" at zero load (during day-light hours). Unless one is allocating production-capacity costs on an hour-by-hour basis, the CCOS results for the Lighting class are generally implausible and they distort the results for the other classes.

Q. How does the format of Staff's CCOS study differ from the format of the Company's study?

A. The most visible difference between the Staff CCOS study and KCP&L's study is the format. Staff's study is presented in a functional format; i.e., costs have been aggregated by the function (production, transmission, distribution, etc.) they support in the electrical system, prior to the allocation of those functional costs to classes. KCP&L's study is presented by the FERC Uniform System of Accounts, with an allocation of each line item of rate base or expense to classes.

Q. Does the difference in formats affect the study results?

A. No. If done properly, either format can be used to represent the same CCOS study. Staff prefers the functional format because it makes describing allocation issues to policy-makers more comprehensible.

Q. Are you certain that format is the only difference between the Staff and KCP&L studies?

A. Yes. I compared the two models by inputting the same cost data and allocation factors in each, and I obtained the same results.

Q. What do you mean by "functionalization of costs"?

A. The functionalization of costs is a procedure where Missouri expenses and return on rate base are aggregated by the function (production, transmission, distribution, etc.) they support in the electrical system.

To understand this concept, please refer to Schedule JP-2, which is a diagram of a generic integrated electrical system, showing how power produced at the generating station is then transmitted through high voltage lines and distributed to the home of a residential (secondary voltage) customer. Other (non-secondary voltage) customers are served from various points along the same system.

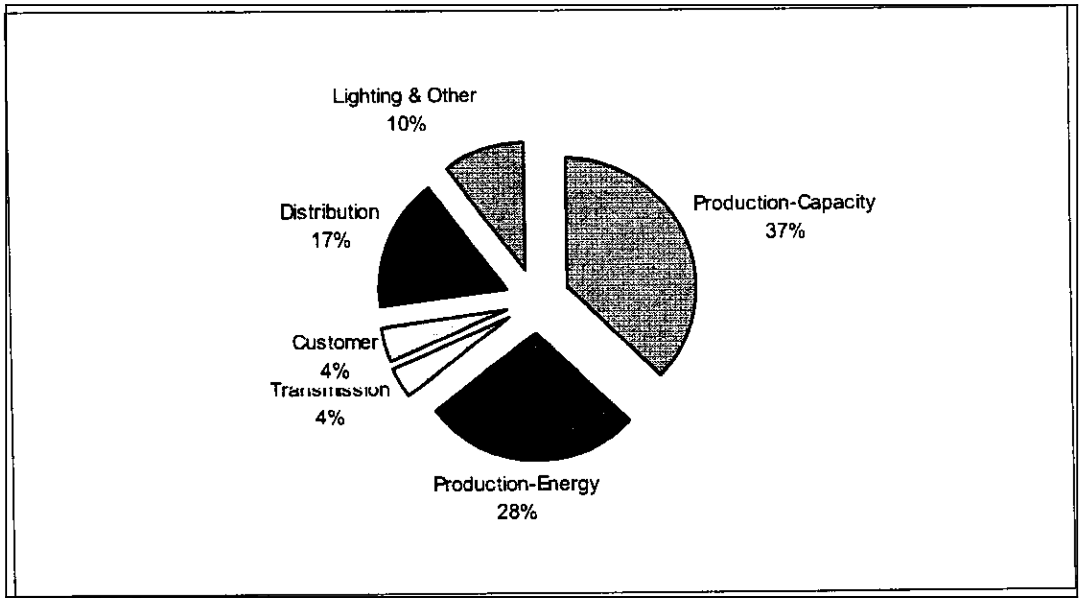
Q. What functional cost categories did you use in Staff's CCOS study?

A. A listing of the functional cost categories used in Staff's CCOS study is presented as Schedule JP-3. These functional cost categories correspond to the operations of KCP&L's electrical system. These major functions are: (1) the generation (production) of electricity at the power plant; (2) the "stepping up" (raising) of voltage level and the subsequent transmission of the electricity through the Company's high voltage transmission system; (3) the distribution of electricity to retail customers at various voltage levels; and (4) the Company's provision of non-electricity services (such as billing, customer assistance, etc.) directly to customers.

Within the production function, a distinction is made between "production-energy", which includes the costs of fuel and variable operations and maintenance expenses, and "production-capacity", which is the Company's investment in generating plants.

Q. What proportion of total costs relate to each major functional category?

A. The chart below shows the percentage of total costs associated with each major function.



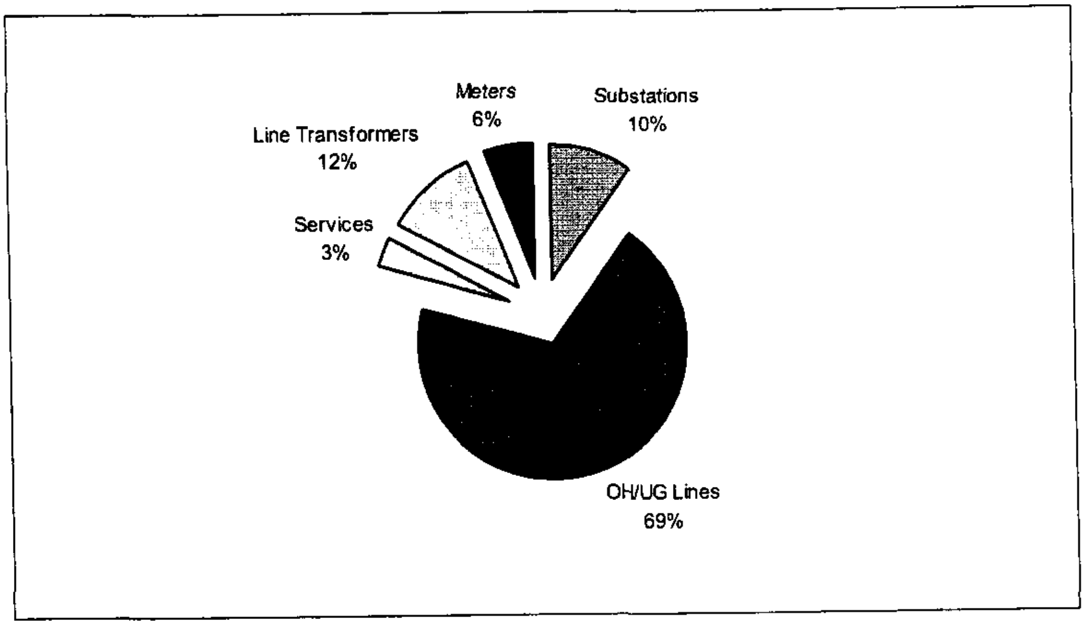
Q. What additional functional categories did you use in Staff's CCOS study?

A. Within the distribution function, a number of sub-categories were segregated to allow for a more refined cost analysis. The distribution categories used in Staff's CCOS study are: (1) substations that "step down" (lower) voltage level from transmission voltage; (2) overhead ("OH") and underground ("UG") lines that move electricity near the premises of the Company's customers; (3) line transformers that further lower electricity voltage to that used by the vast majority of customers; (4) the service line that directly connect to the customer's premise; and (5) metering equipment.

The term "lines" in (2) above includes both overhead conductors and underground cables. Overhead "lines" also includes the costs associated with hardware such as poles, towers, insulators, and crossarms. Underground "lines" refer to both direct buried cable and cable installed in conduit.

Q. What proportion of total distribution costs relate to each distribution category?

A. The chart below shows the percentage of total distribution costs associated with each distribution category.



Q. After costs are functionalized, what is the next step in conducting a CCOS study after costs are functionalized?

A. The next step is to either assign or allocate the costs associated with each functional category to classes. An assignment of costs to classes is done whenever it is known, with certainty, the classes that are responsible for a specific cost category. An example of an assignment of costs is the cost associated with certain facilities that only are used to serve lighting customers. These lighting costs are assignable to the Lighting class because FERC requires companies to record those costs into separate accounts. Certain categories of cost, such as many customer-related costs, are potentially assignable to classes but to do so requires a special study. In this case, KCP&L has done special studies that allow for assignments of customer records & collection, uncollectible accounts, customer assistance, customer deposits, and meter reading costs to classes.

Most categories of cost are not assignable, either in practice or in concept, so must be allocated to classes. The allocation of costs attributes some portion of total functionalized cost to classes based upon a specific allocation method. The choice of allocation method for some categories of costs, specifically production-capacity costs, is typically the most contentious CCOS issue in a case because the overall results of a CCOS study are very sensitive to that choice

Q. What method is Staff using to allocate production and transmission costs to classes?

A. Staff has chosen to use an Average & Peak (A&P) method for allocating the costs associated with production-capacity and transmission to classes. Average & Peak allocation methods recognize that generation is built to meet both peak demands and average demands (energy). The basic components of any A&P allocator are that: (1) a portion of total costs are attributed to each class based upon the class' contribution to annual energy; (2) a portion of total costs are attributed to each class based upon each class' contribution to peak demand; and (3) the split between the "average" (energy-related portion) and the "peak" (demand-related portion) is determined by the system load factor.

Q. Has Staff used an A&P allocation method before?

A. Yes, many times. While Staff's allocation method is referred to in this case as A&P(12 Class Peaks) to differentiate it from the Company's A&P(1 CP) method. it is identical to the Staff method referred to in the past as "12NCD A&P".

Q. In what ways are Staff's version of A&P and KCP&L's version of A&P the same?

A. Both versions of A&P use the same split between the energy-related portion of costs and the demand-related portion of costs. Both versions allocate the average portion on the basis of class contribution to annual energy (i.e., on an equal cents-per-kWh basis).

Q. In what ways do Staff's version of A&P and KCP&L's version of A&P differ?

A. Where the two versions of the A&P allocator differ is the allocation of the demand-related portion of production capacity costs to classes. Staff's version uses multiple peak demands, one from each month, instead of a single annual peak demand. Staff uses class peak demands rather than coincident peak demands (class load at the hour when the system peak occurs) in its computation. The third difference is that Staff's method applies a monthly weighting factor to each month's class peak demand prior to calculating the class contribution to demand.

Q. Why didn't Staff use coincident peak demands when computing A&P?

A. On system peak days, KCP&L's load shape is relatively flat over a sizeable number of contiguous hours. If the value of peak demand among those hours is very similar, then any slight variation in the measurement of peak demand can alter which specific hour of the day is considered to be the peak hour.

Class contribution to coincident peak demand is computed as each class' demand at the hour when the system peak occurs. The class contribution to system peak demand varies greatly, however, depending upon which hour is deemed to be the hour when the system peak demand occurs. For example, the residential class will represent a much larger proportion of the total system demand at 6 pm than at 3 pm. Using hourly class load data from the KCP&L study period in this case, Schedule JP-4 demonstrates the sensitivity of class contribution to coincident demands to the hour of the day when the system peak occurs.

Q. What measure of peak demand did Staff use when computing A&P?

A. Staff used weighted monthly class peak demands in the allocation of the demand-related portion of the A&P allocator. Class peak demand is the maximum demand of each class whenever it occurs. Staff's rationale for using class peak demands is the relative stability of class contribution to class peak demands, when compared to class contribution to coincident peak demand.

Q. How where the weights that Staff applied to the peak demands determined?

A. The Capacity Utilization method was used to determine the weights to apply to each month's class peak demands. Capacity Utilization is a method developed by Dr. Michael S. Proctor of the Staff when he was the Manager of the PSC's Research & Planning Department. The details of this method are presented in an article entitled "Capacity Utilization Responsibility: An Alternative to Peak Responsibility" published in the April 28, 1983 issue of Public Utilities Fortnightly. A copy of Dr. Proctor's article is attached as Schedule JP-5.

Q. What method is Staff using to allocate production-energy costs to classes?

A. Staff is allocating production-energy costs, which mostly consists of fuel and variable O&M expenses, on the basis of class contribution to annual energy. This method is computationally equivalent to assigning each unit (kilowatt-hour) of energy the same cost.

Q. What is Staff's general approach to the allocation of distribution costs to classes?

A. Two factors need to be considered when determining the appropriate method to allocate distribution costs to classes: voltage level and load diversity.

Q. Why is voltage level important in the allocation of distribution costs?

A. It is important that voltage level be considered when performing cost allocation because each customer's use or non-use of specific Company-owned equipment is directly related to its voltage level. KCP&L classifies its customers into one of four voltage level groups for rate purposes: secondary, primary, substation, and transmission. All residential customers are served at secondary voltage, the three general service classes contain customers at both primary and secondary voltage levels; and the large power customer class contains customers taking service in all four categories.

Q. How can voltage level be considered during cost allocation if the classes are composed of customers served at different voltage levels?

A. The standard practice is that only customers who use Company-owned facilities are allocated a portion of the total costs associated with those facilities. Voltage level is the key used to determine which customers fall into which categories. The way this is accomplished in practice is that the demand, energy, and customer number data provided by KCP&L has been segregated by voltage level within each class. The terminology used by Staff and KCP&L in this case to denote which customers are included in the computation of an allocation factor is "@ xxxx" voltage. For example, "class peak @ primary" means that the class peak demands of all customers served at primary voltage or below (i.e., all primary and secondary customers) are included in the computation of the allocator. Conversely, those customers served at voltage levels above primary (i.e., substation and transmission voltages) are allocated none of these costs by excluding their demands.

The table below summarizes the relationship between the various functional categories of distribution costs and which voltage-level groups are allocated a portion of those costs.

Functional Category	Secondary	Primary	Substation	Transmission
Production	Yes	yes	yes	yes
Transmission	Yes	yes	yes	yes
Distribution Substations	Yes	yes	yes	no
OH/UG Lines - Primary	Yes	yes	no	no
OH/UG Lines – Secondary	Yes	no	no	no
Line Transformers	Yes	no	no	no

Q. Does Staff's CCOS study reflect differences in customer voltage level?

A. Yes. My computations of allocation factors for specific functionalized costs have only included the demand, energy, or customer-number data of those customers in each class that utilize the Company-owned facilities.

Q. Why is load diversity important in the allocation of distribution costs?

A. Diversity is a condition that exists when the peak demands of electric customers do not all occur at the same time. The greater the amount of diversity among customers within a class or between classes, the smaller the total capacity (and the total cost) of the equipment required for the utility company to meet its customers' needs.

When allocating demand-related distribution costs, it is important to choose a measure of demand that corresponds to the proper level of diversity.

Q. What measures of demand were available in this case?

A. The standard measures of demand that KCP&L provided are coincident peak demand, class peak demand, and customer maximum demand.

Coincident peak demand is defined to be the demand of each class and each customer at the hour when the overall peak occurs. Coincident peak demand reflects the maximum amount of diversity.

Customer maximum demand reflects the no-diversity situation. It is defined to be the sum of the annual peak demand of each customer, whenever it occurs. Without diversity, there can be no "sharing" of equipment and none of the cost advantages due to sharing.

Class peak demand is defined to be the demand of all customers within a specific class at the hour when the class peak occurs. If the sum of the peak demand of each class is greater than its demand at the hour when the total company peak occurs, which is generally the case, the amount of diversity inherent in class peak demand is less than coincident peak demand but considerably more than customer maximum demand.

In addition to these three standard measures of demand, I created a fourth, that I call "class diversified demand".

Q. What is class diversified demand?

A. Since none of the standard measures of class demand reflect a level of load diversity between customer maximum demand (no diversity) and class peak demand (considerable diversity), I created an "in-between" measure called "diversified demand". Diversified demand for each class was defined to be a weighted average of the class' customer maximum demand and its annual maximum class peak demand. The weighting factors were based on the average number of customers in each class who share a transformer.

Q. Would you summarize the type of demand the Staff used in the allocation of the demand-related portion of the various distribution functional categories?

A. In Staff's CCOS study the following demands were used in the allocation of the demand-related portion of these categories of distribution cost:

Functional Category	Demand Measure	Amount of Diversity
N/A	Coincident Peak	High
Substations	Class Peak	Moderate to High
OH/UG Lines	Diversified Demand	Low to Moderate
Line Transformers	Customer Maximum Demand	None

Q. What method did Staff use to allocate the costs of distribution substations?

A. Staff allocated the costs of distribution substations on the basis of each class' annual peak demand measured at substation voltage. Only those customers served at substation voltage or below (i.e., all substation, primary, and secondary customers) were included in the computation of the allocation factor and thus were allocated any portion of these costs. In other words, none of the costs associated with distribution substations were allocated to customers served at transmission voltage (the only higher voltage level on KCP&L's system) because these customers do not use the services of Company-owned distribution substations.

Q. What method did Staff use to allocate the costs of distribution lines?

A. KCP&L conducted special studies that split the functionalized cost of distribution lines between the portion that serves all primary and secondary customers (OH/UG Lines-Primary) and the portion that serves only secondary customers (OH/UG Lines-Secondary). In addition, KCP&L's special studies of distribution lines further distinguish between demand-related costs and customer-related costs. The customer-related costs were allocated to classes on the basis of weighted number of customers. The demand-related costs were allocated on each class' contribution to diversified demand.

Q. What method did Staff use to allocate the costs of line transformers?

A. Staff allocated the costs of line transformers on the basis of each class' customer maximum demand measured at secondary voltage. Only secondary customers (i.e., no primary, substation, or transmission voltage customers) were allocated any portion of these costs.

Q. What were the results of Staff's CCOS study?

A. A summary of Staff's CCOS study is shown on Schedule JP-6. The general conclusion of the study is that the residential class is paying less than the total cost of serving them and the other classes are paying more than their cost of service. The table below shows the shifts in rate revenue that would be required to ensure that all classes are yielding the same rate of return.

Residential	Small GS	Medium GS	Large GS	Large Power	Total
$13,584,668	($1,491,762)	($6,058,524)	($3,056,705)	($2,977,678)	$0
7.82%	-4.03%	-9.59%	-2.76%	-2.97%	0.00%

Q. How do the Staff's CCOS results compare to KCP&L's CCOS results?

A. When computed from rate revenue, the results of the Company's CCOS at equalized rate of return are:

Residential	Small GS	Medium GS	Large GS	Large Power	Lighting
$15,948,214	($1,247,257)	($6,650,487)	($6,030,381)	($2,705,051)	$684,963
8.53%	-3.54%	-11.94%	-5.86%	-2.83%	10.17%

Staff's CCOS study shows a slightly smaller required revenue shift than Company's study ($13,584,668 vs. $15,948,214). The reason that Staff's percentage increases appear higher than those shown in KCP&L's study is because the Company incorrectly computed them from operating revenue, rather than rate revenue.

RATE DESIGN

Q. Is Staff recommending that the results of its CCOS study be used in this case?

A. Based upon the results of its CCOS study, Staff is recommending that the Commission make a revenue shift between the residential class and the non-residential classes that moves classes closer to cost of service. Staff witness James A. Busch is presenting the details of Staff's rate design recommendation in this case.

Q. What is the significance of Case No.EO-94-199 to Staff's rate design recommendation in this case?

A. Case No. EO-94-199 *In the Investigation of the Customer Class Cost of Service and Comprehensive Rate Design Investigation of Kansas City Power and Light Company* is the source of KCP&L's current rate structures and types of charges (demand charges, energy charges, facilities charges, etc.). Staff is proposing to maintain the rate design features shown on Schedule JP-7, which is an appendix from Case No. EO-94-199.

Q. Which particular rate design feature is of most concern?

A. Maintaining the rate continuity between the four non-residential rate schedules is very important.

Q. What do you mean by "rate continuity"?

A. KCP&L's four non-residential rate schedules were designed so that customers naturally move from one rate schedule to another as they grow or shrink in size and load factor. Since non-residential customers can choose service under any rate schedule, it is fundamentally pricing signals that create rate continuity.

Q. How will moving class revenues towards class cost-of-service affect rate continuity?

A. Rate continuity is not a concern when changing rate levels for the residential or lighting classes, because these customers cannot easily switch from one rate schedule to another in response to price.

Rate continuity is a very important consideration when changing rate levels for the non-residential classes (Small GS, Medium GS, Large GS, and Large Power). For those classes, changing rate levels by different percentages will alter the rate continuity between the rate schedules.

Q. How can you implement revenue shifts between classes in this case without disturbing the existing rate design features?

A. Rate design proposals that preserve rate continuity between rate schedules are those that uniformly increase all rate components on those rate schedules that are "linked".

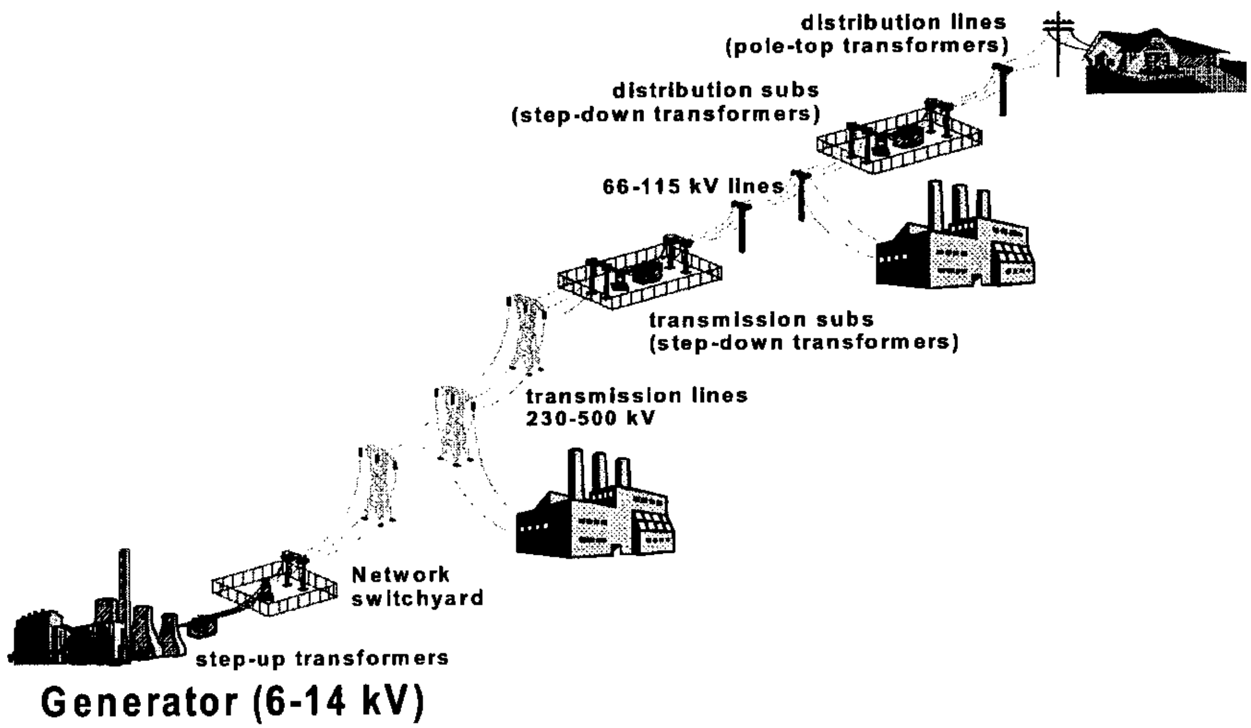
Q. Does this conclude your testimony?

A. Yes, it does.

Participation in MOPSC Cases
Witness: Janice Pyatte

Company	Case Number
The Empire District Electric Company	ER-2006-0315
Aquila, Inc. d/b/a Aquila Networks-L&P	HR-2005-0450
Aquila, Inc. d/b/a Aquila Networks-MPS and L&P	ER-2005-0436
Aquila, Inc. d/b/a Aquila Networks-MPS and L&P	EO-2002-384
The Empire District Electric Company	ER-2004-0570
Aquila, Inc. d/b/a Aquila Networks-MPS and L&P	ER-2004-0034 & HR-2004-0024
The Empire District Electric Company	ER-2002-424
Union Electric Company d/b/a AmerenUE	EC-2002-1
UtiliCorp United, Inc. d/b/a Missouri Public Service	ER-2001-672
The Empire District Electric Company	ER-2001-299
UtiliCorp United and The Empire District Electric Co.	EM-2000-369
UtiliCorp United and St. Joseph Light & Power Co.	EM-2000-292
St. Joseph Light & Power Company	ER-99-247 & EC-98-573
Union Electric Company	EO-96-15
St. Joseph Light & Power Company	EC-98-573
Missouri Public Service	ER-97-394 & ET-98-103
The Empire District Electric Company	ER-97-81
The Empire District Electric Company	ER-95-279
Kansas City Power & Light Company	EO-94-199
The Empire District Electric Company	ER-94-174 & EO-91-74
St. Joseph Light & Power Company	ER-93-41
Missouri Public Service	ER-93-37
Union Electric Company	EM-92-225 & EM-92-253
Union Electric Company	EO-87-175
Arkansas Power & Light Company	ER-85-265
Kansas City Power & Light Company	ER-85-128 & EO-85-185
Union Electric Company	EO-85-17 & ER-85-160
Union Electric Company	ER-84-168
Laclede Gas Company	GR-84-161
Union Electric Company	ER-84-168
Arkansas Power & Light Company	ER-83-206
Kansas City Power & Light Company	ER-83-49
The Empire District Electric Company	EO-82-40
The Empire District Electric Company	ER-81-209
Kansas City Power & Light Company	EO-78-161
Laclede Gas Company	GO-78-38
Union Electric Company	EO-78-163
St. Joseph Light & Power Company	EO-77-56

Basic Components of Electricity Production and Delivery



KANSAS CITY POWER & LIGHT COMPANY
MO PSC CASE NO. ER-2006-0314

SUMMARY OF STAFF FUNCTIONAL CATEGORIES
AND ALLOCATION METHODS

FUNCTIONAL CATEGORY	ALLOCATION METHOD
Production-Capacity	A&P (12 Class Peaks)
Production-Energy	Energy w/ Losses
Transmission	A&P (12 Class Peaks)
Distribution Substations	Class Pk @ Substation
OH/UG Lines	
Pri-Customer Related	Weighted Custs @ Primary
Sec-Customer Related	Weighted Custs @ Secondary
Pri-Demand Related	Diversified Demand @ Primary
Sec-Demand Related	Diversified Demand @ Secondary
Line Transformers	
Sec-Customer Related	Weighted Custs @ Secondary
Sec-Demand Related	Cust Max Demand @ Secondary
Services	Weighted Custs: Services
Meters & Recorders	Weighted Custs: Meters
Company-Owned Lighting	Assigned: Lighting
Meter Reading	Weighted Custs: Meter Reading
Customer Records & Collection	Weighted Custs: Customer Records
Customer Assistance	Weighted Custs: Cust Assistance
Sales Exp	Weighted Avg Customers
Uncollectible	Weighted Custs: Uncollectible
Other Cust Service	Weighted Avg Customers
Customer Deposits	Weighted Custs: Cust Deposits

The Sensitivity of Class Contribution to Missouri Peak Demand to the Hour When the Peak Occurs

This appendix discusses the uncertainty inherent in determining the value of the monthly Missouri maximum (peak) demand, the hour when the peak demand occurs, and each customer class' (coincident) contribution to overall Missouri peak demand.

The source data used to determine hourly class loads is developed from a load research program, using a representative sample of customers and various statistical techniques to infer information about the entire population of customers from the sample group. Hourly class loads are then weather-normalized and losses are applied. Each of these processes introduces a certain level of statistical error. This statistical error is normal and expected for this type of data.

Analysis of overall Missouri hourly demands on the monthly peak day show that, in every month, there are multiple contiguous hours with demands that are nearly identical to peak hour demand. This phenomenon makes the determination of the actual Missouri peak problematic. In cases where there are multiple hours contiguous to the peak hour that have an estimated demand very close (greater than 95%) to peak demand, there is a possibility that the actual Missouri peak may occur at a different hour.

Associated with the uncertainty of which hour is the actual Missouri peak hour is the phenomenon that each customer class' contribution to Missouri peak demand tends to shift hour by hour within the same day. In many cases, this variation in the composition of class demands that make up overall Missouri peak demand can be substantial.

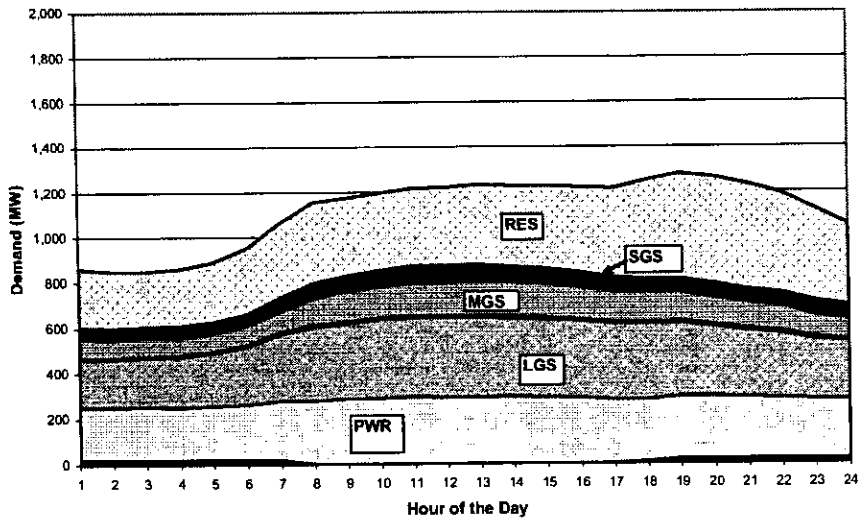
The situation of having multiple contiguous hours, all having a Missouri demand within 95% of the presumed peak demand, and yet showing significant differences in class contribution to peak demand is illustrated using hourly data from the day when KCP&L's February and July monthly Missouri peaks occur. Although February and July have been chosen to illustrate this phenomenon, each month in the test year exhibits this trend.

Page 4 shows a stacked graph of Missouri's demand by class for the peak day in February. This figure shows a broad ridge from the 10th hour of the day to the 20th hour of the day that lies within 95% of the maximum. It can be argued that, in a statistical sense, the true Missouri peak demand lies anywhere along this ridge. The tables on page 4 also show the corresponding class contribution to Missouri peak demand in each of the 11 potential peak hours and the minimum and maximum contribution of each class over the potential peak hours. The residential class contribution, in particular, shows a large variation; it can range from a low of 28.69% to a high of 38.20% of total Missouri demand, a difference of 9.51 percentage points.

Similarly, Page 5 shows a stacked graph of Missouri's demand by class for the peak day in July. On the day of the system peak there are six contiguous hours (13th through the 18th) that are within 95% of the maximum. Again, it can be argued that, in a statistical sense, the true Missouri peak demand lies anywhere within these six hours. The tables on Page 5 shows the corresponding class contribution to Missouri peak demand in each of the six potential peak hours and the minimum and maximum contribution of each class over the potential peak hours. The residential class has the largest difference in class contribution; from a low of 39.20% to a high of 47.56%, a difference of 8.35 percentage points.

In conclusion, the determination of the true hour of Missouri peak demand is problematic given the number of contiguous hours that are identical, once statistical error is considered. Hence each customer class' (coincident) contribution to overall Missouri peak demand is inherently unstable because of its sensitivity to the hour when Missouri peak demand occurs.

KANSAS CITY POWER & LIGHT COMPANY
The Sensitivlty of Class Contribution to Missouri Peak Demand to the Hour When the Peak Occurs
February 7, 2005

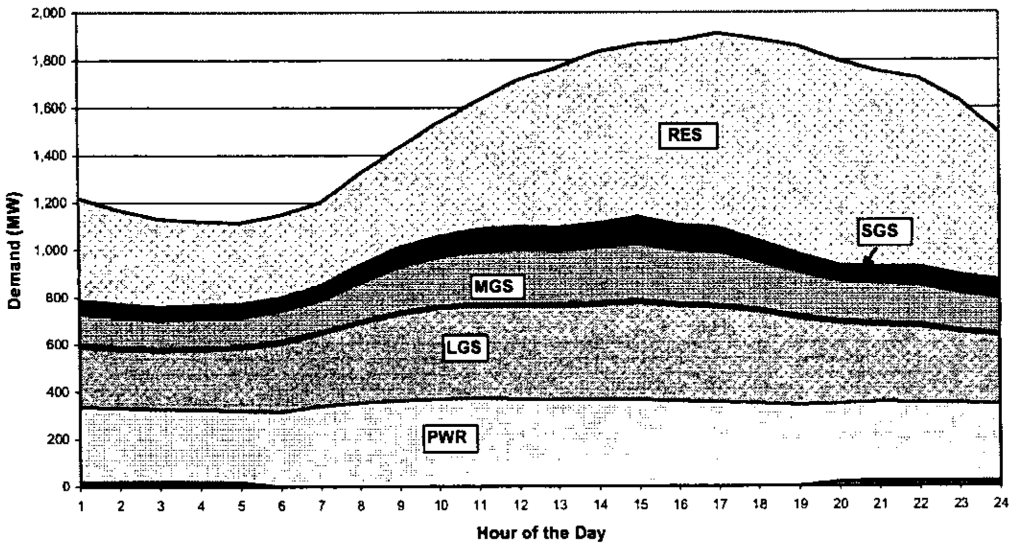


Class	Hr10	Hr11	Hr12	Hr13	Hr14	Hr15	Hr16	Hr17	Hr18	Hr19	Hr20
RES	28.69%	28.75%	29.01%	29.52%	30.21%	31.28%	32.89%	35.38%	36.76%	37.83%	38.20%
SGS	6.18%	6.26%	6.37%	5.69%	5.56%	5.32%	5.16%	4.61%	4.61%	4.90%	4.83%
MGS	11.99%	11.98%	11.86%	12.10%	11.93%	11.49%	10.97%	10.41%	9.98%	9.40%	9.29%
LGS	28.74%	28.87%	28.83%	28.47%	28.21%	27.91%	27.53%	26.73%	25.21%	24.44%	23.93%
PWR	24.34%	24.07%	23.86%	24.16%	24.02%	23.94%	23.41%	22.24%	21.89%	21.86%	22.15%
Lighting	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.58%	1.50%	1.51%	1.55%
Retail	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
% of Peak	95.33%	95.67%	96.49%	96.02%	95.85%	95.44%	95.02%	97.65%	100.00%	98.94%	96.48%

Range and Change in Percent of Class Contribution to Peak

Peak Class	Range Min	Max	Change In Percent
RES	28.69%	38.20%	9.51%
SGS	4.61%	6.37%	1.77%
MGS	9.29%	12.10%	2.81%
LGS	23.93%	28.87%	4.95%
PWR	21.86%	24.34%	2.48%
Lighting	0.00%	1.55%	1.55%

KANSAS CITY POWER & LIGHT COMPANY
The Sensitivity of Class Contribution to Missouri Peak Demand to the Hour When the Peak Occurs
July 20, 2005



Missouri Demand by Class for Peak Day for July 2005

Class	Year	Month	Day	Hr13	Hr14	Hr15	Hr16	Hr17	Hr18
RES	2005	7	20	39.58%	39.20%	41.57%	42.98%	45.24%	47.56%
SGS	2005	7	20	5.68%	6.14%	5.67%	5.41%	4.65%	4.09%
MGS	2005	7	20	12.62%	12.77%	12.08%	11.82%	10.91%	10.15%
LGS	2005	7	20	22.16%	22.21%	21.45%	21.16%	20.65%	19.78%
PWR	2005	7	20	19.90%	19.62%	19.18%	18.58%	18.51%	18.38%
Lighting	2005	7	20	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Retail				100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
% of Peak				96.04%	97.71%	98.42%	100.00%	98.83%	97.28%

Range and Change in Percent of Class Contribution to Peak

Peak Class	Range Min	Range Max	Change In Percent
RES	39.20%	47.56%	8.35%
SGS	4.09%	6.14%	2.05%
MGS	10.15%	12.77%	2.62%
LGS	19.78%	22.21%	2.43%
PWR	18.38%	19.90%	1.52%
Lighting	0.00%	0.00%	0.00%

Capacity Utilization Responsibility: An Alternative to Peak Responsibility

By MICHAEL S. PROCTOR

The intent of this article is to demonstrate that capacity utilization is a proper measure for determining production capacity responsibility, and that under certain assumptions, this results in allocating production capacity costs by the average and peak method.

The purpose of this article is to show the logical fallacy involved in the argument for the use of peak responsibility as the basis for allocating the embedded cost of production plants used to generate electricity. The crux of the argument for peak responsibility is that since peak demand determines the capacity required for production plant, the cost of that plant should be allocated to customers based on their share of peak demand. The principle is one of cost causality; i.e., whatever factor(s) cause cost, those same factors should be used as the basis for allocating cost. On this principle there is no disagreement. However, there is disagreement on whether peak demand is the only causal factor for the entire production plant.

In the process of showing the fallacy involved in peak responsibility, a natural outcome is the development of a causation principle that is theoretically correct. This causation principle is called *capacity utilization responsibility.*

As one might imagine, the load data requirements for an allocation method that is correct for all possible load situations could be overly restrictive. Thus, an approximation to the correct method is developed for the case where the load can be characterized by the typical load data available: class kilowatt-hour consumption and class contribution to peak. This allocation method is called the *average and peak.*

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The Record on Peak Responsibility

As early as 1921, H. E. Eisenmenger[1] recognized that peak responsibility is not the correct measure for allocating production costs to customers. In the summary to Eisenmenger's argument against peak responsibility, he states:[2] "We see that the consumer's demand cost is an intricate function of the entire load curve of the central station and of the entire load curve of the respective consumer, not only of certain parts of those curves."

In 1956, R. E. Caywood[3] recognized potential problems that exist in the use of peak responsibility. In discussing the peak responsibility method, Caywood states:[4]

> It is obvious that this method is not entirely satisfactory because a class load at the time of the system peak might be zero, while at some other time it might be of considerable size; yet no expense would be allocated to it. Furthermore, an allocation made on the basis of today's load conditions might be widely differ-

[1]"*Central Station Rates in Theory and Practice,*" by H. E. Eisenmenger, Fredrick J. Drake and Company, Chicago, Illinois, 1921, pp. 277-299.
[2]Ibid., p. 295.
[3]"*Electric Utility Rate Economics,*" by R. E. Caywood, McGraw-Hill, New York, 1956, pp. 156-167.
[4]Ibid., pp. 156, 157.

ent in the future as the result of a shift of the system peak or a shift of the peak of the load of the class itself.

In 1963, C. W. Bary[5] recognized that peak responsibility is a naive approach to allocating capacity costs. In discussing the distribution of load diversity benefits, Bary states:[6]

> The one which is farthest from meeting the requirements of the general unified theory is the so-called system peak responsibility method, which reflects the demand-cost assignment to individual components on the basis of their loads at the *time* of the system peak load. This method reflects little conceptual perception of the nature and the mutual benefits of load diversity, nor the complex laws of probability governing its behavior.

In 1970, Alfred E. Kahn[7] published his two volumes on the economics of utility regulation. While Kahn seems to support the concept of peak responsibility, it is important to keep in mind Kahn's own qualifications placed on the principle:[8]

> The principle is clear, but it is more complicated than might appear at first reading. Notice, first, the qualification: "if the same type of capacity serves all users." In fact it does not always; in consequence, as we shall see, off-peak users may properly be charged explicitly for some capacity costs. Second, the principle applies to the explicit charging of capacity costs, "as such." Off-peak users, properly paying *short-run* marginal costs [SRMC] will be making a contribution to the covering of capital costs also, if and when SRMC exceeds average variable costs. Third, the principle is framed on the assumption that all rates will be set at marginal cost [MC] (including marginal capacity costs). Under conditions of decreasing costs, uniform marginal cost pricing will not cover total costs. Lacking a government subsidy to make up the difference, privately owned utilities have to charge more than MC on some of their business. In some of these "second-best" circumstances, some (of the difference between average and marginal) capacity costs might better be recovered from off-peak than from peak users.

While the arguments against peak responsibility are well documented in the literature, this method has gained wide acceptance as an appropriate procedure for allocating embedded production plant costs to jurisdictions and customer classes. Perhaps one reason for the acceptance of peak responsibility is that both the National Association of Regulatory Utility Commissioners[9] and the American Public Power Association[10] cost allocation manuals give qualified recognition to the concept of peak responsibility. It should be noted that peak responsibility involves not only the single peak method, but also any method that uses coincident peaks; e.g., summer-winter peaks, summer month peaks, winter month peaks, and 12 coincident month peaks. Also, probabilistic methods, such as loss-of-load probability, that are based on building plant to meet peak-load distributions (load plus plant outages), should be classified as peak responsibility methods.

A second reason for general acceptance of peak responsibility is its ease of application. One generally only needs to look at demands for one to twelve hours and determine the share of demand in those few hours going to each class or jurisdiction.

A third reason for the acceptance of peak responsibility is that it seems to have a strong theoretical foundation in the peak-load pricing literature in economics. The noneconomist reads peak-load pricing in the context that all capacity costs go to the peak period, and as the quote from Kahn indicates, this is a basic misconception.

A final reason for the acceptance of peak responsibility is its intuitive appeal; i.e., peak causes capacity, therefore capacity costs should be allocated on a peak responsibility basis. It is this intuitive appeal that will be challenged in this article.

Capacity Utilitization Responsibility

A basic assumption in the peak responsibility approach is that the production plant is assumed to be characterized by one type of production plant; i.e., no distinction is made between peak, intermediate, and base-load plants. In the case of a single type of plant, the total annual production capacity cost can be determined by the level of peak demand, and no matter what the load shape happens to be, if the peak demand level stays the same, the total production capacity costs also stay the same. It is this observed relationship that has led supporters of the peak responsibility allocation method to claim that peak demand causes production capacity costs.

If production capacity costs are viewed as being fixed over the year, then those fixed costs have been caused by the peak demand. However, the view that production capacity costs are fixed costs within a year, and can only vary from one year to the next places a restriction on one's view of causality. Even if there is only one type of production capacity, why should one's view of that capacity be limited to a single unit whose size is fixed by the level of peak demand? Why should not the decision as to the variable cost of production capacity be viewed as a decision made on small increments of capacity over small periods of time?

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[5] "*Operational Economics of Electric Utilities*," by C. W. Bary, Columbia University Press, New York, 1963, pp. 56-64.

[6] Ibid., p. 58.

[7] "*The Economics of Regulation*," by Alfred E. Kahn, John Wiley and Sons, New York, 1970, pp. 87-122.

[8] Ibid., pp. 89, 90.

[9] *Electric Utility Cost Allocation Manual*, National Association of Regulatory Utility Commissioners, Washington, D. C., 1973, pp. 40-53.

[10] *Cost of Service Procedures for Public Power Systems*, American Public Power Association, Washington, D. C., 1979, pp. X1-X4.

Schedule JP-5-2

The purpose for determining the causality of production capacity costs is ultimately to determine the cost responsibility of the customers that use the production plant. While it is true that at only the time of peak is the fixed plant fully utilized, it is not true that this is the only time that the production plant provides services to the customers. A proper view of cost causality should recognize that during the peak period a greater amount of production capacity is required than at other times, but the fact that peak demand is higher should *only reflect the additional production capacity costs incurred because of the higher demand level.* Within this context production capacity is seen to be a variable cost of production in each and every hour.

A simple example can be used to illustrate the concept of treating production capacity as variable in each hour and calculating capacity responsibility based on the utilization (use) of production capacity. Consider a simplified load curve for two hours. In the first hour total demand is 50 megawatts, and in the second hour total demand is 100 megawatts. In this case 50 megawatts of production capacity is needed to meet demand in the first hour and an *additional* 50 megawatts of production capacity is needed to meet demand in the second hour. In terms of utilization of production capacity, the first and second hour share equal responsibility for the initial 50 megawatts of production capacity, while the second hour carries the full responsibility for the additional 50 megawatts. Thus the total *capacity responsibility* of each hour is given by

Hour One: $(1/2)(50) = 25$ megawatts
Hour Two: $(1/2)(50) + (50) = 75$ megawatts

Notice that this capacity utilization responsibility is not the same as the energy responsibility of 50 megawatt-hours for the first hour and 100 megawatt-hours for the second hour. Nor is the capacity utilization responsibility the same as would be determined by peak responsibility which would place zero megawatts on the first hour and 100 megawatts on the second hour. Moreover, using energy responsibility will understate the production capacity caused by the peak hour, while using peak responsibility will overstate the production capacity caused by the peak hour. Table 1 summarizes the results of applying these three different methods of calculating responsibility for capacity.

TABLE 1
HOURLY RESPONSIBILITIES

	Energy Responsibility	*Capacity Utilization Responsibility*	*Peak Responsibility*
Hour One	1/3	1/4	0
Hour Two	2/3	3/4	1

The final piece of information needed is the share of demand for each customer class in each hour. Suppose there are just two customers: A and B, with demands in each hour as given in Table 2.

TABLE 2
CUSTOMER LOADS

Customer	*Megawatts Hour One*	*Share*	*Megawatts Hour Two*	*Share*	*Megawatt-Hours Total*	*Share*
A	25	1/2	75	3/4	100	2/3
B	25	1/2	25	1/4	50	1/3
System	50	1	100	1	150	1

Customer A's share of hour one's demand is one-half, and hour one's share of capacity utilization responsibility is one-quarter, giving customer A a capacity utilization responsibility for hour one equal to $(1/2)(1/4) = 1/8$. Customer A's share of hour two's demand is three-quarters, and hour two's share of capacity utilization responsibility is three-quarters, giving customer A a capacity utilization responsibility for hour two equal to $(3/4)(3/4) = 9/16$. Adding customer's A's capacity utilization responsibility for both hours gives $1/8 + 9/16 = 11/16$. A similar calculation for customer B gives a capacity utilization responsibility of five-sixteenths.

Table 3 summarizes the capacity responsibility going to each customer using energy, capacity utilization, and peak as the basis for calculating these responsibilities.

TABLE 3
CUSTOMER RESPONSIBILITIES

Class	*Energy Responsibility*	*Capacity Utilization Responsibility*	*Peak Responsibility*
A	2/3	11/16	3/4
B	1/3	5/16	1/4

Notice that energy responsibility allocates too little capacity to A and too much to B, and peak responsibility allocates too much capacity to A and too little to B. Also notice that A's load factor (average energy divided by demand at peak) is below the system average, and B's load factor is above the system average. Moreover, this observation can be generalized to the principle that peak responsibility will always result in allocating too much capacity to customers (classes or jurisdictions) whose load factors are below the system average, and too little capacity to customers (classes or jurisdictions) whose load factors are above the system average. Of course, energy responsibility has the opposite result.

The Average and Peak Allocation Of Production Capacity Costs

The observations from the previous section lead to the following question: If a certain percentage of capacity is allocated based on energy responsibility and the remainder based on peak responsibility, how can that percentage be chosen so that the resulting allocations are the same as those derived using the capacity utilization method? The answer is to use the system load factor to determine the percentage of capacity to be allocated by energy responsibility. This is called the *average and peak* method and is given by the following formula:

$$\left(\begin{matrix}\text{Load}\\ \text{Factor}\end{matrix}\right)\left(\begin{matrix}\text{Energy}\\ \text{Responsibility}\end{matrix}\right) + \left(1 - \begin{matrix}\text{Load}\\ \text{Factor}\end{matrix}\right)\left(\begin{matrix}\text{Peak}\\ \text{Responsibility}\end{matrix}\right)$$

The system load factor is the ratio of average demand to peak demand. For this example it is given by:

$$\begin{aligned} \text{Average Demand} &= (150 \div 2) = 75 \text{ Mw} \\ \text{Peak Demand} &= 100 \text{ Mw} \\ \text{Load Factor} &= (75 \div 100) = \tfrac{3}{4} \end{aligned}$$

The average and peak allocation factor for each customer is given by:

$$\begin{aligned} \text{Customer A: } & (\tfrac{3}{4})(\tfrac{2}{3}) + (\tfrac{1}{4})(\tfrac{3}{4}) = \tfrac{11}{16} \\ \text{Customer B: } & (\tfrac{3}{4})(\tfrac{1}{3}) + (\tfrac{1}{4})(\tfrac{1}{4}) = \tfrac{5}{16} \end{aligned}$$

While the average and peak method has only been shown to produce the same answer as the capacity utilization method for the example of this section, it can also be shown to hold for any case in which demand is characterized by two levels, that is a peak and off-peak (base) level, and the result is independent of the number of hours associated with each period; c.f., the appendix to this article.

Before arriving at any conclusions about applying the average and peak method, keep in mind two very important assumptions. First, production capacity is characterized by one type of production plant. Second, demand is characterized by two levels. Much work has and is being done to develop allocation methods that will allow these two assumptions to be relaxed. These methods are called *time-of-use* cost allocations of embedded production costs.[11] Time-of-use allocations require substantially more load data (essentially they require hourly load profiles for all classes of service). When this type of load information is not available, then the average and peak method provides a viable alternative for reflecting the capacity utilization responsibility approach to the causation of production capacity.

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[11] *Time of Use Cost Allocation and Marginal Cost,* by M. S. Proctor, Missouri Public Service Commission, November, 1979.

Appendix

Average and Peak Capacity Allocation

In this appendix two basic assumptions are made. First, demand is served from a single type plant with constant capacity and running cost. Second, demand is characterized by two periods: peak demand; and base (off-peak) demand. The following definitions are used.

D_p = megawatt demand at peak
D_b = megawatt demand at base
a_p = fraction of time applied to peak demand
a_b = fraction of time applied to base demand

where $a_p + a_b = 1$; i.e., the fraction of time for base and peak demand adds up to the total amount of time serving load.

These fractions can be used to calculate both average demand (energy) and capacity utilization. The following table gives these calculations.

Period	*Average Demand*	*Capacity Utilization*
Base	$a_b D_b$	$a_b D_b$
Peak	$a D_p$	$a_p D_b + (D_p - D_b$
Total	$a_b D_b + a_p D_p$	D_p

Average demand during the base and peak periods is simply the demands of those periods times the fraction of time applied to each. The capacity utilization in the base period is simply that period's fraction of time of use of the capacity required to meet base-load demand ($a_b D_b$). The capacity utilization for the peak period is that period's fraction of time of use of the capacity required to meet base-load demand ($a_p D_b$) plus the difference between base and peak demand ($D_p - D_b$), which represents that portion of total capacity used exclusively during the peak period. When these two are added together, the total capacity utilization is given by $(a_b + a_p)D_b + D_p - D_b = D_b + D_p - D_b = D_p$.

The system load factor is the ratio of the average demand to peak demand, and is given by

$$\text{System Load Factor} = (a_b D_b + a_p D_p) \div D_p$$

Since $D_b < D_p$, it follows that $a_b D_b + a_p D_p < a_b D_p + a_p D_p = (a_b + a_p) D_p = D_p$. Thus, the system load factor is less than one. It also follows that

$$\frac{a_b D_b}{a_b D_b + a_p D_p} > \frac{a_b D_b}{D_p}$$

Thus the average demand contribution to the base period is greater than the capacity utilization contribution to the base period, and subsequently the average demand contribution to the peak period is less than the capacity utilization contribution to the peak period.

Given these basic concepts, the objective in this appendix is to show that *the average and peak method for capac-*

ity allocation to customer classes is equivalent to the capacity utilization method no matter where the levels for α_b and α_p may occur. The following definitions are used for the customer class demand responsibilities:

β_{jp} = class j's contribution (fraction) of demand in the peak period.

β_{jb} = class j's contribution (fraction) of demand in the base period.

The table below (in frame) specifies the average demand (energy), capacity utilization and peak responsibility to demand for the j[th] class.

The average and peak method simply assumes that class contribution to energy and class contribution to peak is known. Then the system load factor is used to define the following allocation factor:

$$\left(\begin{matrix}\text{Load}\\\text{Factor}\end{matrix}\right)\left(\begin{matrix}\text{Class Contribution}\\\text{to Energy}\end{matrix}\right) + \left(1 - \begin{matrix}\text{Load}\\\text{Factor}\end{matrix}\right)\left(\begin{matrix}\text{Class Contribution}\\\text{to Peak}\end{matrix}\right)$$

Substituting into this definition the appropriate terms gives the following results:

1) (Load Factor) (Class Contribution to Energy):

$$\left(\frac{\alpha_b D_b + \alpha_p D_p}{D_p}\right)\left(\frac{\beta_{jb}\,\alpha_b D_b + \beta_{jp}\,\alpha_p D_p}{\alpha_b D_b + \alpha_p D_p}\right) = \left(\frac{\beta_{jb}\,\alpha_b D_b + \beta_{jp}\,\alpha_p D_p}{D_p}\right)$$

2) (1 − Load Factor) (Class Contribution to Peak):

$$\left(\frac{D_p - \alpha_b D_b - \alpha_p D_p}{D_p}\right)\left(\beta_{jp}\right) = \frac{\beta_{jp}\,(D_p - \alpha_b D_b) - \beta_{jp}\,\alpha_p D_p}{D_p}$$

3) Average and Peak (1 + 2):

$$\frac{\beta_{jb}\,\alpha_b D_b + \beta_{jp}\,\alpha_p D_p}{D_p} + \frac{\beta_{jp}\,(D_p - \alpha_b D_b) - \beta_{jp}\,\alpha_p D_p}{D_p}$$

$$= \frac{\beta_{jb}\,\alpha_b D_b + \beta_{jp}\,(D_p - \alpha_b D_b)}{D_p}$$

But this gives exactly the same result as the capacity utilization method for determining class responsibility for capacity. Moreover, no matter how the peak and base periods are chosen, one needs only to determine class contribution to energy, class contribution to peak, and the system load factor in order to calculate the capacity utilization responsibility for each class of load. At the same time it is important to keep in mind the basic assumptions being made; i.e., demand is served from a single type plant and demand can properly be characterized by a peak and base load.

Method	*Base*	*Peak*	*Class Contribution*
Energy	$\beta_{jb}(\alpha_b D_b)$	$\beta_{jp}(\alpha_p D_p)$	$\frac{\beta_{jb}\,\alpha_b D_b + \beta_{jp}\,\alpha_p D_p}{\alpha_b D_b + \alpha_p D_p}$
Capacity Utilization	$\beta_{jb}\,(\alpha_b D_b)$	$\beta_{jp}\,(D_p - \alpha_b D_b)$*	$\frac{\beta_{jb}\,\alpha_b D_b + \beta_{jp}\,(D_p - \alpha_b D_b)}{D_p}$
Peak	$\beta_{jb}(0)$	$\beta_{jp}\,(D_p)$	β_{jp}

*Notice that $\alpha_b D_b = (1 - \alpha_p)D_b$, so that the capacity utilization contribution to peak can be rewritten as $\alpha_p D_b + (D_p - D_b) = D_p - (1 - \alpha_p)D_b = D_p - \alpha_b D_b$.

West Valley Project Gets Extra Money

An additional $5 million of federal funding has been targeted for the West Valley demonstration project. The extra money, plus some creative managing of the design and construction of the nuclear waste solidification project at the site, could result in the conversion of the radioactive liquid there to a durable solid two years sooner than had been originally planned. Dr. William H. Hannum, project director for the U. S. Department of Energy, said recently that the additional money is being transferred to this project from another DOE activity. "The extra funding indicates the importance the Department places on the timely solidification of the liquid wastes stored here." Hannum said that about sixty engineers and nuclear technicians will be added to the project staff in the next several months.

As the first U. S. nuclear waste solidification program of its kind, the West Valley demonstration project will convert almost 600,000 gallons of highly radioactive liquid waste into a durable solid which will be transported to a federal repository for disposal. The project began in February, 1982, when DOE assumed control of the former nuclear fuel reprocessing site. The liquid waste stored there was a by-product of reprocessing from 1966 to 1972. As the prime contractor to the DOE, West Valley Nuclear Services Company, a subsidiary of Westinghouse Electric Corporation, will design, build, and operate the solidification equipment.

MOPSC STAFF FUNCTIONAL CLASS COST OF SERVICE STUDY - SUMMARY OF RESULTS
KANSAS CITY POWER & LIGHT COMPANY - 12 MONTHS ENDING SEPTEMBER 30, 2005
MOPSC CASE NO. ER-2006-0314

FUNCTIONAL CATEGORY	MISSOURI RETAIL	RESIDENTIAL	SMALL GENERAL SERVICE	MEDIUM GENERAL SERVICE	LARGE GENERAL SERVICE	LARGE POWER SERVICE	LIGHTING
Production-Capacity	$217,406,900	$73,296,551	$12,261,753	$25,840,459	$53,375,957	$52,632,180	$0
Production-Energy	$161,960,634	$48,619,394	$8,880,906	$19,114,535	$41,528,981	$43,816,817	$0
Transmission	$22,457,045	$7,571,167	$1,266,578	$2,669,190	$5,513,469	$5,436,641	$0
Distribution Substations	$9,945,346	$4,371,840	$575,882	$1,179,271	$2,050,386	$1,767,967	$0
OH/UG Lines							
Pri-Customer Related	$14,648,988	$7,689,620	$2,547,488	$2,297,196	$1,808,593	$306,091	$0
Sec-Customer Related	$8,197,783	$4,410,867	$1,459,632	$1,310,621	$960,026	$56,638	$0
Pri-Demand Related	$31,031,435	$14,358,975	$2,216,676	$3,609,328	$7,086,815	$3,759,643	$0
Sec-Demand Related	$14,115,863	$7,445,682	$1,146,325	$1,854,852	$3,233,350	$435,654	$0
Line Transformers							
Sec-Customer Related	$5,886,637	$3,167,340	$1,048,128	$941,126	$689,372	$40,671	$0
Sec-Demand Related	$5,490,706	$3,493,205	$420,168	$552,928	$902,769	$121,637	$0
Services	$3,423,384	$1,817,375	$1,167,079	$322,945	$114,204	$1,780	$0
Meters & Recorders	$5,693,974	$3,249,775	$1,059,865	$723,381	$354,838	$306,115	$0
Company-Owned Lighting	$3,691,809	$0	$0	$0	$0	$0	$3,691,809
Meter Reading	$4,373,305	$3,732,156	$393,764	$82,953	$30,718	$133,714	$0
Customer Records & Collection	$10,200,785	$8,098,954	$1,181,363	$508,060	$410,928	$1,479	$0
Customer Assistance	$1,116,892	$269,897	$84,412	$120,796	$352,792	$288,995	$0
Sales Exp	$926,869	$486,537	$161,184	$145,348	$114,433	$19,367	$0
Uncollectible	$3,456,580	$2,998,237	$343,584	$114,758	$0	$0	$0
Other Cust Service	$4,336,006	$2,276,078	$754,040	$679,955	$535,332	$90,601	$0
Customer Deposits	$46,645	$26,136	$17,058	$2,863	$490	$97	$0
Sales-Related A&G Expenses	$16,298,282	$4,855,953	$887,040	$1,909,482	$4,159,921	$4,485,886	$0
Miscellaneous Assignments	$2,456,020	$1,395,749	$165,906	$209,937	$401,449	$282,979	$0
Income Taxes	$38,237,098	$16,956,426	$3,186,533	$4,495,701	$7,484,835	$6,113,603	$0
	$585,398,985	$220,587,916	$41,225,363	$68,685,685	$131,109,658	$120,098,554	$3,691,809
Reallocate Lighting Costs	$0	$1,399,963	$261,637	$435,914	$832,088	$762,206	($3,691,809)
TOTAL COST OF SERVICE	**$585,398,985**	**$221,987,879**	**$41,487,000**	**$69,121,600**	**$131,941,746**	**$120,860,760**	**$0**
CCOS %	100.00%	37.92%	7.09%	11.81%	22.54%	20.65%	0.00%
RATE REVENUE	$484,517,360	$171,390,199	$36,586,080	$62,437,672	$109,196,683	$98,849,995	$6,056,731
Reallocation of Lighting Revenues	$0	$2,296,760	$429,238	$715,155	$1,365,113	$1,250,465	($6,056,731)
TOTAL RATE REVENUE	**$484,517,360**	**$173,686,959**	**$37,015,318**	**$63,152,827**	**$110,561,796**	**$100,100,460**	**$0**
Economic Development Credits	($466,753)	($176,996)	($33,079)	($55,112)	($105,200)	($96,365)	$0
Interruptible (PLCC) Credits	($394,655)	($133,054)	($22,259)	($46,908)	($96,892)	($95,542)	$0
Revenue from Off-System Sales	$92,895,816	$31,318,891	$5,239,326	$11,041,372	$22,807,018	$22,489,209	$0
Miscellaneous Revenue	$8,847,217	$3,707,411	$779,455	$1,087,944	$1,831,730	$1,440,676	$0
TOTAL OPERATING REVENUE	**$585,398,985**	**$208,403,210**	**$42,978,762**	**$75,180,123**	**$134,998,451**	**$123,838,438**	**$0**
RATE REVENUE DEFICIENCY	**$0**	**$13,584,668**	**($1,491,762)**	**($6,058,524)**	**($3,056,705)**	**($2,977,678)**	**$0**
Required % Change							
to operating revenue	**0.00%**	**6.52%**	**-3.47%**	**-8.06%**	**-2.26%**	**-2.40%**	**0.00%**
to rate revenue	**0.00%**	**7.82%**	**-4.03%**	**-9.59%**	**-2.76%**	**-2.97%**	**0.00%**

Appendix A

KANSAS CITY POWER & LIGHT COMPANY CASE NO. EO-94-199
GENERAL FEATURES OF THE STIPULATED RATE DESIGN

CLASS REVENUE REQUIREMENTS ARE BEING MOVED TOWARD COST OF SERVICE LEVELS

The results of the class cost of service studies exchanged by the parties and shown in Appendix B indicate that substantial decreases to the Small General Service, Medium General Service, and Large General Service customer classes are warranted.

This rate design is based on a two-phase reduction in KCPL's revenues. Phase I rates were designed with the residential, large power, lighting, and miscellaneous classes remaining at current revenue levels and the three general service classes (Small GS, Medium GS, and Large GS) receiving a combined decrease of $9,000,000.

Phase II rates were designed to provide an additional decrease of $11,000,000 in rate revenues. The residential, large power, lighting, and miscellaneous classes will each receive a 2.00% reduction from Phase I revenue levels. The remainder of the decrease will be shared by the three general service classes. This results in an additional 3.27% decrease to those classes.

Customers currently served on Special Contracts will remain at current revenue levels during both Phases I and II.

STATUS OF CURRENT TARIFFS AND RIDERS

The intent of this stipulation is to replace most of KCPL's current Missouri general application tariffs with the tariffs shown in Appendix F, to eliminate certain special use tariffs, to implement an optional two-part time-of-use rate schedule for non-residential customers, and to leave selected tariffs unchanged.

The current tariffs which will be replaced are:

Residence & Rural Residence (R)	Residential Time of Day Service (RTDE)
General Service-Small (1-GS,3-GS)	General Service-All Electric (GA)
General Service-Large (1-GL,3-GL)	Primary Service-Large (PL)

The current tariffs which will be eliminated are:

Residence Demand Service (RDS)	Residential Time of Day Service (RTDD)
Schools & Churches (1-SC,3-SC)	Seasonal Recreational (1-SR,3-SR)
Water & Sewer Pumping (1-WS,3-WS)	Summer Amusement Parks (1-SP)
School Trailers with Space Heat	

KCPL's current lighting tariffs and traffic signal tariffs will be retained with the current rate structure and language. The rate levels on these tariffs will remain at current levels until the implementation of Phase II rates. These tariffs are:

Municipal Street Lighting (1-ML, 3-ML)
Private Unmetered Protective Lighting (AL)
Commercial Street Lighting (1-CL)
Municipal Traffic Control Signal (1-TR)
Standby or Breakdown (SA)

The only change to KCPL's current tariff riders is an expansion of the off-peak hours in the Off-Peak Service Option.

CUSTOMER CHOICE OF NEW TARIFFS

Customers may choose to be served on any new tariff for which the customer qualifies. However, customers will initially be placed on whichever new tariff appears to be the most advantageous given the customer's size, load characteristics, and end use.

In addition, non-residential customers will now have the option of choosing to be served on a time-of-use rate.

FEATURES OF THE NEW RESIDENTIAL TARIFFS

A single general application tariff and an optional time-of-day tariff have been designed for residential customers. They will be designated as Residential Service (R) and Residential Time of Day Service (RTOD).

Customer charges are being increased to better reflect the costs associated with service drops, meters, meter reading, billing, and customer assistance.

Geographic distinctions (urban vs rural) in the level of the customer charge will be eliminated.

Customers with separately metered space heat will continue to pay a higher monthly customer charge than standard customers to account for the additional meter.

The new residential tariff increases the summer/winter rate differential to better reflect KCPL's seasonal costs.

Declining block energy charges in the summer, which result in a customer's average cost per kWh declining with additional electricity use, are being replaced with a uniform summer energy rate. This rate structure will send customers a more appropriate price signal.

Special pricing of water heat kWh will be eliminated.

GENERAL DESCRIPTION OF THE NEW COMMERCIAL & INDUSTRIAL TARIFFS

Four general application tariffs and three all-electric tariffs for commercial and industrial customers have been designed. The general application tariffs are designated as Small General Service, Medium General Service, Large General Service, and Large Power Service. Each is intended to serve customers with similar size and load factor characteristics. Both commercial and industrial customers will be served on each tariff. The all-electric tariffs mirror the Small GS, Medium GS, and Large GS general application tariffs in terms of size and rate structure but they require the customer to use electricity as the sole means of providing space heating, cooling, and water heating. The Large Power general application tariff has no companion all-electric tariff.

Small General Service: This tariff was designed for the very small (under 25 kW) commercial and industrial customer. These customers typically have fairly low load factors.

Medium General Service: This tariff was designed for the medium size (25 - 200 kW) customer with a moderate load factor. Customers must have, or be willing to assume, a 25 kW minimum demand for service on this tariff.

Large General Service: This tariff was designed for the large size (200 - 1000 kW) customer with a higher load factor. Customers must have, or be willing to assume, a 200 kW minimum demand for service on this tariff.

Large Power Service: This tariff was designed for the largest size (1000+ kW) customer with a very high load factor. Customers must have, or be willing to assume, a 1000 kW minimum demand for service on this tariff.

Rate structures and rate levels on the new commercial & industrial tariffs have been synchronized in such a way that there is little difference in the annual bill of a customer near the boundary of two tariffs. This rate continuity allows for an orderly transition from one tariff to another as the customer grows.

The Small GS, Medium GS, and Large GS general application tariffs each contain a provision for pricing separately metered space heat kWh at the tail block (lowest price) energy rate in the winter.

Customer bills on each of the all-electric tariffs will be identical in the summer to those on the companion general application tariff, but winter bills will be lower.

Special pricing of separately metered water heat kWh will be eliminated. Energy and demands from this meter will be combined with energy and demands from the general use meter prior to billing.

FEATURES OF THE NEW COMMERCIAL & INDUSTRIAL TARIFFS

UNBUNDLED CHARGES

Charges on the new tariffs have been unbundled to better match the way in which costs are incurred with the way in which costs are recovered.

Customer charges, which recover the costs associated with meter reading, billing, customer assistance, and facilities on the customers' premises, will be implemented for all customers. These charges will be specific to both the tariff and the customer's size.

Facilities charges, which recover the costs associated with lines and transformers, will be implemented for all customers in excess of 25 kW. This charge will be based on each customer's annual maximum demand.

Demand charges will be implemented for all but Small General Service customers.

All tariffs will have energy charges based on the customer's hours use (monthly load factor). These charges, which recover time-of-use costs, provide price incentives to customers to improve their load factor.

SEASONAL CHARGES

Each new tariff contains seasonally differentiated rates (summer rates higher than winter rates) to better reflect KCPL's seasonal costs.

Energy charges on all tariffs are seasonally differentiated.

The Medium GS, Large GS, and Large Power tariffs also contain seasonally differentiated demand charges.

VOLTAGE LEVEL DISTINCTIONS

The General Service and Large Power tariffs recognize voltage level differences between customers.

The levels of the facilities charge account for customer ownership of specific distribution equipment.

The levels of the demand and energy charges reflect the differences in losses at various delivery voltage levels.

If the customer's metering voltage differs from the delivery voltage, the metered demand and energy will be adjusted to reflect losses between the two voltage levels.