Exhibit No.: _____
Issue(s): Cost of Service/Rate Design
Witness/Type of Exhibit: Meisenheimer/Direct
Sponsoring Party: Public Counsel
Case No.: ER-2009-0089

DIRECT TESTIMONY

OF

BARBARA A. MEISENHEIMER

Submitted on Behalf of the Office of the Public Counsel

Kansas City Power & Light Company

CASE NO. ER-2009-0089

February 25, 2009

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Kansas City Power and Light Company for Approval to Make Certain Changes in its Charges for Electric Service To Continue the Implementation of Its Regulatory Plan.	)))))	**ER-2009-0089**

AFFIDAVIT OF BARBARA A. MEISENHEIMER

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

Barbara A. Meisenheimer, of lawful age and being first duly sworn, deposes and states:

1. My name is Barbara A. Meisenheimer. I am Chief Utility Economist for the Office of the Public Counsel.

2. Attached hereto and made a part hereof for all purposes is my direct testimony.

3. I hereby swear and affirm that my statements contained in the attached testimony are true and correct to the best of my knowledge and belief.

Barbara A. Meisenheimer

Subscribed and sworn to me this 25th day of February 2009.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

KENDELLE R. SEIDNER
My Commission Expires
February 4, 2011
Cole County
Commission #07004782

Kendelle R. Seidner
Notary Public

My Commission expires February 4, 2011.

KCPL

Class Cost of Service and Rate Design

ER-2009-0089

Direct Testimony of Barbara Meisenheimer

Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. Barbara A. Meisenheimer, Chief Utility Economist, Office of the Public Counsel, P. O. 2230, Jefferson City, Missouri 65102. I am also an adjunct instructor for William Woods University.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND EMPLOYMENT BACKGROUND.

A. I hold a Bachelor of Science degree in Mathematics from the University of Missouri-Columbia (UMC) and have completed the comprehensive exams for a Ph.D. in Economics from the same institution. My two fields of study are Quantitative Economics and Industrial Organization. My outside field of study is Statistics. I have taught economics courses for the University of Missouri-Columbia, William Woods University, and Lincoln University, mathematics for the University of Missouri-Columbia and statistics for William Woods University.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE COMMISSION?

A. Yes, I have testified on numerous issues before the Missouri Public Service Commission. (PSC or Commission).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my direct testimony is to present Public Counsel's Class Cost of Service (CCOS) studies.

Q. WHAT IS YOUR EXPERIENCE IN THE PREPARATION OF CLASS COST OF SERVICE STUDIES?

A. I have prepared and supervised the preparation of cost of service studies on behalf of Public Counsel for over ten years. These include class cost of service studies related to natural gas, water and electric utilities, and cost studies related to telecommunications services.

Q. HAD PUBLIC COUNSEL ANTICIPATED PREPARING A CCOS STUDY FOR THIS CASE?

A. No. In Case No. ER-2007-0271, Public Counsel did not file or update a class cost of service study in compliance with the Stipulation and Agreement resulting from KCPL's Regulatory Plan, Case No. EO-2005-0329. In the Stipulation and Agreement the signatory parties agreed not to file new or updated class cost of service studies or to propose changes to rate structures in the next two optional rate cases. However in the first of those two optional cases, Case No. ER-2007-0271, parties to the Stipulation and Agreement filed updated CCOS study results and proposed rate structure changes that were accepted by the Commission. In Case No. ER-2007-0271, the Commission also required KCPL to file a CCOS study in this case to evaluate the need for additional rate design changes. While Public Counsel is satisfied to adhere to the original agreement in Case No. ER-2007-0271 by proposing no changes to rate design in direct testimony, based on the Commission's decision in ER-2007-0271, Public Counsel is compelled to file

a CCOS study in this case in order to be prepared to respond to any proposed inter-class revenue shifts proposed by other parties in this case.

Q. PLEASE DISCUSS YOUR CCOS STUDIES.

A. I have prepared two CCOS studies. The first study uses a traditional method of allocating production costs. The second CCOS study illustrates the results of replacing the traditional allocator with a production allocator based on Time of Use (TOU) similar to the TOU Demand allocator I have filed in previous cases. The results of the traditional study are provided in Schedule DIR-BAM nonTOU. The TOU cost of service study results are provided in Schedule DIR-BAM TOU.

Q. WHAT IS THE MAIN PURPOSE OF PERFORMING A CCOS STUDY?

A. The primary purpose of a CCOS study is to determine the relative class cost responsibility for each customer class by allocating costs among the classes based on principles of cost causation. CCOS study results also provide guidance for determining how rates should be designed to collect revenues from customers within a class, depending on customer usage levels and patterns of use.

Q. WHAT IS THE RELATIVE IMPORTANCE OF CCOS STUDY RESULTS IN DEVELOPING RATE DESIGN?

A. CCOS study results provide the Commission with a general guide in setting the just and reasonable rate for the provision of service based on costs. In addition, other factors are also relevant considerations when setting rates including the value of a service, affordability, rate impact, rate continuity, etc. A determination as to the particular manner in which the results of a cost of service study and all

the other factors are balanced in setting rates can only be determined on a case-by-case basis.

Q. PLEASE OUTLINE THE BASIC ELEMENTS OF PREPARING A CCOS STUDY.

A. A CCOS Study is designed to functionalize, classify, and allocate costs.

Functionalizing costs involves categorizing accounts by the type of electric utility function(s) with which each account is associated. The categories of accounts include Production, Transmission, Distribution, Customer Accounts, Administrative and General, etc.

The next step is to classify costs as customer related, demand related, commodity related, or "other" costs. Customer related costs vary in relation to the number of customers. Demand related costs vary with usage during different periods such as peak and average load periods. Commodity related costs vary with annual energy consumption. For example, the cost associated with meter plant and meter reading expense are considered to be customer-related because they vary primarily based on the number of customers served and might occur whether or not the customer uses any electricity.

The final step in the CCOS is to develop and apply allocation factors that apportion a reasonable share of jurisdictional costs to each customer class. Allocation factors should be developed in a manner that is consistent with the functionalization and classification of costs described above. For example, unweighted customer related cost allocation factors are expressed as ratios that reflect the proportion of customers in a particular class to the total number of customers that contribute to the causation of the relevant cost. Likewise, demand

related allocators should reflect each class's use during specific time periods and commodity related allocators should reflect each class's annual consumption. In simpler terms, if the cost for a particular activity were thought of as a pie, then allocators would represent the size of the slices of the "cost" pie that each class would be assigned.

Q. WHICH CUSTOMER CLASSES ARE USED IN YOUR CCOS STUDIES?

A. For both studies of the KCPL system, I used a Residential Class (RG), a Small General Service Class (SGS), a Medium General Service Class (MGS), a Large General Service Class (LGS), a Large Power Service Class (LPS), and a Lighting Class (Lighting).

Q. ON WHAT DATA ARE YOUR CCOS STUDIES BASED?

A. My CCOS studies are based primarily on data provided by the Company including data related to investments, expenses and revenues, peak demand, customer counts and energy use.

Q. HOW IS INTANGIBLE PLANT ALLOCATED?

A. Intangible Plant (FERC Account No. 301) pertains to organization cost. It includes all fees paid to federal or state governments for the privilege of incorporation along with related expenditures. Generally, it should be allocated to each customer class according to the benefits each receives from the existence of this business, or according to the extent to which each class contributes to the overall cost of conducting the business. In this case, I have applied a Gross Plant Allocator to Intangible Plant.

Q. HOW IS PRODUCTION PLANT ALLOCATED?

A. Production Plant includes the cost of land, structures and equipment used in connection with power generation. Both demand and energy characteristics of a system's loads are important determinants of production plant costs. One of my production allocators assigns Production Plant according to a composite allocator that weights (1) a demand related component and (2) an energy related component. This method uses 3 coincident summer peaks to represent the demand related component and average annual energy use to represent the energy related component.

The second production allocation method is a time of use method which assigns demand related fixed plant investments net of depreciation reserve to each hour. The method then sums each class' share of hourly net investments based on only those hours when the class actually used the system. This method involves examining the production and demand for each hour of the year so it reflects both peak period use and average use throughout the year.

Q. REGARDING YOUR FIRST ALLOCATION METHOD, IS A WEIGHTED AVERAGE AND COINCIDENT PEAK (A&CP) METHOD THAT ALLOWS DISCRETION IN SELECTION OF THE NUMBER OF COINCIDENT PEAKS AMONG THE NARUC-RECOGNIZED PRODUCTION CAPACITY COST ALLOCATION METHODS?

A. Yes. Part IV B. of the NARUC Electric Utility Cost Allocation Manual describes methods for developing energy weighted production plant cost allocations. Section 4 of Part IV discusses production cost allocations based on judgmental

energy weightings. Page 57-59 of the NARUC Manual specifically recognizes weighted average and coincident peak methods where the coincident peak (CP) may be estimated based on more than one period of peak use. The Manual describes the method as follows:

> Some regulatory commissions, recognizing that energy loads are an important determinant of production plant costs, require the incorporation of judgmentally-established energy weightings into cost studies. One example is the "peak and average demand" allocator derived by adding together each class's contribution to the system peak demand (or to a specific group of system peak demands; e.g., the 12 monthly CPs) and its average demand. The allocator is effectively the average of the two numbers: class CP (however measured) and class average demand. Two variants of this allocation method are shown in Tables 4-14 and 4-15.

The Manual goes on to provide two examples of weighted methods, one based on average demand and a single period of coincident peak use (A&1CP) and another that incorporates average demand and 12 periods of peak use (A&12CP) in developing an allocator.

I used an A&3CP method in calculating the production allocator. The 3CP I used to represent the peak portion of the allocator falls well within the number of peak periods recognized in the NARUC Manual. I used a measure of load factor (LF) as the weight assigned to the average portion of the allocator and used 1- LF as the weight assigned to the peak portion of the allocator. This is a common method of assigning weights used in the NARUC Manual.

Q. IS A 3CP REPRESENTATIVE OF THE PEAK DEMAND ON THE KCPL SYSTEM?

A. Yes. The 3CP is reasonably representative of the peak demand on KCPL's system. As illustrated in Table 1 the 3CP includes periods when demand was at or in excess of 90% of the system's maximum peak.

Table 1

Coincident Peak (CP) @ Generation (Converterd to MWh)

	RES	SGS	MGS	LGS	LP	Lighting	Total	% Peak
Jan	337	47	148	301	279	20	1132	57%
Feb	488	56	156	333	277	22	1333	67%
Mar	223	38	119	267	302	0	948	48%
Apr	218	52	183	333	313	0	1099	55%
May	368	42	152	235	241	20	1058	53%
Jun	705	91	239	412	364	0	1809	91%
Jul	845	102	248	417	378	0	1991	100%
Aug	762	92	241	422	404	0	1921	96%
Sep	665	91	226	387	354	0	1723	87%
Oct	282	40	120	212	242	22	919	46%
Nov	246	47	145	282	304	22	1046	53%
Dec	370	41	100	203	183	23	920	46%

Q. WHY IS IT REASONABLE TO USE MULTIPLE PEAKS IN DEVELOPING THE MEASURE OF COINCIDENT PEAK USED IN THE PRODUCTION CAPACITY ALLOCATOR?

A. A class's relative share of system demand may vary significantly. Using multiple measures of coincident peak reduces the likelihood of relying on an anomalous single peak as the basis of the allocator. In addition, the system is designed to meet a range of system demands and a class's relative share may vary in that range. I believe it is reasonable to include more than simply the highest single peak to reflect the class's relative share of system demand. Allowing for peaks in excess of 85-90% retains the conceptual focus on determining peak demand while also reflecting each class's relative share of variation in system peak demands.

Q. PLEASE REVIEW YOUR SECOND PRODUCTION COST ALLOCATION METHOD.

A. The Time of Use method assigns production costs to each hour of the year that the specific production occurs. The method then sums each class's share of hourly investments based on only those hours when the class actually uses the system.

Q. DO YOU BELIEVE YOUR TIME OF USE METHOD IS CONSISTENT WITH THE METHOD DESCRIBED BY NARUC IN ITS 1992 ELECTRIC COST MANUAL?

A. Yes it is. The following is a description method from the NARUC manual which is consistent with the method I used to develop the time of use allocation.

> 4. Probability of Dispatch Method
>
> The probability of dispatch (POD) method is primarily a tool for analyzing cost of service by time periods. The method requires analyzing an actual or estimated hourly load curve for the utility and identifying the generating units that would normally be used to serve each hourly load. The annual revenue requirement of each generating unit is divided by the number of hours in the year that it operates, and that "per hour cost" is assigned to each hour that it runs. In allocating production plant costs to classes, the total cost for all units for each hour is allocated to the classes according to the KWH use in each hour. The total production plant cost allocated to each class is then obtained by summing the hourly cost over all hours of the year. These costs may then be recovered via an appropriate combination of demand and energy charges. It must be noted that this method has substantial input data and analysis requirements that may make it prohibitively expensive for utilities that do not develop and maintain the required data.

Q. WHAT WAS YOUR SOURCE OF INFORMATION FOR THE HOURLY LOAD CURVE AND THE GENERATING UNITS THAT WOULD NORMALLY BE USED TO SERVE EACH HOURLY LOAD?

A. I obtained hourly system load information and RealTime production modeling inputs from the Staff. The Staff uses the RealTime model in order to determine

fuel costs. The RealTime model simulates generation dispatch for each hour of the year including information for each generation plant that is in operation regarding the amount of generation in MW.

Q. HOW DID YOU SPREAD THE INVESTMENT COSTS OF THE GENERATING UNITS THAT WOULD NORMALLY BE USED TO SERVE EACH HOURLY LOAD?

A. I used Staff accounting information on net generation plant investments to determine a cost per MW for each plant. I then spread the plant investment cost to each hour by multiplying the per plant investment cost per MW hour by the MW hours produced by the plant and then summing for all plants in operation during the particular hour.

Q. HOW DID YOU THEN ALLOCATE THESE COSTS TO THE CUSTOMER CLASSES?

A. Based on hourly customer load information I apportioned each hour's total production costs to the customer classes based on each class's share of demand for each hour. In the final steps I summed each class's hourly portion of costs to determine the class's share of total costs.

Q. DO YOU VIEW THE TIME OF USE METHOD AS SUPERIOR TO OTHER PRODUCTION COST ALLOCATION METHODS?

Yes. Since it reflects costs and use for all hours of the year I believe it is superior to methods that allocate the total cost based in large part on usage in only a few peak hours. Allocators that overly focus on use in only a few peak hours unfairly over-allocate costs to the residential and small general service class because the

capacity costs actually vary by hour depending on the plants in use. The particular pattern of use by each class over all hours of the year appropriately leads to a difference in overall average cost by class.

Q. HOW MUCH DIFFERENCE DOES THE TIME OF USE METHOD MAKE IN ALLOCATING PRODUCTION COSTS TO CLASSES?

A. It makes a significant difference to allocate production costs by matching production plant use to customer demand on an hourly basis. Table 2 illustrates the difference between my more limited A&3CP allocator and the Time of Use allocator.

Table 2

	RES	SGS	MGS	LGS	LP
Ave&3CP Allocator	34.7%	5.23%	12.23%	24.0%	23.4%
TOU	30.5%	4.51%	13.2%	25.0%	25.9%

Q. HOW DID YOU ALLOCATE TRANSMISSION PLANT?

A. Transmission Plant includes the cost of land, structures and equipment used in connection with transmission operations. Transmission facilities are installed to provide reliable service throughout the year including peak periods and periods of scheduled maintenance. Transmission Plant can also, at times, substitute for generation and can minimize the cost of generation facilities through the sale or purchase of power. Transmission Plant costs can be equitably allocated on the same basis as Production Plant or can be allocated based on another method that

reasonably represents its shared service throughout the year. I chose to use each class's sum of monthly coincident peaks (12CP) to allocate Transmission Plant.

Q. HOW DID YOU ALLOCATE DISTRIBUTION PLANT?

A. Distribution Plant includes the cost of land, structures and equipment used in connection with distribution operations. Distribution plant equipment reduces high-voltage energy from the transmission system to lower voltages, delivers it to the customer and monitors the amounts of energy used by the customer. Many of the distribution costs associated with providing service to electric utility customers are not directly associated with or reasonably assignable to a particular class with precision. For example, with the exception of service drops and meters, most of the facilities between the utility customer's point-of-service and the distribution substation are shared facilities. Since such facilities are not directly related to the number of customers, the associated costs are best classified as demand related, rather than customer related.

In the functionalization and allocation of Distribution Plant, my studies reflect that distribution facilities provide service at two voltage levels: primary and secondary, and that some large industrial customers may choose to take service at primary voltages because of their large electrical requirements. Different allocation factors were used for allocating costs at different levels of the distribution system. The Company class cost of service study included allocation weights used to apportion costs into primary and secondary plant cost categories for FERC Accounts 364-368. Based on information I had available from a previous KCPL CCOS study, I did further disaggregate secondary plant costs for

FERC Accounts 364-368. Primary costs and a portion of secondary costs are treated as demand related costs in my CCOS studies. Demand related costs are assigned to customer classes based on each class's share of non coincident peak demand. The remaining secondary costs are allocated based on each class's maximum month demand.

Q. HOW DID YOU ALLOCATE METER RELATED FACILITIES?

A. Meter facilities costs are generally related to each individual customer. New investment occurs when a new customer is added to the system. Therefore, meter costs are usually classified as customer related. I allocated meter costs based on weighted meter investment by class.

Q. HOW DID YOU ALLOCATE SERVICE RELATED FACILITIES?

Service facilities are classified as customer related. I used the same allocations for services as for meters.

Q. PLEASE SUMMARIZE YOUR TREATMENT OF DISTRIBUTION PLANT COSTS.

The functional categories and classifications for Distribution Plant are as follows:

360-362	Distribution Substations	Demand at Primary Station
364	Poles Towers and Fixtures	Demand at Primary and Customer and Demand at Secondary
365	Overhead Conductors & Devices	Demand at Primary and Customer and Demand at Secondary
366	Underground Conduit	Demand at Primary and Customer and Demand at Secondary
367	Underground Conductors & Devices	Demand at Primary and Customer and Demand at Secondary
368	Line Transformers	Customer at Secondary

369	Services	Customer
370	Meters	Customer

Q. HOW DID YOU ALLOCATE GENERAL PLANT?

A. General Plant includes land, structures and equipment used in support of Production, Transmission and Distribution Plant. Therefore, it was allocated using a composite allocator based on previously allocated net non-general plant.

Q. PLEASE DISCUSS THE METHODS THAT YOU USED TO ALLOCATE EXPENSES.

A. For the expenses that could not be directly assigned, consistent with the principle that "expenses follow plant," the allocators that were applied to the expenses accounts were the same as those applied to the Production, Transmission, and Distribution Plant accounts to which the expenses are related.

Q. HOW DID YOU ALLOCATE POWER PRODUCTION EXPENSES?

A. Power Production Expenses were broken down into demand-related and energy-related production and purchased power costs. The demand-related expenses were allocated based on the demand related allocators in my studies. The energy-related expenses were allocated based on class kWhs at generation. The RealTime production model I used to prepare my TOU production allocator also identifies purchased power by hour. I assigned the cost of purchased power to classes based on class use in hours when power was purchased in the RealTime model.

Q. HOW WERE TRANSMISSION EXPENSES ALLOCATED?

A. Transmission Expenses were allocated according to the "expenses follow plant" principle. The allocators applied to transmission expenses were the same as those I applied to transmission plant.

Q. HOW WERE DISTRIBUTION EXPENSES ALLOCATED?

A. Distribution Expenses were allocated according to the "expenses follow plant" principle. The allocators applied to distribution expenses were the same as those I applied to the plant associated with those expenses. For expenses that are not associated with any particular category of distribution plant, such as supervision and engineering, I used an aggregate distribution expense allocator based on the sum of distribution expenses assigned to each class.

Q. HOW DID YOU ALLOCATE CUSTOMER ACCOUNTS EXPENSES?

A. I allocated most Account Expense Accounts to all customer classes based on unweighted customer numbers. I used the number of customer meters to allocate Meter Reading (Account 902). I used total cost of service to allocate Uncollectible Accounts (Account 904) consistent with uncollectibles being a normal cost of doing business which is discussed as one position recognized in the NARUC Electric Cost Allocation manual.

Q. HOW DID YOU ALLOCATE CUSTOMER SERVICE EXPENSES AND SALES EXPENSES?

A. Customer Service and Sales Expenses including Accounts 907, 908, 909, 910, 911, 912, 913 and 916 were allocated based on the number of customers.

Q. HOW ARE ADMINISTRATIVE AND GENERAL (A & G) EXPENSES ALLOCATED?

A. Property Insurance expense (Account 924) was allocated on the basis of net non-general plant. Regulatory, franchise, general and miscellaneous expenses were allocated based on total cost of services. Rents and maintenance were allocated based on gross plant. The remaining A & G accounts were allocated on payroll.

Q. HOW DID YOU ALLOCATE TAXES OTHER THAN INCOME TAXES?

A. I allocated taxes other than income taxes on total cost of service.

Q. HOW DID YOU ALLOCATE STATE AND FEDERAL INCOME TAXES?

A. These taxes were allocated on the basis of rate base since a utility company's income taxes will be a function of the size of its rate base, and thus each class should contribute revenues for income taxes in proportion with the amount of rate base that is necessary to serve it.

Q. HOW DID YOU ALLOCATE REVENUES?

A. The class rate revenues associated with each class were directly assigned to the class. Other revenues were allocated based on the characteristics of production capacity, production energy or transmission with which they most closely align. The RealTime production model I used to prepare my TOU production allocator also identifies off-system sales by hour. In the CCOS study based on TOU I assigned off-system sales revenue based on a capacity allocator and a variable cost allocator.

Q. PLEASE DESCRIBE THE RESULTS OF PUBLIC COUNSEL'S CLASS COSS STUDY.

A. Schedule DIR-BAM nonTOU and Schedule DIR-BAM TOU show the results of Public Counsel's class cost of service studies. Since a CCOS study is designed to determine the relative cost responsibility of customer classes, the results are based on the assumption that total company revenues remain constant. Line 11 of each schedule shows the current revenue percentage by class. Line 16 of each schedule shows the change in class revenue percentage to achieve equalized rates of return. The study results show that the Residential class is 2.2%-5.3% below cost of service. The SGS appears significantly above costs in both studies. The MGS class is 2.71%-8.34% above cost of service. The LGS class is less than 2% above cost of service in both studies. The LP class is 3.75%-6.96% below cost of service. Both studies indicate that the Lighting class is significantly below cost but I believe this is due to a mismatch of customers and costs included in the data for this class.

Q. DID YOU PERFORM ANY ANALYSIS OF THE CUSTOMER-RELATED COSTS THAT ARE ATTRIBUTABLE TO THE TYPICAL RESIDENTIAL CUSTOMER?

A. Yes, I did. I included costs that are related to services, meters, meter installations, and customer accounts expenses. The costs associated with services, meters, and meter installations include the return on rate base for the relevant plant accounts, distribution operation and maintenance expenses associated with services, meters, and meter installations, plus the depreciation expense, payroll benefits, and property taxes associated with services, meters, and regulators. Generally, these

costs are used to recommend customer charge changes. My studies indicate that the current customer charge exceeds the customer related costs.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

KCPL
ER-2009-0089
Summary of OPC Class Cost of Service Study Results

Line			TOTAL	Residential	Small GS	Medium GS	Large GS	LPS	Lighting
1	O & M EXPENSES		$ 356,539,533	$ 126,170,706	$ 18,276,850	$ 44,970,761	$ 82,051,936	$ 79,982,391	$ 5,086,889
2	DEPREC. & AMORT. EXPENSE		$ 84,731,916	$ 31,184,326	$ 5,131,545	$ 11,088,146	$ 19,005,270	$ 17,195,858	$ 1,126,770
3	TAXES		$ 39,241,860	$ 14,751,165	$ 2,334,087	$ 5,004,778	$ 9,006,190	$ 7,558,641	$ 586,999
4	OTHER OPERATING EXPENSE		$ 81,896,641	$ 29,735,080	$ 5,501,775	$ 10,558,683	$ 18,827,716	$ 16,219,092	$ 1,054,295
5	Subtotal - Expenses and Taxes		$ 562,409,950	$ 201,841,277	$ 31,244,258	$ 71,622,368	$ 128,891,112	$ 120,955,982	$ 7,854,953
6	TOTAL RATE BASE		$ 1,266,068,966	$ 475,920,158	$ 75,305,185	$ 161,470,266	$ 290,568,746	$ 243,866,133	$ 18,938,479
7	IMPLICIT RATE OF RETURN	5.29%	5.29%	5.29%	5.29%	5.29%	5.29%	5.29%	5.29%
8	REQUIRED OPERATING INCOME TO EQUALIZE CLASS RATES OF RETURN		$ 66,992,793	$ 25,182,847	$ 3,984,700	$ 8,544,040	$ 15,375,159	$ 12,903,936	$ 1,002,111
9	MISCELLANEOUS REVENUE CREDIT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	OTHER REVENUE		$ 86,507,498	$ 26,964,919	$ 3,954,708	$ 11,422,020	$ 21,438,153	$ 21,937,354	$ 790,344
11	OFFSETTING REVENUES		$ 86,507,498	$ 26,964,919	$ 3,954,708	$ 11,422,020	$ 21,438,153	$ 21,937,354	$ 790,344
12	REQ. OPER. INCOME LESS OFFSETTING REV.		$ (19,514,705)	$ (1,782,072)	$ 29,992	$ (2,877,979)	$ (6,062,994)	$ (9,033,417)	$ 211,767
13	CURRENT RATE REVENUE		$ 542,895,245	$ 195,759,058	$ 41,072,116	$ 70,661,252	$ 124,277,037	$ 104,637,563	$ 6,488,218
14	CURRENT REVENUE PERCENTAGES		100.00%	36.06%	7.57%	13.02%	22.89%	19.27%	1.20%
15	RATE REVENUE EXCESS OR DEFICIENCY		$ -	$ 4,300,147	$ (9,797,866)	$ (1,916,864)	$ (1,448,919)	$ 7,285,002	$ 1,578,501
16	RATE REVENUE % CHANGE TO EQUALIZE CLASS RATES OF RETURN		0.00%	2.20%	-23.86%	-2.71%	-1.17%	6.96%	24.33%
17	REV. % WITH EQUALIZED ROR		100.00%	36.85%	5.76%	12.66%	22.62%	20.62%	1.49%

KCPL
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Summary of OPC Class Cost of Service Study Results

Line			TOTAL	Residential	Small GS	Medium GS	Large GS	LPS	Lighting
1	O & M EXPENSES		$ 356,539,533	$ 129,238,405	$ 20,544,021	$ 41,431,454	$ 82,163,351	$ 78,495,843	$ 4,666,459
2	DEPREC. & AMORT. EXPENSE		$ 84,731,916	$ 33,428,066	$ 5,505,307	$ 10,573,087	$ 18,466,425	$ 15,875,869	$ 883,162
3	TAXES		$ 39,241,860	$ 15,652,169	$ 2,481,317	$ 4,802,582	$ 8,788,463	$ 7,028,024	$ 489,307
4	OTHER OPERATING EXPENSE		$ 81,896,641	$ 30,692,260	$ 5,675,319	$ 10,316,366	$ 18,605,012	$ 15,658,115	$ 949,568
5	Subtotal - Expenses and Taxes		$ 562,409,950	$ 209,010,900	$ 34,205,964	$ 67,123,489	$ 128,023,251	$ 117,057,851	$ 6,988,496
6	TOTAL RATE BASE		$ 1,266,068,966	$ 504,989,442	$ 80,055,278	$ 154,946,769	$ 283,544,160	$ 226,746,708	$ 15,786,608
7	IMPLICIT RATE OF RETURN	5.29%	5.29%	5.29%	5.29%	5.29%	5.29%	5.29%	5.29%
8	REQUIRED OPERATING INCOME TO EQUALIZE CLASS RATES OF RETURN		$ 66,992,793	$ 26,721,019	$ 4,236,046	$ 8,198,856	$ 15,003,460	$ 11,998,079	$ 835,333
9	MISCELLANEOUS REVENUE CREDIT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	OTHER REVENUE		$ 86,507,498	$ 29,472,755	$ 4,552,920	$ 10,557,116	$ 20,927,647	$ 20,489,275	$ 507,785
11	OFFSETTING REVENUES		$ 86,507,498	$ 29,472,755	$ 4,552,920	$ 10,557,116	$ 20,927,647	$ 20,489,275	$ 507,785
12	REQ. OPER. INCOME LESS OFFSETTING REV.		$ (19,514,705)	$ (2,751,736)	$ (316,873)	$ (2,358,260)	$ (5,924,187)	$ (8,491,196)	$ 327,548
13	CURRENT RATE REVENUE		$ 542,895,245	$ 195,759,058	$ 41,072,116	$ 70,661,252	$ 124,277,037	$ 104,637,563	$ 6,488,218
14	CURRENT REVENUE PERCENTAGES		100.00%	36.06%	7.57%	13.02%	22.89%	19.27%	1.20%
15	RATE REVENUE EXCESS OR DEFICIENCY		$ -	$ 10,500,105	$ (7,183,025)	$ (5,896,024)	$ (2,177,974)	$ 3,929,092	$ 827,825
16	RATE REVENUE % CHANGE TO EQUALIZE CLASS RATES OF RETURN		0.00%	5.36%	-17.49%	-8.34%	-1.75%	3.75%	12.76%
17	REV. % WITH EQUALIZED ROR		100.00%	37.99%	6.24%	11.93%	22.49%	20.00%	1.35%