PUBLIC VERSION
Certain Schedules Attached To This Testimony
Contain "Confidential" Information And Have Been Removed.

BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

DIRECT TESTIMONY OF

BRADLEY D. LUTZ

ON BEHALF OF
KANSAS CITY POWER & LIGHT COMPANY

IN THE MATTER OF THE APPLICATION OF
KANSAS CITY POWER & LIGHT COMPANY
TO MODIFY ITS TARIFFS TO CONTINUE THE
IMPLEMENTATION OF ITS REGULATORY PLAN

DOCKET NO. 07-KCPE-_____-RTS

Q: Please state your name and business address.

A: My name is Bradley D. Lutz. My business address is 1201 Walnut, Kansas City, Missouri 64106-2124.

Q: By whom and in what capacity are you employed?

A: I am employed by Kansas City Power & Light Company ("KCP&L" or "Company") as a Senior Regulatory Analyst.

Q: What are your responsibilities?

A: My responsibilities include regulatory reporting, the preparation of miscellaneous regulatory filings and activities related to the Company's Rules and Regulations, formal customer complaints, evaluating and developing new tariffs related to KCP&L's Demand

Response, Efficiency, and Affordability programs, and various regulatory studies including the class cost of service ("CCOS") study.

Q: Please describe your education, experience and employment history.

A: I hold a Master of Business Administration from Northwest Missouri State University and a Bachelor of Science degree in Engineering Technology from Missouri Western State University.

I have been employed by KCP&L in my current position since September 2005. I joined the Company in August 2002, as an Auditor in the Audit Services Department. Prior to joining KCP&L, I was employed by the St. Joseph Frontier Casino for two years as Information Technology Manager. Prior to St. Joseph Frontier Casino, I was employed by St. Joseph Light and Power Company for nearly 14 years. I held various positions at St. Joseph Light and Power Company, including Engineering Technician-Distribution, Automated Mapping/Facilities Management Coordinator, and my final position as Senior Client Support Specialist-Information Technology.

Q: Have you previously testified in a proceeding at the Kansas Corporation Commission ("KCC") or before any other utility regulatory agency?

A: Yes. I provided direct and rebuttal testimony in KCC Docket No. 07-KCPE-905-RTS.

Q: What is the purpose of your testimony?

A: KCC Docket No. 07-KCPE-905-RTS (the "2007 Rate Case") was filed as the second of four rate cases contemplated under the approved Stipulation and Agreement in KCC Docket No. 04-KCPE-1025-GIE ("Regulatory Plan Stipulation"). KCP&L's 2007 Rate Case was resolved when the parties entered into a Stipulation and Agreement, which the KCC approved on November 20, 2007. The 2007 Rate Case Stipulation and Agreement included a requirement that KCP&L file a CCOS study with its next formal rate case. The purpose of my testimony in this case is to present the results of KCP&L's CCOS study.

Q: What is the purpose of the CCOS study?

A: The purpose of the CCOS study is to determine the contribution that each customer class makes toward the Company's overall rate of return. The CCOS analysis strives to attribute costs in relationship to the cost-causing factors of demand, energy, and customers.

Q: What classes were selected as a basis for this CCOS study?

A: The classes the Company included in the CCOS study are Residential, Small General Service, Medium General Service, Large General Service, Large Power Service, Off-Peak Lighting and Other Lighting. While the Off-Peak Lighting and Other Lighting classes are included in the study, the results were not evaluated since they are not necessarily reliable, as I discuss later in my testimony.

Q: Do these classes conform to the current electric rate tariffs?

A: Yes. The Residential Service class has several rate classifications available within it that include Residential General Use, Residential General Use and Water Heat – One Meter, Residential General Use and Space Heat – One Meter, Residential General Use and Space Heat – 2 Meters, Residential General Use and Water Heat and Separately Metered Space Heat – 2 Meters, and Residential Time of Day Service. The Small General Service, Medium General Service and Large General Service classes also have general usage rates and all-electric rates, plus they are specific to the voltage level at which the customer receives service. The Large Power Service class is distinguished by the specific voltage at which the customer receives service. In total, the Company has five (5) general categories of service (plus Lighting), but has many rate categories to meet the specific needs and configuration of delivered service of the customer and reporting and billing requirements.

Q: What test period was used for the CCOS study?

A: The test period for the CCOS study is the historical 12-month period ending December 2007 as adjusted and presented in the Direct Testimony of Company witness John Weisensee.

Q: Please provide an outline of the CCOS study as you are using it in this case.

A: In the context of this proceeding, KCP&L set out to perform an analysis of the expenses, investments and revenues for the test period. These expenses, investments and revenues were evaluated to identify their relation to providing service to various classes of customers and to determine their relative returns on rate base. The result of this analysis is the CCOS study.

Q: Is the data supporting expenses, investments and revenues used in the CCOS study the same as those used in the Jurisdictional Revenue Requirement study?

A: Yes.

Q: What general categories of cost were examined and considered in the development of the CCOS study?

A: An analysis was made of all elements of investment (rate base) and expense (cost of service) for the purpose of allocating these items to the customer classes. The first step in this process was to functionalize costs.

Q: Please explain what you mean by "functionalize costs."

A: In order to make the appropriate assignment of costs to the appropriate class of customer, it is necessary to first group the costs according to their function. The functions used in the CCOS study were production, transmission, distribution, and other costs.

Q: Were these costs then assigned to the customer classes?

A: No. After making the functional assignments of costs, the next step was to classify the costs.

Q: Please explain what you mean by "classify costs."

A: Functionalized costs are examined to determine if they are customer-related, energy-related, or demand-related.

Q: What do you mean by customer-related, energy-related and demand-related?

A: Customer-related costs are those costs necessary to provide electric service to the customer. Some examples of these costs include meter reading, customer accounting, billing, and some investment in plant equipment such as the meter, service line and other minimal distribution facilities necessary to make service available. Portions of the distribution facility are separated between the customer costs and the demand costs. Energy-related costs are directly related to the consumption of energy and consist of such things as fuel and purchased power. Demand-related costs relate to the investment and expenses associated with the Company's facilities necessary to supply the customer's energy and load requirements at various load levels. The majority of demand-related costs consist of production, transmission and the non-customer portion of distribution plant.

Q: Did the Company perform any special cost studies in order to determine the customer, energy and demand components when the investments or expense were within the same account?

A: The Company filed a CCOS study in its 2006 Rate Case Docket No. 06-KCPE-828-RTS. As part of that case, special studies were performed in order to evaluate various costs. Many of the special study results were reviewed and determined to be appropriate for use in this study. They include:

a) Primary/secondary split of distribution investment contained in Federal Energy Regulatory Commission ("FERC") accounts #364 through #367;
b) Customer/demand split of distribution investment contained in FERC accounts #364 through #368;
c) Meter cost study (typical installed meter and associated replacement cost);
d) Service line cost study (typical installed service line and associated replacement cost);
e) Meter reading;
f) Billing; and
g) Losses (load and no load).

For this CCOS study all of the special studies were reviewed and updated with data from the test period as necessary to reflect the current position of the Company.

Q: With the above classification of plant investment and operating costs into customer-, energy-, and demand-related components, what was the next step in the CCOS study?

A: The next step was to allocate each of the three categories of cost to each customer class utilizing allocation factors appropriate for each of the above categories of cost.

Q: How are the allocation factors for customer-related costs generally determined?

A: Customer-related costs are generally allocated on the basis of the number of customers within each class. Data for the development of the customer-related allocation factors came from Company billing and accounting records. Some of the customer-related accounts were allocated based on a weighted number of customers to reflect the different magnitudes of cost associated with serving those customers.

Q: How are the allocation factors for the energy-related costs generally determined?

A: Energy-related allocation factors were derived on the basis of the respective energy (kilowatt hour) requirements for each customer class. Kilowatt-hour sales to each customer class were available from Company records. The sales data was adjusted to reflect normal weather, system losses and unaccounted for, in order to assign the Company's total system output. Company witness George McCollister described this process in his Direct Testimony.

Q: Was the data for the development of class demand allocation factors also available from Company billing records?

A: No. The data necessary to develop class demand allocation factors (production and transmission) were derived from the Company's load research data. Such data consisted of the hour-by-hour use of electricity by each customer class throughout the study period. Consideration of system losses, unaccounted for, and sampling error was taken into account in determining the class demands. Company witness George McCollister described this process in his Direct Testimony.

Q: Was KCP&L's load research data used to develop any other allocators?

A: Yes, it was used to develop distribution plant allocators based on customers' non-coincident loads within each class.

Q: Are any costs assigned directly to classes?

A: Yes. In those instances where the costs are clearly attributable to a specific class, they are directly assigned to that class.

Q: After the determination of customer, energy and demand allocation factors for the various elements of the Company's costs, what is the next step in the completion of a CCOS study?

A: The next step is to apply the determined allocation factors to each element of rate base and expense in the CCOS study.

Q: Would you describe the various allocation factors and how they were applied to each account?

A: Yes. In fairly simple terms, the Company used an allocation method called the Average and Peak method to allocate production and transmission plant. This gives classes recognition for both usage and contribution to peak load. The demand portion of the distribution plant and related expense was allocated on two types of non-coincident demand ("NCD"). Substation related equipment and expense were allocated on class NCD allocators, while delivery equipment and expense were allocated on customer NCD allocators. The customer portion of the distribution plant and related expense was allocated based on the weighted number of customers. General and intangible plant was allocated based on the sum of combinations of production, transmission, and distribution plant accounts. For example, if no production-related plant was in the account, it was allocated based on an allocator that included only transmission and distribution plant.

Q: Why did the Company select the Average & Peak method using 1CP?

A: There are several reasons for selecting the Average & Peak (1CP) method. They include:

a) The load research sample data was designed based on the system peak demand conditions, thereby the results of the data are designed to give the most accurate data for that period.

b) Average demand is quite accurate in that it comes directly from the Company's actual books and records.

c) The Average & Peak (1CP) method recognizes that our electric utility system is designed to meet both peak demands and energy requirements, and that the production and transmission equipment are designed to meet both.

d) Our system load factor is approximately 50%, meaning that the average load is equal to approximately 50% of the peak demand, therefore recognizing the average demand allocation and peak demand allocation equally reflects our current load factor conditions.

e) Consistency with our prior study. Our 2006 and 2007 CCOS studies were completed using the Average & Peak (1CP) method. Consistency helps facilitate comparisons between the results.

Q: Have any allocation methods changed from the study submitted last year in the 2007 Rate Case?

A: Yes. Besides updating the factors, a new allocator was added for the Energy Efficiency Rider.

Q: Why were the allocators changed?

A: As part of the settlement Stipulation and Agreement for the 2007 Rate Case the Company agreed to utilize an Energy Efficiency Rider to recover Demand Side Management related costs. A new allocator was needed to properly distribute the associated revenues and expenses to the non-lighting classes impacted by the Rider.

Q: Did you consider changing any other allocators for this study?

A: Yes. We considered changing the production allocator to the Base-Intermediate-Peak ("BIP") Method.

Q: What is the BIP Method?

A: The BIP method is best described by the National Association of Regulatory Utility Commissioners in their *Electric Utility Cost Allocation Manual*. It states:

> The BIP method is a time differentiated method that assigns production plant costs to three rating periods: 1) peak hours, 2) secondary peak (intermediate, or shoulder hours) and 3) base loading hours. This method is based on the concept that the specific utility generation resources can be assigned in the cost of service analysis as serving different components of load; i.e., the base, intermediate and peak loads components.[1]

Once divided to the different load types, the associated production costs may be divided and allocated using a combination of other techniques. For example, costs associated with the base load could be allocated based on energy usage, costs associated with the

[1] Electric Utility Cost Allocation Manual, January 1992, National Associated of Regulatory Utility Commissioners, page 60.

intermediate loads could be allocated using the 12 coincident peak method and the peaking costs could be allocated on the 4 coincident peak method.

Q: **Why did you consider this allocator?**

A: As stated earlier, the Company supports an allocation method called the Average & Peak method because it recognizes both usage and contribution to peak load. The Company views the BIP method as a refinement of this approach. The BIP method would allow us to continue to recognize the dual nature of our generating resources and give us a structured and more precise way to incorporate the new Iatan 2 generating station into our rates. Further, the BIP method introduces sufficient detail into the causation of production costs to allow a detailed examination of seasonal costs and the resulting seasonal rate allocations.

Q: **Why didn't you use the BIP method in this filing?**

A: We are still examining the allocation method and would like to better understand it before proposing it in Kansas. The BIP method is being introduced in our Missouri jurisdiction through the work of Mr. Paul Normand, a consultant with Management Applications Consulting. Mr. Normand is a long-time advocate of the method and proposed it as part of a filing required by the Missouri Commission.

Q: **What is the next step in the CCOS study once the allocations are applied to the various rate base, revenue and expense accounts?**

A: The next step is to determine the relative return on rate base for each of the classes in the study. The ratio of class revenues less expenses (net operating income) divided by class rate base will indicate the rate of return being earned by the Company that is attributable to a particular class. It is necessary to keep in mind that this is a snapshot in time. The results of the CCOS study will most likely vary over time. The results of the study will also vary if you apply different allocation factors to the study. By applying different methods to the allocation process, one can change the outcome of the CCOS study.

Q: What are the results of the Company's CCOS study that was prepared and is being submitting in this case?

A: Schedule BDL-1 **(Confidential)**, is a summary of revenue and expenses, net operating income, rate base and rate of return for the total Company and the classes used in this study. Page 1 of Schedule BDL-1 **(Confidential)** reflects class returns for the test period. Page 2 reflects equalized return on equity for all classes and the resulting revenue adjustments, applied before any approved increase in rate revenue, that would be required to cause the classes to provide the same rate of return.

Q: What conclusions have you made from the results of the CCOS study?

A: The individual classes' rate of return at current rates vary, and are shown in the following table.

Class Rate of Return at Current Rates				
Residential Service	Small General Service	Medium General Service	Large General Service	Large Power Service
5.44%	6.33%	9.04%	5.59%	2.16%

Table 1

Q: If rates were changed so that KCP&L earned the same rate of return from each customer class, how much would each class' rates need to change?

A: By the percentages in the table below.

Change Required to Equalize Returns				
Residential Service	Small General Service	Medium General Service	Large General Service	Large Power Service
1.99%	-2.26%	-13.05%	1.23%	11.60%

Table 2

Q: Off-Peak Lighting and Other Lighting are included in your study but not listed in Table 1 or Table 2. Why?

A: In prior cases it has been acknowledged that the rate of return for lighting classes is questionable. It is difficult to calculate the true cost of lighting service due to the distinctiveness of the load pattern and other issues used in determining traditional CCOS studies. Lights are operating at maximum load during the night and at zero load during the day. Unless the allocation method considers hourly operating characteristics, the results are implausible and may seem distorted from the results for the other classes. The Company believes that dedicated studies of the lighting classes would be required to appropriately evaluate their rate of return.

Q: Can you explain the significant difference between the Large General Service and the Large Power classes relative to the others?

A: Yes. In the settlement of the 2007 Rate Case the parties agreed to apply the approved revenue increase directly to the Residential, Large Power and Other Lighting classes. This had the unexpected impact of breaking the relationship between the Large Power and Large General Service classes. In 2008, nearly all of the Large Power customers moved to the Large General Service class, leaving only three customers in the Large Power Class.

Q: Do you have any concerns about the large shift in customers?

A: Yes. With only three customers in the Large Power class we cannot utilize the CCOS study results to properly evaluate the relative rates of return for rate design purposes. It might be reasonable to recombine the Large General Service and Large Power classes to approximate the real rate of return. Regardless, the results should be considered inconclusive and would not warrant any class shifts as part of this case.

Q: What rate adjustments are being proposed for each class?

A: The Company does not propose to change the current relationship of customer class returns to the average jurisdictional return. The Company is recommending an equal percentage increase be applied to all customer classes with no changes to rate design. The tariffs filed with this case are based on applying the overall percentage increase to all tariffs (17.50%). Company witness Tim Rush addresses the rate design as part of his Direct Testimony.

Q: Why are you not suggesting further changes based on the outcome of the CCOS study?

A: It is the Company's position that any additional shift in revenue requirement among classes for the purpose of achieving equal returns of all classes is more appropriately addressed in a future rate design case. Because of the significant investments the Company is making, including investments in customer programs designed to assist customers in managing their energy bills, it is premature to align average class rates of return in this case. It is KCP&L's belief that the appropriate time to move toward equal rate of return for all customer classes is after completion of the Regulatory Plan and the in-service date of Iatan 2.

Q: Does that conclude your testimony?

A: Yes, it does.

BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Application of Kansas City Power & Light Company to Modify Its Tariffs to Continue the Implementation of Its Regulatory Plan	)))	Docket No. 09-KCPE-____-RTS

AFFIDAVIT OF BRADLEY D. LUTZ

STATE OF MISSOURI)
) ss
COUNTY OF JACKSON)

Bradley D. Lutz, being first duly sworn on his oath, states:

1. My name is Bradley D. Lutz. I work in Kansas City, Missouri, and I am employed by Kansas City Power & Light Company as Senior Regulatory Analyst.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Kansas City Power & Light Company consisting of fourteen (14) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

Bradley D. Lutz
Bradley D. Lutz

Subscribed and sworn before me this 4th day of ~~August~~ September 2008.

Nicole A. Wehry
Notary Public

My commission expires: Feb. 4 2011

" NOTARY SEAL "
Nicole A. Wehry, Notary Public
Jackson County, State of Missouri
My Commission Expires 2/4/2011
Commission Number 07391200

KANSAS CITY POWER & LIGHT COMPANY
DOCKET NO. ____________
CLASS COST OF SERVICE FOR KANSAS CUSTOMERS
FOR THE TEST YEAR ENDED DECEMBER 31, 2007

LINE NO.	DESCRIPTION	ALLOCATION BASIS	KANSAS RETAIL COL. 601	RESIDENTIAL COL. 602	SMALL GEN. SERVICE COL. 603	MEDIUM GEN. SERVICE COL. 604	LARGE GEN. SERVICE COL. 605	LARGE PWR SERVICE COL. 606	OFF-PEAK LIGHTING COL. 607	OTHER LIGHTING COL. 608
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
0010	**SCHEDULE 1 - SUMMARY OF OPERATING INC & RATE BASE**									
0020										
0030	OPERATING REVENUE	TSFR 2 870	554,133,187	275,891,586	34,879,852	66,759,587	156,036,290	11,173,491	3,153,216	6,239,165
0040										
0050	OPERATING EXPENSES									
0060	FUEL	TSFR 4 3940	101,560,200	44,529,744	4,855,545	11,677,023	36,372,052	3,275,239	486,526	364,072
0070	PURCHASED POWER	TSFR 4 3950	25,946,066	11,604,235	1,248,522	2,962,201	9,113,999	815,678	114,982	86,448
0080	OTHER OPERATION & MAINTENANCE EXPENSES	TSFR 4 3960	201,865,909	106,809,531	12,902,554	21,041,941	52,757,705	4,080,456	521,456	3,752,267
0090	DEPRECIATION EXPENSES (NET OF CLEARINGS)	TSFR 5 1420	76,728,912	40,202,661	5,305,525	8,271,996	19,890,841	1,452,304	190,710	1,414,876
0100	AMORTIZATION EXPENSES	TSFR 5 1650	20,626,074	10,168,165	1,161,714	2,161,242	6,408,969	562,245	95,337	68,402
0110	INTEREST ON CUSTOMER DEPOSITS	CUST21	90,512	3,803	66,581	12,508	3,463	10	4,147	0
0120	TAXES OTHER THAN INCOME TAXES	TSFR 6 560	33,900,399	17,842,315	2,268,286	3,629,626	8,938,986	667,371	86,384	467,431
0130	FEDERAL AND STATE INCOME TAXES	TSFR 7 1280	19,990,911	8,620,523	1,647,120	4,883,149	4,556,897	(175,737)	620,797	(161,836)
0140	GAINS ON DISPOSITION OF PLANT	NETPLANT	0	0	0	0	0	0	0	0
0150										
0160	TOTAL ELECTRIC OPERATING EXPENSES		480,708,983	239,780,976	29,455,847	54,639,686	138,042,911	10,677,566	2,120,338	5,991,660
0170										
0180	NET ELECTRIC OPERATING INCOME		73,424,204	36,110,610	5,424,005	12,119,901	17,993,379	495,926	1,032,878	247,505
0190										
0200	RATE BASE									
0210	TOTAL ELECTRIC PLANT	TSFR 10 230	2,699,422,995	1,425,019,676	184,416,074	289,667,985	704,699,851	51,774,683	6,850,132	36,994,594
0220	LESS: ACCUM. PROV. FOR DEPREC	TSFR 10 310	1,211,304,741	638,660,084	81,649,484	130,329,690	322,288,233	24,437,260	3,066,139	10,873,852
0230	NET PLANT		1,488,118,254	786,359,592	102,766,589	159,338,295	382,411,618	27,337,423	3,783,993	26,120,743
0240	PLUS:									
0250	WORKING CAPITAL	TSFR 15 380	46,478,090	20,349,400	2,054,410	5,238,315	17,068,033	1,584,904	178,826	4,202
0260	PRIOR NET PREPAID PENSION ASSET	SALWAGES	(147,620)	(76,952)	(9,036)	(15,506)	(40,058)	(3,186)	(396)	(2,486)
0270	PENSION REGULATORY ASSET	SALWAGES	16,297,775	8,495,817	997,640	1,711,894	4,422,525	351,786	43,673	274,441
0280	[redacted]									
0290	REG ASSET - DSM PROGRAMS	DEM1	0	0	0	0	0	0	0	0
0300	REG ASSET - REGULATORY EXPENSE	CLAIMEDREV	0	0	0	0	0	0	0	0
0310	JANUARY 2002 ICE STORM	DISTPLANT	0	0	0	0	0	0	0	0
0320	LESS:									
0330	ACCUM. DEFERRED TAXES	TSFR 8 600	257,387,401	134,697,048	16,764,860	27,846,186	69,232,527	5,216,857	598,852	3,031,071
0340	DEFERRED GAIN ON EMISSION CR.	ENERGY1	36,761,427	16,105,255	1,757,086	4,227,895	13,175,663	1,186,732	176,639	132,157
0350	DEFERRED GAIN ON SO2 ALLOW-100%	ENERGY1	0	0	0	0	0	0	0	0
0360	CUST. ADVANCES FOR CONSTRUCTION	DISTPLANT	2,175,074	1,254,640	232,728	229,123	355,409	9,080	6,505	87,590
0370	CUSTOMER DEPOSITS	CUST21	2,022,444	84,971	1,487,728	279,490	77,369	216	92,670	0
0380										
0390										
0400	TOTAL RATE BASE		1,255,419,408	664,307,535	85,711,386	134,037,250	322,103,158	22,957,231	3,145,922	23,156,927
0410										
0420	RATE OF RETURN		5.84858%	5.43583%	6.32822%	9.04219%	5.58622%	2.16022%	32.83227%	1.06882%
0430	RELATIVE RATE OF RETURN		1.00	0.93	1.08	1.55	0.96	0.37	5.61	0.18
0440										

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
0450	SCHEDULE 1 - SUMMARY AT EQUALIZED CLAIMED RATE OF RETURN									
0460										
0470	RATE BASE									
0480	TOTAL ELECTRIC PLANT	TSFR 10 230	2,699,422,995	1,425,019,676	184,416,074	289,667,985	704,699,851	51,774,683	6,850,132	36,994,594
0490	LESS: ACCUM. PROV. FOR DEPREC	TSFR 10 310	1,211,304,741	638,660,084	81,649,484	130,329,690	322,288,233	24,437,260	3,066,139	10,873,852
0500	NET PLANT		1,488,118,254	786,359,592	102,766,589	159,338,295	382,411,618	27,337,423	3,783,993	26,120,743
0510	ADD: WORKING CAPITAL	TSFR 15 380	46,478,090	20,349,400	2,054,410	5,238,315	17,068,033	1,584,904	178,826	4,202
0520	PROFORMA CWC	TSFR 16 2160	(0)	(79,307)	11,891	123,812	(24,443)	(24,491)	24,553	(32,014)
0530	PRIOR NET PREPAID PENSION ASSET	TSFR 1 260	(147,620)	(76,952)	(9,036)	(15,506)	(40,058)	(3,186)	(396)	(2,486)
0540	PENSION REGULATORY ASSET	TSFR 1 270	16,297,775	8,495,817	997,640	1,711,894	4,422,525	351,786	43,673	274,441
0550	[redacted]									
0560	REG ASSET - DSM PROGRAMS	TSFR 1 290	0	0	0	0	0	0	0	0
0570	REG ASSET - REGULATORY EXPENSE	TSFR 1 300	0	0	0	0	0	0	0	0
0580	JANUARY 2002 ICE STORM	TSFR 1 310	0	0	0	0	0	0	0	0
0590	LESS:									
0600	ACCUM. DEFERRED TAXES	TSFR 8 600	257,387,401	134,697,048	16,764,860	27,846,186	69,232,527	5,216,857	598,852	3,031,071
0610	DEFERRED GAIN ON EMISSION CR.	TSFR 1 340	36,761,427	16,105,255	1,757,086	4,227,895	13,175,663	1,186,732	176,639	132,157
0620	CUST. ADVANCES FOR CONSTRUCTION	TSFR 1 360	2,175,074	1,254,640	232,728	229,123	355,409	9,080	6,505	87,590
0630	CUSTOMER DEPOSITS	TSFR 1 370	2,022,444	84,971	1,487,728	279,490	77,369	216	92,670	0
0640	TOTAL RATE BASE		1,255,419,408	664,228,227	85,723,276	134,161,062	322,078,715	22,932,740	3,170,475	23,124,913
0650	OPERATING INCOME @ 5.849% ROR		73,424,204	38,847,917	5,013,594	7,846,517	18,837,030	1,341,240	185,428	1,352,479
0660										
0670	OPERATING EXPENSES									
0680	FUEL	TSFR 4 3940	101,560,200	44,529,744	4,855,545	11,677,023	36,372,052	3,275,239	486,526	364,072
0690	PURCHASED POWER	TSFR 4 3950	25,946,066	11,604,235	1,248,522	2,962,201	9,113,999	815,678	114,982	86,448
0700	OTHER OPERATION & MAINTENANCE EXPENSES	TSFR 4 3960	201,865,909	106,809,531	12,902,554	21,041,941	52,757,705	4,080,456	521,456	3,752,267
0710	DEPRECIATION EXPENSES	TSFR 5 1420	76,728,912	40,202,661	5,305,525	8,271,996	19,890,841	1,452,304	190,710	1,414,876
0720	AMORTIZATION EXPENSES	TSFR 5 1650	20,626,074	10,168,165	1,161,714	2,161,242	6,408,969	562,245	95,337	68,402
0730	INTEREST ON CUSTOMER DEPOSITS	TSFR 1 110	90,512	3,803	66,581	12,508	3,463	10	4,147	0
0740	TAXES OTHER THAN INCOME TAXES	TSFR 6 560	33,900,399	17,842,315	2,268,286	3,629,626	8,938,986	667,371	86,384	467,431
0750	PLUS: CHANGE IN TAXES OTHER THAN INCOME TAXES		0	0	0	0	0	0	0	0
0760	FEDERAL AND STATE INCOME TAXES	TSFR 7 1280	19,990,911	8,620,523	1,647,120	4,883,149	4,556,897	(175,737)	620,797	(161,836)
0770	PLUS: CHANGE IN FEDERAL AND STATE INCOME TAXES		0	1,459,669	(218,852)	(2,278,782)	449,877	450,764	(451,903)	589,227
0780	GAINS ON DISPOSITION OF PLANT	TSFR 1 140	0	0	0	0	0	0	0	0
0790	TOTAL ELECTRIC OPERATING EXPENSES		480,708,983	241,240,645	29,236,995	52,360,904	138,492,788	11,128,329	1,668,436	6,580,887
0800										
0810	COST OF SERVICE		554,133,187	280,088,561	34,250,589	60,207,420	157,329,818	12,469,569	1,853,864	7,933,366
0820	LESS: PRESENT OTHER REVENUE		144,771,440	64,647,544	7,029,728	16,543,552	50,811,559	4,536,304	645,323	557,430
0830	INCREASE IN 451-MISC SERVICE REVENUE	TSFR 1 920	0	0	0	0	0	0	0	0
0840	INCREASE OTHER	TSFR 1 930	0	0	0	0	0	0	0	0
0850	SALES REVENUE		409,361,747	215,441,017	27,220,861	43,663,869	106,518,259	7,933,264	1,208,541	7,375,936
0860										
0870	TOTAL REVENUE ADJUSTMENT		0	4,196,975	(629,263)	(6,552,166)	1,293,528	1,296,077	(1,299,352)	1,694,201
0880	PERCENT CHANGE (RATE SCHEDULES)		0.00000%	1.98679%	-2.25946%	-13.04796%	1.22930%	11.59957%	-51.81052%	29.81837%