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APR 23 2010

PUBLIC SERVICE
COMMISSION

Via Overnight Mail

April 22, 2010

Mr. Jeff Derouen, Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602

Re: Case No. 2009-00548 and 2009-00549

Dear Mr. Derouen:

Please find enclosed the original and twelve (12) copies each of the DIRECT TESTIMONY AND EXHIBITS of the following KIUC witnesses filed in the above-referenced matter.

1) Stephen J. Baron
2) Lane Kollen
3) Richard A. Baudino
4) Dennis W. Goins
5) Paul A. Coomes

By copy of this letter, all parties listed on the Certificate of Service have been served. Please place these documents of file.

Very Truly Yours,

Michael L. Kurtz, Esq.
Kurt J. Boehm, Esq.
BOEHM, KURTZ & LOWRY

MLKkew
Attachment
cc: Certificate of Service

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing was served by mailing a true and correct copy via electronic mail (when available) and by first-class postage prepaid mail, to all parties on the 22nd day of April, 2010.

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED
APR 23 2010
PUBLIC SERVICE
COMMISSION

IN THE MATTER OF:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS BASE RATES	)))	CASE NO. 2009-00549

AND

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES	)))	CASE NO. 2009-00548

DIRECT TESTIMONY AND EXHIBITS OF STEPHEN J. BARON

ON BEHALF OF

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

April 2010

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF LOUISVILLE GAS AND	)	
ELECTRIC COMPANY FOR AN ADJUSTMENT	)	**CASE NO.**
OF ITS ELECTRIC AND GAS BASE RATES	)	**2009-00549**

AND

APPLICATION OF KENTUCKY UTILITIES	)	
COMPANY FOR AN ADJUSTMENT	)	**CASE NO.**
OF BASE RATES	)	**2009-00548**

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS BASE RATES	)))	**CASE NO. 2009-00549**

AND

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES	)))	**CASE NO. 2009-00548**

DIRECT TESTIMONY OF STEPHEN J. BARON

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by who are you employed?

A. I am the President and a Principal of Kennedy and Associates, a firm of utility rate, planning, and economic consultants in Atlanta, Georgia.

Q. Please describe briefly the nature of the consulting services provided by Kennedy and Associates.

A. Kennedy and Associates provides consulting services in the electric and gas utility industries. Our clients include state agencies and industrial electricity consumers. The firm provides expertise in system planning, load forecasting, financial analysis, cost-of-service, and rate design. Current clients include the Georgia and Louisiana Public Service Commissions, and industrial consumer groups throughout the United States.

Q. Please state your educational background and experience.

A. I graduated from the University of Florida in 1972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, I received a Master of Arts Degree in Economics, also from the University of Florida.

I have more than thirty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

I have presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Maryland, Missouri, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, Utah, Virginia, West Virginia, Wisconsin, Wyoming, the Federal Energy Regulatory Commission and in United States Bankruptcy Court.

A complete copy of my resume and my testimony appearances is contained in Baron Exhibit__(SJB-1).

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Kentucky Industrial Utility Customers ("KIUC"), a group of large industrial customers taking service on the LG&E and KU systems. The KIUC members who take service from the Companies are: Arch Chemicals, Inc., Carbide Industries LLC, Cemex, Clopay Plastics Products Co., Inc., Dow Corning Corporation, E.I. DuPont de Nemours & Co., Ford Motor Co., General Electric – Appliance Park, Golden Foods, MeadWestvaco, NewPage Corp., North American Stainless, Protein Technologies, Square D. Company (US Schneider Electric), TI Group Automotive Systems, and Toyota Motor Engineering and Manufacturing North America, Inc.

Q. Have you previously testified in KU and LG&E rate proceedings before the Kentucky Public Service Commission?

A. Yes. I have testified in 12 KU and LG&E cases since 1981.

Q. How have you organized your testimony with regard to LG&E and KU issues?

A. For many of the issues that I will discuss, I present common testimony that is applicable to both LG&E and KU. This would include discussions of basic principles associated with cost allocation and rate design. However, since the revenue requirement requests and the specific cost of service study results for LG&E and KU rate classes are different, I will be presenting separate analyses and discussions of these results.

For the purposes of organizing my testimony, when I am discussing an issue that is common to both LG&E and KU, I will refer to these companies as ("the Company" or the "Companies"). For a specific LG&E and KU issues I will refer to each Company by name (LG&E or KU).

Q. What is the purpose of your testimony?

A. I am presenting testimony on a variety of cost of service and rate design issues raised by the Company's filings in this case. The first issue that I address concerns the Company's filed cost of service study using the base-intermediate-peak ("BIP") class cost of service methodology. While I do not believe that the BIP methodology is the most reasonable approach to class cost of service analysis, I have relied on this methodology in this case. In particular, the BIP method tends to allocate a greater percentage of the Companies' production and transmission costs to high load factor industrial rate classes because a significant portion of these costs are classified as energy related (the base portion of the BIP method). While I generally support utilizing cost of service results to apportion class revenue increases, and rely on these results for KU in this case, the test year cost of service results for LG&E are not representative, particularly for the large industrial rate classes. LG&E is proposing a relatively uniform increase to each rate class. I will discuss KIUC's proposed apportionment of the increase, which relies on cost of service results from the LG&E's prior 2008 rate case. This is the most current, representative cost of service study for LG&E. For KU, I will present an alternative revenue apportionment based on the BIP methodology that reduces dollar subsidies by 25% at proposed rates.

The next set of issues that I will address concerns the Company's proposed rate design for large commercial and industrial customers. The Companies are proposing a number of changes to their large industrial rates, including changes to the time-of-day rate structure, a conversion to kVa billing for primary service customers from the current kW billing basis and changes in the minimum billing demand determination, the so-called demand ratchet provisions. While KIUC does not oppose the Companies TOD rate structure changes or the switch to kVa billing for KU, we strongly oppose the switch to kVa billing for LG&E, due to the abnormally large increases that will be imposed on some customers in the affected ITODP rate. KIUC also strongly opposes the Companies revisions to the demand ratchet provisions. This is a particularly important issue on KU rate schedule FLS (Fluctuating Load Service) that serves a single customer, North American Stainless. As I will discuss in my testimony, the Companies proposed revision to the FLS demand ratchet is not reasonable, and in fact the current demand ratchet should be reduced for this rate schedule.

Q. Would you please summarize your testimony?

A. Yes. I recommend and conclude the following:

- **The BIP cost of service method, though lacking in some respects is adequate to use in the determination of a fair apportionment of any authorized rate increase for KU in this case; though it is reasonable to consider the cost of service results from both a traditional 12 CP and Average and Excess study. Based on the BIP cost of service results, KU's large industrial rate classes (rates TODP, RTS and FLS) are significantly subsidizing other rate schedules and should receive a lower than average increase. While KU has attempted to reduce a small portion of these subsidies, large customers would continue to pay significant subsidies under the Company's proposal. KIUC recommends that the increase in this case for KU be apportioned to produce a 25% subsidy reduction.**

- **In the alternative, if the Commission does not adopt a full 25% subsidy reduction apportionment for all rate classes, the Commission should apportion the overall increase for KU rate classes so that current subsidies for large industrial customers on Rate Schedules TODP, RTS and FLS are reduced by 25%, with the remaining revenue increase apportioned to all other rate schedules either by 1) applying the Company's recommended increase for the residential class together with a uniform percentage increase for remaining rate classes or 2) a uniform percentage increase for all other classes, including the residential class.**

- **For LG&E, KIUC agrees with the Company that the class cost of service study is not representative of going-forward cost of service, especially for the large customer classes. KIUC's primary recommendation is to rely on the general results of the Company's 2008 cost of service study. This is the most current, representative cost of service study. Based on this, KIUC recommends that large customer rates receive an increase that is 2 percentage points lower than the overall increase approved by the Commission in this case, with the remaining rate classes receiving a uniform increase. As an alternative proposal, KIUC supports the Company's proposed uniform increase for each rate class.**

- **If, as recommend by KIUC, the Commission authorizes a lower overall revenue increase for KU than requested by the Company, KIUC recommends that the overall approved increase be allocated in a manner (as shown later in my testimony) to reduce current rate subsidies by 25%. For LG&E, KIUC recommends an increase that is 2 percentage points lower than the overall increase approved by the Commission in this case.**

- **KIUC generally supports KU's proposed large commercial and industrial rate design that revises the time-of-day rate structures of these rates and converts to a kVa billing demand basis (from the current kW demand basis) for KU primary voltage service customers. However, KIUC strongly objects to the Companies proposal to convert to kVa billing for LG&E. As I discuss in my testimony, some customers on LG&E rate schedule ITODP would receive increases that exceed 19% under the Company's proposal. This is an unreasonable level of increase, when compared to the average increase for rate schedule ITODP of 12.2%.**

- **KIUC strongly objects to the Companies proposed changes to the minimum bill provisions (the "demand ratchet" provisions) for rate schedule FLS. As I discuss in my testimony, there is no basis for the Company's proposed increases and, in fact, the current rate schedule FLS billing demand ratchet (minimum billing demand provisions) should be reduced from the current 50% level, tied to the highest demand during the preceding 11 months, to a 30% level. In future rate cases, the billing demand ratchet for rate schedule RTS (retail transmission service) should also be reduced to 30%.**

II. CLASS COST OF SERVICE AND REVENUE APPORTIONMENT

Q. Have you reviewed the Companies' proposed "base-intermediate-peak" cost allocation methodology?

A. Yes. The BIP method is the class cost allocation method used by LG&E in prior cases and was used for the first time by KU in Case No. 2003-00434.

The basic methodology, as discussed by Company witness Steven Seelye, first functionalizes the Company's production and transmission demand-related costs into three periods. Under the Company's BIP functionalization that is used in both the LG&E and KU studies, total system production and transmission demand-related costs are assigned as follows:

	Assignment of Total P&T Costs
Base	**34.89%**
Winter Peak	**43.25%**
Summer Peak	**21.86%**

These functional allocators for the base, intermediate and peak periods are identical for both LG&E and KU under the Company's methodology. Once the total production and transmission demand-related costs have been functionalized to these three categories, they are allocated to rate classes using three different class allocation factors. For the 34.89% of production and transmission demand-related costs that are assigned to the base period, costs are allocated using class energy use. For the summer peak period costs that comprise 21.86% of all production and transmission demand-related costs, costs are allocated to classes based on class contributions to the summer system peak demand. Finally, for winter peak period costs that comprise 43.25% of the Company's total production and transmission demand-related costs under the BIP method, costs are assigned based on each customer classes' contribution to the summer coincident peak.

Q. Have these BIP percentages changed materially from the Companies' 2008 base rate case?

A. Yes. First, in the 2008 rate case, the "peak" period in the BIP method was the summer peak. This is consistent with the importance of the summer peak in driving generating capacity additions on the Companies' systems. In this case, however, the "peak" period is now the winter peak and 43.25% of the system production and transmission costs are allocated based on rate class winter demands. In the prior case (2008), only 15.32% of the system production and transmission costs were assigned to the winter ("intermediate") period. Again, in this case, only 21.86% of the total system production and transmission costs are assigned to the summer peak period, while in the 2008 rate case, 50.78% of the costs were assigned to the summer peak period. This change, which Mr. Seelye explains is the result of an unusual winter peak during the test year, appears to have caused a significant shift in cost responsibility, especially for LG&E's rate classes. Table 1 below shows a comparison of the BIP percentage factors used to assign production and transmission costs to the base, intermediate and peak periods.

Table 1
Comparison of BIP Classification Percentage

	2009	2008
Base	34.89%	33.89%
Intermediate	43.25%	15.32%
Peak	21.86%	50.78%

Q. Has this shift in cost responsibility to the winter peak affected the class cost of service results in this case?

A. Yes, particularly for LG&E. As noted by Mr. Seelye on page 6 of his LG&E testimony, it "is a highly unusual result based on what the Company has experienced in the past." As I will discuss subsequently in my testimony, while this unusual test year result has impacted the class cost of service study result for both Companies, it appears to have played a more significant role in the LG&E study, perhaps because of the impact of natural gas heating, and thus fewer electric heating customers, on the LG&E system. At any rate, Mr. Seelye has recognized this anomaly and is proposing a uniform increase to each rate class on the LG&E system.

LG&E Cost of Service and Revenue Apportionment

Q. Does KIUC support LG&E's proposal to apply a uniform percentage increase to each rate class?

A. Not as a primary recommendation. Based on my review of the LG&E cost of service study and the problems that Mr. Seelye identified in his testimony, it is reasonable to conclude that the LG&E cost of service results do not provide a representative basis for setting rates going forward. In LG&E's prior base rate case, using a test year ending April 30, 2008, LG&E's industrial rate classes were shown to have rates of return above the system average, in some case substantially above. Table 2 (below), shows the rates of return and relative rates of return for LG&E from the 2008 rate case (Case No. 2008-00252). This table is based on the corrected BIP cost of service results from my testimony in that case.

Table 2
Louisville Gas & Electric Company
LG&E BIP and Corrected BIP Cost of Service Study Results
2008 LG&E Rate Case No. 2008-00252

	LG&E BIP		Corrected BIP	
	Rate of Return	Relative ROR Index	Rate of Return	Relative ROR Index
Residential	5.28%	0.68	5.28%	0.68
General Service	13.01%	1.67	13.01%	1.67
Rate LC	10.39%	1.34	10.99%	1.41
Rate LC-TOD	8.56%	1.10	8.41%	1.08
Rate LP	10.11%	1.30	10.67%	1.37
Rate LP-TOD	7.49%	0.96	8.03%	1.03
Special Contract	5.36%	0.69	3.67%	0.47
Lighting	7.53%	0.97	7.51%	0.97
Rate LC-STOD	5.51%	0.71	5.70%	0.73
Total	7.77%	1.00	7.77%	1.00

Based on these cost of service results from the prior rate case, which had a test year only 18 months older than the test year in this case, it is certainly reasonable to conclude that the LG&E cost of service study developed in this current case is not a reasonable basis to apportion the approved revenue increase to rate classes.

Q. What is KIUC's recommendation in this case for revenue apportionment in the LG&E rate case?

A. In consideration of the problems with the cost of service study in this case, coupled with the impact of even a uniform percentage increase to large manufacturing customers on the LG&E system, KIUC recommends that reliance be placed on the results of the cost of service study produced in the prior 2008 rate case (see Table 2).

Specifically, KIUC recommends as a primary recommendation in this case that LG&E large customer rates receive an increase of 2 percentage points below the system average increase, with the remaining rate classes receiving a uniform percentage increase. As an alternative recommendation, KIUC would support the Company's proposed uniform percentage increase for all rate classes.

Q. Have you developed a set of proposed rate class increases that reflect KIUC's primary recommendation?

A. Yes. Table 3 shows these percentage increases. Also shown are the Company's proposed uniform percentage increases, which would be KIUC's alternative recommendation for LG&E revenue apportionment, in the event that the Commission did not adopt our primary proposal. Based on the Company's requested increase of $94.3 million in rate schedule revenues (12.22%), the large customer class increases would be 10.22% and the increases for all other rate classes would be 12.72%, only about 0.5% greater than proposed by LG&E.

Table 3
LOUISVILLE GAS AND ELECTRIC COMPANY
Summary of Proposed Increase
Based on Sales for the 12 months ended October 31, 2009

	LG&E Proposed			KIUC Proposed	
	Adj. Billings at Current Rates	Increase	Percentage Increase	Increase	Percentage Increase
Residential Rate	$ 302,462,182	$ 36,859,770	12.19%	38,464,321	12.72%
General Service	114,001,397	13,879,697	12.18%	14,497,635	12.72%
Power Service	176,065,555	21,442,743	12.18%	22,390,376	12.72%
Total Commercial TOD Service	$ 45,792,547	$ 5,576,623	12.18%	4,681,937	10.22%
Total Industrial TOD Service	$ 86,997,161	$ 10,596,615	12.18%	8,894,792	10.22%
Retail Transmission Service	20,212,652	2,464,135	12.19%	2,066,589	10.22%
Special Contracts	13,046,506	1,590,095	12.19%	1,333,905	10.22%
Lighting Service	$ 15,159,687	$ 1,847,743	12.19%	1,927,868	12.72%
Total Rate Revenues (w/o CSR Credits)	$ 771,070,235	94,257,422	12.22%	94,257,422	12.22%
Misc Revenues	10,156,418	313,898		313,898	
Total Revenues	781,226,653	94,571,320	12.11%	94,571,320	12.11%

Q. Why do you believe that it is reasonable to place reliance on the 2008 class cost of service results and provide a lower increase to large customer rates?

A. First, because the test year cost study in this case is not representative of the test year or going-forward results, it would not be appropriate to place reliance on that study. This is the basic conclusion of LG&E witness Seelye and I agree with it. At this point, the next best source of evidence is the cost of service study results from the prior case, which is only 18 months older than the current test year. This study indicates that large customer rate classes are paying excessive rates. The 2003 LG&E cost of service study results also indicated that large customer rate classes were paying excessive rates.

While the settlements in those two rate cases did mitigate some of the excessive subsidies paid by large customer rate classes, the subsidy reductions in those cases did not fully move these large customer rate classes towards cost based rates. Finally, the economic downturn in the U.S. and in Kentucky has severely stressed the manufacturing sector and resulted in job losses. As discussed by KIUC witness Dr. Paul Coomes, Professor of Economics at the University of Louisville, those high wage, high benefit manufacturing jobs in export industries bring many benefits to the economy of Kentucky that service sector commercial businesses do not.

Q. In the likely that the Commission authorizes LG&E a smaller revenue requirement increase than it has requested, what is your recommended apportionment?

A. Assuming that the final authorized revenue increase level is lower than the Company's requested increase, KIUC recommends that the approved LG&E overall revenue increase be applied following KIUC's primary recommended apportionment proposal, which would increase LG&E's large customer rates by 2.0

percentage points less than the overall average increase, with the remaining rate classes receiving a uniform percentage increase designed to recover the remaining revenue increase.

<u>KU Cost of Service and Revenue Apportionment</u>

Q. For KU, the Company is proposing to rely on the BIP class cost of service results as a guide to apportioning the overall revenue increase in this case to rate classes. Do you agree with the Company's proposed rate class increases?

A. No. While I do agree with the Company that it is appropriate to use the class cost of service results to apportion the KU revenue increase, I have identified two problems with the KU's analysis. First, the KU BIP cost of service study should be adjusted so that the curtailable credits reflect test year revenue credits actually corresponding to the curtailable credits paid during the test year. This is necessary so that these credits match the test year revenues used in the analysis. While this adjustment does not affect KU's cost of service results at proposed rates (the rates of return shown for each rate class at proposed rates), it does affect the rates of return and the subsidies paid and received by each rate class at present rates. When this correction is made, it becomes clear that KU's proposed rate class increases result in increases in the dollar subsidies paid by large industrial customers to the residential class, not decreases in these subsidies. As a result, KU's proposed industrial rates actually move farther away from cost of service. As I will discuss, KIUC is proposing an alternative apportionment of the overall KU revenue increase that reduces rate class subsidies by 25% in this case.

Q. Would you explain the adjustment that you have made to the KU BIP cost of service study?

A. The KU cost of service study includes an adjustment to address the implied cost associated with curtailable credits. As discussed by KU witnesses Seelye and Conroy, the Company provides curtailable credits to large customers who agree to accept actual and potential curtailments of firm service. These credits are designed to reflect the cost of peaking capacity that would otherwise be required to serve this load if it were firm, instead of curtailable. Since these credits reflect the payment for peaking capacity (in the form of customer offered curtailable load), the credits are treated as a production expense in the cost of service study and allocated as a cost to each rate class, including those classes containing curtailable load. An additional corresponding adjustment is also made to specifically assign this "credit cost" as an expense offset to rate classes containing curtailable load. This second adjustment, which is exactly equal to the first adjustment on a total Company basis acts to offset the lower actual revenues recorded for curtailable customers who received these credits during the test year. Without this second adjustment, the cost of service results for rate classes with curtailable load would be incorrect because it would allocate cost as though these classes were comprised of 100% firm load, but, due to the curtailable credits, have insufficient revenue support for the allocated cost. I agree with this conceptual treatment and have recommended similar approaches in other cases.[1]

Q. What is the specific problem that you have identified with the Company's analysis with regard to the treatment of curtailable credits?

A. The KU cost of service study has used the proposed level of curtailable credits to calculate class rates of return at present rates. Since the test year revenues used in the study reflect the test year level of curtailable credits, the proper credit value to use in the "current rate" cost of service study is the matching level of test year curtailable credits actually paid to curtailable load. While this correction only affects the Company's cost of service results at "present rates" and not the results shown for "proposed rates," which should use the proposed level of curtailable credits, the use of the proposed credits in the "present rate" cost of service study produces an incorrect rate of return result. More importantly, this error causes an incorrect presentation of the level of dollar subsidies paid or received by each rate

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[1] This should not be construed to indicate support for the Companies' curtailable service rate proposals in this case. Dr. Dennis Goins, on behalf of KIUC, addresses the Companies' CSR rate proposals and recommends a number of changes to these rates in his testimony.

class. This has a particularly significant effect on the results for the FLS rate class that has a large amount of curtailable load.

Q. What does your adjusted BIP cost of service study show with regard to the rate of return paid by each rate class on the KU system?

A. Baron Exhibit__(SJB-2) presents the results of my adjusted KU class cost of service study. The only change that I made to the Company's study is to substitute the actual test year level of curtailable credits for the pro-forma value used in the KU study that which reflects KU's proposal to apply the CSR1 credit amount to CSR3 (Seelye KU testimony at page 21). Table 4 below summarizes the Company's and the Corrected BIP cost of service study results for KU.

Table 4
Kentucky Utilities Company
KU BIP and KIUC Adjusted BIP Cost of Service Study Results

	KU BIP		KIUC Adjusted BIP	
	Rate of Return	Relative ROR Index	Rate of Return	Relative ROR Index
Residential	2.33%	0.44	2.36%	0.44
General Service Secondary	9.24%	1.73	9.28%	1.74
All Electric School	2.19%	0.41	2.23%	0.42
Power Service Secondary	8.30%	1.55	8.33%	1.56
Power Service Primary	7.87%	1.47	7.90%	1.48
Time of Day Secondary	5.66%	1.06	5.69%	1.07
Time of Day Primary	6.44%	1.21	6.48%	1.21
Retail Transmission Service	9.73%	1.82	9.77%	1.83
Fluctuating Load Service	13.11%	2.45	10.03%	1.88
Street Lighting	9.34%	1.75	9.34%	1.75
Total	5.34%	1.00	5.34%	1.00

Table 4 summarizes the cost of service results in the form of a relative rate of return index. For the total system, the rate of return index is 1.0. For the residential class, under the corrected BIP method, the rate of return index is 0.44. This means that residential customers are paying a rate of return at approximately 44% of the system average. This is in contrast to the rate of return index for the large customer rate classes that have rate of return indexes of 1.21 (rate TODP), 1.83 (rate RTS) and 1.88 (rate FLS). For these classes, customers are paying rates of return on investment substantially above the system average.

Q. What conclusions do you draw from these "relative rate of return" indices?

A. Based on my adjusted cost of service study and KU's study as filed, residential customers are paying rates of return substantially below the system average rate of return. Based on these results, the Company is proposing to increase residential rates at a higher than average level, while proposing to increase to large commercial and industrial rates at a slightly lower than average level.

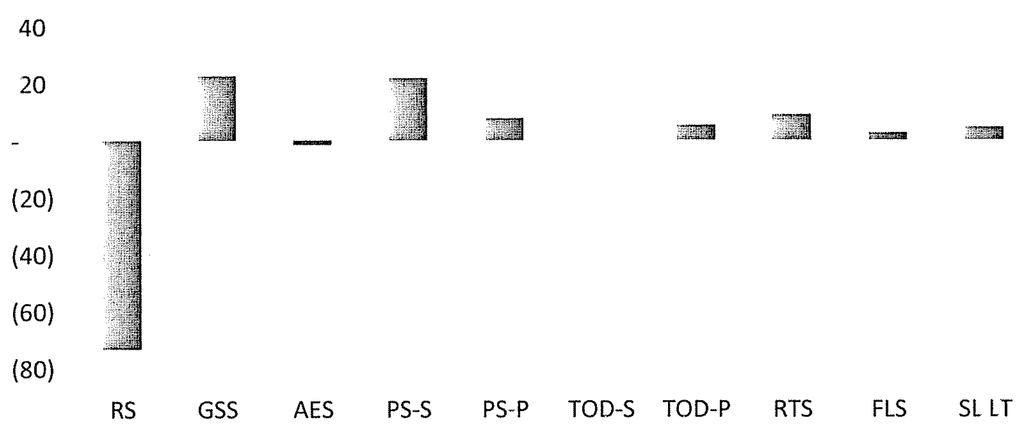
Q. Have you identified any particular subsidy problems in your evaluation of the KU BIP class cost of service results?

A. Yes. As can be seen from Table 4, KU's Large Industrial rates (TODP, RTS and FLS) are paying rates of return on rate base of that are more than "1.2 times", "1.8 times" and "1.8 times" respectively, the average rate of return paid by all KU retail customers. This is highly unreasonable and should be mitigated in this case. These rates are providing huge subsidies to other rate classes, which should be remedied in this case. Table 5 presents the dollar subsidies paid and received by each rate class at present rates. Figure 1 presents a graphic depiction of these dollar subsidies.

Table 5
Kentucky Utilities Company
Dollar Subsidies (Received) and Paid

		Dollar Subsidy
Residential	$	(73,234,953)
General Service Secondary	$	22,807,745
All Electric School	$	(1,501,325)
Power Service Secondary	$	22,093,964
Power Service Primary	$	7,841,345
Time of Day Secondary	$	126,754
Time of Day Primary	$	5,453,436
Retail Transmission Service	$	9,123,726
Fluctuating Load Service	$	2,690,442
Street Lighting	$	4,598,867
Total		0

Figure 1
Dollar Subsidies (Received) and Paid
($million)



Q. Has the Company offered a proposal to adequately address the large disparities between its rates and the underlying cost of service?

A. No. While KU is proposing to move rate classes towards cost of service, there would continue to be substantial subsidies paid by large customer rate classes under the Company's proposals in this case. I believe that the Company's subsidy reduction proposal is inadequate, given the disparities shown in the Company's cost of service study. This is particularly significant in light of the continuing impacts of the economic recession on KU's manufacturing customers and the high-wage, high benefit jobs that industrial customers bring to Kentucky residents.

KIUC witness Dr. Paul Coomes, Professor of Economics at the University of Louisville presents testimony on the specific impact of the many benefits those manufacturing jobs bring to the economy of Kentucky. Given the significant impact of manufacturing job loss on the State, the Commission should adopt rates in this case that reduce the current subsidy costs that are being imposed on these large customers. KU's proposal does not adequately reduce these excessive subsidies built-into large customer rates.

Q. What is your recommendation to reduce subsidies among KU's rate classes in this case?

A. I am recommending a 25% subsidy reduction using the results of KIUC's adjusted BIP cost of service study for KU. Baron Exhibit (SJB-3) presents the results of a revenue increase distribution using a 25% current subsidy reduction criterion. In this analysis, rate classes are allocated the proposed overall KU revenue increase in such a manner that the dollar subsidies paid and received by each rate class at proposed rates are only 75% of the level of these subsidies paid and received at present rates (i.e., a 25% reduction in the current level of dollar subsidies). Table 6 below presents the proposed revenue increases for each rate class assuming that the Company's requested overall revenue increase level is implemented.[2]

[2] As discussed by KIUC witness Kollen, KIUC is recommending a smaller overall increase in KU's rates.

Table 6
Kentucky Utilities Company
Increases with 25% Subsidy Reduction

		Increase	Percent
Residential	$	84,878,652	19.56%
General Service Secondary	$	9,881,348	6.06%
All Electric School	$	1,692,077	20.47%
Power Service Secondary	$	14,443,997	6.59%
Power Service Primary	$	6,328,490	7.24%
Time of Day Secondary	$	955,433	9.58%
Time of Day Primary	$	11,747,159	8.40%
Retail Transmission Service	$	3,331,334	4.58%
Fluctuating Load Service	$	891,017	4.70%
Street Lighting	$	1,946,913	9.28%
Subtotal	$	136,096,420	11.59%
Curtailable Service Riders	$	(1,755,650)	
Total	$	134,340,771	11.49%

Q. If the Commission accepts your recommendation for a 25% subsidy reduction in proposed rates for KU, what will the going-forward level of subsidies be for each rate class?

A. Table 7 below shows the levels of subsidies that will continue in proposed rates if the KIUC recommendation is implemented. Also shown in the table is the level of subsidies that will continue if the Company's recommendation is adopted. As can be seen, even if the KIUC 25% subsidy reduction recommendation is adopted, the amount of subsidies that will continue to be paid will be substantial. For example, customers in rate classes TODP, RTS and FLS, on which KIUC members take the largest portion of their service, will pay $13.0 million in subsidies each year, even if the KIUC recommendation is adopted by the Commission. Though, ideally, this level of subsidy payment should also be eliminated, KIUC recognizes that it is not feasible, from a rate impact standpoint, to eliminate all subsidies in a single rate proceeding.

Table 7
Kentucky Utilities Company
Remaining Subsidies at Proposed Rates

	KU		KIUC	
Residential	$	(81,057,953)	$	(54,926,215)
General Service Secondary	$	23,612,653	$	17,105,808
All Electric School	$	(1,669,000)	$	(1,125,994)
Power Service Secondary	$	25,214,500	$	16,570,473
Power Service Primary	$	8,488,843	$	5,881,008
Time of Day Secondary	$	215,077	$	95,065
Time of Day Primary	$	7,859,434	$	4,090,077
Retail Transmission Service	$	10,769,462	$	6,842,794
Fluctuating Load Service	$	2,999,455	$	2,017,832
Street Lighting	$	3,567,529	$	3,449,150
Total	$	(0)	$	(0)

Q. In the event that the Commission decides not to reduce current dollar subsidies for all KU rate classes by a full 25% in this case, are there alternative approaches that the Commission could adopt and still reduce subsidies paid by industrial customers by 25%?

A. Yes. Given the significance of high paying manufacturing jobs to the State, and the competitive pressures that large industrial customers face nationally and internationally, KIUC has developed two alternatives that reduce the dollar subsidies paid by large industrial customers (Rate Schedules TODP, RTS and FLS) as proposed in Table 6, and recovers the remaining approved revenue increase from all other rate schedules. The first approach ("Alternative 1") reduces the subsidies for Rate Schedules TODP, RTS and FLS by 25%, adopts the Company's proposed increase for the residential class and recovers the remaining portion of the increase on a uniform percentage basis for all other rate classes.

The second approach ("Alternative 2") reduces the subsidies for Rate Schedules TODP, RTS and FLS by 25% and recovers the remaining portion of the increase on a uniform percentage basis for all other rate classes (including the residential class). While I continue to believe that it would be appropriate to make progress towards cost based rates through the implementation of a full 25% subsidy reduction for all rate classes, the Commission may not choose to do so in this case, given the current economic environment. KIUC's alternatives mitigate the impact of a full 25% subsidy reduction to residential customers, while implementing a reasonable (25%) level of subsidy reduction for large industrial customers who, unlike smaller commercial customers, face competition from outside Kentucky (both nationally and internationally). Commercial customers tend to face local competition so that there are minimal differences in power costs among competitors. This is in contrast to large industrial manufacturing customers that face national and international competition.

Q. Have you developed an analysis that reflects your alternative revenue increase apportionment approaches?

A. Yes. Table 8 below summarizes the increases under KIUC's two alternative approaches to apportion the KU increase. Table 9 compares the percentage increases for each rate schedule proposed by KU to the KIUC primary recommendation and the two alternative proposals.

Table 8
Kentucky Utilities Company
KIUC Alternative Increases

	Alternative 1		Alternative 2	
	Increase	Pct	Increase	Pct
Residential	$ 58,746,914	13.54%	$ 55,288,164	12.74%
General Service Secondary	$ 19,659,380	12.06%	$ 20,767,182	12.74%
All Electric School	$ 996,931	12.06%	$ 1,053,108	12.74%
Power Service Secondary	$ 26,439,445	12.06%	$ 27,929,302	12.74%
Power Service Primary	$ 10,550,622	12.06%	$ 11,145,147	12.74%
Time of Day Secondary	$ 1,202,666	12.06%	$ 1,270,436	12.74%
Time of Day Primary	$ 11,747,159	8.40%	$ 11,747,159	8.40%
Retail Transmission Service	$ 3,331,334	4.58%	$ 3,331,334	4.58%
Fluctuating Load Service	$ 891,017	4.70%	$ 891,017	4.70%
Street Lighting	$ 2,530,952	12.06%	$ 2,673,570	12.74%
Total	$ 136,096,420	11.59%	$ 136,096,420	11.59%

Table 9
Kentucky Utilities Company
Summary of Proposed Increases ($millions)

		KIUC		
	KU	Primary	Alt 1	Alt 2
RS	$ 58.7	$ 84.9	$ 58.7	$ 55.3
GSS	$ 16.4	$ 9.9	$ 19.7	$ 20.8
AES	$ 1.1	$ 1.7	$ 1.0	$ 1.1
PS-S	$ 23.1	$ 14.4	$ 26.4	$ 27.9
PS-P	$ 8.9	$ 6.3	$ 10.6	$ 11.1
TOD-S	$ 1.1	$ 1.0	$ 1.2	$ 1.3
TOD-P	$ 15.5	$ 11.7	$ 11.7	$ 11.7
RTS	$ 7.3	$ 3.3	$ 3.3	$ 3.3
FLS	$ 1.9	$ 0.9	$ 0.9	$ 0.9
SL LT	$ 2.1	$ 1.9	$ 2.5	$ 2.7
Total	$ 136.1	$ 136.1	$ 136.1	$ 136.1

Q. In the likely event that the Commission authorizes KU a smaller revenue requirement increase than it has requested, what is your recommended apportionment?

A. Assuming that the final authorized revenue increase level is lower than the Company's requested increase, KIUC recommends that the increases under our rate allocation proposals be scaled-back on a proportionate basis.

III. RATE DESIGN ISSUES

Q. Are the Companies proposing any changes to their large power customer rates in this case?

A. Yes. Both LGE and KU are proposing changes in their large power customer rates. Both Companies are proposing similar changes to the large customer time of day rates by changing the billing demand basis from a kW to a kVa measurement. This change would affect current primary customers on KU rate schedules TODP and LTOD and LGE customers on rate schedules CTODP and ITODP. In addition, both Companies are proposing to change the time-of-day rating periods by dividing the existing on-peak period into a peak and intermediate periods. In addition, the month of May is being added to the summer month season for billing purposes.

Q. Does KIUC oppose the proposed changes to the time-of-day rate structure for KU and LGE large customer rates?

A. No. KIUC does not oppose these changes.

Q. Does KIUC oppose the proposed change to implement kVa demand billing for KU and LG&E primary service customers?

A. While on a conceptual basis, KIUC does not oppose the shift to kVa billing, for the primary service rates of either Company, KIUC does strongly oppose the change for LG&E's primary service rate ITODP. As discussed in response to Commission Staff Data Request of March 1, 2010 No. 70, the impacts of moving to kVa billing to LG&E's customers is much more significant than for KU's primary service customers. As explained in the data response [attached as Baron Exhibit__(SJB-4)], this difference in customer impact is due to existing differences in each Company's method for calculating the power factor adjustment in current rates. Because the billing impact of the proposed shift to kVa billing is relatively smaller for KU's customers, KIUC does not oppose the change for KU's primary service rates.

However, for LG&E's customers, the proposed changes to kVa billing are very substantial and result in a wide dispersion of rate increases to customers on LG&E rate ITODP. While the average increase proposed by LG&E for this rate class is 12.2%, many of the members of KIUC who take service on this rate will receive increase in the range of 18% to 19%. This is also confirmed in the Company's response to Staff Data Request of March 26, 2010 No. 22 [attached as Baron Exhibit__(SJB-5)], in which the Company shows that some customers on the ITODP rate may receive increases of as much as high as 22% and as lows as 9.6%. Such huge disparities among customers on the same rate schedule are not reasonable. Some customers in the rate class will receive increases nearly twice the average increase for the rate class. KIUC members will receive increases approaching this level.

Q. Does your recommendation to reject the implementation of kVa billing for LG&E primary service rate ITODP have any effect on any other rate class or on LG&E itself?

A. No. The rejection of kVa billing will not have any impact on any other rate class and it is completely revenue neutral to the Company. Given the effects of the current economic downturn on LG&E's largest manufacturing customers, it is simply not appropriate to implement a major rate design change that results in some of the Company's largest manufacturing customers receiving increases that are 1.5 to 2 times the average for their own rate class.

Q. Are there additional rate design changes that the Companies are proposing in this case that you would like to address?

A. Yes. Both Companies are proposing change a number of provisions on rate schedule FLS (Fluctuating Load Service). Currently, there is only one customer served on rate FLS on the KU system. There are no customers on this rate on the LGE system. North American Stainless ("NAS") utilizes rate FLS (currently designated as "Industrial Service IS") on the KU system. As discussed by KIUC witness Dennis Goins, NAS is the largest customer on the KU system. The FLS rate provides service to NAS' electric arc furnaces.

KU is proposing three changes to rate schedule FLS, in addition to the significant changes to rate CSR-3 (Curtailable Service Rate 3) discussed by Dr. Goins in his testimony. These three changes are 1) a change to a 5-minute integrated billing demand basis from the current combined 15-minute/5-minute basis; revisions to the time-of-day rating periods that I previously discussed; and finally, a change to the computation in the minimum billing demand. KIUC does not oppose the first two proposed changes (use of a 5-minute integrated billing demand and the changes to the time-of-day periods), but does strongly oppose the proposed change to the FLS minimum billing demand computation. As I will discuss, KU has not justified such a change, which results in a significant shift in risk from the Company's shareholders to its customers.

Q. Would you please discuss the proposed changes to KU's rate FLS minimum bill determination?

A. Currently, rate schedule IS (the existing designation of proposed rate schedule FLS) has a minimum billing demand provision that establishes the monthly billing demand kVa to be the greater of the actual metered demand in the on-peak period and the off-peak period or 60% of the maximum metered demands in each period during the prior 11 months. This provision, which is commonly referred to as a billing demand "ratchet" or simply a "ratchet" results in customers being charged at least for 60% of their highest monthly demand for each of the next 11 months, regardless of the actual demand placed on the KU system. There are identical 60% ratchet provisions associated with the excess monthly fluctuating demands based on the difference between the measured 5-minute demand and the standard 15-minute demand in each period (on-peak and off-peak).

Q. How does a billing demand ratchet work?

A. As a general matter, large customer billing demand ratchets imposes a minimum level of kVa demand for each customer in a month, whether or not the customer actually imposes that level of demand on the system. For example, if a customer's maximum billing demand over the past 11 months was 10,000 kVa, then a 60% billing demand ratchet would charge the customer a minimum demand of 6,000 kVa during the current month, whether or not the customer actually used that much power. In this event, if a customer used, say 4,000 kVa during the month, the customer would be billed as though its demand were actually 6,000 kVa. The extra 2,000 kVa, which is being paid for by the customer via the billing demand ratchet, would also be available to the Company to sell into the off-system market. The margins from such sales would be retained by the Company's shareholders, as would the revenues from the billing demand ratchet provision. This is particularly adverse to large manufacturing customers who, in the face of economic downturns must reduce their production, continue to face ratcheted demands on their bills for up to 11 months following the downturn. Smaller customers are not required to pay for power they don't use.

Q. What are the changes being proposed to the calculation of the rate schedule FLS minimum billing demands?

A. As I discussed previously, KU is proposing to change the existing time-of-day structure for rate schedule FLS to divide existing single on-peak period of the rate into a peak and intermediate period. The proposed FLS rate would have three periods - a peak period, an intermediate period and a base period. KU is proposing to change the current ratchet provisions to a 75% ratchet during the base demand period (with a 20,000 kVa minimum), while maintaining the 60% ratchet for the intermediate and peak periods.

Q. Is there any basis to justify this change in the FLS billing demand ratchet, or for that matter the level of the existing FLS 60% ratchets?

A. No. First, neither KU witness Steven Seelye or Robert Conroy has presented any evidence to justify the proposed FLS billing demand ratchet provisions. Mr. Conroy simply states in his testimony that "[T[hese charges and the minimum design are supported by the testimony and exhibits of Mr. Seelye."[3] Further, I was not able to identify any support in Mr. Seelye's testimony for these changes. The Company's proposed change simply shifts risk from KU shareholders to KU customers, with no off-setting benefits reflecting the reduction in shareholder risk.

More significantly, there is no basis for imposing a 75% demand ratchet on the base demands for an FLS customer that takes service off of the Company's transmission system. At most, a demand ratchet may be justified to recover costs associated with distribution or other facilities specifically designed to serve a single customer, the cost of which is generally specifically assigned to the customer or in some cases the rate class on which the customer takes service. In the case of an FLS customer taking service from the KU transmission system, there is no basis to justify an increase in the ratchet for base demands to 75% from the existing 60% level. In fact, there is no basis for even the existing 60% demand ratchet for rate schedule FLS.

[3] Direct Testimony of Robert Conroy (KU case) at page 16, lines 7 to 8.

The principle source of the costs recovered in the FLS demand charges are production and transmission related costs that are allocated system costs, not specifically assigned distribution costs. The largest portion, by far, are related to the FLS share of KU generating capacity. Based on the Company's filed class cost of service study, fixed production demand related costs comprise 89.9% of the rate base allocated to rate schedule FLS. Transmission related costs comprise 10% of rate base assigned to rate schedule FLS. This means that over 99.9% of rate schedule FLS net cost rate base is associated with generation and transmission costs tied to capacity that can be sold to other customers if an FLS customer's demand is reduced in a month.[4] In the event that an FLS customer's demand drops in any month, the capacity "freed-up" can be sold by the Company to its other retail customers whose load likely grew from test year levels, or to the off-system market in which case the Company would retain the margin from the sales until the next base rate case. In the case of transmission, a similar situation would occur, at least with regard to the revenue support that might be available from sales as a result of increases in the loads of other retail customers.

There is no basis for assuming, as the Company's proposed ratchet provisions do, that the revenue that would otherwise have been produced by the FLS customer will

[4] Based on the KU class cost of service study, there is only $463 of non-production, non-transmission rate base allocated to rate schedule FLS.

be lost, or reduced by 60% for the peak and intermediate demand charge revenues and by 75% for the base demand charge revenues. Rather, the ratchet provisions may result in a windfall to the Company in the event that it is triggered (thus producing minimum billing demand revenues from the FLS customer) and additional revenues from sales to other retail customers or the off-system market.

Q. **How has the evolution of off-system markets over the past 10 to 15 years affected these issues?**

A. With the FERC's issuance of Opinion Number 888, which implemented Open Access Transmission, wholesale power markets have expanded significantly. This has created improved opportunities for KU and LGE to sell capacity and energy off-system to both marketers and other electric utilities. As a result, the risks to the Companies from reductions in sales to large, captive customers has been reduced, since there are alternatives available to recover costs that would otherwise only be available from retail customers.

Q. **What is your recommendation regarding the FLS minimum billing demand provisions?**

A. At a minimum, I recommend that the Commission reject the Company's proposal to increase the base period demand ratchet from the existing 11 month, 60% level to an

11 month 75% ratchet with a 20,000 kVa minimum. Furthermore, I recommend that the current 60% ratchet be reduced to a more reasonable 30% ratchet (with no fixed kVa minimum demand level), in light of the nature of the generation and transmission costs that are subject to the ratchet provisions of the FLS rate. Given that generation and transmission costs comprise over 99% of the FLS revenue requirement, a 30% ratchet is more than reasonable for this rate. As in the case of the Company's proposal in this case, there is no revenue requirement effect in this case, nor is there any impact on any other rate class as a result of KIUC's recommendation on this issue.

Q. Wouldn't the same principles that you discussed to support your recommendation to reduce the billing demand ratchet for rate schedule FLS also apply to rate schedule RTS (Retail Transmission Service) for both KU and LGE?

A. Yes. Because RTS customers take service at transmission voltage and have little or no distribution related costs (other than meters and interconnection facilities to the transmission system), there is no reason to impose a 50% peak and intermediate period demand ratchet and a 75% base period demand ratchet, as the Companies have proposed in this case. However, unlike rate schedule FLS that only has a single customer, the impact of changing the demand ratchet for rate schedule RTS may result in some cost shifting among existing RTS customers to the extent that some customers may have been subject to the existing 50% billing demand ratchet for the rate or would be subject to the proposed ratchet provisions, based on test year billing data. As a result, I am not recommending a change in the proposed RTS demand ratchet provisions in this case. However, I do recommend that the Commission require the Companies to reduce their existing RTS demand ratchet provisions to a 30% level for each TOD rating period in their next base rate case.

Q. Does that complete your testimony?

A. Yes.

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

STEPHEN J. BARON, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Stephen J. Baron

Sworn to and subscribed before me on this 15th day of April 2010.

Notary Public

JESSICA K. INMAN
MY COMMISSION EXPIRES
NOTARY PUBLIC
JULY 31ST, 2011
CHEROKEE COUNTY, GA

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF LOUISVILLE GAS AND	)	
ELECTRIC COMPANY FOR AN ADJUSTMENT	)	CASE NO.
OF ITS ELECTRIC AND GAS BASE RATES	)	2009-00549

AND

APPLICATION OF KENTUCKY UTILITIES	)	
COMPANY FOR AN ADJUSTMENT	)	CASE NO.
OF BASE RATES	)	2009-00548

EXHIBITS

OF

STEPHEN J. BARON

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF LOUISVILLE GAS AND	)	
ELECTRIC COMPANY FOR AN ADJUSTMENT	)	**CASE NO.**
OF ITS ELECTRIC AND GAS BASE RATES	)	**2009-00549**

AND

APPLICATION OF KENTUCKY UTILITIES	)	
COMPANY FOR AN ADJUSTMENT	)	**CASE NO.**
OF BASE RATES	)	**2009-00548**

EXHIBIT__(SJB-1)

OF

STEPHEN J. BARON

Professional Qualifications

Of

Stephen J. Baron

Mr. Baron graduated from the University of Florida in 1972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, he received a Master of Arts Degree in Economics, also from the University of Florida. His areas of specialization were econometrics, statistics, and public utility economics. His thesis concerned the development of an econometric model to forecast electricity sales in the State of Florida, for which he received a grant from the Public Utility Research Center of the University of Florida. In addition, he has advanced study and coursework in time series analysis and dynamic model building.

Mr. Baron has more than thirty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

Following the completion of my graduate work in economics, he joined the staff of the Florida Public Service Commission in August of 1974 as a Rate Economist. His responsibilities included the analysis of rate cases for electric, telephone, and gas utilities, as well as the preparation of cross-examination material and the preparation of staff recommendations.

In December 1975, he joined the Utility Rate Consulting Division of Ebasco Services, Inc.

as an Associate Consultant. In the seven years he worked for Ebasco, he received successive promotions, ultimately to the position of Vice President of Energy Management Services of Ebasco Business Consulting Company. His responsibilities included the management of a staff of consultants engaged in providing services in the areas of econometric modeling, load and energy forecasting, production cost modeling, planning, cost-of-service analysis, cogeneration, and load management.

He joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this capacity he was responsible for the operation and management of the Atlanta office. His duties included the technical and administrative supervision of the staff, budgeting, recruiting, and marketing as well as project management on client engagements. At Coopers & Lybrand, he specialized in utility cost analysis, forecasting, load analysis, economic analysis, and planning.

In January 1984, he joined the consulting firm of Kennedy and Associates as a Vice President and Principal. Mr. Baron became President of the firm in January 1991.

During the course of his career, he has provided consulting services to more than thirty utility, industrial, and Public Service Commission clients, including three international utility clients.

He has presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of "Electrical World." His article on "Standby Electric Rates" was published in the November 8, 1984 issue of "Public Utilities Fortnightly." In February of 1984, he completed a detailed analysis entitled "Load Data Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

Mr. Baron has presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Maryland, Missouri, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, Utah, Virginia, West Virginia, Wisconsin, Wyoming, the Federal Energy Regulatory Commission and in United States Bankruptcy Court. A list of his specific regulatory appearances follows.

**Expert Testimony Appearances
of
Stephen J. Baron
As of March 2010**

Date	Case	Jurisdict.	Party	Utility	Subject
4/81	203(B)	KY	Louisville Gas & Electric Co.	Louisville Gas & Electric Co.	Cost-of-service.
4/81	ER-81-42	MO	Kansas City Power & Light Co.	Kansas City Power & Light Co.	Forecasting.
6/81	U-1933	AZ	Arizona Corporation Commission	Tucson Electric Co.	Forecasting planning.
2/84	8924	KY	Airco Carbide	Louisville Gas & Electric Co.	Revenue requirements, cost-of-service, forecasting, weather normalization.
3/84	84-038-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Excess capacity, cost-of-service, rate design.
5/84	830470-EI	FL	Florida Industrial Power Users' Group	Florida Power Corp.	Allocation of fixed costs, load and capacity balance, and reserve margin. Diversification of utility.
10/84	84-199-U	AR	Arkansas Electric Energy Consumers	Arkansas Power and Light Co.	Cost allocation and rate design.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Interruptible rates, excess capacity, and phase-in.
1/85	85-65	ME	Airco Industrial Gases	Central Maine Power Co.	Interruptible rate design.
2/85	I-840381	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Load and energy forecast.
3/85	9243	KY	Alcan Aluminum Corp., et al.	Louisville Gas & Electric Co.	Economics of completing fossil generating unit.
3/85	3498-U	GA	Attorney General	Georgia Power Co.	Load and energy forecasting, generation planning economics.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
5/85	84-249	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design return multipliers.
5/85		City of Santa Clara	Chamber of Commerce	Santa Clara Municipal	Cost-of-service, rate design.

Expert Testimony Appearances
of
Stephen J. Baron
As of March 2010

Date	Case	Jurisdict.	Party	Utility	Subject
6/85	84-768-E-42T	WV	West Virginia Industrial Intervenors	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
6/85	E-7 Sub 391	NC	Carolina Industrials (CIGFUR III)	Duke Power Co.	Cost-of-service, rate design, interruptible rate design.
7/85	29046	NY	Industrial Energy Users Association	Orange and Rockland Utilities	Cost-of-service, rate design.
10/85	85-043-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Regulatory policy, gas cost-of-service, rate design.
10/85	85-63	ME	Airco Industrial Gases	Central Maine Power Co.	Feasibility of interruptible rates, avoided cost.
2/85	ER-8507698	NJ	Air Products and Chemicals	Jersey Central Power & Light Co.	Rate design.
3/85	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve, prudence, off-system sales guarantee plan.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve margins, prudence, off-system sales guarantee plan.
3/86	85-299U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design, revenue distribution.
3/86	85-726-EL-AIR	OH	Industrial Electric Consumers Group	Ohio Power Co.	Cost-of-service, rate design, interruptible rates.
5/86	86-081-E-GI	WV	West Virginia Energy Users Group	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
8/86	E-7 Sub 408	NC	Carolina Industrial Energy Consumers	Duke Power Co.	Cost-of-service, rate design, interruptible rates.
10/86	U-17378	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Excess capacity, economic analysis of purchased power.
12/86	38063	IN	Industrial Energy Consumers	Indiana & Michigan Power Co.	Interruptible rates.

Expert Testimony Appearances
of
Stephen J. Baron
As of March 2010

Date	Case	Jurisdict.	Party	Utility	Subject
3/87	EL-86-53-001 EL-86-57-001	Federal Energy Regulatory Commission (FERC)	Louisiana Public Service Commission Staff	Gulf States Utilities, Southern Co.	Cost/benefit analysis of unit power sales contract.
4/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Load forecasting and imprudence damages, River Bend Nuclear unit.
5/87	87-023-E-C	WV	Airco Industrial Gases	Monongahela Power Co.	Interruptible rates.
5/87	87-072-E-G1	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Analyze Mon Power's fuel filing and examine the reasonableness of MP's claims.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic dispatching of pumped storage hydro unit.
5/87	9781	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Analysis of impact of 1986 Tax Reform Act.
6/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Economic prudence, evaluation of Vogtle nuclear unit - load forecasting, planning.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in plan for River Bend Nuclear unit.
7/87	85-10-22	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Methodology for refunding rate moderation fund.
8/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Test year sales and revenue forecast.
9/87	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Excess capacity, reliability of generating system.
10/87	R-870651	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Interruptible rate, cost-of-service, revenue allocation, rate design.
10/87	I-860025	PA	Pennsylvania Industrial Intervenors		Proposed rules for cogeneration, avoided cost, rate recovery.
10/87	E-015/	MN	Taconite	Minnesota Power	Excess capacity, power and

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	GR-87-223		Intervenors	& Light Co.	cost-of-service, rate design.
10/87	8702-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue forecasting, weather normalization.
12/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light Power Co.	Excess capacity, nuclear plant phase-in.
3/88	10064	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Revenue forecast, weather normalization rate treatment of cancelled plant.
3/88	87-183-TF	AR	Arkansas Electric Consumers	Arkansas Power & Light Co.	Standby/backup electric rates.
5/88	870171C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
6/88	870172C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
7/88	88-171-EL-AIR 88-170-EL-AIR Interim Rate Case	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison	Financial analysis/need for interim rate relief.
7/88	Appeal of PSC	19th Judicial Docket U-17282	Louisiana Public Service Commission Circuit Court of Louisiana	Gulf States Utilities	Load forecasting, imprudence damages.
11/88	R-880989	PA	United States Steel	Carnegie Gas	Gas cost-of-service, rate design.
11/88	88-171-EL-AIR 88-170-EL-AIR	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison. General Rate Case.	Weather normalization of peak loads, excess capacity, regulatory policy.
3/89	870216/283 284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Calculated avoided capacity, recovery of capacity payments.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cost-of-service, rate design.

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8/89	3840-U	GA	Georgia Public Service Commission	Georgia Power Co.	Revenue forecasting, weather normalization.
9/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Prudence - Palo Verde Nuclear Units 1, 2 and 3, load fore-casting.
10/89	2262	NM	New Mexico Industrial Energy Consumers	Public Service Co. of New Mexico	Fuel adjustment clause, off-system sales, cost-of-service, rate design, marginal cost.
11/89	38728	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Excess capacity, capacity equalization, jurisdictional cost allocation, rate design, interruptible rates.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Jurisdictional cost allocation, O&M expense analysis.
5/90	890366	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Non-utility generator cost recovery.
6/90	R-901609	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Allocation of QF demand charges in the fuel cost, cost-of-service, rate design.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost-of-service, rate design, revenue allocation.
12/90	U-9346 Rebuttal	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Demand-side management, environmental externalities.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, jurisdictional allocation.
12/90	90-205	ME	Airco Industrial Gases	Central Maine Power Co.	Investigation into interruptible service and rates.
1/91	90-12-03 Interim	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Interim rate relief, financial analysis, class revenue allocation.
5/91	90-12-03 Phase II	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Revenue requirements, cost-of-service, rate design, demand-side management.

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8/91	E-7, SUB SUB 487	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Revenue requirements, cost allocation, rate design, demand-side management.
8/91	8341 Phase I	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, rate design, 1990 Clean Air Act Amendments.
8/91	91-372 EL-UNC	OH	Armco Steel Co., L.P.	Cincinnati Gas & Electric Co.	Economic analysis of cogeneration, avoid cost rate.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
9/91	91-231 -E-NC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	8341 - Phase II	MD	Westvaco Corp.	Potomac Edison Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Results of comprehensive management audit.
Note: No testimony was prefiled on this.					
11/91	U-17949 Subdocket A	LA	Louisiana Public Service Commission Staff	South Central Bell Telephone Co. and proposed merger with Southern Bell Telephone Co.	Analysis of South Central Bell's restructuring and
12/91	91-410- EL-AIR	OH	Armco Steel Co., Air Products & Chemicals, Inc.	Cincinnati Gas & Electric Co.	Rate design, interruptible rates.
12/91	P-880286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Evaluation of appropriate avoided capacity costs - QF projects.
1/92	C-913424	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Industrial interruptible rate.
6/92	92-02-19	CT	Connecticut Industrial Energy Consumers	Yankee Gas Co.	Rate design.

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8/92	2437	NM	New Mexico Industrial Intervenors	Public Service Co. of New Mexico	Cost-of-service.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cost-of-service, rate design, energy cost rate.
9/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
10/92	M-00920312 C-007	PA	The GPU Industrial Intervenors	Pennsylvania Electric Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
12/92	U-17949	LA	Louisiana Public Service Commission Staff	South Central Bell Co.	Management audit.
12/92	R-00922378	PA	Armco Advanced Materials Co. The WPP Industrial Intervenors	West Penn Power Co.	Cost-of-service, rate design, energy cost rate, SO_2 allowance rate treatment.
1/93	8487	MD	The Maryland Industrial Group	Baltimore Gas & Electric Co.	Electric cost-of-service and rate design, gas rate design (flexible rates).
2/93	E002/GR-92-1185	MN	North Star Steel Co. Praxair, Inc.	Northern States Power Co.	Interruptible rates.
4/93	EC92 21000 ER92-806-000 (Rebuttal)	Federal Energy Regulatory Commission	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy agreement.	Merger of GSU into Entergy System; impact on system
7/93	93-0114-E-C	WV	Airco Gases	Monongahela Power Co.	Interruptible rates.
8/93	930759-EG	FL	Florida Industrial Power Users' Group	Generic - Electric Utilities	Cost recovery and allocation of DSM costs.
9/93	M-009 30406	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Ratemaking treatment of off-system sales revenues.
11/93	346	KY	Kentucky Industrial Utility Customers	Generic - Gas Utilities	Allocation of gas pipeline transition costs - FERC Order 636.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Nuclear plant prudence, forecasting, excess capacity.

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4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Cost allocation, rate design, rate phase-in plan.
5/94	U-20178	LA	Louisiana Public Service Commission	Louisiana Power & Light Co.	Analysis of least cost integrated resource plan and demand-side management program.
7/94	R-00942986	PA	Armco, Inc.; West Penn Power Industrial Intervenors	West Penn Power Co.	Cost-of-service, allocation of rate increase, rate design, emission allowance sales, and operations and maintenance expense.
7/94	94-0035-E-42T	WV	West Virginia Energy Users Group	Monongahela Power Co.	Cost-of-service, allocation of rate increase, and rate design.
8/94	EC94 13-000	Federal Energy Regulatory Commission	Louisiana Public Service Commission	Gulf States Utilities/Entergy	Analysis of extended reserve shutdown units and violation of system agreement by Entergy.
9/94	R-00943 081 R-00943 081C0001	PA	Lehigh Valley Power Committee	Pennsylvania Public Utility Commission	Analysis of interruptible rate terms and conditions, availability.
9/94	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Evaluation of appropriate avoided cost rate.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements.
10/94	5258-U	GA	Georgia Public Service Commission	Southern Bell Telephone & Telegraph Co.	Proposals to address competition in telecommunication markets.
11/94	EC94-7-000 ER94-898-000	FERC	Louisiana Public Service Commission	El Paso Electric and Central and Southwest	Merger economics, transmission equalization hold harmless proposals.
2/95	941-430EG	CO	CF&I Steel, L.P.	Public Service Company of Colorado	Interruptible rates, cost-of-service.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Cost-of-service, allocation of rate increase, rate design, interruptible rates.
6/95	C-00913424 C-00946104	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Interruptible rates.

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8/95	ER95-112 -000	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Open Access Transmission Tariffs - Wholesale.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Company	Nuclear decommissioning, revenue requirements, capital structure.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	System Energy Resources, Inc.	Nuclear decommissioning, revenue requirements.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear decommissioning and cost of debt capital, capital structure.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Retail competition issues.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Revenue requirement analysis.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Elec. Co., Potomac Elec. Power Co., Constellation Energy Co.	Ratemaking issues associated with a Merger.
8/96	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
2/97	R-973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Competitive restructuring policy issues, stranded cost, transition charges.
6/97	Civil Action No. 94-11474	US Bank-ruptcy Court Middle District of Louisiana	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Confirmation of reorganization plan; analysis of rate paths produced by competing plans.
6/97	R-973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Retail competition issues, rate unbundling, stranded cost analysis.
6/97	8738	MD	Maryland Industrial Group	Generic	Retail competition issues

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7/97	R-973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big River Electric Corp.	Analysis of cost of service issues - Big Rivers Restructuring Plan
10/97	R-974008	PA	Metropolitan Edison Industrial Users	Metropolitan Edison Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	R-974009	PA	Pennsylvania Electric Industrial Customer	Pennsylvania Electric Co.	Retail competition issues, rate unbundling, stranded cost analysis.
11/97	U-22491	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
11/97	P-971265	PA	Philadelphia Area Industrial Energy Users Group	Enron Energy Services Power, Inc./ PECO Energy	Analysis of Retail Restructuring Proposal.
12/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Retail competition issues, rate unbundling, stranded cost analysis.
12/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
3/98 (Allocated Stranded Cost Issues)	U-22092	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Retail competition, stranded cost quantification.
3/98	U-22092		Louisiana Public Service Commission	Gulf States Utilities, Inc.	Stranded cost quantification, restructuring issues.
9/98	U-17735		Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Revenue requirements analysis, weather normalization.
12/98	8794	MD	Maryland Industrial Group and Millennium Inorganic Chemicals Inc.	Baltimore Gas and Electric Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
5/99 (Cross-Answering Testimony)	EC-98-40-000	FERC	Louisiana Public Service Commission	American Electric Power Co. & Central South West Corp.	Merger issues related to market power mitigation proposals.

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5/99 (Response Testimony)	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Performance based regulation, settlement proposal issues, cross-subsidies between electric. gas services.
6/99	98-0452	WV	West Virginia Energy Users Group	Appalachian Power, Monongahela Power, & Potomac Edison Companies	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	99-03-35	CT	Connecticut Industrial \Energy Consumers	United Illuminating Company	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	Adversary Proceeding No. 98-1065	U.S. Bankruptcy Court	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Motion to dissolve preliminary injunction.
7/99	99-03-06	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
12/99	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Ananlysi of Proposed Contract Rates, Market Rates.
03/00	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Evaluation of Cooperative Power Contract Elections
03/00	99-1658-EL-ETP	OH	AK Steel Corporation	Cincinnati Gas & Electric Co.	Electric utility restructuring, stranded cost recovery, rate Unbundling.

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08/00	98-0452 E-GI	WVA	West Virginia Energy Users Group	Appalachian Power Co. American Electric Co.	Electric utility restructuring rate unbundling.
08/00	00-1050 E-T 00-1051-E-T	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Electric utility restructuring rate unbundling.
10/00	SOAH 473-00-1020 PUC 2234	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU, Inc.	Electric utility restructuring rate unbundling.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, revenue requirements.
12/00	EL00-66-000 & ER00-2854 EL95-33-002	LA	Louisiana Public Service Commission	Entergy Services Inc.	Inter-Company System Agreement: Modifications for retail competition, interruptible load.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Addressing Contested Issues	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Jurisdictional Business Separation - Texas Restructuring Plan
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Test year revenue forecast.
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning requirements transmission revenues.
11/01	U-25965	LA	Louisiana Public Service Commission	Generic .	Independent Transmission Company ("Transco"). RTO rate design.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design, resource planning and demand side management.
06/02	U-25965	LA	Louisiana Public Service Commission	Entergy Gulf States Entergy Louisiana	RTO Issues
07/02	U-21453	LA	Louisiana Public Service Commission	SWEPCO, AEP	Jurisdictional Business Sep. - Texas Restructuring Plan.

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08/02	U-25888	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services Inc. and the Entergy Operating Companies	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
11/02	02S-315EG	CO	CF&I Steel & Climax Molybdenum Co.	Public Service Co. of Colorado	Fuel Adjustment Clause
01/03	U-17735	LA	Louisiana Public Service Commission	Louisiana Coops	Contract Issues
02/03	02S-594E	CO	Cripple Creek and Victor Gold Mining Co.	Aquila, Inc.	Revenue requirements, purchased power.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Weather normalization, power purchase expenses, System Agreement expenses.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Tariff MSS-4.
11/03	ER03-583-000 ER03-583-001 ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001 ER03-682-002	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Market-Ing, L.P, and Entergy Power, Inc.	Evaluation of Wholesale Purchased Power Contracts.
12/03	U-27136	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc.	Evaluation of Wholesale Purchased Power Contracts.
01/04	E-01345-03-0437	AZ	Kroger Company	Arizona Public Service Co.	Revenue allocation rate design.
02/04	00032071	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Provider of last resort issues.
03/04	03A-436E	CO	CF&I Steel, LP and Climax Molybedenum	Public Service Company of Colorado	Purchased Power Adjustment Clause.

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04/04	2003-00433 2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service Rate Design
0-6/04	03S-539E	CO	Cripple Creek, Victor Gold Mining Co., Goodrich Corp., Holcim (U.S.,), Inc., and The Trane Co.	Aquila, Inc.	Cost of Service, Rate Design Interruptible Rates
06/04	R-00049255	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
10/04	04S-164E	CO	CF&I Steel Company, Climax Mines	Public Service Company of Colorado	Cost of service, rate design, Interruptible Rates.
03/05	Case No. 2004-00426 Case No. 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
06/05	050045-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
07/05	U-28155	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Independent Coordinator of Transmission – Cost/Benefit
09/05	Case Nos. 05-0402-E-CN 05-0750-E-PC	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Environmental cost recovery, Securitization, Financing Order
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses. Congestion Cost Recovery Mechanism
03/06	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Transmission Prudence Investigation
06/06	R-00061346 C0001-0005	PA	Duquesne Industrial Intervenors & IECPA	Duquesne Light Co.	Cost of Service, Rate Design, Transmission Service Charge, Tariff Issues
06/06	R-00061366 R-00061367 P-00062213 P-00062214		Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Generation Rate Cap, Transmission Service Charge, Cost of Service, Rate Design, Tariff Issues
07/06	U-22092 Sub-J	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.

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07/06	Case No. 2006-00130 Case No. 2006-00129	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
08/06	Case No. PUE-2006-00065	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Allocation of Rev Incr, Off-System Sales margin rate treatment
09/06	E-01345A-05-0816	AZ	Kroger Company	Arizona Public Service Co.	Revenue alllocation, cost of service, rate design.
11/06	Doc. No. 97-01-15RE02	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power United Illuminating	Rate unbundling issues.
01/07	Case No. 06-0960-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Retail Cost of Service Revenue apportionment
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	Implementation of FERC Decision Jurisdictional & Rate Class Allocation
05/07	Case No. 07-63-EL-UNC	OH	Ohio Energy Group	Ohio Power, Columbus Southern Power	Environmental Surcharge Rate Design
05/07	R-00049255 Remand	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
06/07	R-00072155	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues.
07/07	Doc. No. 07F-037E	CO	Gateway Canyons LLC	Grand Valley Power Coop.	Distribution Line Cost Allocation
09/07	Doc. No. 05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
11/07	ER07-682-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Schedule MSS-3. Cost functionalization issues.
1/08	Doc. No. 20000-277-ER-07	WY	Cimarex Energy Company	Rocky Mountain Power (PacifiCorp)	Vintage Pricing, Marginal Cost Pricing Projected Test Year
1/08	Case No. 07-551	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Class Cost of Service, Rate Restructuring, Apportionment of Revenue Increase to Rate Schedules
2/08	ER07-956	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
2/08	Doc No. P-00072342	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Default Service Plan issues.

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3/08	Doc No. E-01933A-05-0650	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design
05/08	08-0278 E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co. American Electric Power Co.	Expanded Net Energy Cost "ENEC" Analysis.
6/08	Case No. 08-124-EL-ATA	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Recovery of Deferred Fuel Cost
7/08	Docket No. 07-035-93	UT	Kroger Company	Rocky Mountain Power Co.	Cost of Service, Rate Design
08/08	Doc. No. 6680-UR-116	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
09/08	Doc. No. 6690-UR-119	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
09/08	Case No. 08-936-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Competitive Solicitation
09/08	Case No. 08-935-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Rate Plan
09/08	Case No. 08-917-EL-SSO 08-918-EL-SSO	OH	Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Provider of Last Resort Rate Plan
10/08	2008-00251 2008-00252	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
11/08	08-1511 E-GI	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost "ENEC" Analysis.
11/08	M-2008-2036188, M-2008-2036197	PA	Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Transmission Service Charge
01/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
01/09	E-01345A-08-0172	AZ	Kroger Company	Arizona Public Service Co.	Cost of Service, Rate Design
02/09	2008-00409	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Cost of Service, Rate Design

Expert Testimony Appearances
of
Stephen J. Baron
As of March 2010

Date	Case	Jurisdict.	Party	Utility	Subject
5/09	PUE-2009 -00018	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Transmission Cost Recovery Rider
5/09	09-0177-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost "ENEC" Analysis
6/09	PUE-2009 -00016	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Fuel Cost Recovery Rider
6/09	PUE-2009 -00038	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Fuel Cost Recovery Rider
7/09	080677-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
8/09	U-20925 (RRF 2004)	LA	Louisiana Public Service Commission Staff	Entergy Louisiana LLC	Interruptible Rate Refund Settlement
9/09	09AL-299E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Energy Cost Rate issues
9/09	Doc. No. 05-UR-104	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
9/09	Doc. No. 6680-UR-117	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
10/09	Docket No. 09-035-23	UT	Kroger Company	Rocky Mountain Power Co.	Cost of Service, Allocation of Rev Increase
10/09	09AL-299E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Cost of Service, Rate Design
11/09	PUE-2009 -00019	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Cost of Service, Rate Design
11/09	09-1485 E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost "ENEC" Analysis.
12/09	Case No. 09-906-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Rate Plan
12/09	ER09-1224	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
12/09	Case No. PUE-2009-00030	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Allocation of Rev Increase, Rate Design

Expert Testimony Appearances
of
Stephen J. Baron
As of March 2010

Date	Case	Jurisdict.	Party	Utility	Subject
2/10	Docket No. 09-035-23	UT	Kroger Company	Rocky Mountain Power Co.	Rate Design
3/10	Case No. 09-1352-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Retail Cost of Service Revenue apportionment

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS BASE RATES	)))	CASE NO. 2009-00549

AND

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES	)))	CASE NO. 2009-00548

EXHIBIT__(SJB-2)

OF

STEPHEN J. BARON

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation
12 Months Ended October 31, 2009
Corrected Interruptible Credit

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Secondary GSS	All Electric School AES
Cost of Service Summary – Pro-Forma							
Operating Revenues							
Total Operating Revenue – Actual				$ 1,221,660,614	$ 468,213,397	$ 156,785,762	$ 8,716,583
Pro-Forma Adjustments:							
Eliminate unbilled revenue			R01	(3,744,529)	$ (1,429,385)	$ (484,496)	$ (26,674)
Adjustment for Mismatch in fuel cost recovery			Energy	(49,848,679)	$ (17,786,542)	$ (5,237,328)	$ (375,754)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI	FAC01	(3,710,701)	$ (1,339,972)	$ (386,233)	$ (33,684)
Remove ECR revenues			ECRREV01	(92,924,384)	$ (34,624,476)	$ (11,981,422)	$ (646,811)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI	ECRREV02	87,584,103	$ 33,637,125	$ 11,667,441	$ 640,200
Remove off-system ECR revenues			ECRREV01	(3,722,927)	$ (1,387,197)	$ (480,024)	$ (25,914)
Eliminate brokered sales			Energy	(256,817)	$ (91,635)	$ (26,982)	$ (1,936)
Eliminate DSM Revenue		DSMREV	DSM01	(12,940,085)	$ (10,563,160)	$ (1,061,969)	$ -
Year end adjustment		YREND	YRE01	9,724,872	$ (3,729,851)	$ 12,261,395	$ (103,605)
Merger Surcredit Revenues			MSCREV	2,800,345	$ 1,190,523	$ 352,574	$ 21,520
Weather Normalized electric operating revenues			TREV01	2,986,579	$ 2,362,665	$ 264,295	$ 12,655
VDT Surcredit Revenues			VDTREV	42	$ (273)	$ 4,074	$ -
Adjustment for Billing corrections & Rate switching			RS01	(186,358)	$ -	$ -	$ -
Adjustment to Late Payment Charge			LPAY	3,141,664	$ 2,331,337	$ 543,289	$ -
Eliminate ECR, MSR, FAC, & DSM accruals			R01	283,654	$ 108,278	$ 36,701	$ 2,021
Total Pro-Forma Operating Revenue			(33,762,178)	$ 1,160,847,393	$ 436,890,835	$ 162,257,077	$ 8,178,602

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation
12 Months Ended October 31, 2009
Corrected Interruptible Credit

Description	Ref	Name	Allocation Vector	Power Service PS-Secondary	Power Service PS-Primary	Time of Day TOD-Secondary	Time of Day TOD-Primary	Retail Transmission Service RTS	Fluctuating Load Service FLS - Transmission	Street Lighting SL LT
Cost of Service Summary -- Pro-Forma										
Operating Revenues										
Total Operating Revenue -- Actual				229,375,482	95,568,618	11,606,703	143,144,983	73,011,536	14,680,215	20,557,334
Pro-Forma Adjustments:										
Eliminate unbilled revenue			R01	(707,374)	(293,251)	(35,734)	(436,711)	(222,230)	(43,993)	(64,680)
Adjustment for Mismatch in fuel cost recovery			Energy	(9,768,092)	(4,288,845)	(569,620)	(7,065,633)	(3,497,695)	(902,237)	(356,935)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI	FAC01	39,974	(296,317)	(993)	(539,386)	(694,222)	(387,783)	(72,086)
Remove ECR revenues			ECRREV01	(17,590,465)	(7,274,470)	(923,786)	(11,025,922)	(5,672,045)	(1,592,149)	(1,592,837)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI	ECRREV02	16,342,562	6,803,053	741,661	10,176,285	4,884,714	1,308,727	1,382,335
Remove off-system ECR revenues			ECRREV01	(704,745)	(291,445)	(37,011)	(441,743)	(227,245)	(63,788)	(63,816)
Eliminate brokered sales			Energy	(50,325)	(22,096)	(2,935)	(36,402)	(18,020)	(4,648)	(1,839)
Eliminate DSM Revenue		DSMREV	DSM01	(1,023,304)	(218,413)	(67,553)	(2,709)	(2,977)	-	-
Year end adjustment		YREND	YRE01	(1,140,255)	(4,224,214)	(931,558)	3,132,208	3,532,765	-	927,987
Merger Surcredit Revenues			MSCREV	483,744	207,745	19,953	289,203	146,181	44,498	44,405
Weather Normalized electric operating revenues			TREV01	241,693	93,420	11,851	-	-	-	-
VDT Surcredit Revenues			VDTREV	(2,121)	(1,974)	-	-	-	-	336
Adjustment for Billing corrections & Rate switching			RS01	(130,088)	(55,180)	-	-	(1,090)	-	-
Adjustment to Late Payment Charge			LPAY	133,502	-	-	84,815	-	-	48,722
Eliminate ECR, MSR, FAC, & DSM accruals			R01	53,585	22,214	2,707	33,082	16,834	3,333	4,900
Total Pro-Forma Operating Revenue			(33,762,178)	215,553,771	85,728,846	9,813,686	137,312,070	71,256,506	13,042,174	20,813,826

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation
12 Months Ended October 31, 2009
Corrected Interruptible Credit

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Secondary GSS	All Electric School AES
Operating Expenses							
Operation and Maintenance Expenses				$ 819,700,590	$ 334,585,427	$ 91,388,266	$ 6,332,603
Depreciation and Amortization Expenses				118,950,010	59,929,389	14,016,902	1,126,245
Regulatory Credits and Accretion Expenses				(258,958)	(116,637)	(27,840)	(2,698)
Property Taxes			NPT	11,424,756	5,679,925	1,331,559	109,528
Other Taxes				8,127,668	4,040,747	947,282	77,919
Gain Disposition of Allowances				(73,173)	(26,109)	(7,688)	(552)
State and Federal Income Taxes			TAXINC	72,669,576	$ 10,562,242	$ 14,977,194	$ 139,251
Specific Assignment of Curtailable Service Rider Credit				(5,641,432)	-	-	-
Allocation of Curtailable Service Rider Credits			INTCRE	$ 5,641,432	$ 2,822,773	$ 613,667	$ 67,517
Adjustments to Operating Expenses:							
Eliminate mismatch in fuel cost recovery			Energy	$ (42,231,035)	$ (15,068,485)	$ (4,436,983)	$ (318,333)
Remove ECR expenses			ECRREV01	(30,178,413)	(11,244,753)	(3,891,124)	(210,060)
Adjust base expenses for full year of ECR roll-in			ECRREV02	22,359,078	8,587,119	2,978,545	163,435
Eliminate brokered sales expenses			Energy	(6,096)	(2,175)	(640)	(46)
Eliminate DSM Expenses			DSMREV	(7,500,349)	(6,122,633)	(615,540)	-
Year end adjustment			YREND	5,885,824	(2,257,433)	7,421,014	(62,705)
Adjustment for change in depreciation rate			DET	19,212,820	9,679,802	2,264,012	181,911
Labor adjustment			LBT	784,464	408,355	96,333	6,257
Weather Normalized electric operating expenses			TEXP01	1,489,506	1,079,155	103,622	6,016
Adjustment for pension/post retir benefit			LBT	(139,829)	(72,788)	(17,171)	(1,115)
Adjustment for increase in property insurance			UPT	373,107	183,174	43,045	3,602
Adjustment for increase in liability insurance			UPT	574,164	281,881	66,241	5,543
Adjustment for Hazard Tree program			SDALL	3,791,496	2,669,733	556,943	27,633
Storm damage adjustment			SDALL	(1,267,873)	(892,756)	(186,241)	(9,240)
Eliminate advertising expenses (See Functional Assignment)			REVUC	(799,431)	(305,164)	(103,436)	(5,695)
Adjustment for retired mainframe			RBT	(843,623)	(412,566)	(97,270)	(8,097)
Amortization of rate case expenses			OMT	595,187	242,943	66,357	4,598
Adjustment for injuries and damages account 925 (See Functio			UPT	200,710	98,537	23,156	1,938
Adjustment for EKPC settlement charges			Energy	1,785,051	636,925	187,546	13,456
Adjustment for MISO Exit Fee			PLTRT	(83,909)	(37,782)	(9,019)	(875)
Adjustment for 2008 Wind Storm			SDALL	2,454,286	1,728,154	360,517	17,887
Adjustment for 2009 Winter Storm			SDALL	11,447,352	8,060,506	1,681,533	83,430
Adjustment for KCCS Asset			PLPPT	360,504	162,327	38,748	3,757
Adjustment for CMRG Asset			PLPPT	1,940	874	209	20
Adjustment for SW Power Pool Expense			PLPPT	(896,454)	(403,654)	(96,353)	(9,343)
Adjustment for MISO RSG Settlement			PLTRT	(510,123)	(229,698)	(54,829)	(5,317)
Adjustment to reflect expiration of OMU contract			PLPPT	(15,673,235)	(7,057,324)	(1,684,602)	(163,352)
Adjustment for reversal of OMU uncollectible expense			PLPPT	1,754,505	790,016	188,579	18,286
Adjustment for property tax expense (See Functional Assignme			UPT	1,199,643	588,955	138,402	11,582
Adjustment for reserve margin demand purchases			PPSDA	(1,339,238)	(592,213)	(134,511)	(9,509)
Federal & State Income Tax Adjustment			ITADJ	(12,217,289)	(7,920,712)	244,362	(103,320)
Federal & State Income Tax Interest Adjustment			TAXINC	(545,180)	(79,240)	(112,362)	(1,045)
Prior income tax adjustments			TAXINC	1,126,171	163,685	232,104	2,158
Adjustment for domestic production activities			TAXINC	(457,757)	(66,533)	(94,344)	(877)
Adjustment for tax basis depreciation reduction			UPT	1,442,607	708,236	166,432	13,928
Adjustment for 2003 Ice Storm Amortization			SDALL	(527,718)	(371,586)	(77,518)	(3,846)
Total Expense Adjustments				$ (38,379,137)	$ (17,067,117)	$ 5,245,754	$ (347,337)
Total Operating Expenses		TOE		$ 992,161,332	$ 400,410,640	$ 128,485,096	$ 7,502,478
Net Operating Income (Adjusted)				$ 168,686,061	$ 36,480,195	$ 33,771,981	$ 676,125
Net Cost Rate Base				$ 3,176,812,335	$ 1,553,590,094	$ 366,288,526	$ 30,488,830
Adjustment to Reflect Depreciation Reserve			DET	$ (19,212,820)	$ (9,679,802)	$ (2,264,012)	$ (181,911)
Cash Working Capital			OMLF	$ (306,067)	$ (170,905)	$ (39,874)	$ (2,532)
Adjusted Net Cost Rate Base				$ 3,157,293,448	$ 1,543,739,386	$ 363,984,640	$ 30,304,386
Rate of Return				5.34%	2.36%	9.28%	2.23%

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation
12 Months Ended October 31, 2009
Corrected Interruptible Credit

Description	Ref	Name	Allocation Vector	Power Service PS-Secondary	Power Service PS-Primary	Time of Day TOD-Secondary	Time of Day TOD-Primary	Retail Transmission Service RTS	Fluctuating Load Service FLS - Transmission	Street Lighting SL LT
Operating Expenses										
Operation and Maintenance Expenses				$ 148,421,028	$ 61,977,975	$ 8,137,019	$ 100,926,738	$ 48,602,863	$ 12,652,438	$ 6,676,232
Depreciation and Amortization Expenses				16,775,720	6,865,781	816,045	10,771,184	4,466,512	1,246,000	2,936,231
Regulatory Credits and Accretion Expenses				(43,407)	(18,753)	(2,158)	(29,378)	(13,625)	(3,801)	(661)
Property Taxes			NPT	1,649,137	680,373	80,475	1,067,155	450,455	125,664	250,483
Other Taxes				1,173,210	484,023	57,250	759,183	320,457	89,399	178,196
Gain Disposition of Allowances				(14,339)	(6,296)	(836)	(10,372)	(5,134)	(1,324)	(524)
State and Federal Income Taxes			TAXINC	$ 18,716,559	$ 7,854,197	$ 739,957	$ 8,422,411	$ 5,993,004	$ 1,938,778	$ 3,325,983
Specific Assignment of Curtailable Service Rider Credit				-	(126,145)	-	-	-	(5,515,286)	-
Allocation of Curtailable Service Rider Credits			INTCRE	$ 860,548	$ 367,665	$ 37,676	$ 554,954	$ 244,068	$ 72,564	$ -
Adjustments to Operating Expenses:										
Eliminate mismatch in fuel cost recovery			Energy	$ (8,275,377)	$ (3,633,443)	$ (482,573)	$ (5,985,895)	$ (2,963,194)	$ (764,362)	$ (302,389)
Remove ECR expenses			ECRREV01	(5,712,734)	(2,362,479)	(300,012)	(3,580,813)	(1,842,071)	(517,071)	(517,295)
Adjust base expenses for full year of ECR roll-in			ECRREV02	4,172,043	1,736,731	189,336	2,597,873	1,247,004	334,101	352,892
Eliminate brokered sales expenses			Energy	(1,195)	(524)	(70)	(864)	(428)	(110)	(44)
Eliminate DSM Expenses			DSMREV	(593,129)	(126,597)	(39,155)	(1,570)	(1,725)	-	-
Year end adjustment			YREND	(690,121)	(2,556,638)	(563,811)	1,895,719	2,138,150	-	561,649
Adjustment for change in depreciation rate			DET	2,709,616	1,108,962	131,808	1,739,763	721,432	201,254	474,260
Labor adjustment			LBT	113,839	39,984	5,158	62,665	26,751	7,190	17,931
Weather Normalized electric operating expenses			TEXP01	209,475	80,967	10,271	-	-	-	-
Adjustment for pension/post retir benefit			LBT	(20,292)	(7,127)	(919)	(11,170)	(4,768)	(1,282)	(3,196)
Adjustment for increase in property insurance			UPT	54,525	22,622	2,670	35,481	15,125	4,220	8,643
Adjustment for increase in liability insurance			UPT	83,907	34,813	4,108	54,601	23,275	6,494	13,301
Adjustment for Hazard Tree program			SDALL	271,282	69,369	12,103	110,737	-	-	73,696
Storm damage adjustment			SDALL	(90,716)	(23,197)	(4,047)	(37,030)	-	-	(24,644)
Eliminate advertising expenses (See Functional Assignment)			REVUC	(151,020)	(62,607)	(7,629)	(93,235)	(47,445)	(9,392)	(13,809)
Adjustment for retired mainframe			RBT	(123,950)	(51,421)	(6,088)	(80,739)	(34,555)	(9,618)	(19,321)
Amortization of rate case expenses			OMT	107,769	45,002	5,908	73,283	35,291	9,187	4,848
Adjustment for injuries and damages account 925 (See Functio			UPT	29,331	12,170	1,436	19,087	8,136	2,270	4,650
Adjustment for EKPC settlement charges			Energy	349,789	153,581	20,398	253,016	125,250	32,309	12,782
Adjustment for MISO Exit Fee			PLTRT	(14,071)	(6,079)	(699)	(9,524)	(4,418)	(1,233)	(210)
Adjustment for 2008 Wind Storm			SDALL	175,604	44,904	7,835	71,681	-	-	47,704
Adjustment for 2009 Winter Storm			SDALL	819,058	209,442	36,542	334,338	-	-	222,504
Adjustment for KCCS Asset			PLPPT	60,452	26,119	3,005	40,918	18,980	5,296	901
Adjustment for CMRG Asset			PLPPT	325	141	16	220	102	28	5
Adjustment for SW Power Pool Expense			PLPPT	(150,324)	(64,950)	(7,472)	(101,750)	(47,198)	(13,169)	(2,240)
Adjustment for MISO RSG Settlement			PLTRT	(85,541)	(36,959)	(4,252)	(57,901)	(26,858)	(7,494)	(1,274)
Adjustment to reflect expiration of OMU contract			PLPPT	(2,628,212)	(1,135,559)	(130,641)	(1,778,961)	(825,193)	(230,236)	(39,156)
Adjustment for reversal of OMU uncollectible expense			PLPPT	294,209	127,118	14,624	199,142	92,374	25,773	4,383
Adjustment for property tax expense (See Functional Assignme			UPT	175,312	72,737	8,584	114,082	48,630	13,567	27,791
Adjustment for reserve margin demand purchases			PPSDA	(233,020)	(93,117)	(12,294)	(163,931)	(76,001)	(24,643)	-
Federal & State Income Tax Adjustment			ITADJ	(1,713,675)	(1,275,466)	(253,121)	(560,071)	(140,940)	(258,899)	(235,448)
Federal & State Income Tax Interest Adjustment			TAXINC	(140,415)	(58,924)	(5,551)	(63,186)	(44,961)	(14,545)	(24,952)
Prior income tax adjustments			TAXINC	290,053	121,718	11,467	130,523	92,874	30,046	51,543
Adjustment for domestic production activities			TAXINC	(117,899)	(49,475)	(4,661)	(53,054)	(37,751)	(12,213)	(20,951)
Adjustment for tax basis depreciation reduction			UPT	210,818	87,469	10,323	137,187	58,479	16,315	33,419
Adjustment for 2003 Ice Storm Amortization			SDALL	(37,758)	(9,655)	(1,685)	(15,413)	-	-	(10,257)
Total Expense Adjustments				$ (10,652,040)	$ (7,560,372)	$ (1,349,086)	$ (4,724,790)	$ (1,445,650)	$ (1,176,216)	$ 697,718
Total Operating Expenses		TOE		$ 176,886,416	$ 70,518,449	$ 8,516,343	$ 117,737,086	$ 58,612,951	$ 9,428,215	$ 14,063,658
Net Operating Income (Adjusted)				$ 38,667,355	$ 15,210,397	$ 1,297,343	$ 19,574,985	$ 12,643,555	$ 3,613,959	$ 6,750,168
Net Cost Rate Base				$ 466,754,072	$ 193,633,653	$ 22,925,740	$ 304,035,500	$ 130,121,703	$ 36,217,500	$ 72,756,718
Adjustment to Reflect Depreciation Reserve			DET	$ (2,709,616)	$ (1,108,962)	$ (131,808)	$ (1,739,763)	$ (721,432)	$ (201,254)	$ (474,260)
Cash Working Capital			OMLF	$ (42,095)	$ (13,810)	$ (1,696)	$ (21,024)	$ (8,417)	$ (2,340)	$ (3,374)
Adjusted Net Cost Rate Base				$ 464,002,361	$ 192,510,881	$ 22,792,236	$ 302,274,712	$ 129,391,855	$ 36,013,906	$ 72,279,083
Rate of Return				8.33%	7.90%	5.69%	6.48%	9.77%	10.03%	9.34%

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF LOUISVILLE GAS AND	)	
ELECTRIC COMPANY FOR AN ADJUSTMENT	)	**CASE NO.**
OF ITS ELECTRIC AND GAS BASE RATES	)	**2009-00549**

AND

APPLICATION OF KENTUCKY UTILITIES	)	
COMPANY FOR AN ADJUSTMENT	)	**CASE NO.**
OF BASE RATES	)	**2009-00548**

EXHIBIT__(SJB-3)

OF

STEPHEN J. BARON

KENTUCKY UTILITIES COMPANY
Corrected BIP CCOSS
12 Months Ended October 31, 2009
Application of 25% Subsidy Reduction

Description	Total System	Residential Rate RS	General Service Secondary GSS	All Electric School AES
Cost of Service Summary -- Pro-Forma				
Total Pro-Forma Operating Revenue	$ 1,166,488,825	$ 436,890,835	$ 162,257,077	$ 8,178,602
Total Operating Expenses	$ 997,802,764	$ 400,410,640	$ 128,485,096	$ 7,502,478
Net Operating Income (Adjusted)	$ 168,686,061	$ 36,480,195	$ 33,771,981	$ 676,125
Net Cost Rate Base	$ 3,157,293,448	$ 1,543,739,386	$ 363,984,640	$ 30,304,386
Rate of Return	5.34%	2.36%	9.28%	2.23%
Subsidy at Current Rates	0	(73,234,953)	22,807,745	(1,501,325)
KU Proposed Increases				
Proposed Base Rate Increase	136,096,420	58,746,914	16,388,192	1,149,071
Increase in Miscellaneous Charges	926,170	446,497	201,774	2,587
Incremental Curtailable Credit	(1,755,650)	(878,465)	(190,977)	(21,012)
Incremental Income Taxes	(50,307,709)	$ (21,688,162)	$ (6,099,018)	$ (420,504)
Net Operating Income after increase	253,645,292	$ 73,106,978	$ 44,071,951	$ 1,386,267
Rate of Return at KU Proposed Rates	8.03%	4.74%	12.11%	4.57%
Subsidy at KU Proposed Rates	(0)	(81,057,953)	23,612,653	(1,669,000)
Change in Subsidy resulting from KU Proposed Rates		10.7%	3.5%	11.2%
Base Rate Increase Required for Equalized Rates of Return	136,096,420	139,804,867	(7,224,461)	2,818,071
Base Rate increase Required for 25% Subsidy Reduction	136,096,420	84,878,652	9,881,348	1,692,077
Incremental Curtailable Credit	(1,755,650)	(878,465)	(190,977)	(21,012)
Incremental Income Taxes	(50,307,709)	(31,406,929)	(3,679,030)	(622,455)
Net Operating Income after increase	253,645,292	$ 89,519,949	$ 39,985,095	$ 1,727,322
Rate of Return after 25% Subsidy Reduction	8.03%	5.80%	10.99%	5.70%
Subsidy after 25% Subsidy Reduction	(0)	(54,926,215)	17,105,808	(1,125,994)
Change in Subsidy resulting from 25% Subsidy Reduction		-25.0%	-25.0%	-25.0%
Adjusted Revenue at Current Rates	1,174,375,664	433,896,060	162,978,796	8,264,689
Percentage Increase proposed by KU	11.59%	13.54%	10.06%	13.90%
Percentage Increase to achieve equalized Rates of Return	11.59%	32.22%	-4.43%	34.10%
Percentage Increase to achieve 25% subsidy reduction	11.59%	19.56%	6.06%	20.47%

KENTUCKY UTILITIES COMPANY
Corrected BIP CCOSS
12 Months Ended October 31, 2009
Application of 25% Subsidy Reduction

Description	Power Service PS-Secondary	Power Service PS-Primary	Time of Day TOD-Secondary	Time of Day TOD-Primary	Retail Transmission Service RTS	Fluctuating Load Service FLS - Transmission	Street Lighting SL LT
Cost of Service Summary -- Pro-Forma							
Total Pro-Forma Operating Revenue	$ 215,553,771	$ 85,854,991	$ 9,813,686	$ 137,312,070	$ 71,256,506	$ 18,557,460	$ 20,813,826
Total Operating Expenses	$ 176,886,416	$ 70,644,594	$ 8,516,343	$ 117,737,086	$ 58,612,951	$ 14,943,501	$ 14,063,658
Net Operating Income (Adjusted)	$ 38,667,355	$ 15,210,397	$ 1,297,343	$ 19,574,985	$ 12,643,555	$ 3,613,959	$ 6,750,168
Net Cost Rate Base	$ 464,002,361	$ 192,510,881	$ 22,792,236	$ 302,274,712	$ 129,391,855	$ 36,013,906	$ 72,279,083
Rate of Return	8.33%	7.90%	5.69%	6.48%	9.77%	10.03%	9.34%
Subsidy at Current Rates	22,093,964	7,841,345	126,754	5,453,436	9,123,726	2,690,442	4,598,867
KU Proposed Increases							
Proposed Base Rate Increase	23,088,024	8,936,324	1,075,445	15,516,516	7,258,002	1,872,641	2,065,292
Increase in Miscellaneous Charges	179,429	73,278	1,085	12,449	7,185	1,887	0
Incremental Curtailable Credit	(267,808)	(114,420)	(11,725)	(172,705)	(75,955)	(22,582)	-
Incremental Income Taxes	$ (8,553,897)	$ (3,308,245)	$ (396,016)	$ (5,711,212)	$ (2,673,778)	$ (688,765)	$ (768,112)
Net Operating Income after increase	$ 53,113,102	$ 20,797,334	$ 1,966,131	$ 29,220,032	$ 17,159,009	$ 4,777,139	$ 8,047,349
Rate of Return at KU Proposed Rates	11.45%	10.80%	8.63%	9.67%	13.26%	13.26%	11.13%
Subsidy at KU Proposed Rates	25,214,500	8,488,843	215,077	7,859,434	10,769,462	2,999,455	3,567,529
Change in Subsidy resulting from KU Proposed Rates	14.1%	8.3%	69.7%	44.1%	18.0%	11.5%	-22.4%
Base Rate Increase Required for Equalized Rates of Return	(2,126,476)	447,481	860,367	7,657,082	(3,511,460)	(1,126,814)	(1,502,237)
Base Rate increase Required for 25% Subsidy Reduction	14,443,997	6,328,490	955,433	11,747,159	3,331,334	891,017	1,946,913
Incremental Curtailable Credit	(267,808)	(114,420)	(11,725)	(172,705)	(75,955)	(22,582)	-
Incremental Income Taxes	(5,339,059)	(2,338,354)	(351,382)	(4,309,335)	(1,213,394)	(323,685)	(724,085)
Net Operating Income after increase	$ 47,683,913	$ 19,159,390	$ 1,890,753	$ 26,852,552	$ 14,692,725	$ 4,160,595	$ 7,972,997
Rate of Return after 25% Subsidy Reduction	10.28%	9.95%	8.30%	8.88%	11.36%	11.55%	11.03%
Subsidy after 25% Subsidy Reduction	16,570,473	5,881,008	95,065	4,090,077	6,842,794	2,017,832	3,449,150
Change in Subsidy resulting from 25% Subsidy Reduction	-25.0%	-25.0%	-25.0%	-25.0%	-25.0%	-25.0%	-25.0%
Adjusted Revenue at Current Rates	219,186,409	87,466,013	9,970,256	139,874,751	72,780,342	18,976,432	20,981,916
Percentage Increase proposed by KU	10.53%	10.22%	10.79%	11.09%	9.97%	9.87%	9.84%
Percentage Increase to achieve equalized Rates of Return	-0.97%	0.51%	8.63%	5.47%	-4.82%	-5.94%	-7.16%
Percentage Increase to achieve 25% subsidy reduction	6.59%	7.24%	9.58%	8.40%	4.58%	4.70%	9.28%

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF LOUISVILLE GAS AND	)	
ELECTRIC COMPANY FOR AN ADJUSTMENT	)	CASE NO.
OF ITS ELECTRIC AND GAS BASE RATES	)	2009-00549

AND

APPLICATION OF KENTUCKY UTILITIES	)	
COMPANY FOR AN ADJUSTMENT	)	CASE NO.
OF BASE RATES	)	2009-00548

EXHIBIT__(SJB-4)

OF

STEPHEN J. BARON

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2009-00549

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 70

Responding Witness: Robert M. Conroy/William Steven Seelye

Q-70. Refer to page 11 of the Conroy Testimony. Explain the differences that Rate ITODP customers will see in their bills and how many customers will be affected by the move to kVA billing for customers migrated to this new rate. Provide the same information for Rate CTODP rate customers.

A-70. Under the current Rate ITOD, the rate structure consists of a customer charge, time-differentiated demand charge billed on a kW basis, energy charge, and power factor provision. Under the power factor provision, the monthly demand charge is decreased 0.4% for each whole percent by which the monthly average power factor exceeds an 80% lagging power factor and is increased 0.6% for each whole one percent by which the monthly average power factor is less than 80% lagging. A lagging power factor relates to whether the customer's power is affected by inductive load requirements, such as motor load; whereas leading power factor relates to whether the customer's power is affected by capacitive load requirements, including capacitors and lightly loaded circuits.

Under the current tariff, power factor is determined on an average basis, which means that the power factor is calculated by dividing the kilowatt hours (kWh) by the kilovolt-amp hours (kVAh) for the month. Therefore, the demand charge is adjusted on the basis of the relationship between average kW demands and average kVA demands for the month. Additionally, under LG&E's current tariff customer demands are adjusted against an 80% power factor.

Under the proposed Rate ITODP, the power factor provision is being eliminated and the billing demand will be determined on a kVA basis rather than on a kW basis. The consequences of billing on a maximum kVA basis are customers will be strongly encouraged to increase their power factor to unity power factor, i.e., a 100% power factor at the time of their maximum demands. During off-peak periods, there are fewer *sinks for reactive power* operating on the system, such as inductors and transformers, but the *sources of reactive power* during off-peak conditions, such as fixed capacitors and lightly loaded circuits, can have the effect of creating leading power factor conditions. As a result, during non-peak conditions leading power factors can be more problematic than lagging power factors. An important aspect of kVA billing is that it corrects for both leading and lagging power factors.

For the ITODP customers as a whole, there is no difference between the total demand charge revenue calculated on a kVA basis and the demand charge revenue that would have otherwise been calculated on a kW basis. However, the effect on individual customers will vary depending on their power factor. In contrast to KU, LG&E's power factor adjustment is determined on the basis of average power factor rather than the power factor calculated during the 15-minute interval when the customer's demand is determined. For KU, the power factor adjustment is based on the power factor determined at the time when the demand is measured for billing purposes. Furthermore, for KU, the demand is adjusted against a 90% rather than an 80% power factor. As a result, large power customers on LG&E's system show a much larger variation in power factor at the time of the measured demand. For this reason, the variation of the impact on individual customers of billing on a kVA basis is anticipated to be larger on the LG&E system than the KU system, because customers on KU's system have already been encouraged to install capacitors to correct against a 90% power factor. Spot checks of individual power factors for ITODP on the LG&E system indicate that customer power factors vary in any given month from 50% to 100%, depending on the amount of motor load that a customer might have and whether the customer has installed capacitors.

For CTODP customers there is also no difference between the total demand charge revenue calculated on a kVA basis and the demand charge revenue that would have otherwise been calculated on a kW basis. Likewise, the effect on individual customers will vary from customer to customer depending on their power factor. Based on spot checks there appear to be less variation in the power factors for CTODP customers than ITODP customers, with power factors varying from 90% to 100%.

The Company has not performed an individual impact analysis of the proposed rates on each primary voltage customer; however, the change proposed by LG&E is much closer to the current approach used by KU. Customers with poor power factors will likely determine that it is less costly to install capacitor banks than continue to pay higher demand charges as a result of maintaining low power factors. Such an investment in capacitors could be paid for in less than a year by lower demand charges on the customer's bills.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF LOUISVILLE GAS AND	)	
ELECTRIC COMPANY FOR AN ADJUSTMENT	)	**CASE NO.**
OF ITS ELECTRIC AND GAS BASE RATES	)	**2009-00549**

AND

APPLICATION OF KENTUCKY UTILITIES	)	
COMPANY FOR AN ADJUSTMENT	)	**CASE NO.**
OF BASE RATES	)	**2009-00548**

EXHIBIT__(SJB-5)

OF

STEPHEN J. BARON

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2009-00549

Response to Third Data Request of Commission Staff
Dated March 26, 2010

Question No. 22

Responding Witness: Chris Hermann/William Steven Seelye

Q-22. Refer to the response to Item 93 of Staff's Second Request, which discusses the effect of the proposal to bill primary voltage customers on a kVA basis rather than a kW basis. The response states that, with everything else being equal, a customer with a lower than average power factor would experience a relatively larger increase as a result of the proposal.

a. For an average primary service customer served under each applicable rate class, with all billing factors other than power factor constant, provide the billing calculations (two calculations for each rate class) showing power factors at the extreme high and extreme low that LG&E has observed, or believes attainable under the rates. Include the percentage increases for both rate classes for each calculation.

b. LG&E states that customers with low load factors will likely determine it is less costly to install capacitor banks than continue to pay higher demand charges as a result of maintaining low power factors. Explain whether LG&E believes this conclusion should be intuitive to the customer, or if it would expect to notify the customer of the alternative.

A-22. a. See attached.

b. LG&E believes that for most if not all customers served under ITOD-P and CTOD-P it will be obvious to these customers that their power factors can be improved by installing capacitor banks. Customers eligible for this rate are already served on a power factor correction rate, and therefore are already familiar with the power factor correction concept. This rate is applicable to customers with demands of at least 250 KVA, and many customers served under this rate have demands far in excess of this level. Therefore, these are not small customers, but are among the largest customers on LG&E's system. Many of these customers have electrical engineers on their staff with responsibilities for managing their energy facilities and energy costs. Furthermore, customers under these rates are assigned account executives who regularly communicate with most of the customers served under ITOD-P and CTOD-P. All of the account executives at LG&E are aware of this change and many have already had discussions with a number of primary voltage customers who would be affected by the change. The Company's account executives will provide notice to customers on their options for improving power factor.

LOUISVILLE GAS and ELECTRIC COMPANY

Calculation of Proposed Increase on an Average Customer's Base Rate Billing

Typical Power Factor

Power Factor = 0.95

Industrial Primary Time-of-Day Service

	Average Usage		Current Rate	Billing Summer	Billing Winter	Billing Annual
Customer Charge			$120.00	$120.00	$120.00	$1,440.00
Energy Charge	3,121,800	kWh	$0.02616	$81,666.29	$81,666.29	$979,995.48
Demand Charge						
Basic	6,601	kW	$3.85	$25,413.85	$25,413.85	$304,966.20
Summer	7,390	kW	$9.35	$69,096.50		$276,386.00
Winter	6,014	kW	$6.76		$40,654.64	$325,237.12
Subtotal Demand						$906,589.32
Total						$1,888,024.80

	Average Usage		Proposed Rate	Billing Annual	Increase Dollars	Increase Per Cent
Customer Charge			$300.00	$3,600.00	$2,160.00	150.00%
Energy Charge	3,121,800	kWh	$0.02936	$1,099,872.58	$119,877.10	12.23%
Demand Charge						
Base	6,926	kVA	$4.12	$342,421.44		
Intermediate	6,792	kVA	$3.42	$278,743.68		
Peak	6,712	kVA	$4.92	$396,276.48		
Subtotal Demand				$1,017,441.60	$110,852.28	12.23%
Total				$2,120,914.18	$232,889.38	12.34%

LOUISVILLE GAS and ELECTRIC COMPANY

Calculation of Proposed Increase on an Average Customer's Base Rate Billing

High Power Factor

Power Factor = 1.00

Industrial Primary Time-of-Day Service

	Average Usage	Current Rate	Billing Summer	Billing Winter	Billing Annual
Customer Charge		$120.00	$120.00	$120.00	$1,440.00
Energy Charge	3,121,800 kWh	$0.02616	$81,666.29	$81,666.29	$979,995.48
Demand Charge					
Basic	6,601 kW	$3.85	$25,413.85	$25,413.85	$304,966.20
Summer	7,390 kW	$9.35	$69,096.50		$276,386.00
Winter	6,014 kW	$6.76		$40,654.64	$325,237.12
Subtotal Demand					$906,589.32
Total					$1,888,024.80

	Average Usage	Proposed Rate	Billing Annual	Increase Dollars	Increase Per Cent
Customer Charge		$300.00	$3,600.00	$2,160.00	150.00%
Energy Charge	3,121,800 kWh	$0.02936	$1,099,872.58	$119,877.10	12.23%
Demand Charge					
Base	6,580 kVA	$4.12	$325,300.37		
Intermediate	6,452 kVA	$3.42	$264,806.50		
Peak	6,376 kVA	$4.92	$376,462.66		
Subtotal Demand			$966,569.53	$59,980.21	6.62%
Total			$2,070,042.11	$182,017.31	9.64%

Note: The power factor adjustment in the current rate is based on average monthly power factor, while the power factor adjustment in the proposed rate (i.e. kVA billing) is effectively based on power factor at the time of the maximum demand. This spreadsheet assumes that the power factor at the time of the applicable maximum demand is 1.00 but the average power factor is unchanged.

LOUISVILLE GAS and ELECTRIC COMPANY

Calculation of Proposed Increase on an Average Customer's Base Rate Billing

High Power Factor

Power Factor = 0.80

Industrial Primary Time-of-Day Service

	Average Usage	Current Rate	Billing Summer	Billing Winter	Billing Annual
Customer Charge		$120.00	$120.00	$120.00	$1,440.00
Energy Charge	3,121,800 kWh	$0.02616	$81,666.29	$81,666.29	$979,995.48
Demand Charge					
Basic	6,601 kW	$3.85	$25,413.85	$25,413.85	$304,966.20
Summer	7,390 kW	$9.35	$69,096.50		$276,386.00
Winter	6,014 kW	$6.76		$40,654.64	$325,237.12
Subtotal Demand					$906,589.32
Total					$1,888,024.80

	Average Usage	Proposed Rate	Billing Annual	Increase Dollars	Increase Per Cent
Customer Charge		$300.00	$3,600.00	$2,160.00	150.00%
Energy Charge	3,121,800 kWh	$0.02936	$1,099,872.58	$119,877.10	12.23%
Demand Charge					
Base	8,225 kVA	$4.12	$406,625.46		
Intermediate	8,066 kVA	$3.42	$331,008.12		
Peak	7,971 kVA	$4.92	$470,578.32		
Subtotal Demand			$1,208,211.90	$301,622.58	33.27%
Total			$2,311,684.48	$423,659.68	22.44%

Note: The power factor adjustment in the current rate is based on average monthly power factor, while the power factor adjustment in the proposed rate (i.e. kVA billing) is effectively based on power factor at the time of the maximum demand. This spreadsheet assumes that the power factor at the time of the applicable maximum demand is 0.70 but the average power factor is unchanged.