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PUBLIC SERVICE
COMMISSION

Via Overnight Mail

April 7, 2010

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

Re: Case No. 2009-00459

Dear Mr. Derouen:

Please find enclosed the original and twelve (12) copies each of the DIRECT TESTIMONY AND EXHIBITS of: PAUL A. COOMES, STEPHEN J. BARON, RICHARD A. BAUDINO, and LANE KOLLEN on behalf of THE KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC. filed in the above-referenced matter. By copy of this letter, all parties listed on the Certificate of Service have been served.

Please place this document of file.

Very Truly Yours,

David F. Boehm, Esq.
Michael L. Kurtz, 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 e-mailing a true and correct copy via electronic mail (when available) and by OVERNIGHT MAIL, (unless otherwise noted) to all parties on the 7th day of April, 2010.

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Michael L. Kurtz, Esq.

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APR 08 2010

PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:	:	
THE APPLICATION FOR GENERAL	:	
ADJUSTMENT OF ELECTRIC RATES OF	:	Case No. 2009-00459
KENTUCKY POWER COMPANY	:	
	:	

DIRECT TESTIMONY AND EXHIBITS

OF

PAUL A. COOMES

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

APRIL, 2010

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF: **THE APPLICATION FOR GENERAL** **ADJUSTMENT OF ELECTRIC RATES OF** **KENTUCKY POWER COMPANY**	: : : : :	**Case No. 2009-00459**

DIRECT TESTIMONY OF PAUL A. COOMES

Q. Please state your name, address, and profession.

A. My name is Paul A. Coomes. My address is 3604 Trail Ridge Road, Louisville KY 40241. I am a consulting economist. I have a Ph.D. in economics from the University of Texas. I am also a professor of economics at the University of Louisville.

Q. Have you testified before the Kentucky Public Utility Commission?

A. Yes, I have testified and submitted testimony several times before the Kentucky Public Service Commission, to present studies I have performed for utilities and aluminum companies.

Q. Why are you here today?

A. I have been retained by the law firm representing the Kentucky Industrial Utility Customers. KIUC seeks to document the relative economic importance of their members, which include prominent manufacturers around the state. They also wish to document the large amount of energy purchased by these industrial customers. I have prepared a report and will give a summary of my findings today, as well as answer any questions you have.

Q. In summary, what did you find about the relative economic importance of manufacturing and related industries relative to other industries in Kentucky?

A. Economic activity in Kentucky is classified under hundreds of different industries, but some are much more important than others in terms of overall growth and prosperity in the state. The most important industries are those that export their goods and services to customers around the US and the world. Firms in these industries bring new dollars into Kentucky and thereby lift firms in other linked industries, as well as the incomes of Kentucky households. As household incomes grow, so do sales and employment in support industries (and governments) that provide goods and services to households. The export-based industries are the engines of growth, and hence the target of economic development agencies, while the support industries are essentially captive and require no incentives to operate in the state.

From this perspective, the most important industries are nearly all in the manufacturing, distribution, mining and agricultural sectors, and the least important industries are those in the finance, real estate, retail, health care, education and personal services sectors. In terms of export-based industries with significant employment in Kentucky, those with the greatest spin-off impacts are: petroleum refining, beef and pork slaughtering, fluid milk manufacturing, tobacco (non-cigarette) manufacturing, meat processing, soap and detergent manufacturing, automobile and light truck manufacturing.

Other major employers with large employment multipliers include: motor vehicle parts manufacturing, insurance carriers, coal mining, cattle ranching and farming, poultry processing, millwork, sawmills, computer equipment, poultry production, distilleries, glass products, frozen food manufacturing, logging, plastic material manufacturing, cookie manufacturing, aluminum fabrication, steel and aluminum production.

Q. And in summary, what did you find concerning energy purchases by these industrial operations in Kentucky?

A. These economically important industries are also among the largest consumers of electricity in Kentucky. Primary aluminum production, for example, spends around $130,000 per employee on electricity, whereas the typical retail or service business spends only a few hundred dollars per employee annually on electricity. Indeed, Kentucky has a strong presence of many of the most energy-intensive industries in the United States, attracted here partly because of our historically competitive electricity rates. I have identified at least eight manufacturing industries in Kentucky that purchase more than $10,000 of electricity per employee. These industries also have large employment multipliers, thereby lifting economic activity in other industries and raising household incomes statewide.

Q. Briefly, what methods did you use to analyze the importance of these industries?

A. I have used the IMPLAN modeling system to organize detailed economic estimates on industrial activity in Kentucky. I sorted the estimates to reveal which industries have the most employment and which have the most employment spinoff impacts. As a measure of spinoff, I use what are called 'Type I employment multipliers'. These measure how much total employment in Kentucky would rise per new job in the reference industry, due to vendor linkages among industries. The Type I multipliers exclude the additional household spending impacts (Type II), and allow us to focus clearly on industrial linkages that drive the overall economy.

Q. Do you have any exhibits to illustrate the different impacts among industries?

A. Yes, I have provided two charts and a table. In the first chart (PAC-1) I plot employment and the interindustry job multipliers for all 490 industries represented in the IMPLAN model. This overall view serves to highlight the extreme differences in interindustry linkages between some important export-base industries and those that serve primarily a local market. Note that the highest job multipliers are in some small food and agricultural processing industries, while the industries with the most jobs primarily sell to Kentucky residents, e.g., restaurants and bars.

In the second chart (PAC-2) I zoom in on industries that have significant employment and have relatively high job multipliers. I use 500 employees as a threshold for employment size and 1.5 as the threshold for job multipliers. Of 490 industries, only 95 meet both criteria, and many of those are industries that serve primarily Kentucky residents.

This filtering clearly reveals the relative economic importance of industries in Kentucky. Note that the industries with the highest job multipliers are all manufacturing and food processing related. Ignoring the home construction, home remodeling and telecommunications industries - which are not exporters but rather dependent on residential incomes - the largest employers are motor vehicle parts manufacturing, insurance carriers, coal mining, automobile manufacturing, and cattle ranching.

A complete list of export-based industries with greater than 500 employees and with an employment multiplier above 1.5 is provided in the table (PAC-3). There are 86 industries, directly employing 227,000 persons, that meet these criteria. Virtually every industry listed is classified as manufacturing. The highest job multiplier is for petroleum refineries, followed by beef and pork slaughtering, milk manufacturing, and other tobacco manufacturing. The reader should not focus so much on the magnitudes of the multipliers as on the ranking of the industry multipliers. For example, it is unlikely that the true (unknown) employment multiplier for petroleum refining is 11, but it is likely that the industry has one of the highest job multipliers in Kentucky. Given the measurement problems inherent in these regional analyses, the input-output modeling tools can generate extremely high (unrealistic) multipliers, especially for smaller industries with strong linkages to the rest of the economy. The main conclusion supported by this list is that a fraction of industries in Kentucky directly or indirectly support most of the employment in the state.

Q. Do you have any exhibits that illustrate the energy-intensiveness of these industries?

A. Yes, see PAC-4. Many of the industries we identify as having great employment impacts in Kentucky also are among the most energy-intensive. Whereas a household or a small business may spend a few thousand dollars annually on electricity and natural gas, the average aluminum smelter, for example, will purchase more than $20 million in electricity. Larger retail and commercial firms, hospitals, and the like purchase energy for heating, air conditioning and lighting, with annual energy expenditures per employee of perhaps a few hundred dollars. Many manufacturing operations use energy as part of their production processes, and may purchase tens of thousands of dollars of electricity per employee annually.

Some other examples, drawn from our list of high employment multipliers above, illustrate the distinction between a manufacturing operation and a service operation. The average electricity purchases annually for a poultry processing plant purchases is over $800,000, for a fluid milk plant over $500,000, and for a meat processing plant over $230,000, driven largely by their massive refrigeration requirements. The average petroleum refinery purchases over $14 million per year in electricity. The average truck manufacturing plant purchases $2.7 million in electricity annually, automobile manufacturing plants purchase $1.1 million, and motor vehicle parts plants purchase $200,000.

In Exhibit PAC-4 I display the top 50 manufacturing industries nationally, in terms of electricity purchases per employee, and also show purchases per business establishment for these detailed industries. (The 2007 Economic Census estimates for manufacturing in Kentucky have not yet been published. Moreover, while it will provide good detail on output, employment, payroll and other aggregates, it will not show energy purchases by industry.) The listing is particularly interesting since many of the top energy using industries are prominent in Kentucky. The highest electricity purchases per employee ($131,000) are in the primary aluminum industry, and Kentucky represents a large share of this national industry. Other prominent Kentucky industries in the list include petroleum refining, secondary aluminum, paperboard, steel, plastics, soybean processing, paper, and aluminum sheet, plate, and foil. These industries all purchase more than $10,000 of electricity per employee. And nearly all purchase more than $1 million in electricity per plant. Indeed, access to Kentucky's historically inexpensive electricity is the reason many of these industries are located in the state.

Q. Does that conclude your testimony today?

A. Yes, thank you.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF: THE APPLICATION FOR GENERAL ADJUSTMENT OF ELECTRIC RATES OF KENTUCKY POWER COMPANY	: : : : :	Case No. 2009-00459

AFFIDAVIT OF PAUL COOMES

STATE OF KENTUCKY)
COUNTY OF ______________)

Paul Coomes being first duly sworn, deposes and states that:

1. He is a consulting economist and Professor of Economics at the University of Louisville;

2. He is the witness who sponsors the accompanying testimony entitled "Direct Testimony and Exhibits of Paul Coomes;"

3. Said testimony was prepared by him and under his direction and supervision;

4. If inquiries were made as to the facts and schedules in said testimony he would respond as therein set forth; and

5. The aforesaid testimony and schedules are true and correct to the best of his knowledge, information and belief.

Paul Coomes

Paul Coomes KY C95H06597 exp 11-14-2013

Subscribed and sworn to or affirmed before me this 20th day of April, 2010, by Paul Coomes.

Teresa Schnurr

Notary Public Notary Id 403568

TERESA SCHNURR
NOTARY PUBLIC
STATE AT LARGE
KENTUCKY
MY COMMISSION EXPIRES AUG. 27, 2013

F:\Kentucky\Affidavit Paul Coomes.doc

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:	:	
THE APPLICATION FOR GENERAL	:	
ADJUSTMENT OF ELECTRIC RATES OF	:	Case No. 2009-00459
KENTUCKY POWER COMPANY	:	
	:	

EXHIBITS

OF

PAUL A. COOMES

ON BEHALF OF THE
KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

Exhibit PAC-1

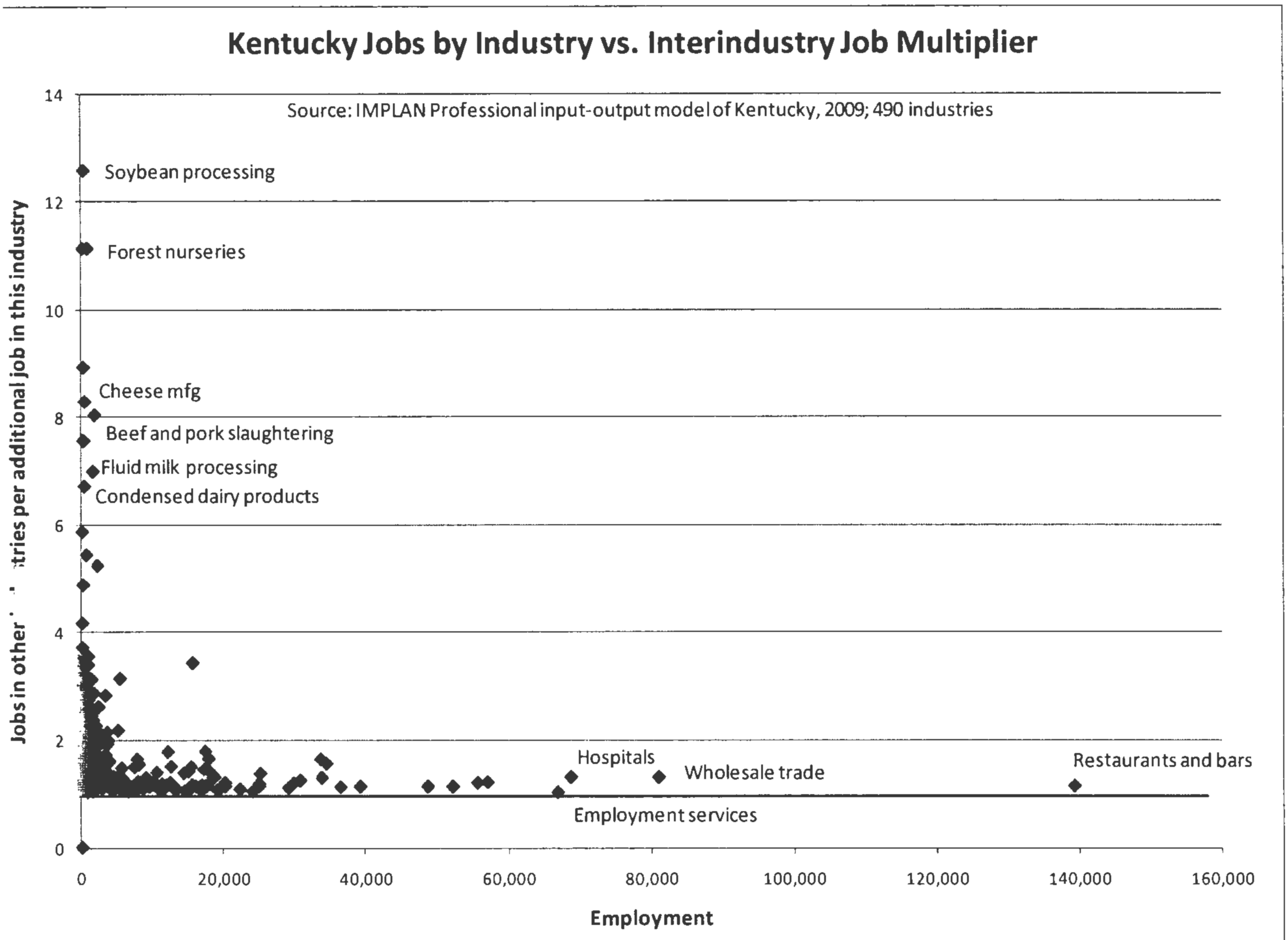

Exhibit PAC-2

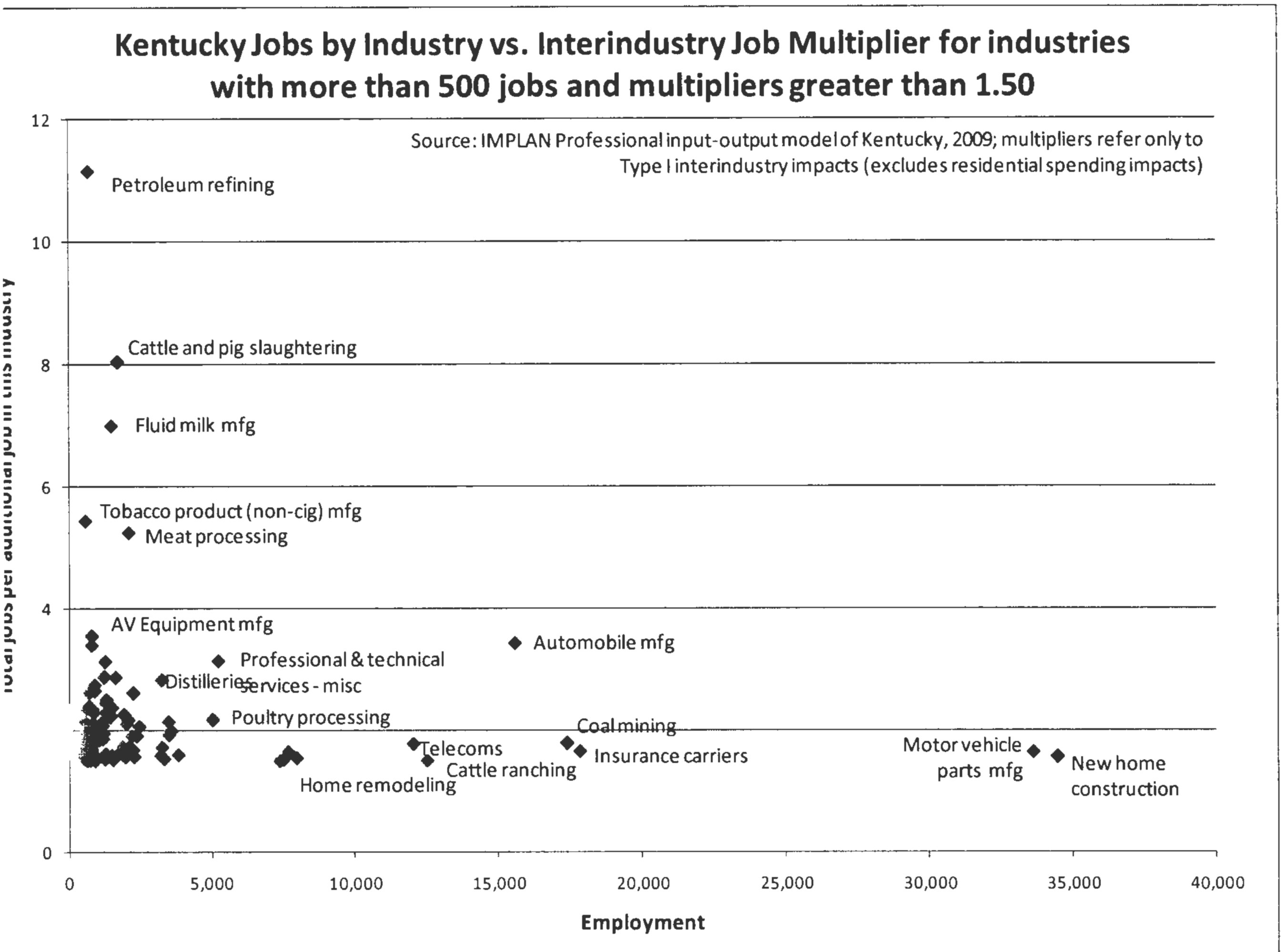

Exhibit PAC-3

IMPLAN Sector Number	Industry description	Employ ment	Employme nt Multiplier (Type I)
142	Petroleum refineries	703.0	11.140
67	Animal- except poultry- slaughtering	1,712.0	8.041
62	Fluid milk manufacturing	1,495.0	6.992
91	Other tobacco product manufacturing	577.0	5.436
68	Meat processed from carcasses	2,099.0	5.239
163	Soap and other detergent manufacturing	792.0	3.549
344	Automobile and light truck manufacturing	15,548.0	3.427
309	Audio and video equipment manufacturing	785.0	3.397
450	All other miscellaneous professional and tech	5,219.0	3.143
203	Iron and steel mills	1,262.0	3.127
160	Pharmaceutical and medicine manufacturing	1,237.0	2.883
151	Other basic organic chemical manufacturing	1,225.0	2.870
88	Distilleries	3,235.0	2.826
47	Other animal food manufacturing	899.0	2.745
396	Pipeline transportation	898.0	2.647
78	Roasted nuts and peanut butter manufacturing	705.0	2.621
152	Plastics material and resin manufacturing	2,237.0	2.615
125	Paper and paperboard mills	1,306.0	2.504
331	Household laundry equipment manufacturing	1,267.0	2.447
27	Drilling oil and gas wells	696.0	2.404
134	Sanitary paper product manufacturing	818.0	2.342
61	Fruit and vegetable canning and drying	569.0	2.339
286	Other engine equipment manufacturing	1,275.0	2.293
259	Construction machinery manufacturing	854.0	2.284
150	Other basic inorganic chemical manufacturing	1,921.0	2.258
434	Machinery and equipment rental and leasing	1,461.0	2.244
393	Water transportation	1,431.0	2.225
70	Poultry processing	5,014.0	2.176
211	Aluminum sheet- plate- and foil manufacturing	2,062.0	2.171
84	All other food manufacturing	1,207.0	2.164
305	Other computer peripheral equipment manufactu	3,470.0	2.145
351	Aircraft manufacturing	550.0	2.143
171	Other miscellaneous chemical product manufact	820.0	2.130
209	Primary aluminum production	1,999.0	2.103
216	Copper rolling- drawing- and extruding	1,156.0	2.080
161	Paint and coating manufacturing	1,174.0	2.078
60	Frozen food manufacturing	2,456.0	2.064
423	Information services	683.0	2.060
162	Adhesive manufacturing	918.0	2.021

Exhibit PAC-3 (cont)

IMPLAN Sector Number	Industry description	Employment	Employment Multiplier (Type I)
75	Mixes and dough made from purchased flour	744.0	2.019
352	Aircraft engine and engine parts manufacturin	807.0	1.956
332	Other major household appliance manufacturing	1,196.0	1.952
112	Sawmills	3,486.0	1.922
167	Printing ink manufacturing	580.0	1.919
14	Logging	2,363.0	1.908
74	Cookie and cracker manufacturing	2,193.0	1.903
153	Synthetic rubber manufacturing	1,004.0	1.894
206	Rolled steel shape manufacturing	1,177.0	1.862
317	Totalizing fluid meters and counting devices	566.0	1.857
257	Farm machinery and equipment manufacturing	1,041.0	1.850
20	Coal mining	17,357.0	1.792
289	Air and gas compressor manufacturing	786.0	1.754
129	Coated and laminated paper and packaging mate	1,870.0	1.735
418	Motion picture and video industries	2,091.0	1.722
452	Office administrative services	3,241.0	1.720
329	Household cooking appliance manufacturing	571.0	1.720
417	Software publishers	589.0	1.696
115	Veneer and plywood manufacturing	785.0	1.687
445	Environmental and other technical consulting	2,217.0	1.676
205	Iron- steel pipe and tube from purchased stee	779.0	1.673
427	Insurance carriers	17,815.0	1.653
424	Data processing services	7,664.0	1.646
350	Motor vehicle parts manufacturing	33,606.0	1.638
325	Electric lamp bulb and part manufacturing	1,280.0	1.613
300	Fluid power pump and motor manufacturing	773.0	1.611
288	Pump and pumping equipment manufacturing	554.0	1.607
292	Conveyor and conveying equipment manufacturin	1,714.0	1.606
119	Other millwork- including flooring	3,820.0	1.598
190	Glass and glass products- except glass contai	3,193.0	1.588
130	Coated and uncoated paper bag manufacturing	887.0	1.588
278	AC- refrigeration- and forced air heating	1,497.0	1.583
249	Ball and roller bearing manufacturing	572.0	1.567
432	Automotive equipment rental and leasing	2,272.0	1.567
294	Industrial truck- trailer- and stacker manufa	1,217.0	1.566
346	Motor vehicle body manufacturing	1,556.0	1.565
381	Sporting and athletic goods manufacturing	733.0	1.550
333	Electric power and specialty transformer manu	504.0	1.543
12	Poultry and egg production	3,321.0	1.533
29	Support activities for other mining	1,257.0	1.530
193	Concrete block and brick manufacturing	545.0	1.530
118	Cut stock- resawing lumber- and planing	1,538.0	1.521
340	Other communication and energy wire manufactu	744.0	1.514
173	Plastics pipe- fittings- and profile shapes	914.0	1.505
11	Cattle ranching and farming	12,504.0	1.503
280	Metal cutting machine tool manufacturing	637.0	1.503
444	Management consulting services	7,357.0	1.501

Exhibit PAC-4

2007 NAICS code	Meaning of 2007 NAICS code	Purchased Electricity per business establishment	Purchased Electricity per Employee
Top 50 US Manufacturing Industries, Electricity Purchases per Employee and Establishment			
331312	Primary aluminum production	$22,695,722	$131,007
325181	Alkalies and chlorine manufacturing	$11,988,000	$92,302
325120	Industrial gas manufacturing	$1,712,054	$86,156
322122	Newsprint mills	$18,050,381	$77,091
325110	Petrochemical manufacturing	$9,573,232	$57,913
331112	Electrometallurgical ferroalloy product manufacturing	$5,863,450	$54,696
325192	Cyclic crude and intermediate manufacturing	$5,015,710	$51,726
325311	Nitrogenous fertilizer manufacturing	$1,226,173	$48,797
327310	Cement manufacturing	$2,671,589	$45,457
324110	Petroleum refineries	$14,528,561	$42,230
311221	Wet corn milling	$5,387,609	$40,815
331314	Secondary smelting and alloying of aluminum	$1,968,754	$32,789
325188	All other basic inorganic chemical manufacturing	$1,811,216	$31,923
331419	Primary nonferrous metal, except Cu and Al	$1,360,197	$30,856
322130	Paperboard mills	$5,726,968	$29,228
325193	Ethyl alcohol manufacturing	$1,113,575	$28,045
331111	Iron and steel mills	$7,538,793	$24,962
325182	Carbon black manufacturing	$1,201,281	$24,162
311213	Malt manufacturing	$944,680	$23,109
325211	Plastics material and resin manufacturing	$1,550,325	$23,054
27410	Lime manufacturing	$1,038,614	$19,731
325131	Inorganic dye and pigment manufacturing	$1,542,792	$19,473
311222	Soybean processing	$888,105	$17,657
325199	All other basic organic chemical manufacturing	$1,596,993	$16,352
322121	Paper (except newsprint) mills	$5,148,066	$16,342
321219	Reconstituted wood product manufacturing	$1,255,592	$16,105
311223	Other oilseed processing	$585,378	$16,032
325312	Phosphatic fertilizer manufacturing	$1,225,738	$15,654
311211	Flour milling	$516,617	$14,714
327213	Glass container manufacturing	$3,410,556	$14,623
322110	Pulp mills	$2,626,359	$14,093
327420	Gypsum product manufacturing	$626,109	$14,087
327992	Ground or treated mineral and earth manufacturing	$340,004	$13,502
326160	Plastics bottle manufacturing	$996,277	$13,451
325212	Synthetic rubber manufacturing	$794,566	$12,331
327211	Flat glass manufacturing	$2,695,383	$12,321
331411	Primary smelting and refining of copper	$1,668,000	$12,244
327993	Mineral wool manufacturing	$751,534	$12,213
325222	Noncellulosic organic fiber manufacturing	$1,624,596	$12,059
324199	All other petroleum and coal products manufacturing	$374,990	$11,948
325221	Cellulosic organic fiber manufacturing	$1,040,800	$11,539
314992	Tire cord and tire fabric mills	$1,713,182	$10,537
331315	Aluminum sheet, plate, and foil manufacturing	$1,601,052	$10,446
332431	Metal can manufacturing	$1,026,182	$10,087
311225	Fats and oils refining and blending	$650,521	$9,456
325191	Gum and wood chemical manufacturing	$304,216	$9,296
331513	Steel foundries (except investment)	$791,355	$9,289
313111	Yarn spinning mills	$908,394	$9,139
31421	Copper rolling, drawing, and extruding	$1,057,322	$9,046
11212	Rice milling	$530,200	$9,026

Source: US Census Bureau, 2007 Economic Census
http://factfinder.census.gov/servlet/IBQTable?_bm=y&-geo_id=&-ds_name=EC0731I1&-_lang=en

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

GENERAL ADJUSTMENTS IN	)	
ELECTRIC RATES OF	)	CASE NO.
KENTUCKY POWER COMPANY	)	2009-00459

DIRECT TESTIMONY

AND EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF THE

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:

GENERAL ADJUSTMENTS IN	)	
ELECTRIC RATES OF	)	**CASE NO.**
KENTUCKY POWER COMPANY	)	**2009-00459**

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

GENERAL ADJUSTMENTS IN	)	
ELECTRIC RATES OF	)	CASE NO.
KENTUCKY POWER COMPANY	)	2009-00459

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 whom 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. Have you previously presented testimony before the Kentucky Public Service Commission?

A. Yes. I have testified before the Kentucky Public Service Commission in fourteen cases over the past thirty years, including Kentucky Power cases. I have also testified in numerous AEP cases in other jurisdictions, including Ohio, West Virginia, Virginia, Indiana, Louisiana and Before the Federal Energy Regulatory Commission.

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

A. I am testifying on behalf of the Kentucky Industrial Utility Customers, Inc. ("KIUC"). KIUC members take service on a number of KPCo rate schedules, primarily on rates CIP-TOD and QP.

Q. What is the purpose of your testimony?

A. I will address issues related to the Company's filed class cost of service study, the allocation of the requested increase among rate schedules, and the Company's proposal to implement a Transmission Adjustment Tariff.

With regard to the cost of service and revenue increase allocation issues, KPCo has filed a 12 coincident peak ("12 CP") class cost of service study in this case. The results of this study indicate that all of the Company's rate classes except the residential class are paying subsidies, while the residential rate class is receiving substantial subsidies at current rates.[1] As in the Company's 2005 rate case, KPCo is proposing to reduce subsidies paid and received by each rate class by 10% in this case. I will address this proposal and discuss KIUC's recommendation to reduce current subsidies by 25%.

The next issue that I address concerns the Company's proposed revisions to Rate Schedule QP (Quantity Power) rate design. As discussed in the Direct Testimony of Company witness David Roush, KPCo is proposing to modify the current design of Rate Schedule QP to incorporate an hours-use provision in the QP energy charge. This change, which is being implemented to transition customers between the Large General Service Rate ("LGS") and Rate Schedule QP, substantially reduces the kW

[1] As will be discussed subsequently in my testimony, under the Company's filed class cost of service study, the residential class is paying a negative rate of return on rate base (i.e., rate RS customers are not even covering the operating expenses associated with their electric service).

demand charge of the rate. As I will discuss, this change results in larger percentage increase to the effective demand charge for high load factor QP customers.

I will also propose extending the Company's Real Time Pricing tariff for an additional three years. This tariff should also be modified to allow customers to select it for any twelve month period, not just the twelve month period beginning June 1st of each year.

The final issue that I address concerns KPCo's proposal to implement a Transmission Adjustment ("TA") Tariff in this case to recover KPCo's share of AEP PJM costs. The proposed tariff would adjust annually to recover the then approved PJM costs allocated to KPCo and also include a cost tracking mechanism that would recover over/under recoveries each month. KIUC opposes this proposed TA mechanism for a number of legal and policy reasons. Though I do not believe that the Company's proposal should be adopted, I will also address concerns with the proposed TA cost tracker mechanism, in the event that the Commission does approve the Company's request.

Q. Would you please summarize your recommendations in this case?

A. Yes,

- **For the purposes of setting rates and allocating the authorized increase in this case, the Company's filed 12 CP cost of service study is reasonable. However, the Company's proposal to reduce interclass subsidies by 10% in this case is an inadequate response to the large disparities that currently exist between rates and cost of service.**

- **The Commission authorized revenue increase in this case should be allocated to rate classes in a manner designed to reduce current rate subsidies paid and received by each rate class by 25%. The Company's "12 CP" class cost of service study shows that the residential class is paying a rate of return on rate base of negative 2.88%. The residential class is currently receiving almost $35.1 million annually in subsidies from other KPCo rate classes.**

- **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 so that current subsidies for large industrial customers on Rate Schedules QP and CIP-TOD 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.**

- **If, as recommend by KIUC, the Commission authorizes a lower revenue increase than requested by the Company, KIUC recommends that the increase be allocated in a manner (as shown later in my testimony) to reduce current rate subsidies by 25%.**

- **The Company's proposed rate design changes to Rate Schedule QP should be modified so that the effective increases in the on-peak demand charge for high load factor customers are approximately the same as the average percentage increase in the QP demand charge. KPCo's proposed rate design unreasonably increases the on-peak demand charge for QP**

customers with high load factors by 43%, compared to the average demand charge increase for the rate of 34%.

- **KPCo currently has an experimental Real Time Pricing tariff that is set to terminate on or about May 31, 2011. Although there are currently no customers taking service on this tariff, the Commission should extend the experimental tariff for an additional 3 year period. Also, the tariff should be modified to permit customers to enter service under this tariff during any month, as long as the customer maintains service for at least a 12 month consecutive period.**

- **KPCo's proposal to implement a Transmission Adjustment Tariff should be rejected because there are no provisions for such an adjustment mechanism in Kentucky Statutes and there has been no evidentiary showing by the Company to justify a separate recovery mechanism for changes in PJM transmission expenses. Rather, the base revenue requirements approved by the Commission in this case should incorporate the revenue requirement effects of the test year level of PJM OATT charges incurred by the Company.**

II. CLASS COST OF SERVICE AND REVENUE APPORTIONMENT OF THE INCREASE TO RATE CLASSES

Q. **Would you please discuss the results of the Company's filed class cost of service study?**

A. Yes. The Company has filed a 12 CP class cost of service study for the 12 months ended September 30, 2009. The results of this test year study indicate that the residential class has a rate of return on rate base of -2.88%, which means that residential customers did not pay sufficient revenues during the test year to even cover the operating expenses associated with their usage of power from KPCo, let alone a return on the invested capital (generating units, transmission plant, distribution facilities) built to serve these customers. Rather, KPCo's return on investment built to serve residential customers was provided by all of the other KPCo rate classes (SGS, MGS, LGS, QP, CIP-TOD, MW, OL and SL).

Figure 1 below shows a graph of the test year relative rates of return produced by each rate class using the results of the Company's analysis.

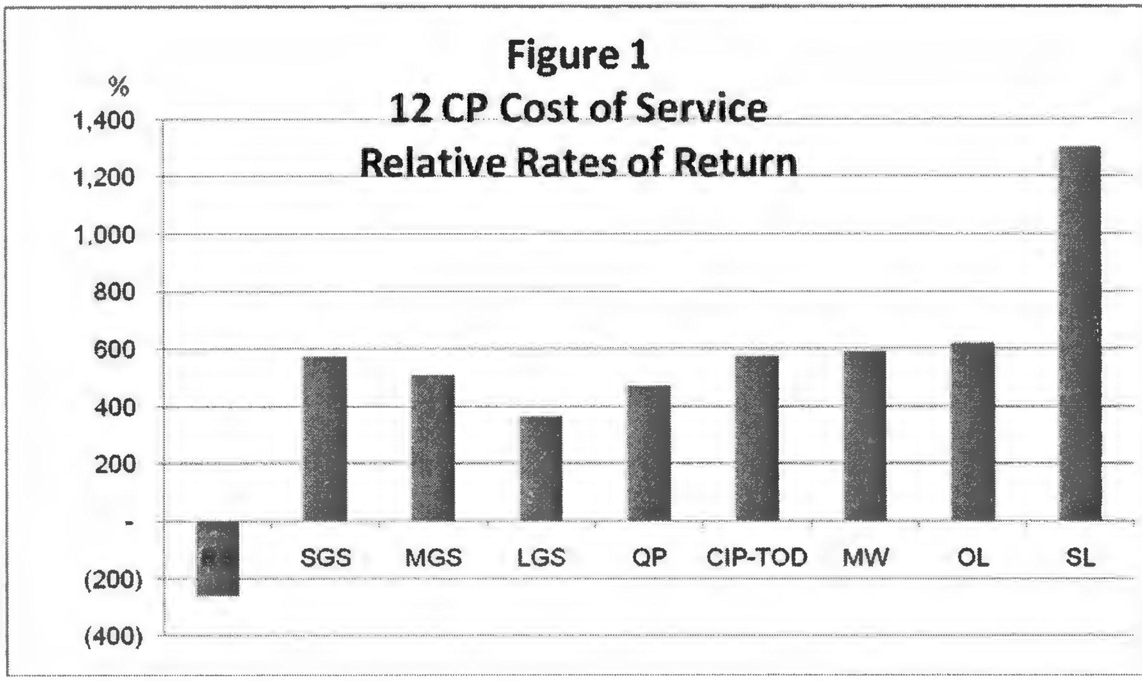
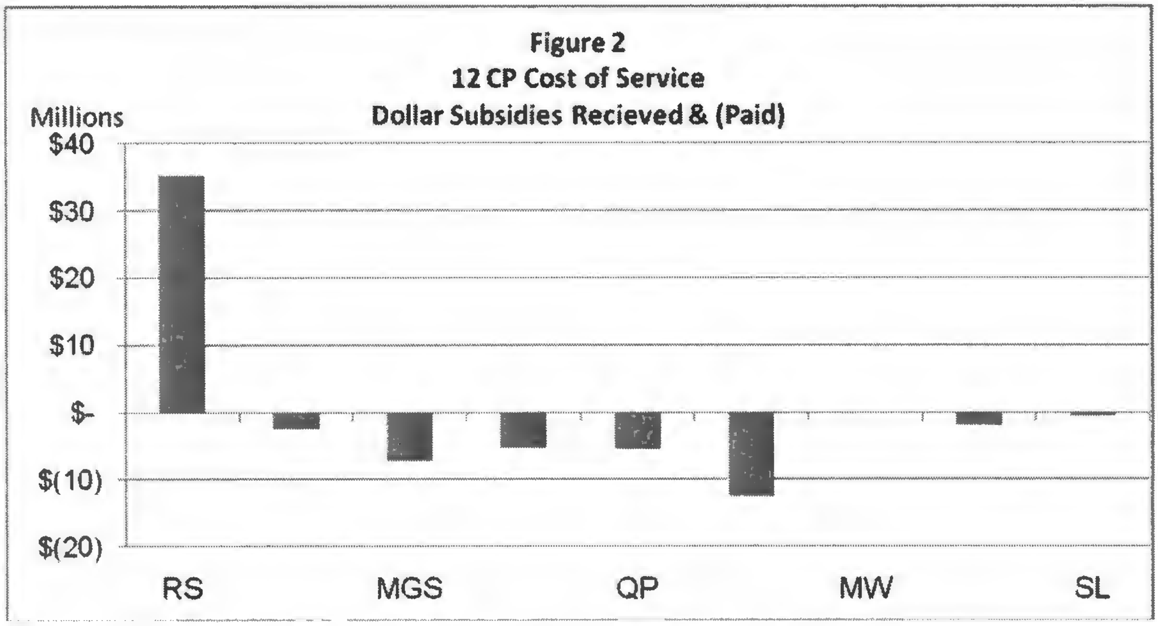


Figure 1
12 CP Cost of Service
Relative Rates of Return

Q. How does this translate into dollar subsidies paid by each of the other rate classes to support the residential class?

A. Figure 2 below shows a chart of the dollar subsidies paid and received by each rate class, using the results of the Company's own study. As can be seen, the residential class received test year rate subsidies of $35.1 million. Rate schedules CIP-TOD and QP paid about $18 million of this subsidy. Effectively, industrial manufacturers on <u>rates CIP-TOD and QP overpaid by more than $18 million, or about 10%</u>, during the 12 months ended September 2009. In particular, customers on rate CIP-TOD have paid by far the largest dollar subsidy of any rate schedule.



Q. What are the implications of these results for revenue allocation in this case?

A. As should be obvious from these results, KPCo's rates are substantially out of line with cost of service. The Company's large commercial and industrial customers on rate schedules QP and CIP-TOD are paying substantial amounts ($18 million annually) in excess of the cost of providing these customers electric power. Given the infrequency of rate cases, this case presents a unique opportunity for the Commission to address this substantial subsidy problem.

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

A. No. KPCo is proposing to reduce subsidies paid and received currently by 10% in its recommended revenue increases to each rate class. The result, of course, is that after the increase in this case, each rate class will continue to pay (or in the case of the residential class, receive) subsidies of 90% of the current level. 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 KPCo'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. KPCo's proposal does not adequately reduce these excessive subsidies built-into large customer rates.

While the Company is proposing to make a modest subsidy reduction (10%), industrial customers would continue to pay $16 million annually in excess power charges due to the continuation of large subsidies to the residential class in KPCo's rate structure. The largest member of KIUC's Kentucky Power group is an oil refining customer. During the past 10 years in the U.S., eight oil refining facilities have shut down, which represents a 5% reduction in the number of refiners, and the jobs that they provided. The Commission should, to the extent feasible, insure that rate making policies do not contribute to further losses in manufacturing jobs in the State.

Q. What is your recommendation to reduce subsidies in this case?

A. I am recommending a 25% subsidy reduction using the results of the Company's filed 12 CP cost of service study. Baron Exhibit (SJB-2) presents the results of a revenue increase distribution using a 25% current subsidy reduction criterion. The methodology that is shown in Exhibit__(SJB-2) is the same as the Company's proposal except that each rate class is assigned an increase based on a 25% subsidy reduction instead of the KPCo proposed 10% reduction. Table 1 below presents the proposed revenue increases for each rate class assuming that the Company's requested overall revenue increase level is implemented.[2]

Table 1
Revenue Increases @ 25% Subsidy Reduction Using 12 CP Study
(@ KPCo requested overall increase)

Class		Increase	Percent
RS	$	74,113,042	37.6
SGS		2,881,012	19.8
MGS		9,832,401	19.0
LGS		11,800,958	20.0
QP		8,353,129	15.2
CIP-TOD		14,446,810	11.6
MW		92,948	16.0
OL		1,948,590	29.6
SL		157,124	13.9
Total	$	123,626,014	24.3

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

A. Table 2 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 QP and CIP-TOD, on which KIUC members take the largest portion of their service, will pay $13.4 million in subsidies each year, even if

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

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 2
Remaining Subsidies at Proposed Rates
(12 CP Study)

Class	KIUC	KPCo
RS	$ 26,356,786	$ 31,628,141
SGS	(1,866,179)	(2,239,413)
MGS	(5,326,479)	(6,391,774)
LGS	(3,898,931)	(4,678,718)
QP	(4,047,720)	(4,857,264)
CIP-TOD	(9,360,226)	(11,232,271)
MW	(62,682)	(75,218)
OL	(1,408,712)	(1,690,453)
SL	(385,858)	(463,030)
Total	$ -	$ -

Q. In the event that the Commission decides not to reduce current dollar subsidies for all 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 QP and CIP-TOD) as proposed in Table 1, and recovers the remaining approved revenue increase from all other rate schedules. The first approach ("Alternative 1") reduces the subsidies for Rate Schedules QP and CIP-TOD by 25%, adopts the Company's proposed increase for the residential class (a 10% subsidy reduction) 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 QP and CIP-TOD 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. Baron Exhibit__(SJB-3) and Exhibit__(SJB-4) present the results of the two alternatives that I just discussed. Table 3 below summarizes the increase under KIUC's alternative approaches.

Table 3
KIUC Alternative Class Increases

Class	Alternative 1	Alternative 2
RS	$ 68,841,686	$ 60,096,782
SGS	3,486,701	4,440,005
MGS	12,373,299	15,756,303
LGS	14,135,555	18,000,380
QP	8,353,129	8,353,129
CIP-TOD	14,446,810	14,446,810
MW	139,617	177,790
OL	1,578,596	2,010,203
SL	270,620	344,611
Total	$ 123,626,013	$ 123,626,013

Q. Have you prepared a table that summarizes each of the KIUC rate schedule revenue increase proposals, compared to the KPCo proposal in this case?

A. Yes. Table 4 provides this summary.

Table 4
Summary of Proposed Increases ($millions)

Class	KPCo	KIUC Primary	KIUC Alt 1	KIUC Alt 2
RS	$68.84	$74.11	$ 68.84	$ 60.10
SGS	$3.25	$2.88	$ 3.49	$ 4.44
MGS	$10.90	$9.83	$ 12.37	$ 15.76
LGS	$12.58	$11.80	$ 14.14	$ 18.00
QP	$9.16	$8.35	$ 8.35	$ 8.35
CIP-TOD	$16.32	$14.45	$ 14.45	$ 14.45
MW	$0.11	$0.09	$ 0.14	$ 0.18
OL	$2.23	$1.95	$ 1.58	$ 2.01
SL	$0.23	$0.16	$ 0.27	$ 0.34
Total	$123.63	$123.63	$ 123.63	$ 123.63

Q. In the likely that the Commission authorizes KPCo 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. Have you reviewed the Company's proposed changes to Rate Schedule QP that incorporate an hours-use blocking provision into the rate?

A. Yes. As described by Company witness David Roush, KPCo is revising Rate Schedule QP to incorporate a load factor blocking (hours-use) rate design that provides for an improved transition between Rate Schedules QP and LGS. Currently, Rate Schedule QP is a straightforward demand, energy and customer ("DEC") type rate, though it does recover a small amount (about 15%) of demand related costs in the energy charge. Under the revised QP rate design, a large portion of the kW demand charge is shifted to the first 350 hours-use energy charge. The "excess" energy charge, according to Mr. Roush, will continue to contain "15% of demand cost, which is consistent with the current QP rate design.

To see the impact of the Company's proposal, Table 5 below summarizes the increases by rate element for the QP Primary rate. Similar results occur for the other voltages (i.e., secondary, sub-transmission and transmission).

Table 5			
QP Rate Design - Primary Voltage Service			
	Present	Proposed	% Change
On-Peak Demand	11.53	$4.15	-64.01%
Off-peak Excess	3.31	6.09	83.99%
Alternate Feed	4.04	4.72	16.83%
Excess KVAR	0.67	0.76	13.43%
Energy - Block 1	0.03233	0.07324	126.54%
Energy - Block 2	0.03233	0.03800	17.54%
Customer	276.00	276.00	0.00%

As can be seen, there is a substantial 64 % reduction in the current QP demand charge and a corresponding substantial (127%) increase in the proposed 1st energy block (350 hours-use of demand).

Q. Do you have any concerns with the Company's proposal to redesign Rate QP?

A. Yes. While I understand the Company's objective to create a smoother transition for customers from Rate Schedule LGS to QP, the impact on high load factor QP customers is substantial, relative to the average increase for QP customers. Table 6 below shows the effective increase in the QP primary voltage demand charge under the Company's proposal. The "effective demand charge" consists of the stated demand charge of $4.15/kW and the implied demand charge contained in the 1st block energy charge. This implied demand charge varies with a customer's load factor. For each kW of demand, the higher a customer's load factor, the greater the demand charge being recovered in the 1st 350 hours-use block. Once a customer's load factor reaches 48.6%, there is no additional demand charge imposed as the customer increases its load factor.

Table 6
Effective Demand Charge Increases - QP Primary

	Effective Demand Charge - $/kW			
Load Factor	On-Pk kW	First 350 kWh	Total	% Increase
20.0%	$4.15	$5.07	$9.22	-20.00%
25.0%	$4.15	$6.34	$10.49	-8.99%
30.0%	$4.15	$7.61	$11.76	2.01%
35.0%	$4.15	$8.88	$13.03	13.01%
40.0%	$4.15	$10.15	$14.30	24.02%
48.6%	$4.15	$12.33	$16.48	42.97%
60.0%	$4.15	$12.33	$16.48	42.97%
80.0%	$4.15	$12.33	$16.48	42.97%
100.0%	$4.15	$12.33	$16.48	42.97%
Average	$4.15	$11.37	$15.52	34.57%

As can be seen from this table, as a customer's load factor increases, the effective kW demand charge increase grows rapidly. The overall result is that higher load factor QP customers will receive a larger than average QP increase.

Q. Do you have any alternative recommendation on this issue?

A. As I indicated earlier, I understand the Company's objective for changing the QP rate design. My recommendation would be to revise the proposed QP design in a manner that would mitigate the impact on high load factor customers. This can be accomplished by changing the hours-use breakpoint (i.e., reduce it below 350 hours-use) or reducing the amount of demand costs that are being shifted to the 1st energy block of the rate. I recommend that the Company be required to incorporate one of these two solutions in its compliance rate filing in this case.

Q. Are there any additional rate design issues that you would like to address?

A. Yes. The Company currently has an experimental real time pricing rate available to large customers (Tariff R.T.P.). This experimental rate was approved for a three year period by the Commission in Case No. 2007-00166 (Order of February 1, 2008). Based on a starting date of June 1, 2008, the RTP rate will expire on May 31, 2011. In fact, new customers will not be accepted after June 1, 2010. Customers can elect service on this rate for a portion of their Rate Schedule QP or CIP-TOD load by submitting a nomination for each PJM planning year prior to May 15th, for service beginning on June 1 (which corresponds to the PJM planning year June 1 to May 31). Though there are currently no customers participating on this rate, KIUC requests that it be continued for an additional three year period. Because this is a new concept in Kentucky, customers may not have been in a position to adequately evaluate participating in the RTP rate. Also, during 2008 and 2009, customers have been experiencing significant economic dislocations that may not have permitted the type of evaluation that was necessary to make commitments to this rate. As a result, KIUC believes that the Commission should continue the RTP tariff for at least an additional three year period.

Q. Are there any changes that you recommend to the current RTP tariff?

A. Yes. The current tariff requires that participating customers elect service under the tariff annually, prior to May 15th to correspond to the PJM planning year. While this provision may be reasonable for incremental load that is not currently being served by the Company (and thus not included in the AEP planning projections submitted to PJM), the load at issue in this instance (existing QP or CIP-TOD load) is already included in AEP's requirements that are provided to PJM. As a result, there does not appear to be any reason why a customer that elects to convert a portion of its load from Rate Schedule QP or CIP-TOD to RTP should not be permitted to do so in any month, as long as the customer commits for a 12 month period. KIUC recommends that the tariff be modified to permit this additional flexibility so that a customer can elect to participate during any calendar month.

IV. TRANSMISSION ADJUSTMENT TARIFF

Q. Have you reviewed the Company's proposal to implement a Transmission Adjustment Tariff to recover PJM OATT costs allocated to KPCo?

A. Yes. As discussed by KPCo witnesses Dennis Bethel and David Roush, the Company is proposing a Transmission Adjustment Tariff ("TA") that effectively replaces the Company's test year transmission revenue requirement (i.e., return on and of transmission rate base and transmission operating expenses) with the charges KPCo incurs from PJM via the OATT. The KPCo OATT charges are based on the Company's member load ratio share ("MLR") of the AEP charges from PJM. The TA essentially calculates the difference between KPCo's PJM costs and base transmission revenue requirements. This TA amount, coupled with the "base" rate recovery of these same "base" transmission revenue requirements effectively results in customers being charged transmission costs based solely on the PJM OATT. The TA would be adjusted annually to reflect changes in the PJM OATT charges. Finally, the Company proposes a tracking mechanism that would accrue over/under-recoveries of transmission costs versus actual PJM charges monthly. These accrued amounts (positive or negative) would be included in future period TA charges.

Q. Is the Company's proposal reasonable?

A. No. For a number of reasons that I discuss below, the Commission should not adopt the TA proposal. Rather, as discussed by KIUC witness Lane Kollen, the Company's base rate revenue requirements should reflect the PJM OATT charges paid by the Company in the test year, as normalized for September 2009 levels.

Q. Would you explain why you oppose the Company's TA proposal?

A. First, I have been advised by KIUC counsel that the proposed TA surcharge mechanism is not consistent with Kentucky Statutes. In particular, there are no statutory provisions to establish such an adjustment mechanism. Though I am not offering testimony on the legality of the Company's proposal, I should note that other charges incurred by the Company pursuant to FERC approved tariffs are recovered in KPCo base rates and not through a rider or adjustment mechanism. For example, AEP capacity settlement charges that are allocated to the Company pursuant to the FERC approved AEP Interconnection Agreement ("Pool Agreement") are recovered in base rates. These costs, which are fixed cost, are similar to the type of charges being imposed on KPCo for transmission service from PJM (i.e., Network Integration Service charges, which are the predominant source of these charges, are fixed, demand related costs similar to the capacity settlement charges). Like the PJM charges, these capacity settlement charges vary as AEP

Operating Company loads change and as new generation resources are added to various AEP Companies.[3]

Q. Has KPCo presented any evidence in this case that there is a financial necessity to recover PJM transmission expenses through an annual adjustment mechanism, rather than through traditional ratemaking via a base rate proceeding?

A. No. While the Company cited the potential for an 1100% increase in PJM Regional Transmission Expansion Plan charges over the next 5 years (Bethel Direct Testimony at page 22), these charges currently constitute only about 3% of KPCo's charges from PJM that are proposed to be recovered in the TA. If, as Mr. Bethel projects, this component of the KPCo PJM charges does rapidly increase over the next five years, there is nothing that would prevent the Company from filing a base rate case, assuming that the single cost increase in and of itself caused KPCo's earned rate of return to deteriorate. There certainly is no evidence in this case that would support a financial need to recover PJM OATT expenses outside of a traditional base rate proceeding.

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[3] In February 2009, Century Aluminum, a 330 mW customer of APCo reduced its load to approximately 10 mW. This had a material effect on the MLRs of each AEP Company.

Q. Are there any additional issues that you would like to address regarding the Company's TA proposal?

A. Yes. Though I oppose the TA Tariff proposal, if the Commission approves the tariff, there should be modifications made to the proposed cost tracker mechanism discussed by KPCo witness Diana Gregory. The Company's proposal, as I understand Ms. Gregory's testimony, is to track the difference between 1) the revenue recovered pursuant to the TA and the "base transmission revenues" and 2) the actual charges received from PJM for transmission service. Since both the TA and the actual PJM OATT charges to KPCo vary with mWh sales and demands, there is a reasonable basis to compare these two amounts; however, the third component of the tracker appears to be fixed at test year levels, since there are no "base transmission revenues" identifiable in KPCo's bundled tariffs. As a result, it appears that the Company is proposing to compare the $49 million in base transmission revenue requirements plus the TA revenue amounts to the actual PJM OATT charges incurred by the Company. This comparison would appear to result in a mismatch because 1 of the 3 elements of the tracker is fixed, while the other two vary with the level of mWh sales and demands on the system. Absent some other refinement that is not discussed in witness Gregory's testimony, this proposed mechanism would lead to an incorrect accrual of over/under recoveries.

Q. What is your recommendation regarding the Company's request for approval of the TA Tariff?

A. I recommend that the Commission reject the Company's proposal and include the PJM OATT expenses and base revenue transmission credit in the calculation of base revenue requirements. My specific recommendation is to reject the TA Tariff and reduce the Company's base revenue requirements by the amount of the difference between 1) the $49,514,393 transmission revenue requirement calculated by KPCo based on its "owned" transmission investment and expenses and 2) KPCo's share of the AEP PJM OATT transmission expenses of $42,475,930. KIUC witness Kollen will incorporate this $7,038,463 adjustment (reduction) in his quantification of the Company's base rate revenue requirement.

Q. In the Company's response to Commission Staff's Second Set of Data Requests, Item No. 57c, KPCo stated that if the TA Tariff proposal is rejected by the Commission, then test year transmission revenue requirements would be set at the $49 million level based on the KPCo's transmission plant and expenses, rather than the PJM OATT costs that the Company pays for transmission service. Is that a reasonable proposal?

A. No. Pursuant to AEP's participation in PJM, KPCo pays for transmission service to meet the requirements of its retail and wholesale customers based on its share of

AEP charges under the PJM OATT. KPCo, as a transmission owner, receives revenues from PJM to cover its costs associated with transmission plant and expenses that are included in the development of the PJM OATT rates. The Company is implicitly recognizing this transactional relationship in its TA Tariff proposal and there is no reason to not follow the same conceptual methodology in developing base rate revenue requirements in the event that the TA Tariff is rejected by the Commission.

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 6th day of April 2010.

Jessica K. I

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:

GENERAL ADJUSTMENTS IN	)	
ELECTRIC RATES OF	)	CASE NO.
KENTUCKY POWER COMPANY	)	2009-00459

EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF THE

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:

GENERAL ADJUSTMENTS IN	)	
ELECTRIC RATES OF	)	CASE NO.
KENTUCKY POWER COMPANY	)	2009-00459

EXHIBIT__(SJB-1)

OF

STEPHEN J. BARON

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

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.

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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.

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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.

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

Date	Case	Jurisdict.	Party	Utility	Subject
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:

GENERAL ADJUSTMENTS IN	)	
ELECTRIC RATES OF	)	CASE NO.
KENTUCKY POWER COMPANY	)	2009-00459

EXHIBIT__(SJB-2)

OF

STEPHEN J. BARON

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

Kentucky Power Company
Proposed Revenue Allocation
Twelve Months Ended September 30, 2009
25% Subsidy Reduction

Current Class (1)	Current Revenue (2)	Current ROR % (3)	Current ROR Index (4)	Proposed Increase (5)	Proposed Increase % (6)	Proposed Revenue (7)	Proposed ROR % (8)	Proposed ROR Index (9)
RS	196,964,517	-2.88	(259)	74,113,042	37.63	271,077,559	5.53	65
SGS	14,551,918	6.37	574	2,881,012	19.80	17,432,930	12.46	146
MGS	51,640,578	5.64	508	9,832,401	19.04	61,472,979	11.92	140
LGS	58,995,442	4.05	365	11,800,958	20.00	70,796,400	10.72	126
QP	54,976,107	5.23	471	8,353,129	15.19	63,329,236	11.61	136
CIP-TOD	124,336,206	6.37	574	14,446,810	11.62	138,783,016	12.46	146
MW	582,698	6.55	590	92,948	15.95	675,646	12.60	148
OL	6,588,349	6.86	618	1,948,590	29.58	8,536,939	12.83	151
SL	1,129,448	14.45	1302	157,124	13.91	1,286,572	18.52	217
Total	509,765,263	1.11	100	123,626,014	24.25	633,391,277	8.52	100

Kentucky Power Company
Proposed Revenue Allocation
Twelve Months Ended September 30, 2009
25% Subsidy Reduction

Current Class (1)	Current Revenue (2)	Rate Base (3)	Current Income (4)	Current ROR % (5)	Current Equalized Rate of Return: Percent Increase (6)	Revenue Increase (7)	Income Increase (8)	Income (9)	ROR % (10)	Sales Revenue (11)	Current Subsidy (12)=(11)-(2)
RS	196,964,517	535,133,286	(15,409,365)	-2.88	17.84	35,142,378	21,329,901	5,920,536	1.11	232,106,895	35,142,378
SGS	14,551,918	28,695,586	1,827,730	6.37	-17.10	(2,488,237)	(1,510,252)	317,478	1.11	12,063,681	(2,488,237)
MGS	51,640,578	95,086,690	5,362,597	5.64	-13.75	(7,101,971)	(4,310,589)	1,052,008	1.11	44,538,607	(7,101,971)
LGS	58,995,442	107,314,277	4,342,599	4.05	-8.81	(5,198,574)	(3,155,309)	1,187,290	1.11	53,796,868	(5,198,574)
QP	54,976,107	79,477,481	4,155,034	5.23	-9.82	(5,396,960)	(3,275,721)	879,313	1.11	49,579,147	(5,396,960)
CIP-TOD	124,336,206	143,900,076	9,167,065	6.37	-10.04	(12,480,301)	(7,575,002)	1,592,063	1.11	111,855,905	(12,480,301)
MW	582,698	932,532	61,044	6.55	-14.34	(83,576)	(50,727)	10,317	1.11	499,122	(83,576)
OL	6,588,349	19,808,487	1,359,190	6.86	-28.51	(1,878,281)	(1,140,035)	219,155	1.11	4,710,068	(1,878,281)
SL	1,129,448	2,340,686	338,163	14.45	-45.55	(514,478)	(312,266)	25,897	1.11	614,970	(514,478)
Total	509,765,263	1,012,689,101	11,204,057	1.11	0.00	0	0	11,204,057	1.11	509,765,263	0

Kentucky Power Company
Proposed Revenue Allocation
Twelve Months Ended September 30, 2009
25% Subsidy Reduction

					Proposed Equalized Rate of Return						75% of	
Current Class (1)	Current Revenue (2)	Rate Base (3)	Current Income (4)	Current ROR % (5)	Percent Increase (6)	Revenue Increase (7)	Income Increase (8)	Income (9)	ROR % (10)	Sales Revenue (11)	Current Subsidy (12)	Proposed Increase (13)=(7)-(12)
RS	196,964,517	535,133,286	(15,409,365)	-2.88	51.01	100,469,826	60,980,834	45,571,469	8.52	297,434,343	26,356,784	74,113,042
SGS	14,551,918	28,695,586	1,827,730	6.37	6.97	1,014,834	615,960	2,443,690	8.52	15,566,752	(1,866,178)	2,881,012
MGS	51,640,578	95,086,690	5,362,597	5.64	8.73	4,505,923	2,734,900	8,097,497	8.52	56,146,501	(5,326,478)	9,832,401
LGS	58,995,442	107,314,277	4,342,599	4.05	13.39	7,902,027	4,796,188	9,138,787	8.52	66,897,469	(3,898,931)	11,800,958
QP	54,976,107	79,477,481	4,155,034	5.23	7.83	4,305,409	2,613,197	6,768,231	8.52	59,281,516	(4,047,720)	8,353,129
CIP-TOD	124,336,206	143,900,076	9,167,065	6.37	4.09	5,086,584	3,087,336	12,254,401	8.52	129,422,790	(9,360,226)	14,446,810
MW	582,698	932,532	61,044	6.55	5.19	30,266	18,370	79,414	8.52	612,964	(62,682)	92,948
OL	6,588,349	19,808,487	1,359,190	6.86	8.19	539,879	327,683	1,686,873	8.52	7,128,228	(1,408,711)	1,948,590
SL	1,129,448	2,340,686	338,163	14.45	-20.25	(228,735)	(138,832)	199,331	8.52	900,713	(385,859)	157,124
Total	509,765,263	1,012,689,101	11,204,057	1.11	24.25	123,626,013	75,035,636	86,239,693	8.52	633,391,276	(1)	123,626,014

Kentucky Power Company
Proposed Revenue Allocation
Twelve Months Ended September 30, 2009
25% Subsidy Reduction

					Proposed Revenue Allocation			Rev Chg	Present	Proposed		
Current Class (1)	Current Revenue (2)	Rate Base (3)	Current Income (4)	Current ROR % (5)	Percent Increase (6)	Revenue Increase (7)	ROR % (11)	from 10% Reduction	ROR Index	ROR Index	Current Subsidy	Proposed Subsidy
RS	196,964,517	535,133,286	(15,409,365)	-2.88	37.63	74,113,042	5.53	5,271,356	(2.595)	0.649	35,142,380	26,356,786
SGS	14,551,918	28,695,586	1,827,730	6.37	19.80	2,881,012	12.46	(373,235)	5.739	1.462	-2,488,237	-1,866,179
MGS	51,640,578	95,086,690	5,362,597	5.64	19.04	9,832,401	11.92	(1,065,296)	5.081	1.399	-7,101,971	-5,326,479
LGS	58,995,442	107,314,277	4,342,599	4.05	20.00	11,800,958	10.72	(779,786)	3.649	1.258	-5,198,574	-3,898,931
QP	54,976,107	79,477,481	4,155,034	5.23	15.19	8,353,129	11.61	(809,544)	4.712	1.363	-5,396,960	-4,047,720
CIP-TOD	124,336,206	143,900,076	9,167,065	6.37	11.62	14,446,810	12.46	(1,872,045)	5.739	1.462	-12,480,301	-9,360,226
MW	582,698	932,532	61,044	6.55	15.95	92,948	12.60	(12,536)	5.901	1.479	-83,576	-62,682
OL	6,588,349	19,808,487	1,359,190	6.86	29.58	1,948,590	12.83	(281,742)	6.180	1.506	-1,878,281	-1,408,712
SL	1,129,448	2,340,686	338,163	14.45	13.91	157,124	18.52	(77,171)	13.018	2.174	-514,478	-385,858
Total	509,765,263	1,012,689,101	11,204,057	1.11	24.25	123,626,014	8.52	1			3	0

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

GENERAL ADJUSTMENTS IN	)	
ELECTRIC RATES OF	)	**CASE NO.**
KENTUCKY POWER COMPANY	)	**2009-00459**

EXHIBIT__(SJB-3)

OF

STEPHEN J. BARON

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

Baron Exhibit__(SJB-3)

Kentucky Power Company
Proposed Revenue Allocation
Twelve Months Ended September 30, 2009
QP/CIP-TOD 25% Subsidy Reduction, Residential @ KPCo Proposed, All Others @ Equal %

					Proposed Revenue Allocation							
Current Class (1)	Current Revenue (2)	Rate Base (3)	Current Income (4)	Current ROR % (5)	Percent Increase (6)	Revenue Increase (7)	ROR % (11)	Rev Chg from 10% Reduction	Present ROR Index	Proposed ROR Index	Current Subsidy	Proposed Subsidy
RS	196,964,517	535,133,286	(15,409,365)	-2.88	34.95	68,841,686	4.93	0	(2.595)	0.579	35,142,380	31,628,143
SGS	14,551,918	28,695,586	1,827,730	6.37	23.96	3,486,701	13.74	232,454	5.739	1.613	-2,488,237	-2,471,868
MGS	51,640,578	95,086,690	5,362,597	5.64	23.96	12,373,299	13.54	1,475,602	5.081	1.589	-7,101,971	-7,867,377
LGS	58,995,442	107,314,277	4,342,599	4.05	23.96	14,135,555	12.04	1,554,811	3.649	1.413	-5,198,574	-6,233,529
QP	54,976,107	79,477,481	4,155,034	5.23	15.19	8,353,129	11.61	(809,544)	4.712	1.363	-5,396,960	-4,047,720
CIP-TOD	124,336,206	143,900,076	9,167,065	6.37	11.62	14,446,810	12.46	(1,872,045)	5.739	1.462	-12,480,301	-9,360,226
MW	582,698	932,532	61,044	6.55	23.96	139,617	15.63	34,133	5.901	1.835	-83,576	-109,350
OL	6,588,349	19,808,487	1,359,190	6.86	23.96	1,578,596	11.70	(651,736)	6.180	1.373	-1,878,281	-1,038,717
SL	1,129,448	2,340,686	338,163	14.45	23.96	270,620	21.46	36,325	13.018	2.519	-514,478	-499,355
Total	509,765,263	1,012,689,101	11,204,057	1.11	24.25	123,626,013	8.52	0			3	0

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

GENERAL ADJUSTMENTS IN	)	
ELECTRIC RATES OF	)	CASE NO.
KENTUCKY POWER COMPANY	)	2009-00459

EXHIBIT__(SJB-4)

OF

STEPHEN J. BARON

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

Baron Exhibit__(SJB-4)

Kentucky Power Company
Proposed Revenue Allocation
Twelve Months Ended September 30, 2009
QP/CIP-TOD 25% Subsidy Reduction, All Others @ Equal %

					Proposed Revenue Allocation			Rev Chg	Present	Proposed		
Current Class (1)	Current Revenue (2)	Rate Base (3)	Current Income (4)	Current ROR % (5)	Percent Increase (6)	Revenue Increase (7)	ROR % (11)	from 10% Reduction	ROR Index	ROR Index	Current Subsidy	Proposed Subsidy
RS	196,964,517	535,133,286	(15,409,365)	-2.88	30.51	60,096,782	3.94	(8,744,904)	(2.595)	0.462	-35,142,380	-40,373,047
SGS	14,551,918	28,695,586	1,827,730	6.37	30.51	4,440,005	15.76	1,185,758	5.739	1.850	2,488,237	3,425,172
MGS	51,640,578	95,086,690	5,362,597	5.64	30.51	15,756,303	15.70	4,858,606	5.081	1.843	7,101,971	11,250,381
LGS	58,995,442	107,314,277	4,342,599	4.05	30.51	18,000,380	14.23	5,419,636	3.649	1.670	5,198,574	10,098,353
QP	54,976,107	79,477,481	4,155,034	5.23	15.19	8,353,129	11.61	(809,544)	4.712	1.363	5,396,960	4,047,720
CIP-TOD	124,336,206	143,900,076	9,167,065	6.37	11.62	14,446,810	12.46	(1,872,045)	5.739	1.462	12,480,301	9,360,226
MW	582,698	932,532	61,044	6.55	30.51	177,790	18.12	72,306	5.901	2.127	83,576	147,525
OL	6,588,349	19,808,487	1,359,190	6.86	30.51	2,010,203	13.02	(220,129)	6.180	1.528	1,878,281	1,470,324
SL	1,129,448	2,340,686	338,163	14.45	30.51	344,611	23.38	110,316	13.018	2.744	514,478	573,346
Total	509,765,263	1,012,689,101	11,204,057	1.11	24.25	123,626,013	8.52	0			(3)	0

BEFORE THE

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PUBLIC SERVICE COMMISSION

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF THE)
GENERAL ADJUSTMENTS IN)
ELECTRIC RATES OF) Docket No. 2009-00459
KENTUCKY POWER COMPANY)

DIRECT TESTIMONY

AND EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CONSUMERS

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

April 2010

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF THE	**)**	
GENERAL ADJUSTMENTS IN	**)**	
ELECTRIC RATES OF	**)**	**Docket No. 2009-00459**
KENTUCKY POWER COMPANY	**)**	

TABLE OF CONTENTS

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF THE	)	
GENERAL ADJUSTMENTS IN	)	
ELECTRIC RATES OF	)	**Docket No. 2009-00459**
KENTUCKY POWER COMPANY	)	

DIRECT TESTIMONY OF RICHARD A. BAUDINO

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Richard A. Baudino. 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 whom are you employed?

A. I am a consultant with Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I received my Master of Arts degree with a major in Economics and a minor in Statistics from New Mexico State University in 1982. I also received my Bachelor of Arts Degree with majors in Economics and English from New Mexico State in 1979.

I began my professional career with the New Mexico Public Service Commission Staff in October 1982 and was employed there as a Utility Economist. During my employment with the Staff, my responsibilities included the analysis of a broad range of issues in the ratemaking field. Areas in which I testified included cost of service, rate of return, rate design, revenue requirements, analysis of sale/leasebacks of generating plants, utility finance issues, and generating plant phase-ins.

In October 1989, I joined the utility consulting firm of Kennedy and Associates as a Senior Consultant where my duties and responsibilities covered substantially the same areas as those during my tenure with the New Mexico Public Service Commission Staff. I became Manager in July 1992 and was named Director of Consulting in January 1995. Currently, I am a consultant with Kennedy and Associates.

Exhibit ____(RAB-1) summarizes my expert testimony experience.

Q. **On whose behalf are you testifying?**

A. I am testifying on behalf of the Kentucky Industrial Utility Consumers ("KIUC").

Q. **What is the purpose of your Direct Testimony?**

A. The purpose of my direct testimony is to address the allowed return on equity for Kentucky Power Company ("KPC" or "Company").

Q. **Please summarize your Direct Testimony.**

A. Based on my independent analysis in this case, I recommend that the Public Service Commission of Kentucky ("KPSC" or "Commission") adopt an allowed return on equity ("ROE") of 10.10% for Kentucky Power. My recommendation is based on the results of several Discounted Cash Flow ("DCF") analyses for a comparison group of electric utilities that is similar to KPC. I also performed two Capital Asset Pricing Model Analyses but did not incorporate them into my recommendation. My review of all of the results from my DCF and CAPM analyses show that a 10.10% ROE for KPC is reasonable, even generous, in today's market.

Turning to the Company's testimony, the Commission should reject the return on equity recommendation of 11.75% of Dr. William Avera, witness for Kentucky Power. As I will explain in detail in Section IV of my Direct Testimony, Dr. Avera's subjective approach greatly overstates the required return on equity for the Companies. Even more importantly, however, the results from Dr. Avera's quantitative analyses do not support his 11.75% ROE recommendation. Dr. Avera's recommended equity return exceeds the range of results for his utility proxy group. Dr. Avera's recommended ROE only is supported by the ROE results from a group of unregulated non-utility companies, whose investor required returns are higher than the required return for a regulated electric company like KPC. This non-utility group completely fails to reflect the stable, lower-risk regulated utility operations of Kentucky Power. Dr. Avera's recommended return on equity of 11.75% would also harm Kentucky ratepayers because it would result in excessive rate levels and, at the same time, provide investors an inflated return on equity.

II. REVIEW OF ECONOMIC AND FINANCIAL CONDITIONS

Q. Mr. Baudino, what has the trend been in long-term capital costs over the last few years?

A. Exhibit ____(RAB-2) presents a graphic depiction of the trend in interest rates from January 2000 through December 2009. The interest rates shown are for the 20-year U.S. Treasury Bond and the average public utility bond from the Mergent Bond Record. Exhibit ____(RAB-2) shows that the yields on long-term Treasury and utility bonds have declined since early 2000, although rates have been quite volatile. Yields trended downward from 2002 through 2006, with the 20-year Treasury bond yield declining from 5.69% to 4.78% at the end of December 2006. The yield on the average public utility bond also decreased significantly over that time, falling from 7.83% in March 2002 to 5.83% in December 2006, a decline of 200 basis points. Public utility bond yields fell far more than long-term Treasury yields over the last four years.

2007 saw a rise in bond yields, fueled in part by investors' concerns over turmoil and defaults associated with the sub-prime lending market. This accelerated in 2008, a year in which world financial markets experienced tumultuous changes and volatility not seen since the Great Depression. As noted in the SBBI 2009 Yearbook, both large and small company stocks declined around 37% for the year.[1] Investors, in a

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1 *2009 Ibbotson SBBI Classic Yearbook*, Morningstar, page 11.

flight to quality and safety, also pulled their funds out of those corporate bonds that were perceived to be higher risk and invested in the safety of Treasury securities.[2] The 2009 SBBI Yearbook reported that long-term Treasury Bonds returned 25.87% during 2008, while long-term corporate bonds returned 8.78%. Thus, bonds significantly outperformed stocks in 2008.

The stocks of electric utilities did not fare well during the financial market upheaval of 2008. The Dow Jones Utility Average was down from its opening level in January 2008 of 532.50 to 370.76 at the end of December, a decline of 30.4%. This decline was smaller than the decline in the overall stock market. Utility bond yields also increased significantly during the year, rising from 6.08% in January to a high of 7.80% in November. And as investors flocked to the safety of Treasury securities, the yield spread between long-term Treasury securities and the index of public utility bonds widened from 1.73% in January to 3.69% in December, the highest spread during the entire period shown in Exhibit ___(RAB-2).

In 2009, utility bond yields fell significantly from November 2008 levels as did the spread between public utility bond yields and long-term Treasuries. The average utility bond yield in December 2009 was 5.86%, a decline of almost 200 basis points from November 2008. At the end of December the yield spread between utility bonds and the long-term Treasury bond declined substantially to 1.46%. This is much closer to the historical spread.

So far in 2010, interest rates and bond yields have stayed near the levels seen at the end of 2009. On April 1, 2010, the average public utility bond yield was 5.77%, according to Moody's Credit Trends. And at the end of March 2010 the 20-year Treasury yield was 4.55%.

Q. How does the investment community regard the electric utility industry as a whole?

A. In its February 5, 2010, report on the Electric Utility – West group of companies, Value Line noted that:

> In 2009, the Value Line Utility Average (which includes all utilities, not just electrics) rose 5.3%. By contrast, the Value Line Geometric Average soared 36.8%. This was a reversal of the previous year, in which the utilities fell sharply, but only about half as much as the broad market averages, which declined around 40%. So far in 2010, the Value Line Utility Average has fallen 3.6% while the Value Line Composite Average has fallen 1.3%. With the economy in recovery, investors are apparently focusing less attention on industries that are known for their defensive characteristics, such as utilities.
>
> * * *
>
> We estimate that earnings will recover nicely in 2010. We base our estimates on a return to normal weather conditions, which would help the second- and third-quarter profit comparisons for many utilities. Also, with the economy recovering, sales to commercial and industrial customers should rebound, particularly since the comparisons are easy. The low interest rate environment benefits this industry as well. As long as utilities maintain investment-grade credit ratings, they can usually refinance maturing borrowings at lower rates. And rates on many issues of variable-rate debt are now below 1%.

In its February 26, 2010 report on the Electric Utility – West group of companies, Value Line also noted the following:

All told, the main draw for electric utility stocks is the prospect of consistent income. Each utility in this issue offers a dividend, which for the most part is quite generous in relation to those in other industries.

Standard and Poor's also opined on the outlook for the regulated electric utility industry in a recent article entitled *Slightly Positive Outlook for U.S. Regulated Electric Utilities Supports Ratings Stability* dated February 2, 2010. This S&P report noted that the "vast majority of U.S. investor-owned electric utility companies we rate have stable outlooks on their ratings", reflecting an industry that "despite the overall U.S. economy, is slightly positive in our base case." The report also stated that the industry's credit fundamentals "indicate that most, if not all, electric utilities should continue to have ample access to capital markets and credit." S&P also reported that banks were willing to renegotiate credit facilities, but at more demand terms than in the past.

Q. Briefly describe Kentucky Power Company.

A. Kentucky Power Company is a regulated operating subsidiary of American Electric Power Company ("AEP"). The Company engages in the generation, transmission, and distribution of electricity to about 175,000 Kentucky retail customers. KPC's rates and operations are regulated by the KPSC and the FERC. According to AEP's 2009 10-K report, KPC owned 1,060 megawatts ("mWs") of coal-fired generation. The Company's total revenues in 2009 were $632.5 million, with net income of $23.9 million. Total net property, plant and equipment in 2009 was $1.134 billion.

In a recent handout presentation to Morgan Stanley dated March 11, 2010, AEP reported that it had significant planned capital expenditures totaling $2.04 billion in 2010 and $1.96 billion in 2011. Of these totals, KPC's planned capital expenditures were a relatively modest $52 million and $71 million in 2010 and 2011, respectively. In addition, KPC has no significant long-term debt maturities forecast for 2010 through 2012, according to the AEP presentation.

Q. How is Kentucky Power viewed by the major bond rating agencies?

A. Kentucky Power's bonds are rated BBB/Baa2 by S&P and Moody's rating agencies, respectively. KPC's ratings outlook from both agencies is stable. This stable outlook for KPC contrasts with Moody's current outlook for AEP, which is negative.

The Company provided recent rating reports on both AEP and KPC in discovery, which provide each agency's current credit evaluation of the Company. In its December 29, 2009 report on KPC, S&P noted the following credit strengths for the Company:

- Steady utility operating cash flow.
- KPC is part of a large, diverse regulated utility operation.
- AEP's low-cost generation asset profile.

Credit weaknesses include:

- AEP's marketing operations, though small, detract from credit profile.
- Aggressive consolidated debt leverage.

S&P also stated that its stable outlook for AEP and its subsidiaries assumed timely recovery of investments in environmental compliance, system reliability, and continued emphasis on its regulated operations.

Moody's January 28, 2010 report on KPC noted that factors driving the credit rating included constructive regulatory environment, weak financial metrics, and sizeable capital expenditures that could pressure current ratings. Moody's also noted that Kentucky is considered to be in a "protracted recession, in part due to its heavy exposure to the automotive manufacturing industry."

Q. Mr. Baudino, what is your conclusion regarding the financial health and overall risk of Kentucky Power?

A. Kentucky Power Company is a solid, BBB/Baa investment grade electric utility whose ratings appear to be well supported by its credit fundamentals. Although AEP's current rating outlook is negative from Moody's, KPC's stable outlook suggests that its operations are less risky than its parent and lend stability and lower risk to AEP's overall credit profile.

III. DETERMINATION OF FAIR RATE OF RETURN

Q. Please describe the methods you employed in estimating a fair rate of return for FPL.

A. I employed a Discounted Cash Flow ("DCF") analysis for a group of comparison electric companies to estimate the cost of equity for the Company's regulated electric operations. I also employed several Capital Asset Pricing Model ("CAPM") analyses using both historical and forward-looking data.

Q. What are the main guidelines to which you adhere in estimating the cost of equity for a firm?

A. Generally speaking, the estimated cost of equity should be comparable to the returns of other firms with similar risk structures and should be sufficient for the firm to attract capital. These are the basic standards set out by the United States Supreme Court in *Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944)* and *Bluefield W.W. & Improv. Co. v. Public Service Comm'n, 262 U.S. 679 (1922).*

From an economist's perspective, the notion of "opportunity cost" plays a vital role in estimating the return on equity. One measures the opportunity cost of an investment equal to what one would have obtained in the next best alternative. For example, let us suppose that an investor decides to purchase the stock of a publicly traded electric utility. That investor made the decision based on the expectation of dividend payments and perhaps some appreciation in the stock's value over time; however, that investor's opportunity cost is measured by what she or he could have invested in as the next best alternative. That alternative could have been another utility stock, a utility bond, a mutual fund, a money market fund, or any other number of investment vehicles.

The key determinant in deciding whether to invest, however, is based on comparative levels of risk. Our hypothetical investor would not invest in a particular electric company stock if it offered a return lower than other investments of similar risk. The opportunity cost simply would not justify such an investment. Thus, the task for the rate of return analyst is to estimate a return that is equal to the return being offered by other risk-comparable firms.

Q. What are the major types of risk faced by utility companies?

A. In general, risk associated with the holding of common stock can be separated into three major categories: business risk, financial risk, and liquidity risk. Business risk refers to risks inherent in the operation of the business. Volatility of the firm's sales, long-term demand for its product(s), the amount of operating leverage, and quality of management are all factors that affect business risk. The quality of regulation at the state and federal levels also plays an important role in business risk for regulated utility companies.

Financial risk refers to the impact on a firm's future cash flows from the use of debt in the capital structure. Interest payments to bondholders represent a prior call on the firm's cash flows and must be met before income is available to the common shareholders. Additional debt means additional variability in the firm's earnings, leading to additional risk.

Liquidity risk refers to the ability of an investor to quickly sell an investment without a substantial price concession. The easier it is for an investor to sell an investment for cash, the lower the liquidity risk will be. Stock markets, such as the New York and American Stock Exchanges, help ease liquidity risk substantially. Investors who own stocks that are traded in these markets know on a daily basis what the market prices of their investments are and that they can sell these investments fairly quickly. Many electric utility stocks are traded on the New York Stock Exchange and are considered liquid investments.

Q. Are there any indices available to investors that quantify the total risk of a company?

A. Bond ratings are tools that investors use to assess the risk comparability of firms. Bond rating agencies such as Moody's and Standard and Poor's perform detailed analyses of factors that contribute to the risk of a particular investment. The end result of their analyses is a bond rating that reflects these risks. This information can then be used to select a comparison group for use in the Discounted Cash Flow model.

Discounted Cash Flow ("DCF") Model

Q. Please describe the basic DCF approach.

A. The basic DCF approach is rooted in valuation theory. It is based on the premise that the value of a financial asset is determined by its ability to generate future net cash flows. In the case of a common stock, those future cash flows take the form of dividends and appreciation in stock price. The value of the stock to investors is the discounted present value of future cash flows. The general equation then is:

$$V = \frac{R}{(1+r)} + \frac{R}{(1+r)^2} + \frac{R}{(1+r)^3} + \ldots \frac{R}{(1+r)^n}$$

Where: V = *asset value*
R = *yearly cash flows*
r = *discount rate*

This is no different from determining the value of any asset from an economic point of view; however, the commonly employed DCF model makes certain simplifying assumptions. One is that the stream of income from the equity share is assumed to be perpetual; that is, there is no salvage or residual value at the end of some maturity date (as is the case with a bond). Another important assumption is that financial markets are reasonably efficient; that is, they correctly evaluate the cash flows relative to the appropriate discount rate, thus rendering the stock price efficient relative to other alternatives. Finally, the model I employ also assumes a constant growth rate in dividends. The fundamental relationship employed in the DCF method is described by the formula:

$$k = \frac{D_1}{P_0} + g$$

Where: D_1 = *the next period dividend*
P_0 = *current stock price*
g = *expected growth rate*
k = *investor-required return*

Under the formula, it is apparent that "k" must reflect the investors' expected return. Use of the DCF method to determine an investor-required return is complicated by the need to express investors' expectations relative to dividends, earnings, and book value over an infinite time horizon. Financial theory suggests that stockholders purchase common stock on the assumption that there will be some change in the rate of dividend payments over time. We assume that the rate of growth in dividends is constant over the assumed time horizon, but the model could easily handle varying growth rates if we knew what they were. Finally, the relevant time frame is prospective rather than retrospective.

Q. What was your first step in conducting your DCF analysis for Kentucky Power?

A. My first step was to construct a comparison group of companies with a risk profile that is reasonably similar to KPC.

Q. Please describe your approach for selecting a comparison group of electric companies.

A. I used several criteria to select a comparison group. First, using the April 2010 issue of the AUS Utility Reports, I selected electric companies that were rated Baa and/or BBB by Moody's and Standard and Poor's. As I mentioned earlier in my testimony, KPC carries senior secured bond ratings of BBB from S&P and Baa2 from Moody's, so using the BBB/Baa criteria assures that the companies in the comparison group carry bond ratings that are similar to the Company.

From that group, I selected companies that had at least 50% of their revenues from electric operations and that had long-term earnings growth forecasts from Value Line and either Zacks Investment Research ("Zacks") or First Call/Thomson Financial. I will describe Zacks and First Call/Thomson Financial later in my testimony. From this group, I then eliminated companies that had recently cut or eliminated dividends, were recently or currently involved in merger activities, or had recent experience with significant earnings fluctuations. Companies that did not pass these screens are not appropriate candidates to which one can apply the DCF formula because of unrepresentative market prices (in terms of companies that are merger candidates) or non-constant growth in earnings or dividends.

The resulting group of fourteen comparison electric companies that I used in my analysis is shown in the table below.

TABLE 1
ELECTRIC UTILITY COMPARISON GROUP

1	American Electric Power Co. (NYSE-AEP)	BBB	Baa2
2	Avista Corporation (NYSE-AVA)	BBB+	Baa1
3	Central Vermont Public Serv. Corp. (NYSE-CV)	NR	Baa1
4	Cleco Corporation (NYSE-CNL)	BBB	Baa1
5	Empire District Electric Co. (NYSE-EDE)	BBB+	Baa1
6	Entergy Corporation (NYSE-ETR)	A-	Baa1
7	Northeast Utilities (NYSE-NU)	BBB+	A3
8	OGE Energy Corp. (NYSE-OGE)	BBB +	Baa1
9	PG&E Corporation (NYSE-PCG)	BBB+	A3
10	Pinnacle West Capital Corp. (NYSE-PNW)	BBB-	Baa2
11	TECO Energy, Inc. (NYSE-TE)	BBB	Baa1
12	UIL Holdings Corporation (NYSE-UIL)	NR	Baa2
13	UniSource Energy Corporation (NYSE-UNS)	BBB+	NR
14	Westar Energy, Inc. (NYSE-WR)	BBB	Baa1

Q. What was your first step in determining the DCF return on equity for the comparison group?

A. I first determined the current dividend yield, D_1/P_0, from the basic equation. My general practice is to use six months as the most reasonable period over which to estimate the dividend yield.

Q. Why is that your general practice?

A. A six-month period smoothes out price fluctuations and provides a representative "average" stock price for determining the dividend yield. This is especially important now considering the recent volatility in the stock market.

Q. Which six-month period did you use and what were the results?

A. The six-month period I used covered the months from October 2009 through March 2010. I obtained historical prices and dividends from "Yahoo! Finance." The annualized dividend divided by the average monthly price represents the average dividend yield for each month in the period.

The resulting average dividend yield for the group is 4.82%. These calculations are shown in Exhibit ____(RAB-3).

Q. Mr. Baudino, did the dividend yield for your comparison group exhibit volatility over the six-month period you used in your analysis?

A. Yes. Page 3 of Exhibit ____(RAB-3) shows the monthly average yields for the comparison group, which ranged from 4.60% to 4.96%. Obviously, increased volatility in the stock market affected utility stock prices as well.

Q. Having established the average dividend yield, how did you determine the investors' expected growth rate for the electric comparison group?

A. The investors' expected growth rate, in theory, correctly forecasts the constant rate of growth in dividends. The dividend growth rate is a function of earnings growth and the payout ratio, neither of which is known precisely for the future. We refer to a perpetual growth rate since the DCF model has no arbitrary cut-off point. We must estimate the investors' expected growth rate because there is no way to know with absolute certainty what investors expect the growth rate to be in the short term, much less in perpetuity.

In this analysis, I relied on three major sources of analysts' forecasts for growth. These sources are Value Line, Zacks, and Thomson Financial.

Q. Please briefly describe Value Line, Zacks, and Thomson Financial.

A. Value Line is an investment survey that is published for approximately 1,700 companies, both regulated and unregulated. It is updated quarterly and probably represents the most comprehensive and widely used of all investment information services. It provides both historical and forecasted information on a number of important data elements. Value Line neither participates in financial markets as a broker nor works for the utility industry in any capacity of which I am aware.

According to Zacks' website, Zacks "was formed in 1978 to compile, analyze, and distribute investment research to both institutional and individual investors." Zacks gathers opinions from a variety of analysts on earnings growth forecasts for numerous firms including regulated electric utilities. The estimates of the analysts responding are combined to produce consensus average and median estimates of earnings growth.

Like Zacks, Thomson Financial also provides detailed investment research on numerous companies. Thomson also compiles and reports consensus analysts' forecasts of earnings growth. I also obtained these forecasts from Yahoo! Finance.

Q. Why did you rely on analysts' forecasts in your analysis?

A. Return on equity analysis is a forward-looking process. Five-year or ten-year historical growth rates may not accurately represent investor expectations for dividend growth. Analysts' forecasts for earnings and dividend growth provide better proxies for the expected growth component in the DCF model than historical growth rates. Analysts' forecasts are also widely available to investors and one can reasonably assume that they influence investor expectations.

Q. How did you utilize your data sources to estimate growth rates for the comparison group?

A. Exhibit____(RAB-4) presents the Value Line, Zacks, and Thomson Financial forecasted growth estimates. These earnings and dividend growth estimates for the comparison group are summarized on Columns (1) through (5) of Exhibit ____(RAB-4).

I also utilized the sustainable growth formula in estimating the expected growth rate. The sustainable growth method, also known as the retention ratio method, recognizes that the firm retains a portion of its earnings to fuel growth in dividends. These retained earnings, which are plowed back into the firm's asset base, are expected to earn a rate of return. This, in turn, generates growth in the firm's book value, market value, and dividends. The sustainable growth method is calculated using the following formula:

$$G = B * R$$

Where: G = *expected retention growth rate*
B = *the firm's expected retention ratio*
R = *the expected return*

In its proper form, this calculation is forward-looking. That is, the investors' expected retention ratio and return must be used in order to measure what investors anticipate will happen in the future. Data on expected retention ratios and returns may be obtained from Value Line.

The expected sustainable growth estimates for the comparison group are presented in Column (3) on page 1 of Exhibit ____(RAB-4). The data came from the Value Line forecasts for the comparison group.

Q. How did you approach the calculation of earnings growth forecasts in this case?

A. For purposes of this case, I looked at three different methods for calculating the expected growth rates for my comparison group.

For Method 1, I calculated the average of all the growth rates for the companies in my comparison group using Value Line, Zacks, and Thomson. I excluded negative values because they are inconsistent with the assumption of constant positive growth in the DCF formula.

For Method 2, I calculated the median growth rates for my comparison group. The median value represents the middle value in a data range and is not influenced by excessively high or low numbers in the data set. The median growth rate for each forecast provides additional valuable information regarding expected growth rates for the group.

For Method 3, I omitted double-digit growth rates and growth rates that were near zero (less than 1%) from the calculation of the averages. This is similar to omitting the high and low values from the calculation. These calculations are shown on page 2 of Exhibit ____(RAB-4).

The expected growth rates produced by these three methods range from 3.25% to 6.25%.

Q. Why did you eliminate high and low growth rate forecasts in Method 3?

A. With respect to growth rates near zero, it is reasonable to conclude that investors expect positive long-term earnings and dividend growth over time. Including growth rates of 1% or less may understate expected growth for the comparison group. Regarding double-digit growth rates, it is highly unlikely that investors would expect such high growth rates over the long run for electric utilities. Indeed, the vast majority of growth forecasts is in the single digits and reflects the more conservative, less risky financial profile of a regulated industry.

Q. How did you proceed to determine the DCF return of equity for the electric comparison group?

A. To estimate the expected dividend yield (D_1) for the group, the current dividend yield must be moved forward in time to account for dividend increases over the next twelve months. I estimated the expected dividend yield by multiplying the current dividend yield by one plus one-half the expected growth rate. I should note that for Method 3, I excluded the dividend yields for companies whose growth rates were excluded from each respective source.

I then added the expected growth rates to the expected dividend yield. The calculations of the resulting DCF returns on equity for both methods are presented on page 2 of Exhibit ____(RAB-4).

Q. Please explain how you calculated your DCF cost of equity estimates and summarize the results.

A. Page 2 of Exhibit ____(RAB-4) presents the DCF results utilizing the three different methods. Method 1 utilizes the average growth rates for the comparison group. I used the Value Line earnings and dividend growth forecasts and the consensus analysts' forecasts. The average DCF cost of equity result is 10.55%. The midpoint of the four growth rates is 10.25%.

Method 2 employs the median growth rates from Value Line, Zacks, and Thomson. The average DCF return on equity is 10.13% and the midpoint of the results is 9.69%.

Method 3 employs the growth rates for the group excluding double digit growth forecasts and forecasts less than or equal to 1.0%. The average of these growth rates results in a DCF estimate of 10.30%. The midpoint of the growth rates results in a DCF estimate of 10.00%.

Capital Asset Pricing Model

Q. Briefly summarize the Capital Asset Pricing Model ("CAPM") approach.

A. The theory underlying the CAPM approach is that investors, through diversified portfolios, may combine assets to minimize the total risk of the portfolio. Diversification allows investors to diversify away all risks specific to a particular company and be left only with market risk that affects all companies. Thus, the CAPM theory identifies two types of risks for a security: company-specific risk and market risk. Company-specific risk includes such events as strikes, management errors, marketing failures, lawsuits, and other events that are unique to a particular firm. Market risk includes inflation, business cycles, war, variations in interest rates, and changes in consumer confidence. Market risk tends to affect all stocks and cannot be diversified away. The idea behind the CAPM is that diversified investors are rewarded with returns based on market risk.

Within the CAPM framework, the expected return on a security is equal to the risk-free rate of return plus a risk premium that is proportional to the security's market, or non-diversifiable, risk. Beta is the factor that reflects the inherent market risk of a security and measures the volatility of a particular security relative to the overall market for securities. For example, a stock with a beta of 1.0 indicates that if the market rises by 15%, that stock will also rise by 15%. This stock moves in tandem with movements in the overall market. Stocks with a beta of 0.5 will only rise or fall 50% as much as the overall market. So with an increase in the market of 15%, this stock will only rise 7.5%. Stocks with betas greater than 1.0 will rise and fall more than the overall market. Thus, beta is the measure of the relative risk of individual securities vis-à-vis the market.

Based on the foregoing discussion, the equation for determining the return for a security in the CAPM framework is:

$$K = Rf + \beta(MRP)$$

Where: K = *Required Return on equity*
Rf = *Risk-free rate*
MRP = *Market risk premium*
β = *Beta*

This equation tells us about the risk/return relationship posited by the CAPM. Investors are risk averse and will only accept higher risk if they receive higher returns. These returns can be determined in relation to a stock's beta and the market risk premium. The general level of risk aversion in the economy determines the market risk premium. If the risk-free rate of return is 3.0% and the required return on the total market is 15%, then the risk premium is 12%. Any stock's required return can be determined by multiplying its beta by the market risk premium. Stocks with betas greater than 1.0 are considered riskier than the overall market and will have higher required returns. Conversely, stocks with betas less than 1.0 will have required returns lower than the market as a whole.

Q. In general, are there concerns regarding the use of the CAPM in estimating the return on equity?

A. Yes. As briefly discussed earlier, there is some controversy surrounding the use of the CAPM.[3] There is evidence that beta is not the primary factor in determining the risk of a security. For example, Value Line's "Safety Rank" is a measure of total risk, not its calculated beta coefficient. Beta coefficients usually describe only a small amount of total investment risk. Finally, a considerable amount of judgment must be employed in determining the risk-free rate and market return portions of the CAPM equation. The analyst's application of judgment can significantly influence the results obtained from the CAPM. My past experience with the CAPM indicates that it is prudent to use a wide variety of data in estimating returns. Of course, the range of results may also be wide, indicating the difficulty in obtaining a reliable estimate from the CAPM.

Q. Is it nonetheless a useful tool?

A. The CAPM is often presented in utility rate proceedings as one alternative method of estimating the investor required return on equity. And, in my opinion, it provides some useful supplemental evidence that may be considered by the analyst. However, the DCF is a superior tool in the cost of capital toolbox, and I recommend that the Commission place primary reliance on it in this proceeding.

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3 For a more complete discussion of some of the controversy surrounding the use of the CAPM, refer to *A Random Walk Down Wall Street* by Burton Malkiel, pp. 229 – 239, 1999 edition.

Q. Turning to the formula above, where did you start your analysis?

A. I started by calculating the market risk premium, which is the required return on the market as a whole less the risk free rate of return.

Q. How did you estimate the market return portion of the CAPM?

A. The first source I used was the Value Line Investment Survey for Windows for March 15, 2010. Value Line provides a summary statistical report detailing, among other things, forecasted growth in dividends, earnings, and book value for the companies Value Line follows. I have presented these three growth rates and the average on page 2 of Exhibit ____(RAB-5). The average growth rate is 8.14%. Combining this growth rate with the average expected dividend yield of the Value Line companies of 2.27% results in an expected market return of 10.41%. The detailed calculations are shown on page 1 Exhibit ____(RAB-5).

I also considered a supplemental check to this market estimate. Morningstar publishes a study of historical returns on the stock market in its *Ibbotson SBBI 2010 Valuation Yearbook*. Some analysts employ this historical data to estimate the market risk premium of stocks over the risk-free rate. The assumption is that a risk premium calculated over a long period of time is reflective of investor expectations going forward. Exhibit ____(RAB-6) presents the calculation of the market return using the historical data.

Q. Please address the use of historical earned returns to estimate the market risk premium.

A. The use of historic earned returns on the S&P 500 to estimate the current market risk premium is rather suspect because it naively assumes that investors currently expect historic risk premiums to continue unchanged into the future regardless of present or forecasted economic conditions. Brigham, Shome, and Vinson noted the following with respect to the use of historic risk premiums calculated using the returns as reported by Ibbotson and Sinquefield (referred to in the quote as "I&S"):

> There are both conceptual and measurement problems with using I&S data for purposes of estimating the cost of capital. Conceptually, there is no compelling reason to think that investors expect the same relative returns that were earned in the past. Indeed, evidence presented in the following sections indicates that relative expected returns should, and do, vary significantly over time. Empirically, the measured historic premium is sensitive both to the choice of estimation horizon and to the end points. These choices are essentially arbitrary, yet can result in significant differences in the final outcome.[4]

In summary, the use of historic earned returns should be viewed with a great deal of caution. There is no real support for the proposition that an unchanging, mechanically applied historical risk premium is representative of current investor expectations and return requirements.

Q. How did you determine the risk free rate?

A. I used the average yields on the 20-year Treasury bond and five-year Treasury note over the six-month period from September 2009 through February 2010. The 20-

4 Brigham, E.F., Shome, D.K. and Vinson, S.R., "The Risk Premium Approach to Measuring a Utility's Cost of Equity," *Financial Management*, Spring 1985, pp. 33-45.

year Treasury bond is often used by rate of return analysts as the risk-free rate, but it contains a significant amount of interest rate risk. The five-year Treasury note carries less interest rate risk than the 20-year bond and is more stable than three-month Treasury bills. Therefore, I have employed both of these securities as proxies for the risk-free rate of return. This approach provides a reasonable range over which the CAPM may be estimated.

Q. **What is your estimate of the market risk premium?**

A. Exhibit ____(RAB-5), line 9 of page 1, presents my estimates of the market risk premium based on a DCF analysis applied to current market data. The market risk premium is 6.09% using the 20-year Treasury bond and 8.06% using the five-year Treasury bond.

Utilizing the historical Ibbotson data on market returns, the market risk premium ranges from 4.70% to 6.60%. This is shown on Exhibit ____(RAB-6).

Q. **How did you determine the value for beta?**

A. I obtained the betas for the companies in the electric company comparison group from most recent Value Line reports. The average of the Value Line betas for the electric group is .71.

Q. **Please summarize the CAPM results.**

A. The CAPM results using the 20-year and five-year Treasury bond yields and Value Line market return data range from 8.08% to 8.65%.

The CAPM results using the historical Ibbotson data range from 7.66% to 9.01%. These results are shown on Exhibit ____(RAB-6).

Conclusions and Recommendations

Q. Please summarize the cost of equity you recommend the Commission adopt for Kentucky Power.

A. I recommend that the Commission adopt the DCF model I developed and the cost of equity estimates for the comparison group of electric utility companies that I compiled. The results for the electric company comparison group using the constant-growth DCF model and the expected growth rate forecasts ranged from 9.69% to 10.55%. Based on this range of results, I recommend that the Commission adopt a 10.10% return on equity for Kentucky Power in this proceeding. This recommendation is near the middle of the range of results for DCF analyses.

I offer this recommendation to the Commission as a just and reasonable estimate of investor return on equity requirements for a BBB/Baa electric utility company such as KPC. Further, it should be noted that the CAPM results are far lower than the DCF results in this proceeding. This is the case with both the forward-looking and the historical versions of the CAPM. I do not rely on the CAPM for my ROE recommendation, but these results suggest that choosing a DCF estimate toward the lower end of the range is certainly reasonable in this case. In fact, 10.10% is generous when taking into account all the DCF and CAPM results in this case.

Q. Mr. Baudino, is there other evidence that suggests your 10.1% ROE recommendation is reasonable?

A. Yes. My review of the Value Line reports for the companies in my comparison group had information relevant to current requested and allowed ROEs for several of the companies. Value Line reported that Avista was recently granted an allowed ROE of 10.2% in Washington. And in a recent pending case Northeast Utilities subsidiary Connecticut Light and Power is asking for a ROE of 10.5%. Empire District is asking for a ROE of 11% in its pending rate case. These ROEs are fairly consistent with my recommended 10.10% for KPC. They also underscore how far out of line Dr. Avera's recommended 11.75% ROE is in this proceeding. I will address Dr. Avera's testimony later.

Q. Will you address the Company's capital structure?

A. No. Mr. Kollen, witness for KIUC, will address KPC's capital structure in detail. I have reviewed Mr. Kollen's adjustments and recommendations regarding capital structure and I support them.

IV. RESPONSE TO KENTUCKY POWER TESTIMONY

Q. Have you reviewed the Direct Testimony of Dr. William Avera?

A. Yes.

Q. Please summarize your conclusions with respect to Dr. Avera's testimony and return on equity recommendation.

A. My conclusions regarding Dr. Avera's testimony and return on equity recommendation are as follows.

First, Dr. Avera's recommended 11.75% return on equity is grossly overstated. His recommendation fails to track the results of his Utility Proxy Group analyses, all but one of which range from 10.1% to 11.1%. The one result that is based on stock price growth, 12.4%, is a clear outlier, is inconsistent with DCF theory and practice, and should be rejected.

Second, Dr. Avera failed to include forecasted dividend growth in his DCF analyses. Failing to include this important information led to a significant overstatement of his DCF results.

Third, Dr. Avera overstated the Market Risk Premium in his CAPM analysis because of a faulty approach to estimating the market return portion of the CAPM. My CAPM results suggest much lower expected returns.

Fourth, Dr. Avera's expected earnings approach is inappropriate and should be rejected by the Commission.

Fifth, Dr. Avera's consideration of an adjustment for flotation costs is inappropriate and should be rejected.

Dr. Avera's ROE Range and Recommendation

Q. Please summarize the results of Dr. Avera's ROE analyses.

A. Dr. Avera used three methods to estimate the cost of equity for KPC: the DCF model, the CAPM, and an expected earning approach. He used two groups of companies to estimate the cost of equity, one composed of regulated electric utilities ("Utility Proxy Group") and another using unregulated companies ("Non-Utility Proxy Group"). The Non-Utility Proxy group completely excluded regulated utility operations. The results from his various methods are as follows:

Utility Proxy Group:

DCF - 10.1% to 11.1%
DCF Stock Price – 12.4%
CAPM – 9.9%
Expected earnings - 10.5% - 11.3%

Non-Utility Proxy Group:

DCF - 11.4% - 13.0%
CAPM – 10.3%

Based on these results, Dr. Avera recommended a range for Kentucky Power's cost of equity of 10.80% - 12.40%, excluding flotation costs. Adding flotation costs raised the bounds of the range to 10.95% - 12.55%. His recommended ROE is 11.75%.

Q. In your opinion, do the results of Dr. Avera's various analyses support his recommended 11.75% ROE for KPC?

A. No. Most of Dr. Avera's results suggest a much lower ROE, more in the range of 10.0% - 11.0% if the Utility Proxy Group results are used. Only the Non-Utility Proxy Group results support anything significantly above 11.0%. In my view, Dr. Avera essentially discarded the results from his Utility Proxy Group in favor of cost of equity results from a group of unregulated companies.

Q. Is it appropriate to use a group of unregulated companies that do not have the monopoly service characteristics of electric utilities to estimate a fair return on equity for a regulated electric company such as Kentucky Power?

A. No, not at all. Dr. Avera's use of unregulated non-utility companies to estimate a fair rate of return for the Companies is completely inappropriate and should be rejected by the Commission.

Utilities have protected markets (i.e., service territories), enjoy full recovery of prudently incurred costs, and may increase their rates to cover increases in costs. In fact, in the case of Kentucky Power, the Company has approved rate adjustment mechanisms such as the fuel adjustment charge, environmental surcharge and demand side management surcharge, something that unregulated firms do not have. Generally, the non-utility companies simply do not have these benefits and must compete with other firms for sales and for customers. Obviously, the non-utility companies have higher overall risk structures than lower risk electric companies like KPC and will have higher required returns from their shareholders. It is not at all surprising that Dr. Avera's ROE results for his Non-Utility Proxy Group were substantially higher than the results for his Utility Proxy Group. Given the higher business risk for the non-utility group of companies, this is exactly the result that would have been expected; however, these results do not form any kind of reasonable basis to estimate the investor required ROE for Kentucky Power. On the contrary, the returns from the non-utility proxy group are a good measure of returns that are, by definition, substantially in excess of those to be expected in the utility segment.

Q. Earlier you mentioned that using a stock price forecast resulted in a DCF ROE of 12.4%. Please explain why this formulation of the DCF should be rejected.

A. Dr. Avera used Value Line's stock price forecast over the next 5 years to estimate the growth rate for his Utility Proxy Group. Using a stock price forecast is inconsistent with the principle embodied in the DCF model that the investor expects certain cash flows that grow over time. Those cash flows are based on earnings and dividends, not a forecast of what a company's stock price might be in a few years. Stock price forecasts may have nothing whatsoever to do with the actual expected cash flows, i.e., dividends. Stock price forecasts can be influenced by the vicissitudes of the market. For example, stock price growth forecasts could be relatively high if a recovery from a severely depressed market is expected. The market as a whole lost over 30% of its value in 2008, so the high ROE of 12.4% might include some expectation of stock price recovery over the next few years. Certainly, Dr. Avera's stock price DCF result of 12.4% greatly exceeds all of his other DCF results for his Utility Proxy Group, so much so that it should be considered an outlier and be rejected.

Q. Do you have any concluding remarks for this section of your response to Dr. Avera?

A. Yes. In my response to Dr. Avera's DCF and CAPM analyses, I will confine my remarks to the results from his Utility Proxy Group analyses. I will not further address the Non-Utility Proxy Group because I have already explained why the Commission should reject the use of this group in estimating the cost of equity for Kentucky Power.

DCF Analyses and Dividend Growth Forecasts

Q. Please summarize Dr. Avera's approach to the DCF model and its results.

A. Dr. Avera utilized the constant growth form of the DCF model to estimate the fair return on equity. He employed analysts' earnings growth forecasts from Value Line, First Call, IBES, and Zacks to estimate the growth component of the model. As I mentioned earlier, Dr. Avera also included Value Line's stock price growth forecast from Value Line as one of his growth rates.

Q. Did Dr. Avera consider dividend growth forecasts in his DCF analysis?

A. No. Dr. Avera failed to include lower dividend growth forecasts in his analysis.

On page 30 of his Direct Testimony, Dr. Avera opined that dividend growth rates "are not likely to provide a meaningful guide to investors' current growth expectations." In support of this opinion, he cited articles from the Association for Investment Management and Research, the *Financial Analysts Journal* and Value Line's description of its Timeliness Rank.

Q. Should Dr. Avera have included dividend growth forecasts in his DCF analyses?

A. Yes. Dr. Avera erred in failing to include dividend growth forecasts from Value Line in his DCF analyses. With respect to regulated utility companies, dividend growth provides the primary source of cash flow to the investor. It is certainly the case that earnings growth fuels dividend growth and should be considered in estimating the ROE using the DCF model; however, Value Line's dividend growth forecasts are widely available to investors and can reasonably be assumed to influence their expectations with respect to growth. I weighted earnings growth 75% and dividend growth 25% in my average growth calculations, so I agree to some extent with Dr. Avera that earnings growth is the primary factor considered by investors. But it should not be considered the only factor.

Regarding the article from the *Financial Analysts Journal* cited by Dr. Avera on page 32 of his testimony, it is not surprising that earnings and cash flow are considered more important than book value and dividends, particularly for non-utility companies that may not pay out much in the way of dividends; however, this is certainly not the case for utility companies.

Q. What is the average dividend growth rate for Dr. Avera's Utility Proxy Group?

A. The average dividend growth rate forecast from Value Line is 4.06%. I have included these forecasts in Exhibit ____(RAB-7). Please note that I excluded Allegheny Energy and Ameren due to aberrant or negative growth rates. As shown in Exhibit ___(RAB-7), including Value Line's dividend growth forecast results in a DCF cost of equity of 9.06% for Dr. Avera's Utility Proxy Group. This result is relatively close to my DCF ROE using average dividend growth for the comparison group of 9.29%.

As I mentioned earlier in my testimony, lower near-term dividend growth rates must be considered and incorporated in the DCF analysis. Although earnings growth forecasts are currently higher, the lower dividend growth rates expected over the next few years will be incorporated into investors' expected return for the electric utility industry. Relying on earnings growth rates alone, as Dr. Avera has done, will overstate investors' required returns and lead to an inflated ROE recommendation.

<u>Capital Asset Pricing Model</u>

Q. Please present your conclusions regarding the results of Dr. Avera's CAPM analysis.

A. I disagree with Dr. Avera's formulation of the CAPM. Dr. Avera estimated the market return portion of the CAPM by estimating the current market return for dividend paying stocks in the S&P 500. This limited his so-called "market" return to only 348 companies.

The market return portion of the CAPM should represent the most comprehensive estimate of the total return for all investment alternatives, not just a small subset of publicly traded stocks. In practice, of course, finding such an estimate is difficult and is one of the more thorny problems in estimating an accurate ROE when using the CAPM. If one limits the market return to stocks, then there are more comprehensive measures of the stock market available, such as the Value Line Investment Survey that I used in my CAPM analysis. Value Line's projected earnings growth used a sample of over 1400 stocks, its book value growth estimate used over 1500 stocks, and its dividend growth estimate used over 800 stocks. These are much broader samples than Dr. Avera's limited sample of dividend paying stocks from the S&P 500.

The forward-looking CAPM results I present in Exhibit ___(RAB-6) using a broader market index suggest much lower required rates of return than Dr. Avera recommends in his testimony.

Q. Dr. Avera did not present historical market returns in his CAPM analysis. Has Dr. Avera used historic return in his past ROE testimonies?

A. Yes. Dr. Avera used to present historical market returns from the SBBI Yearbook in his past testimonies. In this case, Dr. Avera did not use historic market returns.

As I previously testified, I have concerns regarding the use of historical market returns to estimate the investor required return on equity for electric utilities. It should be noted, however, that the historical market return data I presented in Exhibit ___(RAB-7) suggests much lower CAPM ROEs than the 9.9% - 10.3% number that Dr. Avera recommended in his testimony. Furthermore, my alternative forward-looking CAPM results also underscore Dr. Avera's overstatement of the CAPM results.

Expected Earning Approach

Q. Please comment on Dr. Avera's expected earning approach.

A. Dr. Avera's expected earnings approach should be rejected by the Commission.

All Dr. Avera did in this analysis was report Value Line's forecasted returns on book equity for 2009, 2010 and the period 2012 - 2014. He did not use any market-based model such as the DCF or CAPM. Forecasted earned returns on book equity may have nothing whatsoever to do with investors' required returns in the marketplace. For example, if earned returns on book equity exceed the market-based DCF return on equity, then investors may expect a company to earn more on book equity than the market-based required rate of return. Instead, I recommend that the Commission utilize a range of returns generated by the DCF model in setting the Companies' cost of equity in this case.

It is also worth noting that the expected earnings approach fails to support Dr. Avera's 11.75% ROE recommendation in this case. The range of results calculated by Dr. Avera is 10.5% - 11.3%. Even the top end of this range is 45 basis points below his recommended ROE.

Flotation Costs

Q. On page 49 of his Direct Testimony, Dr. Avera recommended a 15 basis point flotation cost adjustment to his ROE range. Do you agree with a flotation cost adjustment?

A. No, I do not. I do not recommend that the Commission consider such an adjustment in setting Kentucky Power's cost of equity.

In my opinion it is likely that flotation costs are already accounted for in current stock prices and that adding an adjustment for flotation costs amounts to double counting. A DCF model using current stock prices should already account for investor expectations regarding the collection of flotation costs. Multiplying the dividend yield by a 3% flotation cost adjustment, for example, essentially assumes that the current stock price is wrong and that it must be adjusted downward to increase the dividend yield and the resulting cost of equity. I do not believe that this is an appropriate assumption. Current stock prices most likely already account for flotation costs, to the extent that such costs are even accounted for by investors.

Q. Does this complete your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:	:	
THE APPLICATION FOR GENERAL ADJUSTMENT	:	
OF ELECTRIC RATES OF KENTUCKY POWER	:	**Case No. 2009-00459**
COMPANY	:	
	:	

AFFIDAVIT OF RICHARD A. BAUDINO

STATE OF NORTH CAROLINA)
COUNTY OF DAVIDSON)

Richard A. Baudino being first duly sworn, deposes and states that:

1. He is a consultant with Kennedy & Associates;

2. He is the witness who sponsors the accompanying testimony entitled "Direct Testimony and Exhibits of Richard A. Baudino;"

3. Said testimony was prepared by him and under his direction and supervision;

4. If inquiries were made as to the facts and schedules in said testimony he would respond as therein set forth; and

5. The aforesaid testimony and schedules are true and correct to the best of his knowledge, information and belief.

Richard A. Baudino

Richard A. Baudino

Subscribed and sworn to or affirmed before me this 6th day of April, 2010, by Richard A. Baudino.

Marcia P. Wilson

Notary Public

MARCIA P WILSON
Notary Public
Davidson County, NC
My Commission Expires June 29, 2013

C:\Documents and Settings\Rick Baudino\Local Settings\Temporary Internet Files\Content.IE5\HO2BC1ZD\Affidavit Richard Baudino.doc

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF THE	)	
GENERAL ADJUSTMENTS IN	)	
ELECTRIC RATES OF	)	**Docket No. 2009-00459**
KENTUCKY POWER COMPANY	)	

EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CONSUMERS

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

April 2010

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF THE	)	
GENERAL ADJUSTMENTS IN	)	
ELECTRIC RATES OF	)	**Docket No. 2009-00459**
KENTUCKY POWER COMPANY	)	

EXHIBIT __(RAB-1)

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CONSUMERS

RESUME OF RICHARD A. BAUDINO

EDUCATION

New Mexico State University, M.A.
Major in Economics
Minor in Statistics

New Mexico State University, B.A.
Economics
English

Twenty five years of experience in utility ratemaking. Broad based experience in revenue requirement analysis, cost of capital, utility financing, phase-ins, auditing and rate design. Has designed revenue requirement and rate design analysis programs.

REGULATORY TESTIMONY

Preparation and presentation of expert testimony in the areas of:

Electric and Gas Utility Rate Design
Cost of Capital for Electric, Gas and Water Companies
Ratemaking Treatment of Generating Plant Sale/Leasebacks
Electric and Gas Utility Cost of Service
Revenue Requirements
Gas industry restructuring and competition
Fuel cost auditing

RESUME OF RICHARD A. BAUDINO

EXPERIENCE

1989 to Present: **Kennedy and Associates: Consultant** - Responsible for consulting assignments in the area of revenue requirements, rate design, cost of capital, economic analysis of generation alternatives, gas industry restructuring and competition.

1982 to 1989: **New Mexico Public Service Commission Staff: Utility Economist** - Responsible for preparation of analysis and expert testimony in the areas of rate of return, cost allocation, rate design, finance, phase-in of electric generating plants, and sale/leaseback transactions.

CLIENTS SERVED

Regulatory Commissions

Louisiana Public Service Commission
Georgia Public Service Commission
New Mexico Public Service Commission

Industrial Groups

Ad Hoc Committee for a Competitive Electric Supply System
Air Products and Chemicals, Inc.
Arkansas Electric Energy Consumers
Arkansas Gas Consumers
Armco Steel Company, L.P.
Association of Business Advocating Tariff Equity
CF&I Steel, L.P.
Climax Molybdenum Company
General Electric Company
Industrial Energy Consumers
Kentucky Industrial Utility Consumers
Large Electric Consumers Organization
Newport Steel
Northwest Arkansas Gas Consumers
Maryland Industrial Group
Occidental Chemical
PSI Industrial Group
Taconite Intervenors (Minnesota)
Tyson Foods
West Virginia Energy Users Group

Expert Testimony Appearances
of
Richard A. Baudino
As of March 2010

Date	Case	Jurisdict.	Party	Utility	Subject
3/83	1780	NM	New Mexico Public Service Commission	Boles Water Co.	Rate design, rate of return.
10/83	1803, 1817	NM	New Mexico Public Service Commission	Southwestern Electric Coop	Rate design.
11/84	1833	NM	New Mexico Public Service Commission	El Paso Electric Co.	Service contract approval, rate design, performance standards for Palo Verde nuclear generating system
1983	1835	NM	New Mexico Public Service Commission	Public Service Co. of NM	Rate design.
1984	1848	NM	New Mexico Public Service Commission	Sangre de Cristo Water Co.	Rate design.
02/85	1906	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
09/84	1907	NM	New Mexico Public Service Commission	Jornada Water Co.	Rate of return.
11/85	1957	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
04/86	2009	NM	New Mexico Public Service Commission	El Paso Electric Co.	Phase-in plan, treatment of sale/leaseback expense.
06/86	2032	NM	New Mexico Public Service Commission	El Paso Electric Co.	Sale/leaseback approval.
09/86	2033	NM	New Mexico Public Service Commission	El Paso Electric Co.	Order to show cause, PVNGS audit.
02/87	2074	NM	New Mexico Public Service Commission	El Paso Electric Co.	Diversification.
05/87	2089	NM	New Mexico Public Service Commission	El Paso Electric Co.	Fuel factor adjustment.
08/87	2092	NM	New Mexico Public Service Commission	El Paso Electric Co.	Rate design.
10/88	2146	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Financial effects of restructuring, reorganization.

Expert Testimony Appearances
of
Richard A. Baudino
As of March 2010

Date	Case	Jurisdict.	Party	Utility	Subject
07/88	2162	NM	New Mexico Public Service Commission	El Paso Electric Co.	Revenue requirements, rate design, rate of return.
01/89	2194	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Economic development.
1/89	2253	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Financing.
08/89	2259	NM	New Mexico Public Service Commission	Homestead Water Co.	Rate of return, rate design.
10/89	2262	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Rate of return.
09/89	2269	NM	New Mexico Public Service Commission	Ruidoso Natural Gas Co.	Rate of return, expense from affiliated interest.
12/89	89-208-TF	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Rider M-33.
01/90	U-17282	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
09/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Cost of equity.
09/90	90-004-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Cost of equity, transportation rate.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
04/91	91-037-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Transportation rates.
12/91	91-410-EL-AIR	OH	Air Products & Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Cost of equity.
05/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Cost of equity, rate of return.
09/92	92-032-U	AR	Arkansas Gas	Arkansas Louisiana	Cost of equity, rate of

Expert Testimony Appearances
of
Richard A. Baudino
As of March 2010

Date	Case	Jurisdict.	Party	Utility	Subject
			Consumers	Gas Co.	return, cost-of-service.
09/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost of equity, rate of return.
09/92	92-009-U	AR	Tyson Foods	General Waterworks	Cost allocation, rate design.
01/93	92-346	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Cost allocation.
01/93	39498	IN	PSI Industrial Group	PSI Energy	Refund allocation.
01/93	U-10105	MI	Association of Businesses Advocating Tariff Equality (ABATE)	Michigan Consolidated Gas Co.	Return on equity.
04/93	92-1464-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Return on equity.
09/93	93-189-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Transportation service terms and conditions.
09/93	93-081-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost-of-service, transportation rates, rate supplements; return on equity; revenue requirements.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Historical reviews; evaluation of economic studies.
03/94	10320	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Trimble County CWIP revenue refund.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Evaluation of the cost of equity, capital structure, and rate of return.
5/94	R-00942993	PA	PG&W Industrial Intervenors	Pennsylvania Gas & Water Co.	Analysis of recovery of transition costs.

**Expert Testimony Appearances
of
Richard A. Baudino
As of March 2010**

Date	Case	Jurisdict.	Party	Utility	Subject
5/94	R-00943001	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Evaluation of cost allocation, rate design, rate plan, and carrying charge proposals.
7/94	R-00942986	PA	Armco, Inc., West Penn Power Industrial Intervenors	West Penn Power Co.	Return on equity and rate of return.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Return on equity and rate of return.
8/94	8652	MD	Westvaco Corp.	Potomac Edison Co.	Return on equity and rate of return.
9/94	930357-C	AR	West Central Arkansas Gas Consumers	Arkansas Oklahoma Gas Corp.	Evaluation of transportation service.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Return on equity.
9/94	8629	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Transition costs.
11/94	94-175-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Cost-of-service, rate design, rate of return.
3/95	RP94-343-000	FERC	Arkansas Gas Consumers	NorAm Gas Transmission	Rate of return.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Return on equity.
6/95	U-10755	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Revenue requirements.
7/95	8697	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost allocation and rate design.
8/95	95-254-TF U-2811	AR	Tyson Foods, Inc.	Southwest Arkansas Electric Cooperative	Refund allocation.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	Systems Energy Resources, Inc.	Return on Equity.
11/95	I-940032	PA	Industrial Energy Consumers of	State-wide - all utilities	Investigation into Electric Power Competition.

Expert Testimony Appearances
of
Richard A. Baudino
As of March 2010

Date	Case	Jurisdict.	Party	Utility	Subject
			Pennsylvania		
5/96	96-030-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Revenue requirements, rate of return and cost of service.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Potomac Electric Power Co. and Constellation Energy Corp.	Return on Equity.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Return on equity, rate of return.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
1/97	RP96-199-000	FERC	The Industrial Gas Users Conference	Mississippi River Transmission Corp.	Revenue requirements, rate of return and cost of service.
3/97	96-420-U	AR	West Central Arkansas Gas Corp.	Arkansas Oklahoma Gas Corp.	Revenue requirements, rate of return, cost of service and rate design.
7/97	U-11220	MI	Association of Business Advocating Tariff Equity	Michigan Gas Co. and Southeastern Michigan Gas Co.	Transportation Balancing Provisions
7/97	R-00973944	PA	Pennsylvania American Water Large Users Group	Pennsylvania-American Water Co.	Rate of return, cost of service, revenue requirements.
3/98	8390-U	GA	Georgia Natural Gas Group and the Georgia Textile Manufacturers Assoc.	Atlanta Gas Light	Rate of return, restructuring issues, unbundling, rate design issues.
7/98	R-00984280	PA	PG Energy, Inc.	PGE Industrial Intervenors	Cost allocation.
8/98	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Return on equity, rate of return.
10/98	U-23327	LA	Louisiana Public	SWEPCO, CSW and	Analysis of proposed merger.

**Expert Testimony Appearances
of
Richard A. Baudino
As of March 2010**

Date	Case	Jurisdict.	Party	Utility	Subject
			Service Commission	AEP	
12/98	98-577	ME	Maine Office of the Public Advocate	Maine Public Service Co.	Return on equity, rate of return.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity, rate of return.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co	Return on equity.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Return on equity.
4/99	R-984554	PA	T. W. Phillips Users Group	T. W. Phillips Gas and Oil Co.	Allocation of purchased gas costs.
6/99	R-0099462	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Balancing charges.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States,Inc.	Cost of debt.
10/99	R-00994782	PA	Peoples Industrial Intervenors	Peoples Natural Gas Co.	Restructuring issues.
10/99	R-00994781	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Restructuring, balancing charges, rate flexing, alternate fuel.
01/00	R-00994786	PA	UGI Industrial Intervenors	UGI Utilities, Inc.	Universal service costs, balancing, penalty charges, capacity assignment.

Expert Testimony Appearances
of
Richard A. Baudino
As of March 2010

Date	Case	Jurisdict.	Party	Utility	Subject
01/00	8829	MD	Maryland Industrial Gr. & United States	Baltimore Gas & Electric Co.	Revenue requirements, cost allocation, rate design.
02/00	R-00994788	PA	Penn Fuel Transportation	PFG Gas, Inc., and	Tariff charges, balancing provisions.
05/00	U-17735	LA	Louisiana Public Service Comm.	Louisiana Electric Cooperative	Rate restructuring.
07/00	2000-080	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric Co.	Cost allocation.
07/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket E)	LA	Louisiana Public Service Comm.	Southwestern Electric Power Co.	Stranded cost analysis.
09/00	R-00005654	PA	Philadelphia Industrial And Commercial Gas Users Group.	Philadelphia Gas Works	Interim relief analysis.
10/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B)	LA	Louisiana Public Service Comm.	Entergy Gulf States, Inc.	Restructuring, Business Separation Plan.
11/00	R-00005277 (Rebuttal)	PA	Penn Fuel Transportation Customers	PFG Gas, Inc. and North Penn Gas Co.	Cost allocation issues.
12/00	U-24993	LA	Louisiana Public Service Comm.	Entergy Gulf States, Inc.	Return on equity.
03/01	U-22092	LA	Louisiana Public Service Comm.	Entergy Gulf States, Inc.	Stranded cost analysis.
04/01	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B) (Addressing Contested Issues)	LA	Louisiana Public Service Comm.	Entergy Gulf States, Inc.	Restructuring issues.
04/01	R-00006042	PA	Philadelphia Industrial and Commercial Gas Users Group	Philadelphia Gas Works	Revenue requirements, cost allocation and tariff issues.
11/01	U-25687	LA	Louisiana Public Service Comm.	Entergy Gulf States, Inc.	Return on equity.
03/02	14311-U	GA	Georgia Public Service Commission	Atlanta Gas Light	Capital structure.

Expert Testimony Appearances
of
Richard A. Baudino
As of March 2010

Date	Case	Jurisdict.	Party	Utility	Subject
08/02	2002-00145	KY	Kentucky Industrial Utility Customers	Columbia Gas of Kentucky	Revenue requirements.
09/02	M-00021612	PA	Philadelphia Industrial And Commercial Gas Users Group	Philadelphia Gas Works	Transportation rates, terms, and conditions.
01/03	2002-00169	KY	Kentucky Industrial Utility Customers	Kentucky Power	Return on equity.
02/03	02S-594E	CO	Cripple Creek & Victor Gold Mining Company	Aquila Networks – WPC	Return on equity.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
10/03	CV020495AB	GA	The Landings Assn., Inc.	Utilities Inc. of GA	Revenue requirement & overcharge refund
03/04	2003-00433	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric	Return on equity, Cost allocation & rate design
03/04	2003-00434	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Return on equity
4/04	04S-035E	CO	Cripple Creek & Victor Gold Mining Company, Goodrich Corp., Holcim (U.S.) Inc., and The Trane Co.	Aquila Networks – WPC	Return on equity.
9/04	U-23327, Subdocket B	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Fuel cost review
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on Equity

Expert Testimony Appearances
of
Richard A. Baudino
As of March 2010

Date	Case	Jurisdict.	Party	Utility	Subject
06/05	050045-EI	FL	South Florida Hospital and HeallthCare Assoc.	Florida Power & Light Co.	Return on equity
08/05	9036	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirement, cost allocation, rate design, Tariff issues.
01/06	2005-0034	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Return on equity.
03/06	05-1278-E-PC-PW-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Return on equity.
04/06	U-25116	LA	Louisiana Public Service Commission	Entergy Louisiana, LLC	Transmission Issues
07/06	U-23327	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on equity, Service quality
08/06	ER-2006-0314	MO	Missouri Office of the Public Counsel	Kansas City Power & Light Co.	Return on equity, Weighted cost of capital
08/06	06S-234EG	CO	CF&I Steel, L.P. & Climax Molybdenum	Public Service Company of Colorado	Return on equity, Weighted cost of capital
01/07	06-0960-E-42T	WV	West Virginia Energy Users Group	Monongahela Power & Potomac Edison	Return on Equity
01/07	43112		AK Steel, Inc.	Vectren South, Inc.	Cost allocation, rate design
05/07	2006-661		Maine Office of the Public Advocate	Bangor Hydro-Electric	Return on equity, weighted cost of capital.
09/07	07-07-01		Connecticut Industrial Energy Consumers	Connecticut Light & Power	Return on equity, weighted cost of capital
10/07	05-UR-103		Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Return on equity
11/07	29797		Louisiana Public Service Commission	Cleco Power :LLC & Southwestern Elec. Power	Lignite Pricing, support of settlement
01/08	07-551-EL-AIR		Ohio Energy Group	Ohio Edison, Cleveland Electric, Toledo Edison	Return on equity
03/08	07-0585, 07-0585,	IL	The Commercial Group	Ameren	Cost allocation, rate design

Expert Testimony Appearances
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Richard A. Baudino
As of March 2010

Date	Case	Jurisdict.	Party	Utility	Subject
	07-0587, 07-0588, 07-0589, 07-0590, (consol.)				
04/08	07-0566	IL	The Commercial Group	Commonwealth Edison	Cost allocation, rate design
06/08	R-2008-2011621	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Cost and revenue allocation, Tariff issues
07/08	R-2008-2028394	PA	Philadelphia Area Industrial Energy users Group	PECO Energy	Cost and revenue allocation, Tariff issues
07/08	R-2008-2039634	PA	PPL Gas Large Users Gp.	PPL Gas	Retainage, LUFG Pct.
08/08	6680-UR-116	WI	Wisconsin Industrial Energy Group	Wisconsin P&L	Cost of Equity
08/08	6690-UR-119	WI	Wisconsin Industrial Energy Group	Wisconsin PS	Cost of Equity
09/08	ER-2008-0318	MO	The Commercial Group	AmerenUE	Cost and revenue allocation
10/08	R-2008-2029325	PA	U.S. Steel & Univ. of Pittsburgh Med. Ctr.	Equitable Gas Co.	Cost and revenue allocation
10/08	08-G-0609	NY	Multiple Intervenors	Niagara Mohawk Power	Cost and Revenue allocation
12/08	27800-U	GA	Georgia Public Service Commission	Georgia Power Company	CWIP/AFUDC issues, Review financial projections
03/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Capital Structure
04/09	E002/GR-08-1065		The Commercial Group	Northern States Power	Cost and revenue allocation and rate design
05/09	08-0532		The Commercial Group	Commonwealth Edison	Cost and revenue allocation
07/09	080677-EI		South Florida Hospital and Health Care Assn.	Florida Power & Light	Cost of equity, capital structure, Cost of short-term debt
07/09	U-30975	LA	Louisiana PSC	Cleco LLC, Southwestern Public Service Co.	Lignite mine purchase

**Expert Testimony Appearances
of
Richard A. Baudino
As of March 2010**

Date	Case	Jurisdict.	Party	Utility	Subject
10/09	4220-UR-116	WI	Wisconsin Industrial Energy Group	Northern States Power	Class cost of service, rate design
10/09	M-2009-2123945	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Smart Meter Plan cost allocation
10/009	M-2009-2123944	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Smart Meter Plan cost allocation
10/09	M-2009-2123951	PA	West Penn Power Industrial Intervenors	West Penn Power	Smart Meter Plan cost allocation
11/09	M-2009-2123948	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Smart Meter Plan cost allocation
11/09	M-2009-2123950	PA	Met-Ed Industrial Users Gp. Penelec Industrial Customer Alliance, Penn Power Users Group	Metropolitan Edison, Pennsylvania Electric Co., Pennsylvania Power Co.	Smart Meter Plan cost allocation
03/10	09-1352-E-42T	WV	West Virginia Energy Users Gp.	Monongahela Power, Potomac Edison	Return on equity, rate of return
03/10	E015/GR-09-1151	MN	Large Power Intervenors	Minnesota Power	Return on equity, rate of return

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF THE	)	
GENERAL ADJUSTMENTS IN	)	
ELECTRIC RATES OF	)	**Docket No. 2009-00459**
KENTUCKY POWER COMPANY	)	

EXHIBIT __(RAB-2)

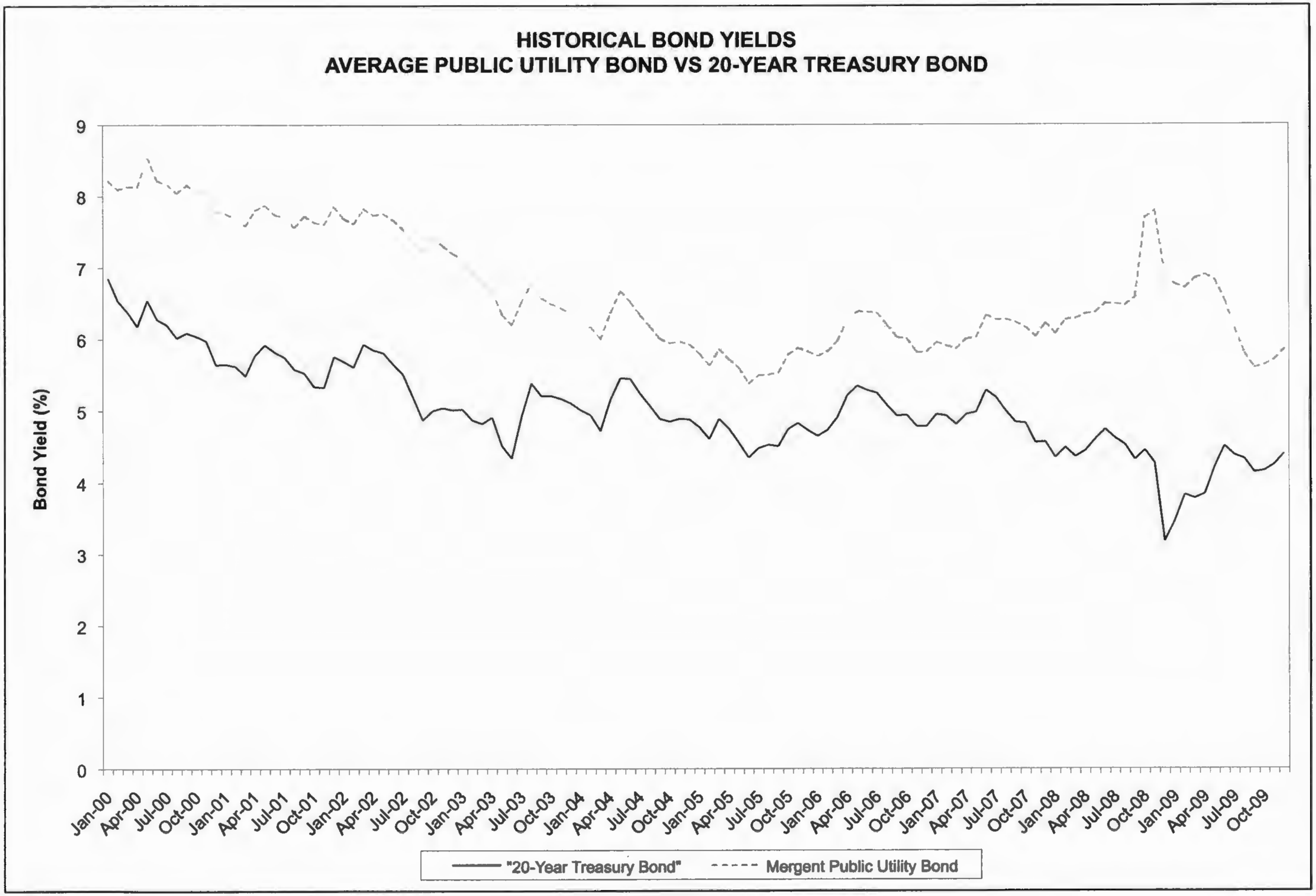
OF

RICHARD A. BAUDINO

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CONSUMERS

Exhibit ___(RAB-2)



BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF THE	)	
GENERAL ADJUSTMENTS IN	)	
ELECTRIC RATES OF	)	**Docket No. 2009-00459**
KENTUCKY POWER COMPANY	)	

EXHIBIT __(RAB-3)

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CONSUMERS

KENTUCKY POWER COMPANY
COMPARISON GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Mar-10	Feb-10	Jan-10	Dec-09	Nov-09	Oct-09
American Electric Power	High Price ($)	34.970	35.110	36.860	36.510	32.310	31.870
	Low Price ($)	33.680	32.680	34.360	32.250	30.230	29.590
	Avg. Price ($)	34.325	33.895	35.610	34.380	31.270	30.730
	Dividend ($)	0.410	0.410	0.410	0.410	0.410	0.410
	Mo. Avg. Div.	4.78%	4.84%	4.61%	4.77%	5.24%	5.34%
	6 mos. Avg.	4.93%					
Avista	High Price ($)	21.660	22.370	22.370	22.440	20.950	21.110
	Low Price ($)	20.390	20.320	20.320	20.560	18.480	18.880
	Avg. Price ($)	21.025	21.345	21.345	21.500	19.715	19.995
	Dividend ($)	0.250	0.250	0.210	0.210	0.210	0.210
	Mo. Avg. Div.	4.76%	4.68%	3.94%	3.91%	4.26%	4.20%
	6 mos. Avg.	4.29%					
Central Vermont	High Price ($)	21.000	20.290	21.480	21.100	19.640	21.100
	Low Price ($)	19.460	18.720	19.580	19.340	18.660	18.990
	Avg. Price ($)	20.230	19.505	20.530	20.220	19.150	20.045
	Dividend ($)	0.230	0.230	0.230	0.230	0.230	0.230
	Mo. Avg. Div.	4.55%	4.72%	4.48%	4.55%	4.80%	4.59%
	6 mos. Avg.	4.61%					
Cleco	High Price ($)	27.190	26.620	27.670	28.140	26.260	25.850
	Low Price ($)	25.220	24.320	25.650	25.530	24.030	24.020
	Avg. Price ($)	26.205	25.470	26.660	26.835	25.145	24.935
	Dividend ($)	0.225	0.225	0.225	0.225	0.225	0.225
	Mo. Avg. Div.	3.43%	3.53%	3.38%	3.35%	3.58%	3.61%
	6 mos. Avg.	3.48%					
Empire District Electric	High Price ($)	18.360	18.820	19.300	19.360	18.770	18.660
	Low Price ($)	17.920	17.750	18.260	18.180	17.780	17.910
	Avg. Price ($)	18.140	18.285	18.780	18.770	18.275	18.285
	Dividend ($)	0.320	0.320	0.320	0.320	0.320	0.320
	Mo. Avg. Div.	7.06%	7.00%	6.82%	6.82%	7.00%	7.00%
	6 mos. Avg.	6.95%					
Entergy	High Price ($)	82.110	80.180	83.090	84.440	80.300	81.820
	Low Price ($)	75.970	75.250	76.230	78.870	76.100	76.560
	Avg. Price ($)	79.040	77.715	79.660	81.655	78.200	79.190
	Dividend ($)	0.750	0.750	0.750	0.750	0.750	0.750
	Mo. Avg. Div.	3.80%	3.86%	3.77%	3.67%	3.84%	3.79%
	6 mos. Avg.	3.79%					

KENTUCKY POWER COMPANY
COMPARISON GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Mar-10	Feb-10	Jan-10	Dec-09	Nov-09	Oct-09
Northeast Utilities	High Price ($)	28.000	26.830	26.620	26.480	24.600	24.010
	Low Price ($)	25.720	24.680	25.100	24.160	22.200	22.640
	Avg. Price ($)	26.860	25.755	25.860	25.320	23.400	23.325
	Dividend ($)	0.256	0.256	0.238	0.238	0.238	0.238
	Mo. Avg. Div.	3.81%	3.98%	3.68%	3.76%	4.07%	4.08%
	6 mos. Avg.	3.90%					
OGE Energy	High Price ($)	39.320	37.830	37.920	37.790	35.050	35.130
	Low Price ($)	36.560	34.920	35.500	33.050	32.330	31.660
	Avg. Price ($)	37.940	36.375	36.710	35.420	33.690	33.395
	Dividend ($)	0.363	0.363	0.363	0.355	0.355	0.355
	Mo. Avg. Div.	3.83%	3.99%	3.96%	4.01%	4.21%	4.25%
	6 mos. Avg.	4.04%					
PG&E	High Price ($)	43.420	43.350	45.630	45.790	43.000	43.210
	Low Price ($)	41.890	40.580	42.180	42.560	40.400	39.740
	Avg. Price ($)	42.655	41.965	43.905	44.175	41.700	41.475
	Dividend ($)	0.455	0.420	0.420	0.420	0.420	0.420
	Mo. Avg. Div.	4.27%	4.00%	3.83%	3.80%	4.03%	4.05%
	6 mos. Avg.	4.00%					
Pinnacle West	High Price ($)	38.370	37.850	37.810	37.960	35.480	34.710
	Low Price ($)	36.420	34.620	35.620	35.100	31.080	31.310
	Avg. Price ($)	37.395	36.235	36.715	36.530	33.280	33.010
	Dividend ($)	0.525	0.525	0.525	0.525	0.525	0.525
	Mo. Avg. Div.	5.62%	5.80%	5.72%	5.75%	6.31%	6.36%
	6 mos. Avg.	5.93%					
TECO	High Price ($)	16.250	15.990	16.540	16.710	15.170	14.690
	Low Price ($)	15.290	14.460	15.460	14.770	14.030	13.450
	Avg. Price ($)	15.770	15.225	16.000	15.740	14.600	14.070
	Dividend ($)	0.200	0.200	0.200	0.200	0.200	0.200
	Mo. Avg. Div.	5.07%	5.25%	5.00%	5.08%	5.48%	5.69%
	6 mos. Avg.	5.26%					
UIL Holdings	High Price ($)	28.720	27.850	28.740	29.000	27.500	27.760
	Low Price ($)	27.500	25.300	26.800	26.870	25.270	25.350
	Avg. Price ($)	28.110	26.575	27.770	27.935	26.385	26.555
	Dividend ($)	0.432	0.432	0.432	0.432	0.432	0.432
	Mo. Avg. Div.	6.15%	6.50%	6.22%	6.19%	6.55%	6.51%
	6 mos. Avg.	6.35%					

KENTUCKY POWER COMPANY
COMPARISON GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Mar-10	Feb-10	Jan-10	Dec-09	Nov-09	Oct-09
UniSource Energy	High Price ($)	32.370	32.440	33.550	33.250	30.500	31.050
	Low Price ($)	29.210	29.130	30.740	29.790	28.080	27.810
	Avg. Price ($)	30.790	30.785	32.145	31.520	29.290	29.430
	Dividend ($)	0.390	0.390	0.290	0.290	0.290	0.290
	Mo. Avg. Div.	5.07%	5.07%	3.61%	3.68%	3.96%	3.94%
	6 mos. Avg.	4.22%					
Westar Energy	High Price ($)	22.700	22.330	22.780	22.300	20.930	20.530
	Low Price ($)	21.390	20.560	21.060	20.580	18.910	19.120
	Avg. Price ($)	22.045	21.445	21.920	21.440	19.920	19.825
	Dividend ($)	0.310	0.300	0.300	0.300	0.300	0.300
	Mo. Avg. Div.	5.62%	5.60%	5.47%	5.60%	6.02%	6.05%
	6 mos. Avg.	5.73%					
Average Dividend Yield	4.82%						
Monthly Group Average		4.84%	4.92%	4.60%	4.64%	4.95%	4.96%

Source: Yahoo! Finance

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF THE	)	
GENERAL ADJUSTMENTS IN	)	
ELECTRIC RATES OF	)	**Docket No. 2009-00459**
KENTUCKY POWER COMPANY	)	

EXHIBIT __(RAB-4)

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CONSUMERS

KENTUCKY POWER COMPANY
COMPARISON GROUP
DCF Growth Rate Analysis

Company	(1) Value Line DPS	(2) Value Line EPS	(3) Value Line B x R	(4) Zacks	(5) First Call/ Thomson
American Electric Power Co.	2.50%	3.00%	4.50%	3.60%	4.00%
Avista Corporation	11.50%	6.50%	3.00%	4.75%	4.67%
Central Vermont Public Serv. Corp.	1.00%	3.00%	3.00%	N/A	8.90%
Cleco Corporation	6.50%	8.00%	5.00%	9.00%	4.00%
Empire District Electric Co.	1.00%	7.00%	2.50%	N/A	6.00%
Entergy Corporation	4.00%	5.00%	7.00%	4.00%	6.53%
Northeast Utilities	7.00%	7.00%	4.00%	7.91%	7.81%
OGE Energy Corp.	2.50%	5.00%	6.50%	5.50%	6.00%
PG&E Corporation	7.50%	6.50%	6.00%	7.67%	7.16%
Pinnacle West Capital Corp.	1.00%	3.00%	3.00%	7.00%	7.00%
TECO Energy, Inc.	3.00%	6.00%	5.00%	6.20%	7.93%
UIL Holdings Corporation	0.00%	3.00%	2.50%	4.00%	4.43%
UniSource Energy Corporation	10.00%	17.00%	5.50%	5.00%	5.00%
Westar Energy, Inc.	3.50%	7.50%	3.50%	5.00%	4.50%
Averages excluding negative values	4.36%	6.25%	4.36%	5.80%	6.00%
Median Values	3.25%	6.25%	4.25%	5.25%	6.00%
Averages excl. > or =10% & < or = 1%	4.56%	5.42%	4.36%	5.80%	6.00%

Sources: Zack's and First Call/Thomson Earnings Reports, retrieved March 29, 2010
Value Line Investment Survey, February 5, February 26, and March 26, 2010

RETURN ON EQUITY CALCULATION
KENTUCKY POWER COMPANY

	(1) Value Line Dividend Gr.	(2) Value Line Earnings Gr.	(3) Zack's Earning Gr.	(4) First Call Earning Gr.	(5) Average of All Gr. Rates
Method 1:					
Dividend Yield	4.82%	4.82%	4.82%	4.82%	4.82%
Growth Rate	4.36%	6.25%	5.80%	6.00%	5.60%
Expected Div. Yield	4.92%	4.97%	4.96%	4.96%	4.95%
DCF Return on Equity	***9.28%***	***11.22%***	***10.76%***	***10.96%***	***10.55%***
Midpoint of Results					***10.25%***
Method 2:					
Dividend Yield	4.82%	4.82%	4.82%	4.82%	4.82%
Median Growth Rate	3.25%	6.25%	5.25%	6.00%	5.19%
Expected Div. Yield	4.90%	4.97%	4.95%	4.96%	4.94%
DCF Return on Equity	***8.15%***	***11.22%***	***10.20%***	***10.96%***	***10.13%***
Midpoint of Results					***9.69%***
Method 3:					
Dividend Yield	4.39%	4.87%	4.82%	4.82%	4.72%
Growth Rate Excl. Rates > 10% & < or = 1%	4.56%	5.42%	5.80%	6.00%	5.45%
Expected Div. Yield	4.49%	5.00%	4.96%	4.96%	4.85%
DCF Return on Equity	***9.05%***	***10.42%***	***10.76%***	***10.96%***	***10.30%***
Midpoint of Results					***10.00%***

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF THE	)	
GENERAL ADJUSTMENTS IN	)	
ELECTRIC RATES OF	)	**Docket No. 2009-00459**
KENTUCKY POWER COMPANY	)	

EXHIBIT __(RAB-5)

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CONSUMERS

KENTUCKY POWER COMPANY
Capital Asset Pricing Model Analysis
Comparison Group

20-Year Treasury Bond, Value Line Beta

Line No.			Value Line
1	Market Required Return Estimate		
2		Expected Dividend Yield	2.27%
3		Expected Growth	8.14%
4		Required Return	10.41%
5	Risk-free Rate of Return, 20-Year Treasury Bond		
6		Average of Last Six Months	4.32%
8	Risk Premium		
9		@ 6 Month Average RFR (Line 4 minus Line 6)	6.09%
10	Comparison Group Beta		0.71
11	Comparison Group Beta * Risk Premium		
12		@ 6 Month Average RFR (Line 10 * Line 9)	4.33%
13	CAPM Return on Equity		
14		@ 6 Month Average RFR (Line 12 plus Line 6)	8.65%

5-Year Treasury Bond, Value Line Beta

Line No.			Value Line
1	Market Required Return Estimate		
2		Expected Dividend Yield	2.27%
3		Expected Growth	8.14%
4		Required Return	10.41%
5	Risk-free Rate of Return, 5-Year Treasury Bond		
6		Average of Last Six Months	2.35%
8	Risk Premium		
9		@ 6 Month Average RFR (Line 4 minus Line 6)	8.06%
10	Comparison Group Beta		0.71
11	Comparison Group Beta * Risk Premium		
12		@ 6 Month Average RFR (Line 9 * Line 10)	5.73%
13	CAPM Return on Equity		
14		@ 6 Month Average RFR (Line 12 plus Line 6)	8.08%

KENTUCKY POWER COMPANY
Capital Asset Pricing Model Analysis
Comparison Group

Supporting Data for CAPM Analyses

20 Year Treasury Bond Data

	Avg. Yield
September-09	4.14%
October-09	4.16%
November-09	4.24%
December-09	4.40%
January-10	4.50%
February-10	4.48%
6 month average	4.32%

5 Year Treasury Bond Data

	Avg. Yield
September-09	2.37%
October-09	2.33%
November-09	2.23%
December-09	2.34%
January-10	2.48%
February-10	2.36%
6 month average	2.35%

Value Line Market Growth Rate Data:

Forecasted Data:	
Earnings	9.26%
Book Value	8.18%
Dividends	6.99%
Average	8.14%

Source: Value Line Investment Survey for Windows, March 15, 2010

Comparison Group Betas:	Value Line
American Electric Power Co.	0.70
Avista Corporation	0.70
Central Vermont Public Serv. Corp.	0.75
Cleco Corporation	0.65
Empire District Electric Co.	0.70
Entergy Corp.	0.70
Northeast Utilities	0.70
OGE Energy Corp.	0.75
PG&E Corp.	0.55
Pinnacle West Capital Corp.	0.75
TECO Energy, Inc.	0.85
UIL Holdings Corporation	0.70
UniSource Energy Corporation	0.70
Westar Energy, Inc.	0.75
Average Beta	0.71

Sources: Value Line reports

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF THE	)	
GENERAL ADJUSTMENTS IN	)	
ELECTRIC RATES OF	)	**Docket No. 2009-00459**
KENTUCKY POWER COMPANY	)	

EXHIBIT __(RAB-6)

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CONSUMERS

Exhibit ____ (RAB-6)

KENTUCKY POWER COMPANY
Capital Asset Pricing Model Analysis
Historic Market Premium

	Geometric Mean	Arithmetic Mean
Long-Term Annual Return on Stocks	9.80%	11.80%
Long-Term Annual Income Return on Long-Term Government Bonds	5.10%	5.20%
Historical Market Risk Premium	4.70%	6.60%
Comparison Group Beta, Value Line	0.71	0.71
Beta * Market Premium	3.34%	4.69%
Current 20-Year Treasury Bond Yield	4.32%	4.32%
CAPM Cost of Equity, Value Line Beta	**7.66%**	**9.01%**

Source: *Ibbotson SBBI 2010 Valuation Yearbook,* Morningstar

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF THE	)	
GENERAL ADJUSTMENTS IN	)	
ELECTRIC RATES OF	)	**Docket No. 2009-00459**
KENTUCKY POWER COMPANY	)	

EXHIBIT __(RAB-7)

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CONSUMERS

Exhibit ___(RAB-7)

AVERA UTILITY PROXY GROUP
DCF ANALYSIS WITH VALUE LINE DIVIDEND GROWTH FORECASTS

	Avera Div. Yield	Value Line Div. Growth	DCF ROE
Allegheny Energy	2.40%	25.00%	27.40%
ALLETE	5.10%	1.00%	6.10%
Alliant Energy	5.70%	5.50%	11.20%
Ameren Corp	6.20%	-5.50%	0.70%
American Electric Power	5.40%	2.50%	7.90%
Edison International	3.90%	4.00%	7.90%
First Energy	5.00%	2.50%	7.50%
OGE Energy	4.10%	2.50%	6.60%
Otter Tail Corp	5.10%	1.50%	6.60%
PG&E Corp.	4.30%	7.50%	11.80%
Portland General	5.20%	5.50%	10.70%
PPL Corp.	5.00%	5.50%	10.50%
Progress Energy	6.60%	1.00%	7.60%
PS Enterprises	4.60%	4.00%	8.60%
SCANA Corp.	5.50%	2.00%	7.50%
Sempra Energy	3.20%	8.50%	11.70%
UIL Holdings	6.60%	0.00%	6.60%
Westar Energy	6.20%	3.50%	9.70%
Wisconsin Energy	3.40%	13.00%	16.40%
Xcel Energy	5.20%	3.00%	8.20%
Average	5.01%	4.06%	9.06%

Note: Allegheny Energy and Ameren were excluded from the average calculations.

Source: 2010 Value Line Reports

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PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

GENERAL ADJUSTMENTS IN	)	
ELECTRIC RATES OF	)	CASE NO. 2009-00459
KENTUCKY POWER COMPANY	)	

DIRECT TESTIMONY

AND EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

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:

GENERAL ADJUSTMENTS IN	)	
ELECTRIC RAATES OF	)	CASE NO. 2009-00459
KENTUCKY POWER COMPANY	)	

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

GENERAL ADJUSTMENTS IN	)	
ELECTRIC RATES OF	)	**CASE NO. 2009-00459**
KENTUCKY POWER COMPANY	)	

DIRECT TESTIMONY OF LANE KOLLEN

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Lane Kollen. 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 whom are you employed?

A. I am a utility rate and planning consultant holding the position of Vice President and Principal with the firm of Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I earned a Bachelor of Business Administration in Accounting degree and a Master of Business Administration degree from the University of Toledo. I also earned a Master of Arts degree from Luther Rice University. I am a Certified Public Accountant ("CPA"), with a practice license, and a Certified Management Accountant ("CMA").

I have been an active participant in the utility industry for more than thirty years, initially as an employee of The Toledo Edison Company from 1976 to 1983 and thereafter as a consultant in the industry since 1983. I have testified as an expert witness on planning, ratemaking, accounting, finance, and tax issues in proceedings before regulatory commissions and courts at the federal and state levels on nearly two hundred occasions.

I have testified before the Kentucky Public Service Commission on numerous occasions, including the most recent Kentucky Power Company ("KPC" or "Company") base rate proceeding, Case No. 2005-00341; the pending KPC wind power proceeding, Case No. 2009-00545; various Company Environmental Cost Recovery ("ECR") proceedings; numerous Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") base rate proceedings; numerous LG&E and KU ECR and fuel adjustment clause ("FAC") proceedings; and other proceedings involving Big Rivers Electric Corporation and East Kentucky Power Cooperative, Inc. My qualifications and regulatory appearances are further detailed in my Exhibit___(LK-1).

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Kentucky Industrial Utility Customers, Inc. ("KIUC"), a group of large customers taking electric service on the KPC system.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to summarize the KIUC revenue requirement recommendations, to address specific issues that affect the Company's revenue requirement and to quantify the effect on the revenue requirement of the return on equity recommendation offered by KIUC witness Mr. Richard Baudino.

Q. Please summarize your testimony.

A. I recommend that the Commission increase the Company's base rates by no more than $40.981 million, a reduction of at least $82.645 million compared to the Company's requested increase of $123.626 million.

The following table lists each KIUC adjustment and the effect on the Company's claimed revenue deficiency, which include the adjustments I address, the effect of the transmission expense adjustments sponsored by KIUC witness Mr. Stephen J. Baron, and the effect on the revenue requirement of the return on common equity recommendation sponsored by KIUC witness Mr. Richard Baudino.

Kentucky Power Company Revenue Requirement Summary of KIUC Recommendations Case No. 2009-00459 For the Test Year Ended September 30, 2009 ($ Millions)	
Increase Requested by Company	**123.626**
Operating Income Issues	
Restore Test Year OSS Margins to 100%	(7.546)
Reject Post-Test Year Adjustment for Wind Power Purchase	(14.480)
Reject Post-Test Year Adjustment for Additional AEP Capacity Payments-I&M Sale to CPL	(3.164)
Remove Enhanced Reliability and Service Plan O&M Expense	(16.374)
Remove Enhance Reliability and Service Plan Depreciation Expense	(0.373)
Correct Company's Adjustment to Normalize Storm Damage Costs	(10.213)
Remove Incentive Compensation Expense Tied to Financial Performance	(0.991)
Remove Short Term Interest Expense and Interest Income from Operating Expenses	(1.876)
Adjust OATT Transmission Expense	(7.038)
Reflect Section 199 Income Tax Deduction in Income Tax Expense	(1.362)
Cost of Capital Issues	
Reflect 13 Month Average Short Term Debt	(3.751)
Reflect Short Term Debt Rate of 1%	(0.876)
Apply Big Sandy Coal Stock Adjustment to all Capital Components	(2.273)
Remove Company's Proposed Reliability Capital Adjustment	(1.089)
Reflect Return on Equity of 10.1%	(11.240)
Total KIUC Adjustments to KPCO Request	**(82.645)**
KIUC Recommended Increase	**40.981**

In addition to the revenue requirement issues on the preceding table, KIUC recommends that the Commission reject the Company's proposals to modify the SSC and the environmental cost recovery rider ("ECR") and to establish a transmission cost recovery rider. I address the first two of these three proposals and KIUC witness Mr. Baron addresses the transmission rider proposal.

I recommend that the Commission reject the Company's proposals to modify the SSC from the present sharing of 70% to ratepayers to a reduced 50% sharing to ratepayers and to effectively eliminate the sharing threshold by including only 50% of the test year OSS margins as a reduction to the base revenue requirement. Instead of the Company's proposal, the Commission should retain the sharing of 70% to ratepayers and reset the sharing threshold to the test year OSS margins used to establish the base revenue requirement in this proceeding.

Finally, I recommend that the Commission reject the Company's proposal to modify the ECR rider to eliminate the effect of the § 199 domestic production activities deduction presently reflected in the income tax rate used to gross-up the common equity return in that rider.

The remainder of my testimony is structured to sequentially address each of the issues on the preceding table. Amounts cited throughout the testimony are Kentucky retail-jurisdictional ("jurisdictional") unless otherwise indicated as "total Company."

II. OPERATING INCOME ISSUES

<u>Company Has Understated Off-System Sales Margins</u>

Q. Please describe the Company's adjustment to reduce the off-system sales margins.

A. The Company proposes an adjustment to reduce OSS margins by $7.546 million, although the adjustment is shown on Section V Schedule 4 as an increase to O&M expense. This adjustment actually is comprised of four separate adjustments that are detailed on Section V Workpaper S-4 page 26 and described by Mr. Wagner on page 40 of his Direct Testimony in a single question and answer. The Company's actual test year OSS margins were $15.614 million (total Company) and $15.411 million (jurisdictional) before these four separate adjustments are applied.

The Company's first adjustment increases the actual test year amount by $0.129 million (total Company) and $0.127 million (jurisdictional) to reflect the September 2009 change to increase the MLR to correct an error in the Ohio Power Company load used to compute the MLR.

The second and third adjustments reduce the actual test year amount by $0.060 million (total Company) and $0.392 million (total Company), respectively, to reflect the reductions in OSS margins due to the termination of the Indiana &Michigan ("I&M") sale to Carolina Power & Light ("CPL") effective on January 1, 2010. The jurisdictional amounts are $0.060 million and $0.387 million, respectively.

The fourth adjustment reduces the adjusted test year amount by $7.645 million (total Company) and $7.546 million (jurisdictional) to remove 50% of the adjusted margins from the revenue requirement.

Q. Do you disagree with the Company's first adjustment, i.e., to correct the MLR

allocation of the OSS margins?

A. No. This is an appropriate adjustment to normalize test year expenses for known and measurable changes.

Q. Do you disagree with the Company's second and third adjustments?

A. Yes. The Commission should reject these adjustments for several reasons. First, these are selective post-test year adjustments that are not known and measurable when considered against the fact that this capacity and energy did not simply disappear from the AEP System. The capacity and energy still remain available to the AEP pool for OSS sales, or if used by the AEP System itself, frees up other capacity and energy for resale to third parties.

In response to KIUC 1-43, the Company refused to provide a quantification of the OSS margins from this capacity and energy under the alternative assumptions that it was sold to a third party through bilateral contract or sold into PJM and stated that "[t]o the extent there are any such sales, they will be included in the system sales tracker." Of course, in the SSC, the Company will retain a portion of the OSS margins while proposing that the entirety of its proposed reductions in the margins be proformed into base rates without any sharing.

Second, the Company's adjustments fail to capture the annualized effects of the additional energy that will be produced by the Big Sandy 1 unit due to the December

2009 turbine uprate or the additional energy that will be available if the proposed wind power PPA is authorized in Case No. 2009-00545. The Company states that the Big Sandy 1 turbine retrofit described in response to KIUC 1-75 resulted in a capacity uprate of 13mW to 18mW and that "for a given capacity factor, the unit will produce approximately 5% to 7% more energy," according to its response to KIUC 2-23. I have attached a copy of the Company's response to KIUC 1-75 as my Exhibit___(LK-2) and a copy of the response to KIUC 2-23 as my Exhibit___(LK-3).

If the Commission considers the Company's proposed adjustments as known and measurable and includes them as reductions to the test year OSS margins, then certainly the OSS margins available from the Big Sandy 1 turbine uprate and the wind power PPAs are known and measurable and the OSS margins available from the increased energy should be included as well. The dichotomy in the Company's proposed treatment of these multiple events illustrates the inequities of the Company's selective post-test year adjustments.

Third, the Company's second and third adjustments assume a static amount of OSS margins for the test year, apparently under the assumption that the test year amount is normalized and represents an ongoing level of margins, except, of course, for the proforma adjustments that it has selectively identified and incorporated in its claimed revenue requirement. However, the OSS margins are not static and in fact the test year amounts represent a "low point" compared to prior years, compared to the Company's actual amount of $17.124 million for calendar year 2009 and compared to its projections for the next several years, according to its response to AG 1-9. The Company's actual OSS margins were $27.645 million in 2005, $49.892 million in 2006, $51.285 million in 2007, and $45.353 million in 2008, according its response to AG 1-9. Further, the Company projects that its OSS margins will be $26.796 million in 2010, or nearly double the actual amount in the test year, $29.494 million in 2011, $43.637 million in 2012, and $70.602 million in 2013, according to its response to AG 1-9. I have attached a copy of the Company's response to AG 1-9 as my Exhibit___(LK-4).

Q. If the Commission adopts the Company's proposed second and third adjustments to OSS margins to reflect the termination of the I&M sale to CPL, what is your recommendation?

A. In that case, I recommend that the Commission capture the Company's own projection of OSS margins of $26.8 million (total Company) for calendar year 2010 so that all effects of post-test year adjustments, at least through 2010 are properly reflected in the OSS margins used to quantify the revenue requirement. Alternatively, the Commission could use a five year average of historic amounts using 2005 through 2009 actual data to normalize the test year amount, which would be $38.260 million.

Q. Do you agree with the Company's fourth adjustment to the OSS margins to

eliminate 50% of the adjusted test year amount?

A. No. The Company's proposal is extremely aggressive, lacks any logical or other support and arbitrarily serves to increase the Company's claimed revenue requirement. Since the SSC was adopted, the test year OSS margins have been used as and to reset the SSC threshold above or below which the SSC sharing provisions apply.

There is absolutely no reason for the Commission to simply remove 50% of the test year OSS margins from the revenue requirement. Such a removal will require the ratepayers to pay the Company $7.546 million more than its adjusted test year cost to provide service for the benefit of the Company's shareholder. Such an adjustment would be arbitrary, contrary to any public policy objective and serve only to harm the very ratepayers who face the impact of the Company's rate increase.

Such an adjustment will not incentivize the Company to generate additional OSS margins. To the extent the Commission continues the SSC and maintains some sharing percentage between the Company and the ratepayers for amounts above the threshold, the sharing arguably provides the incentive, to the extent such an incentive is necessary or appropriate or affects the conduct of AEPSC, not an arbitrary reduction of the baseline test year OSS margins used for the threshold itself.

In addition, the test year OSS margins already are the low-point compared to prior years, compared to calendar year 2009, and compared to the Company's own projections of OSS margins in 2010 and future years due to market conditions and the economic recession. Thus, the Company's proposal further reduces an already low amount.

Finally, the Company's proposed adjustment is inequitable in that it would require the ratepayers to pay for the entirety of the infrastructure costs necessary to make the OSS sales. The Company has proposed no sharing of these test year costs, which it confirmed in response to KIUC 1-55. I have attached a copy of the Company's response to KIUC 1-55 as my Exhibit__(LK-5).

<u>Company Has Not Justified Wind Power Purchase</u>

Q. Please describe the Company's request to recover the costs of its proposed wind power purchase.

A. The Company requests recovery of $14.480 million for the base rate costs of a proposed wind power purchase agreement with FPL Illinois Wind, LLC. The Company also has pending before the Commission an Application for approval of this contract in Case No. 2009-00545. The Company's adjustment in this proceeding assumes that the Commission will approve the contract in Case No. 2009-00545.

Q. Did KIUC oppose this contract in Case No. 2009-00545?

A. Yes. On behalf of KIUC, I opposed approval of the contract in my Direct Testimony in that proceeding. I cited the following reasons that the Commission should not approve the contract, which are applicable in this proceeding as well:

1. There presently are no renewable mandates at either the federal or state levels. Thus, this contract is discretionary and should be subject to a needs determination and subject to the traditional least cost standard for supply-side resources.

2. Even if the Commonwealth were to enact H.B. 3 into law, or something similar, this contract will not qualify because the resource is not located in Kentucky. Thus, approval of the contract will not accomplish any renewable objective from the perspective of the Commonwealth.

3. The Company has provided no studies in this proceeding to demonstrate that the purchases pursuant to this contract are necessary. The Company does not need additional energy. The Company presently is energy long and already sells 33% of its energy into the AEP pool for use by other AEP companies and for resale into the off-system sales market. The purchases will simply increase the sales into the AEP pool and increase the percentage of energy sold to the AEP pool from 33% to 36%.

4. The Company has provided no studies in this proceeding to demonstrate that the purchases pursuant to this contract are economic compared to using its present generation or purchasing from the AEP pool.

5. The Company has other options to meet potential renewable standards, such as biomass co-firing at the Big Sandy station, which it presently is testing, or the purchase of renewable energy credits.

6. The Company's shareholders will retain a portion of the increased off-system sales margins due to the additional energy from the purchases pursuant to its System Sales Clause. The Company is unwilling to use the retained portion of those margins to offset the cost of these purchases.

7. The Company has failed to consider the effect on its costs and the revenue requirement due to a richer common equity ratio to offset the rating agencies' imputation of debt equivalents for purchased power contracts.

Q. If the Commission rejects the contract in Case No. 2009-00545, should the

Company's adjustment for this expense be removed in this proceeding?

A. Yes. If the Commission rejects the contract in Case No. 2009-00545, the Company will not incur the expense and it should not be included in the revenue requirement for that reason alone.

Q. **Are there additional reasons why the Commission should reject this expense in this proceeding?**

A. Yes. First, the Commission should not adopt this selective post-test year adjustment unless it adopts other post-test year adjustments that reduce the revenue requirement, of which there are several that I have identified. The Company proposes two selective post-test year adjustments that increase purchased power expense. In addition to the increase due to the wind power contract of $14.480 million, the Company also proposes a net increase in AEP pool capacity costs of $8.907 million, $3.164 million of which is due to the termination on January 1, 2010 of the I&M sale to CPL.

In contrast to these selective post-test year adjustments, the Company proposed no adjustments to increase OSS margins from the historic test year levels, despite its own projections that the OSS margins will increase dramatically in 2010 and years thereafter and despite the increase in margins specifically due to: 1) the increase in energy available from the wind power purchase if it is approved in Case No. 2009-00545, 2) the increase in the Big Sandy 1 capacity and energy due to a post-test year turbine uprate, and 3) the increase in capacity and energy available to the AEP pool from the termination of the I&M sale of 250 mW to CPL on January 1, 2010.

Second, the Company's proposed adjustment for the wind power contract is not known and measurable. The contract may not start coincident with the date rates become effective in this proceeding. If there is a lag, then the Company will overrecover, all else equal. In addition, the Company's adjustment is nothing more than the product of an assumption regarding generation times the contract rate per kWh. In other words, the Company simply assumed that it would incur $14.480 million in expense. If the actual generation is less than the assumption, then the expense necessarily will be less.

Third, the Company's adjustment extends two years beyond the end of the test year and reflects the amount the Company assumes that it will incur in the first twelve months of the contract. If indeed the contract commences in July 2010, then the Company will not incur the full annual expense in 2010 and in fact, will not incur the full annual expense until 2011. Thus, this proposed adjustment extends nearly two years beyond the end of the historic test year ending September 30, 2009.

Commission Should Reject Post-Test Year Adjustment for AEP Capacity Payments for Termination of I&M Sale to CPL

Q. Please describe the Company's adjustment to increase purchased power expense for AEP capacity payments due to the termination of the I&M sale to CPL.

A. In addition to the Company's adjustment to eliminate the OSS margins from this sale that I previously addressed, the Company also proposes an adjustment to increase the purchased power expense by $3.193 million (total Company) and $3.164 million (jurisdictional) for an increase in AEP pool capacity payments upon the termination of the sale on January 1, 2010. The total Company amount and jurisdictional factor are shown on Section V Workpaper S-4 page 9. The basis for the adjustment is described by Mr. Wagner on pages 35-36 of his Direct Testimony and the computations are detailed on his Exhibit EKW-14.

Q. Should the Commission adopt this adjustment?

A. No. This adjustment is a selective post-test year adjustment and is not known and measurable. As I previously explained in the OSS margin section of my testimony, this capacity and energy still is available to the AEP system; however, the Company claims that it doesn't know how the capacity will be allocated or to whom, according to its response to KIUC 1-43. In other words, even though the Company provided its responses to KIUC Initial Data Requests on February 26, 2010, it would have the Commission believe that it doesn't know what AEP will do with this capacity or energy. In its response to KIUC 1-43, the Company states that "it cannot be predicted with certainty where the energy from the 250 MW of capacity will be allocated. It is possible that the energy from this 250 MW may be allocated internally to it's owner Indiana Michigan Power Company. It is also possible that the 250 MW could be used for primary deliveries to other deficit sister companies. The likelihood of allocation to system sales cannot be known at this time."

In addition, and as I previously explained, the Company has not incorporated a related adjustment to increase OSS margins, nor has it incorporated any other post-test year adjustments to reflect increases in OSS margins, whether from additional capacity and energy available to the AEP system or increases in forward prices.

Company Has Not Justified Cost of Proposed Enhanced Reliability and Service Plan

Q. Please describe the Company's request to implement and recover the costs of a proposed "Enhanced Reliability and Service Plan" ("Plan").

A. The Company proposes an increase to O&M expense of $16.374 million, an increase to depreciation expense of $0.373 million and an increase in capitalization of $9.423 million to capitalization for the future costs of this Plan. This Plan actually consists of four plans that the Company proposes to implement after base rates are reset in this proceeding. The four proposed plans and the O&M expenses and capital expenditures are described and quantified by Company witness Mr. Everett Phillips. These plans are as follows:

1. Enhanced Vegetation Initiative. The Company proposes to convert from its present performance based vegetation management program to a cycle based program. The Company projects that it will incur incremental O&M expense and capital expenditures to implement this initiative over the next five years.

2. Enhanced Equipment Inspection and Mitigation Initiative. The Company proposes to implement expanded "equipment inspection and mitigation," which it will use to "proactively identify and replace hardware and equipment that either are prone to failure or that have the increased likelihood to fail."

3. Distribution Work Force Planning Initiative. The Company proposes to hire 31 additional distribution employees to replace its "aging workforce."

4. gridSMART Initiative. The Company proposes to install additional SCADA equipment in substations and distribution lines, distribution automation ("DA") equipment, and integrated volt var control ("IVVC").

Q. Is this Plan discretionary?

A. Yes. The Company has identified this Plan and the four component plans as incremental to its present operations, implying that if it does not obtain rate recovery of these costs, then it will not implement the plans.

Q. Has another AEP Company recently determined that it would not seek adoption of a similar Plan due to the present economic conditions?

A. Yes. Appalachian Power Company ("APCo") intentionally did not seek recovery of the costs of a similar plan in a pending rate case (PUE 2009-00030) before the Virginia State Corporation Commission because of the "current economic conditions." In that proceeding, APCo witness Mr. Philip Wright stated that the Company had analyzed a "more aggressive" approach to vegetation management, namely a "cycle-based approach," but "the Company realizes that now is not the time to implement this program given current economic conditions." [Wright Direct at 10].

Q. **If the Plan is discretionary and there is no demonstrated need for or cost/benefit to the Plan, should the Commission reject incremental rate recovery in this proceeding?**

A. Yes. There is no reason to unnecessarily increase the rate increase resulting from this proceeding. The Commission should take every step to ensure that only necessary and reasonable costs are included in the Company's revenue requirement and the resulting rate increase, particularly given the current economic conditions.

Q. **Has the Company demonstrated a need for this Plan?**

A. No. It is the Company's obligation to demonstrate that present spend rates (expense and capital expenditures) are inadequate and that there is a need for this Plan and its components. It has not done so. First, the Company has not demonstrated that its service quality has deteriorated or that it will deteriorate in the future either in the form of "hard" statistics, such as System Average Interruption Frequency Index ("SAIFI"), System Average Interruption Duration Index ("SAIDI") and other reliability metrics, or in the form of "soft" data such as surveys of customer satisfaction. In fact, to the contrary, Mr. Phillips has gone to great lengths in his testimony to describe and demonstrate that the Company's present Distribution Asset Management Programs are "designed to maximize the efficiency of expenditures and optimize system performance."

Second, the Company has not demonstrated that its current operations and activities are ineffective, insufficient, or inadequate to meet customer requirements. To the contrary, Mr. Phillips provides extensive testimony that the Company is providing safe and reliable service with its existing programs. "KPCo's Distribution Asset Management, Major Distribution Reliability and Capacity Additions, and Vegetation Management Programs are designed to ensure that customer expectations are satisfied by the Company['s] ability to provide safe and reliable service," according to Mr. Phillips on page 9 of his Direct Testimony. "KPCo's existing distribution vegetation management program employs a performance-based approach, which prioritizes work on KPCo's facilities after taking into consideration a number of input variables . . . KPCo has used the performance-based approach for many years to allocate resources to particular circuits, or portions of circuits, " according to Mr. Phillips on page 8 of his Direct Testimony. "Each year, KPCo undertakes various major distribution reliability improvements in addition to those included in the Asset Management Programs . . . previously described," according to Mr. Phillips on page 7 of his Direct Testimony. "KPCo's reliability-related customer satisfaction regulatory scores above the MSI-supplied national benchmark," according to Mr. Phillips on page 9 of his Direct Testimony.

Third, the Company's claims that its distribution system is "deteriorating" and that there is a "deteriorating reliability trend," are not substantiated by the evidence presented in the Company's filing. Mr. Phillips cites deterioration in the SAIDI, excluding major events on pages 11-12 of his Direct Testimony. However, over the five years of data presented, the SAIDI has varied significantly and there is insufficient evidence to conclude that there is or will be a sustained increase in SAIDI (suggesting deteriorating performance) or any other reliability metric. The Company's support for the claim that its distribution system is "deteriorating" is based solely on the decline in the SAIDI referenced by Mr. Phillips on page 12 of his Direct Testimony, according to the Company's response to KIUC 1-59.

Fourth, the Company's claim that there are "increasing customer expectations" is based on a single question in the Company's customer surveys conducted with 200 residential and 200 commercial customers by third party vendor MSI, according to its response to KIUC 1-58. The Commission should consider whether this generalized claim and the responses to a single question in a customer survey are sufficient evidence of the need to trigger a massive spending program over the next five years and sustained increased levels of distribution O&M and capital expenditures thereafter or whether more substantial and objective evidence of customer needs or reliability is necessary. I have attached a copy of the Company's response to KIUC 1-58 as my Exhibit___(LK-6).

Q. The Company claims that a cycle based program will increase reliability compared to the existing performance based approach. [Phillips Direct at 13]. Has the Company demonstrated that this claim is correct?

A. No. In KIUC 1-61, the Company was asked to provide "all evidence that a cycle based program will increase reliability compared to a performance based approach." In its response, the Company provided no studies, but referred to its response to AG 1-32; however, it provided no studies in response to that request either. In KIUC 2-22, the Company was asked to confirm that were no such studies. In response to KIUC 2-22, the Company's response cites to an E.On 2008 report and a report prepared for EEI by Davies Consulting, Inc., neither of which demonstrates that a cycle based program will increase reliability compared to a performance based program. In fact, rather than supporting the cycle based approach, the Davies Report states that "[u]tilities are beginning to evaluate the RCM philosophy [reliability centered maintenance or performance based approach] to replace traditional time based programs [cycle based approach] in the hope they will reduce costs and improve reliability."

Apparently, the only evidence arguably in support of the Company's proposition that the cycle based program will increase reliability compared to the performance based program is the experience of another AEP utility, Public Service Company of Oklahoma ("PSO"). PSO increased its vegetation management spend rate after it was authorized ratemaking recovery through a rider for reliability improvement costs. However, the experience of PSO demonstrates only that a utility can improve reliability if it funds increased activities; this experience does not demonstrate the superiority of the cycle based approach compared to a performance based approach.

Thus, the Company has presented no evidence whatsoever that demonstrates the superiority of a cycle-based approach compared to a performance-based approach or the need to increase ratemaking recovery and funding for such an approach.

Q. Has the Company provided any cost/benefit analyses that demonstrate the cost-effectiveness of its proposed Plan or any of its components?

A. No. In addition to its failure to demonstrate the need for additional funding to improve reliability and its failure to demonstrate that the cycle based approach is superior to a performance based approach, the Company has not demonstrated that its proposal is cost-effective. It has not provided a single cost/benefit study or provided any analyses to demonstrate that it will save money now or in the future or that the cost to improve reliability is reasonable given the potential improvement(s). This is an important issue because it is one of the three foundations necessary for the Company to justify an increase in O&M expense beyond the test year levels in this proceeding.

In AG 1-32, the Company was asked to provide all studies and analyses that address the "economics and/or cost effectiveness of the performance-based versus cyclic vegetation management approach relied on by the Company." The Company failed to provide a single study or any analyses. In AG 2-11, the Company again was asked to provide all such studies and analyses. In its response, the Company stated "[t]he Company does not have documents related to the cost effectiveness of one approach versus another."

In KIUC 2-26, the Company was asked to "describe and identify the baseline and metrics proposed . . . to measure 'the cost effectiveness' of the Company's Enhanced Vegetation Management Initiative." The Company failed to describe and identify the baseline or any metrics to measure the cost-effectiveness of its Plan. I have attached a copy of the Company's response to KIUC 2-26 as my Exhibit___(LK-7).

Q. Will there ever be any savings resulting from the Company's proposed Plan?

A. No. The Company's projections show incremental O&M expense and capital expenditures even beyond the proposed five year transition period for its proposed Enhanced Vegetation Initiative, according to the table on page 23 of Mr. Phillips' Direct Testimony. The ongoing costs for this one initiative exceed the annual costs of the other three plans that are part of the Plan. Thus, even if the incremental costs for the other three plans are eliminated after the plans are fully implemented, there still will be net incremental costs of the Plan due to the Enhanced Vegetation Initiative. Absent any net savings from the Company's Plan, the Commission should not approve rate recovery or the Company's proposed adjustment to increase expense. It will result in a permanent increase in costs for which the ratepayers apparently never will receive a savings benefit.

Q. How does the cost of the Company's proposed Enhanced Vegetation Management Initiative compare to the spend rate in the test year?

A. The Company plans to triple its spend rate on O&M expense and double its spend rate on capital expenditures. In the test year, the Company spent $7.24 million in O&M expense and $2.54 million in capital expenditures on distribution vegetation management, according to the table on page 22 of Mr. Phillips' Direct Testimony. If its Enhanced Vegetation Management Initiative is approved, the Company plans to spend an additional $13.93 million in Year 1 in O&M expense and an additional $1.84 million in capital expenditures, and steadily increasing amounts every year thereafter for an additional four years, according to the table on page 23 of Mr. Phillips' Direct Testimony.

Q. Is this proposed increased spend rate reasonable even if the Commission determines that additional spending on vegetation management is appropriate?

A. No. It is extremely and unnecessarily aggressive. The Commission should reduce the ratemaking recovery from that requested by the Company in order to limit the proposed increased spend rate if it determines that additional spending on vegetation management is appropriate.

Q. Do you have any further comments on the Company's proposed Enhanced Equipment Inspection and Mitigation Initiative.

A. Yes. The Company has not demonstrated that this plan is necessary or cost-effective and that it cannot maintain or implement continuing improvements at its test year level of O&M expense and rate base. The Company already performs a biennial visual inspection of its equipment. The Company has not demonstrated that the present inspections are insufficient or that it cannot use the technology described by Mr. Phillips during these inspections to identify problem components and replace them as well as replace or reinforce poles and replace spacer cable without additional expense or capital investment beyond that reflected in the test year.

Q. Do you have any further comments on the Company's proposed Distribution Workforce Planning Initiative?

A. Yes. The Company has not demonstrated that hiring additional distribution employees is necessary or cost-effective. The Company already has in place an apprentice and journeyman program that trains younger distribution field employees to ensure that thre is ongoing skill development and knowledge transfer. In addition, the workforce is sized to meet the current needs of the Company. The Company has made no attempt to demonstrate that its present workforce is inadequate to meets its current needs. The Company has not demonstrated that it can cost-effectively utilize additional employees and has provided no staffing studies that indicate that it is understaffed in professional positions, field positions or support positions or that its present training and development programs are inadequate to meet the Company's needs as individual employees retire and younger employees replace them in senior and supervisory positions. This process is ongoing and the Company has failed to identify any unique circumstances that now require excessive staffing, even temporarily, above and beyond that already built into the present cost structure for training and development to ensure a sufficient and well-trained workforce on a continuing basis.

Q. Do you have any further comments on the Company's proposed gridSMART Initiative?

A. Yes. The Company already is in the process of implementing many of the components of this plan. For example, the Company already is in the process of implementing SCADA in substations and distribution lines. These costs already are embedded in the test year. Mr. Phillips acknowledges that the Company already has installed SCADA in 37 distribution stations out of 92. [Phillips Dirct at 36-37]. In addition, most of the costs for this plan are capital expenditures, which are part of the Company's ongoing process to implement technology and achieve enhanced performance and restraint or reductions in costs through investment. The Commission does not need to prematurely provide recovery of these capital expenditures.

Q. Please address the depreciation expense on the capital expenditures pursuant to the Company's Plan.

A. The Commission should reject the Company's proposal to include depreciation expense on future capital expenditures pursuant to the Plan. This is bad regulatory policy for several reasons. First, it requires the Commission to micromanage the Company by approving capital expenditure recovery well beyond the test year, presumably for specific projects and activities.

Second, if the Commission adopts this approach of providing recovery for alleged incremental costs for alleged new or expanded programs, it will become the precedent for potentially unlimited requests for alleged incremental costs for alleged new or expanded programs in future cases.

Third, it will be very difficult for the Commission to ensure that the amounts authorized actually are spent for that purpose because it will not be able to trace the additional recovery allowed to the actual amounts expended, whether expense or capital expenditures. The Company, not the Commission, will determine its annual spend rates based on its financial results and its budgeting and planning process and adjust its actual expenditures, either in the alleged new or expanded programs or in its other programs.

The Commission will not be able to control the Company's decisions or spending levels without ever-increasing involvement in the Company's decision-making process.

Fourth, it will result in increased spending if the discipline of historic test year cost recovery is abandoned, particularly if it is abandoned without the structure of a projected test year where all elements of the ratemaking formula for the projected test year can be considered together. If the Company can reach beyond the historic test year and selectively increase its capitalization and the related depreciation expense, this necessarily will increase the Company's spend rate and increase costs to ratepayers. Even worse, this scenario will be compounded in future rate cases as the Company likely will attempt to expand the post-test year costs for which it seeks recovery.

Company Incorrectly Quantified Normalization Major Storms Adjustment

Q. Please describe the Company's proforma adjustments to normalize the expenses of major storms incurred during the test year.

A. In its filing, the Company proposes two adjustments related to storm expense incurred during the test year. The first adjustment is to reduce storm damage expense to reflect a three year average of expense, excluding amounts that were deferred and reflected in the second adjustment. This first adjustment is described by Company witness Mr. Ranie K. Wohnhas on pages 7-8 of his Direct Testimony. The computations are detailed on Section V Workpaper S-4 page 15.

The second adjustment is to reflect the amortization of certain significant test year storm expenses that the Company expensed during the test year, but subsequently deferred on its accounting books through a negative adjustment to expense when the Company received authorization from the Commission to defer these certain expenses. This second adjustment is described by Mr. Wohnhas on pages 8-9 of his Direct Testimony. The computations are detailed on Section V Workpaper S-4 page 20.

Q. Did the Company incorrectly quantify the first adjustment to normalize storm damage expense based on a three year average of expense, excluding amounts that were deferred pursuant to the Commission's order?

A. Yes. The Company incorrectly computed the normalized storm damage expense on Section V Workpaper S-4 page 15. The Company correctly computed the three year average expense, excluding the expense amounts that were deferred. However, it subtracted the test year expense excluding the deferral to compute the proforma adjustment instead of the actual expense in the test year, which was not reduced for the deferral. The reduction in expense due to the deferral did not occur until after the test year and was not reflected in the test year per books expense amounts.

Q. Does the Company agree that it computed the proforma adjustment incorrectly?

A. Yes. The Company acknowledged that its computation was incorrect and provided a revised quantification in response to KIUC 1-76. I have attached a copy of the Company's response to KIUC 1-76 as my Exhibit___(LK-8).

Q. Was the Company's revised quantification provided in response to KIUC 1-76 correct?

A. No. The revised quantification also was incorrect, but for a different reason. The revised quantification incorrectly reduced this first proforma adjustment by the amount of the separate second proforma adjustment for the amortization expense, thus effectively double counting the amortization expense in the first and second proforma adjustments.

Q. Has the Company revised the quantification a second time to correct this new error?

A. Yes. The correct quantification of this adjustment reduces the revenue requirement by $10.213 million compared to the Company's filing. In response to Staff 3-25, the Company acknowledged that it's quantification in response to KIUC 1-76 had "combined the correct normalization adjustment with the amortization adjustment." In that response, the Company provided another revised quantification for the "correct normalization adjustment" in the same format as Section V Workpaper S-4 page 15. This quantification results in a proforma adjustment to reduce expense by $11.414

million compared to the adjustment in its filing to reduce expense by $1.201 million. The difference is $10.213 million, which is equivalent to the storm expenses incurred during the test year, but which were not deferred until after the test year upon receiving Commission authorization for the deferral.

<u>Company Improperly Included Incentive Compensation Expense Tied to AEP Financial Performance</u>

Q. Please describe the Company's request for recovery of incentive compensation expense tied to AEP financial performance.

A. The Company included $0.991 million in this category of incentive compensation expense in the projected test year for its Long Term Incentive Plan ("LTIP"), which is paid to the AEP executive management based on achievement of AEP financial performance. The expense amount was provided in response to KIUC 1-29. I have attached a copy of the Company's response to KIUC 1-29 as my Exhibit___(LK-9).

The primary purpose of the AEP LTIP is to motivate managers to maximize shareholder value by linking a portion of their compensation directly to shareholder return, according to Company witness Mr. David Jolley on pages 17-18 of his Direct Testimony. The LTIP provides grants or awards in the form of performance units (units are similar to shares of AEP common stock but have no voting rights) with a three year performance and vesting period beginning January 1st of each year. Performance units are earned based on the achievement of two equally weighted performance measures compared to the target: three-year total shareholder return measured relative to the S&P Utilities and three-year cumulative earnings per share measured relative to a Board approved target, according to Mr. Jolley on page 18 of his Direct Testimony.

Q. Should the AEP LTIP incentive compensation expense be included in the Company's revenue requirement?

A. No. The expense incurred to incentivize financial performance benefits shareholders, not ratepayers. This expense is not directly tied to the achievement of regulated utility service requirements and in fact, benefits shareholders to the detriment of ratepayers in rate proceedings such as this. In addition, the Company's request to embed these expenses in the revenue requirement tends to become self-effectuating. The Company did not incur this expense to achieve target levels of customer service or expense levels that directly benefit ratepayers, but rather the expense was incurred to directly benefit AEP shareholders. Thus, the expense should be directly assigned to AEP shareholders, not ratepayers.

<u>Company Improperly Included Short Term Interest Expense and Interest Income in Operating Expenses</u>

Q. Please describe the Company's request to include short-term debt interest, net of interest income, in operating expenses.

A. The Company proposes to increase O&M expense by $1.876 million for a "Temporary

Interest Expense" adjustment. This adjustment is the net of the test year actual short term debt interest expense and short term investment interest income booked below the line by the Company in accounts 430 and 419, respectively, according to Mr. Wagner on page 34 of his Direct Testimony. Mr. Wagner claims that this adjustment is "required to reflect this cost in the Company's test year cost of service."

Q. Is the recovery of short-term debt interest in O&M expenses appropriate?

A. No. First, the proper place to include short-term debt interest expense is in the rate of return applied to capitalization and to include short-term debt and the related interest expense in the computation of the rate of return. The Company's request is particularly egregious because it compounds the harm to ratepayers from the Company's failure to properly include short-term debt in the capital structure. The Company's failure to include short term debt in the capital structure simply assumed away the benefit to ratepayers of the actual lower costs from this form of financing through the rate of return, and then compounded this harm by adding an adjustment to include the net interest expense as an O&M expense. I subsequently discuss the Company's failure to include short-term debt in the capital structure in the Cost of Capital section of my testimony.

Second, the proper place to include short-term interest income also is in the rate of return applied to capitalization and to include short-term investments and the related interest income in the computation of the rate of return. As a practical matter, this is accomplished by using a thirteen month average of short term debt in the capital structure because it captures the effects when the Company is a net investor in the AEP Money Pool, particularly if the thirteen month average is computed using daily balances.

Q. Since it filed this case, has the Company reconsidered its proposed "temporary interest expense" adjustment in O&M expenses?

A. Yes. In response to Staff 2-66, the Company acknowledged that the short term debt interest expense should not be included in O&M expense because it is properly included in the rate of return. I have attached a copy of the Company's response to Staff 2-66 as my Exhibit___(LK-10).

Company Failed to Reflect Section 199 Tax Deduction in Income Tax Expense

Q. Did the Company reflect the Section 199 tax deduction in the gross conversion factor?

A. No. The Company's computation of the gross conversion factor is provided in Section V Workpaper S-2 page 2 of 3 and there is no Section 199 deduction reflected. In addition, there is no separate computation of the reduction in income tax expense due to the Section 199 deduction in the Company's computation of operating income. The

Company did not include the Section 199 deduction because it "did not reflect a Section 199 deduction in the calculation of . . . taxable income in 2008" and because it does not expect to "have positive qualified manufacturing income in 2009 or 2010," according to Mr. Wagner in his Direct Testimony on pages 14-15.

Q. What is the Section 199 deduction?

A. The Section 199 deduction allows a deduction against taxable income for qualified domestic production (manufacturing) activities. The Section 199 deduction is computed by applying a rate against qualified domestic production income. The rate was 6% in 2009 and increased to 9% effective January 1, 2010.

Q. Has the Commission reflected this deduction in prior KPCo proceedings?

A. Yes. The Commission presently incorporates this deduction in the computation of the Company's gross conversion factor used in the ECR surcharge filings. It should be noted that the Company actively opposed the inclusion of this deduction in its ECR filings and appealed the Commission's decision to the Franklin Circuit Court and after it was affirmed there, appealed it to the Kentucky Court of Appeals. Both courts affirmed the Commission's decision.

Q. Did LG&E and KU reflect the Section 199 deduction in their pending rate cases?

A. Yes. LG&E and KU both reflected this deduction in the computation of their operating income in their pending rate cases before in the Commission in Case Nos. 2009-00549 and 2009-00548, respectively. I have attached a copy of the LG&E schedule showing the computation of the Section 199 adjustment to reduce income tax expense as my Exhibit___(LK-11). In the LG&E and KU computations, those Companies multiplied their respective taxable incomes times the percentage of production plant to total plant included in rate base, multiplied the resulting qualified production activities income by the 9% rate to compute the amount of the deduction, subtracted the actual deduction for the test year, and then multiplied the adjustment to the deduction by the combined federal and state income tax rate to compute the reduction in income tax expense.

Q. Is the fact that the Company did not have a Section 199 deduction in 2008 and does not expect to have one in 2009 or 2010 relevant to whether the deduction should be reflected in the revenue requirement in this proceeding?

A. No. There are several reasons why this is not relevant. First, the Company is a member of the AEP affiliate group, which files a consolidated tax return. The Company is allocated a share of the AEP Section 199 deduction. If AEP on a consolidated basis is not eligible because of losses at other affiliates or for any other reason, then the Company does not receive the deduction.

Second, although the Company is member of the AEP affiliate group, the

Commission historically has computed the Company's income tax expense for ratemaking purposes as if it were a standalone entity. Historically, this has meant recovery of income tax expense for ratemaking purposes that does not reflect the savings in income tax expense resulting from filing a consolidated income tax return. The Company should not be allowed to recover a hypothetical income tax expense on the assumption that it is a standalone entity, but then deny ratepayers the benefit of all deductions for which it would be eligible as a standalone entity.

Third, any rate increase resulting from this case will increase the Company's taxable income as well as that of AEP on a consolidated basis, which in turn will increase the likelihood of AEP being able to use the Section 199 deduction.

Fourth, the assumption under the concept of a standalone entity for income tax purposes is that the Company's income tax expense is computed at the marginal combined federal and state income tax rates, in other words, a hypothetical maximum amount of income tax expense regardless of its actual expense. This same concept of a standalone entity dictates that the tax benefits to which the Company may be eligible also are computed on a standalone entity basis.

Q. Have you quantified the effect of including the Section 199 deduction in the Company's revenue requirement?

A. Yes. The effect is to reduce the Company's revenue requirement by $1.362 million. I computed this amount using the LG&E and KU methodology that I previously described. The computations are detailed on my Exhibit___(LK-12). I made this computation after all other KIUC adjustments to the capital structure and costs of capital were incorporated into the revenue requirement. I note this because the sequence in which the adjustments are made affects their quantification.

III. COST OF CAPITAL ISSUES

Company Improperly Failed to Include Short Term Debt in Capital Structure

Q. Please describe the amount of short term debt the Company included in the capital structure.

A. The Company included *negative* $21.507 million in short term debt in the capital structure as detailed in Section V Schedule 3 of its filing. The Company's starting point was the per books amount of short-term debt at September 30, 2009 of $0. From that starting point, the Company subtracted the entirety of the proposed Big Sandy coal stock adjustment, added a prorata amount for the capital costs it projects that it will spend over the next three years pursuant to its proposed Reliability plan, and then subtracted prorata amounts for various other adjustments.

Q. Did the Company actually use short-term debt during the test year?

A. Yes. The Company used short term debt in each month during the test year, based on the fact that it booked interest expense each month on its AEP Money Pool borrowings during the month. The interest expense booked each month was provided in response to KIUC 1-40(d) and (e) page 3 of 3, a copy of which I have attached as my Exhibit___(LK-13).

The Company had outstanding short term debt on the last day of each month during the test year, except for the months of July through September 2009, according to Section V, Workpaper S-3 page 2 of 3 of its filing. The 13 month average of the outstanding short term debt during the test year was $89.775 million, according to that same schedule in its filing.

Q. How does the amount of short-term debt actually used by the Company compare to its overall capitalization during the test year?

A. Short term debt represented a very large percentage of the Company's actual capitalization during the test year. For example, at May 31, 2009, the Company had short term debt outstanding of $168.665 million. By comparison, at September 31, 2009, the Company had a total capitalization of $994.690 million, according to Section V Schedule 3 of its filing. That amount of short term debt represents nearly 17% of the Company's total capitalization.

Q. Does the Company plan to continue to use short term debt?

A. Yes. The Company stated that its "financing plan does include short-term debt" in response to KIUC 1-38. I have attached a copy of the Company's response to KIUC 1-38 as my Exhibit___(LK-14).

Q. What is the significance of the fact that the Company used large amounts of short term debt during the test year and plans to continue to use short term debt in the future?

A. The significance is that the Company's costs are substantially lower than portrayed in its filing and these lower costs are not reflected in its claimed revenue requirement. If the Commission does not reflect an appropriate amount of short-term debt in the capital structure, the Company will recover from ratepayers an excessive cost of capital grossed-up for income taxes, but actually finance using substantially lower cost short-term debt. This will allow the Company to effectively arbitrage its recovery from ratepayers by assuming for ratemaking purposes that it would not use lower cost short-term debt financing, but then actually use that form of financing and retain the savings.

The present cost of short-term debt ranges from 0.17%% for 30 day commercial paper to 0.42% for 270 day commercial paper based on the market interest rates published in the *Wall Street Journal.* In contrast to the extremely low cost of short-term debt, the Company's cost of capital, as shown on Section V Workpaper S-2 page 1 of 3 in its filing and grossed-up for income taxes is 11.95%.

Q. In response to KIUC 1-38, the Company claims that the Commission has used the test year-end balance of short-term debt in prior ratemaking proceedings, including its most recent base rate proceeding in Case No. 2005-00341. Please respond.

A. Regardless of the manner in which the revenue requirement was computed in prior proceedings, the Commission should consider the evidence in this proceeding. There is no evidence that the Commission specifically adjudicated the issue in the prior proceedings as to whether the test year end or some other measure of the amount of short term debt was more appropriate for use in the test year capital structure. Further, Case No. 2005-00341 was settled and the Company's filing in that proceeding cannot be relied on as determinative of the issue in this proceeding.

Q. Is there a better measure of the level of short term debt than the test year-end balance?

A. Yes. The Commission should use a 13 month average during the test year rather than the test year end. The 13 month average provides a better representation of the short term debt that actually was used during the test year compared to a single day at the end of the test year and averages the variability in the amounts outstanding throughout the test year. Other Commissions, such as the Georgia Public Service Commission, use a 13 month average for this reason rather than the amount on the last day of the test year because the amount varies from month to month and even from day to day.

In addition, the Commission should consider whether the balance on a single day is an appropriate measure of the Company's costs for ratemaking purposes or whether the Company might be incentivized under such a methodology to reduce its short term debt to zero on the last day of the test year so that it will have the opportunity to arbitrage against an excessive cost of capital and retain the savings for its shareholder rather than providing those savings to its ratepayers.

Q. Have you quantified the effect of using a 13 month average of short term debt?

A. Yes. The effect is to reduce the Company's revenue requirement by $3.751 million. The computations are detailed on my Exhibit___(LK-15) in Sections I and II. In Section I of this exhibit, I reflect the grossed-up cost of capital included in the Company's filing using the Company's cost of capital from Section V Workpaper S-2 page 1 of 3 from its filing. In Section II, I added $89.775 million in short term debt and reduced the long-term debt by an equivalent amount. I did not adjust the common equity due to the relatively low common equity ratio even in the absence of such an adjustment in consideration of the rating agencies' capital structure metrics. I did not adjust the accounts receivables financing because the amount of such financing is determined independently of the other sources of financing.

Company Overstated the Cost of Short Term Debt

Q. Please describe the Company's proposed short term debt interest rate.

A. The Company proposes a short term debt interest rate of 2.29% based on its actual short term debt interest expense incurred during the test year divided by the 13 month average short term debt for the test year. The Company's computation of the interest rate is detailed on Section V Workpaper S-3 page 2 of 3.

Q. Should the Commission adopt the Company's proposed short term debt interest rate?

A. No. The Commission should update the Company's historic short term debt interest rate to reflect present rates. The present rates range from 0.17% to 0.42% for 30 day commercial paper and 270 day commercial paper, respectively. The present rates range from 0.25% for one month LIBOR to 0.92% for one year LIBOR. These rates were obtained from the *Wall Street Journal* on April 6, 2010.

Q. What short term debt interest rate do you recommend?

A. I recommend that the Commission adopt a 1.0% short term debt interest rate. This rate is slightly in excess of the highest short term debt rates available in the market for the next year.

Q. Have you quantified the effect of using a 1.0% short term debt interest rate?

A. Yes. The effect is to reduce the Company's revenue requirement by $0.876 million. The computations are detailed on my Exhibit___(LK-15) in Sections II and III. In Section II of this exhibit, I reflect the grossed-up cost of capital from the Company's filing adjusted to include the 13 month average of short term debt, but at the Company's proposed 2.29% short term debt interest rate. In Section III of this exhibit, I modified the short term debt interest rate to 1.0%. I computed the difference in the grossed up rates of return in Sections II and III and multiplied the result times the Company's total jurisdictional capitalization.

Company Improperly Applied Big Sandy Coal Stock Adjustment Only to Short Term Debt

Q. Please describe the Company's proposed Big Sandy coal stock adjustment.

A. The Company proposes a reduction in the Big Sandy coal inventory to reflect a 30 day target inventory amount. This adjustment is described by Company witness Mr. Errol Wagner in a single question and answer on page 26 of his Direct Testimony. Mr. Wagner proposes to take the entire amount of the adjustment as a reduction to short-term debt instead of over all components of the capital structure based on his claim that "coal inventory is usually financed with short term debt."

Q. Is the claim correct that "coal inventory is usually financed with short term debt?"

A. No. First, the Company has provided no evidence in support of this claim, nor is there any valid evidence. The Company was asked to provide all support for this claim in KIUC 1-36(a). In its response to that request, the Company provided no evidence that coal inventory is usually financed with short term debt. It simply cited to adjustments made in prior Commission decisions. That does not constitute evidence of the Company's actual financing activities.

Second, such a claim is inconsistent with the Company's assumption of no short term debt in the capital structure. Thus, the Company's claim results in the anomalous result of a negative short term debt amount in the Company's capitalization and capital structure, a result that is inherently unreasonable and should be rejected.

Third, the evidence demonstrates that this claim is not correct. For example, in July, August and September 2009, the month end balances of short term debt were $0, according to Section V Workpaper S-2 page 2 of 3 in the Company's filing. Yet, the Big Sandy coal inventory at September 30, 2009 was $41.527 million, according to Section V Workpaper S-3 page 3 of 3 in its filing. If there was no short-term debt outstanding at September 30, 2009, then logically it could not have been used to finance the $41.527 million in coal inventory on that same date.

Q. In response to KIUC 1-36(a), the Company claims that the Commission historically has made the adjustment to reflect a target Big Sandy coal inventory to the short term debt. Please respond.

A. Regardless of the manner in which the revenue requirement was computed in those proceedings, the Commission should consider the evidence in this proceeding. There is no evidence that the Commission specifically adjudicated the issue in the prior proceedings as to whether such an adjustment should be made to short term debt or prorated across all components of capitalization. Further, Case No. 2005-00341 was settled and the Company's filing in that proceeding cannot be relied on as determinative of the issue in this proceeding.

Q. How should the Commission reflect the Big Sandy coal stock adjustment in the revenue requirement?

A. The Commission should reflect the adjustment as a reduction to all capital components on a prorata basis to reflect the fact that the coal inventory is financed by all sources of financing, not solely short term debt. If the Commission includes short term debt in the capitalization, then the Big Sandy coal stock adjustment should reduce short term debt along with all other capital components, but if it does not include short term debt in the capitalization, then the adjustment should be prorated over all other capital components, excluding the receivables financing. In no event should the Big Sandy coal stock adjustment result in negative short term debt.

Q. Have you quantified the effect of the Big Sandy coal stock adjustment applied on a prorate basis to all capital components?

A. Yes. The effect is to reduce the Company's revenue requirement by $2.273 million. The computations are detailed in Section IV of my Exhibit___(LK-15). I computed the revenue requirement effect by taking the difference in the grossed-up rate of return from Section IV and the grossed-up rate of return from Section III and then multiplying this difference in the returns times the Company's total jurisdictional capitalization.

<u>Company Improperly Increased Capitalization for Future Reliability Capital Costs</u>

Q. Please describe the Company's proposed reliability capital adjustment.

A. The Company proposes an increase to capitalization for future capital expenditures that it plans to make over the next three years pursuant to its proposed reliability and service enhancement plan. The Company increased its capitalization by $9.423 million (total Company) on a prorata basis over all capital components, including short-term debt, except for the receivables financing.

Q. Should the Commission include this adjustment in the Company's revenue

requirement?

A. No. As I previously discussed in the Operating Income of my section of my testimony, the Commission should reject this proposed plan and the related costs. The Company has not justified the increased expenses or future capital expenditures and has failed to demonstrate that there is a cost benefit to ratepayers. In addition, the Company's proposed adjustment to increase capitalization proforms capitalization for projected costs through 2013, or four years beyond the end of the historic test year. The Commission should reject such selective post-test year adjustments for single costs without consideration of all other revenue, expense and capitalization amounts quantified on a consistent basis.

Q. Have you quantified the effect of the removing the Company's proposed reliability capital adjustment from its claimed revenue requirement?

A. Yes. The effect is to reduce the Company's revenue requirement by $1.089 million. The computations are detailed in Section V of my Exhibit___(LK-15). In the first step of the computation, I computed the difference in the grossed-up rate of return from Section V less the grossed-up rate of return from Section IV and then multiplied the difference in the rate of return times returns times the Company's total jurisdictional capitalization. In the second step, I multiplied the rate of return from Section V times the reduction in the jurisdictional amount of the reduction in total capitalization. In the third step, I added the results of the first and second steps.

Quantification of Return on Common Equity Recommended by KIUC

Q. Have you quantified the effect on the Company's revenue requirement of the return on equity recommendation sponsored by KIUC witness Mr. Richard Baudino?

A. Yes. The effect is a reduction in the revenue requirement of $11.240 million. This reduction is incremental to the reductions for the other cost of capital recommendations that I address. The computations are detailed in Section VI of my Exhibit___(LK-15). I computed the revenue requirement effect by taking the difference in the grossed-up rate of return from Section VI less the grossed-up rate of return from Section V and then multiplying this difference in the returns times the Company's total jurisdictional capitalization after the removal of the Company's proposed reliability capital adjustment.

Q. What is the effect on the revenue requirement of each 1.0% return on common equity?

A. The effect on the revenue requirement of each 1.0% return on common equity is $6.812 million.

Q. What is the pretax return on common equity requested by the Company and that recommended by KIUC?

A. The pretax return on common equity requested by the Company is 19.28%. The pretax return recommended by KIUC is 16.57%. The pretax return is the return on common equity that must be recovered from ratepayers in the revenue requirement. It includes federal and state income taxes that must be recovered in the revenue requirement, but that are expensed by the Company in computing its earned return. For this purpose, I included only the income tax gross-up to the return on common equity, although the revenue requirement also includes a gross-up for uncollectible account and the Commission maintenance fee.

IV. PROPOSED MODIFICATIONS TO THE SSC AND ECR RIDER

Commission Should Reject Company's Proposed Modifications to System Sales Clause

Q. Please describe the Company's proposed modification to the System Sales Clause.

A. The Company proposes a revised threshold and sharing percentages compared to the present SSC. The present SSC threshold is based on the $24.855 million OSS margins in the test year in the Company's last base rate case. The Company proposes to reduce the SSC threshold to $7.546 million to reflect only 50% of the jurisdictional OSS margins in the test year. The present SSC sharing percentages are tiered such that if the actual margins exceed the $24.855 million threshold, but are less than $30.000 million, then the ratepayers receive 70% and the Company receives 30% of the first tier excess over this initial threshold; if the actual margins exceed $30.000 million, then the ratepayers receive 60% and the Company receives 40% of this second tier excess in addition to the first tier of sharing. The Company proposes to modify the SSC sharing percentages to reflect a single tier such that if the actual margins exceed the proposed $7.546 million threshold, then the ratepayers receive 50% and the Company receives 50% of the excess. The Company's proposal is addressed by Mr. Thomas Myers in his Direct Testimony.

Q. What are the reasons cited by the Company's in support of its proposed modifications to the SSC?

A. The Company cites the following reasons in support of its proposed modifications, according to Mr. Myers on pages 6-11 of his Direct Testimony:

1. Provides "a level of rate certainty for customers in the form of an embedded base rate credit of $7.645 million."

2. Provides Company "a reasonable benefit for incurring 100% of the risk associated with embedding in retail rates for KPCo customers 50% of the test year level of OSS margins."

3. Provides Company "a prudent incentive for AEPSC to optimize OSS margins by incurring and effectively managing the risks and volatility inherent to the wholesale power markets."

4. "[H]elps to mitigate the significant and volatile costs associated with managing

the aforementioned [wholesale power market] risks."

5. Provides "better balance of risks and rewards associated with wholesale power markets."

Q. Do any of these reasons cited by the Company demonstrate that its proposal is superior to the present SSC, assuming that the threshold is updated for the test year OSS margins?

A. No. Assuming that any of these reasons are valid, which they are not, they would be equally valid in support of the present SSC. If the threshold is reset at $15.290 million (total Company), this would provide "rate certainty" to customers. If the sharing percentage is left at 30% to the Company, it would provide more than a "reasonable benefit" to the Company. If the sharing percentage is left at 30% to the Company, it would provide more than a "prudent incentive" to the Company. If the threshold is reset at $15.290 million and the sharing percentage is left at 30% to the Company, it would have no effect on the Company's ability to "mitigate the significant and volatile costs associated with managing the aforementioned [wholesale power markets] risks." If the threshold is reset at $15.290 million and the sharing percentage is left at 30% to the Company, it would provide a "better balance of risks and rewards associated with wholesale power markets" than the Company's proposal.

Q. Please respond to the Company's claim that its proposal provides "rate certainty"

for ratepayers.

A. The Company's proposal does provide "rate certainty" for ratepayers, but of a different sort than portrayed by Mr. Myers. The certainty is that ratepayers will be harmed because the Company proposes a reduction in the base revenue requirement of 50% of the test year OSS margins as the starting point for its proposal. As I noted previously, the test year OSS margins were at historic lows compared to the last five years, compared to the 2009 calendar year and compared to the Company's projections for the next several years. In addition, the certainty is that ratepayers will be harmed by a reduction in the threshold for sharing and a significant reduction in the sharing percentage over that threshold. Further, the certainty is that the ratepayers provide the Company recovery of all its fixed infrastructure investment costs and operating expenses incurred to make these wholesale sales.

Q. Please respond to the Company's claim that it's proposal provides a "reasonable benefit for incurring 100% of the risk associated with embedding in retail rates for KPCo customers 50% of the test year level of OSS margin."

A. Fundamentally, neither the Company nor AEPSC, on behalf of the Company, incur 100% of the risk associated with achieving OSS margins. First, and as I noted previously, the ratepayers provide the Company 100% recovery of all fixed infrastructure investment costs and operating expenses incurred to make these wholesale sales. Thus, neither the Company nor AEPSC bear any of that risk.

Second, the Company has virtually no risk associated with embedding in retail rates 50% of the test year OSS margins and, indeed, would have almost no risk associated with embedding in retail rates 100% of the test year OSS margins based on its margins in prior years and its projected margins in future years. To the contrary, the Company has shifted the risk to the ratepayers so that even if the Company achieves the lowpoint OSS margins achieved during the test year, the ratepayers will provide 50% of those OSS margins to the Company.

Third, a 50% share of the OSS margins is not a "reasonable benefit." The proposed 50% sharing to the Company is excessive given the present 30% sharing and given the Company's 0% responsibility for the fixed infrastructure investment costs and operating expenses incurred to trade in the wholesale market.

Q. Please respond to the Company's claim that its proposal provides "a prudent incentive for AEPSC to optimize OSS margins by incurring and effectively managing the risks and volatility inherent to the wholesale power markets."

A. I disagree. First, there is no evidence that the Company or AEPSC require an "incentive" to optimize OSS margins. To the contrary, the Company acknowledged in response to KIUC 1-48 that "[b]usiness decisions regarding how AEPSC will optimize OSS margins are made on an AEP system basis and not on an individual operating company basis. . . AEPSC has no specific plans to alter the management of the System's OSS based on the outcome of this proceeding." I have attached a copy of the Company's response to KIUC 1-48 as my Exhibit___(LK_16).

Second, the Company's proposal provides an excessive sharing, not a "prudent incentive." There is no evidence that an incentive is necessary at all, but certainly the present 30% sharing is "incentive" enough.

Third, there is a wide variety of sharing that is recognized for retail ratemaking purposes among the AEP utilities, including some jurisdictions in which there is no sharing at all. For example, in West Virginia, Appalachian Power Company flows through 100% of the OSS margins to ratepayers. The AEP 2009 10-K includes a table showing the sharing recognized in the various retail jurisdictions. The Company's proposal for sharing would be the most favorable to the Company of all the AEP jurisdictions. I have attached a copy of the relevant pages from that filing as my Exhibit___(LK-17).

Q. How does AEPSC actually respond to changes in sharing of OSS margins for retail ratemaking purposes?

A. AEPSC acts to optimize OSS margins regardless of changes for retail ratemaking purposes. Thus, any claim that AEPSC will act better or improve its optimization of OSS margins if it is allowed to retain more of those margins is not borne out by any evidence. There were no changes in AEP System trading activities that resulted from the change to 0% sharing to Appalachian Power Company when the West Virginia Commission re-established the Electric Net Energy Cost ("ENEC") clause in conjunction with "reregulation" of the generation function, according to the Company's response to KIUC 1-51. I have attached a copy of the Company's response to KIUC 1-51 as my Exhibit__(LK-18).

Q. Please respond to the Company's claim that its proposal "helps to mitigate the significant and volatile costs associated with managing the aforementioned [wholesale power market] risks."

A. There is no evidence whatsoever that a lower sharing threshold and greater sharing percentages to the Company have any effect on the Company's ability to mitigate costs associated with managing wholesale power risks. Those costs and risks exist independently of the retail ratemaking mechanisms that exist for the Company and other AEP utilities. The ratepayers pay the entirety of the fixed costs incurred by AEPSC to manage wholesale power market risk.

Q. Please response to the Company's claim that its proposal provides a "better balance of risks and rewards associated with wholesale power markets."

A. It is not a better balance from the perspective of ratepayers. The Commission should be reluctant to provide the Company an excessive share of the OSS margins for simply continuing to optimize OSS even without a sharing, let alone an excessive sharing.

Q. What is your recommendation regarding the SSC?

A. I recommend that the Commission reset the sharing threshold to the $15.290 million (total Company) in OSS margins for the test year. In addition, I recommend that the Commission maintain the present 70% sharing factor for OSS margins above this level.

<u>Commission Should Reject Proposed Modification to ECR Rider for Section 199</u>

Q. Please describe the Company's request to modify the Environmental Cost Recovery rider.

A. The Company proposes to modify the ECR formula to remove the Section 199 deduction from the computation of the gross revenue conversion factor. This request is not found in the Company's Application, but rather in a single question and answer on page 15 of Mr. Wagner's Direct Testimony. The basis for this proposal is that "KPCo is not eligible to take advantage of the Section 199 deduction provision of the Internal Revenue Code," according to Mr. Wagner.

Q. Should the Commission modify the ECR in this proceeding?

A. No. There are several reasons why this is inappropriate. First, KPCo is eligible for the Section 199 deduction when the ECR revenue requirement is considered on a standalone basis and the Company has presented no evidence to the contrary in this or in any other proceeding. The purpose of the ECR is to provide the Company recovery of qualified and approved environmental costs. The recovery is determined in accordance with a formula using actual costs and is not determined on the same basis as base rates. For example, the ECR formula uses rate base while base rates are computed using capitalization. The ECR formula does not use proforma adjustments while base rates reflect numerous proforma adjustments for various reasons. The ECR formula computes standalone income tax expense based on the gross conversion factor applied to the equity return on rate base while the income tax expense for base rates reflects the per books amount adjusted for the effects of proforma adjustments.

Second, the Company's proposal is a collateral attack on an issue that has been extensively litigated in prior ECR proceedings, the Commission already has decided and that has been affirmed by the Franklin Circuit Court and the Kentucky Court of Appeals.[1] The Company's argument in this proceeding is nothing more than an attempt to relitigate an issue that already has been decided and the Company offers no new arguments.

Third, the Company should make any proposal to modify the ECR formula in an ECR proceeding, not a base rate proceeding.

Q. How should the Commission proceed on this issue?

A. The Commission should explicitly reject the Company's proposal in this proceeding to ensure that the Company's proposal isn't tacitly "adopted" simply by neglecting to

[1] Stumbo v. Kentucky Public Service Commission et al. No. 2006-CA-002349-MR, Kentucky Court of Appeals, December 7, 2007. In affirming the Franklin Circuit County Court on this issue, the Court of Appeals found that the recognition of the Section 199 deduction was consistent with the Commission's historic use of the "stand-alone entity method" of computing KPCo's tax recovery and that this was advantageous to KPCo compared to the consolidated entity method of computing KPCo's tax recovery.

explicitly reject it.

Q. Does this complete your testimony?

A. Yes.

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

LANE KOLLEN, 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.

Lane Kollen

Sworn to and subscribed before me on this
6th 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:

GENERAL ADJUSTMENTS IN	)	
ELECTRIC RATES OF	)	CASE NO. 2009-00459
KENTUCKY POWER COMPANY	)	

EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

APRIL 2010

EXHIBIT ____ (LK-1)

RESUME OF LANE KOLLEN, VICE PRESIDENT

EDUCATION

University of Toledo, BBA
Accounting

University of Toledo, MBA

Luther Rice University, MA

PROFESSIONAL CERTIFICATIONS

Certified Public Accountant (CPA)

Certified Management Accountant (CMA)

PROFESSIONAL AFFILIATIONS

American Institute of Certified Public Accountants

Georgia Society of Certified Public Accountants

Institute of Management Accountants

More than thirty years of utility industry experience in the financial, rate, tax, and planning areas. Specialization in revenue requirements analyses, taxes, evaluation of rate and financial impacts of traditional and nontraditional ratemaking, utility mergers/acquisition and diversification. Expertise in proprietary and nonproprietary software systems used by utilities for budgeting, rate case support and strategic and financial planning.

RESUME OF LANE KOLLEN, VICE PRESIDENT

EXPERIENCE

1986 to Present:

J. Kennedy and Associates, Inc.: Vice President and Principal. Responsible for utility stranded cost analysis, revenue requirements analysis, cash flow projections and solvency, financial and cash effects of traditional and nontraditional ratemaking, and research, speaking and writing on the effects of tax law changes. Testimony before Connecticut, Florida, Georgia, Indiana, Louisiana, Kentucky, Maine, Maryland, Minnesota, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Texas, West Virginia and Wisconsin state regulatory commissions and the Federal Energy Regulatory Commission.

1983 to 1986:

Energy Management Associates: Lead Consultant.
Consulting in the areas of strategic and financial planning, traditional and nontraditional ratemaking, rate case support and testimony, diversification and generation expansion planning. Directed consulting and software development projects utilizing PROSCREEN II and ACUMEN proprietary software products. Utilized ACUMEN detailed corporate simulation system, PROSCREEN II strategic planning system and other custom developed software to support utility rate case filings including test year revenue requirements, rate base, operating income and pro-forma adjustments. Also utilized these software products for revenue simulation, budget preparation and cost-of-service analyses.

1976 to 1983:

The Toledo Edison Company: Planning Supervisor.
Responsible for financial planning activities including generation expansion planning, capital and expense budgeting, evaluation of tax law changes, rate case strategy and support and computerized financial modeling using proprietary and nonproprietary software products. Directed the modeling and evaluation of planning alternatives including:

Rate phase-ins.
Construction project cancellations and write-offs.
Construction project delays.
Capacity swaps.
Financing alternatives.
Competitive pricing for off-system sales.
Sale/leasebacks.

RESUME OF LANE KOLLEN, VICE PRESIDENT

CLIENTS SERVED

Industrial Companies and Groups

Air Products and Chemicals, Inc.
Airco Industrial Gases
Alcan Aluminum
Armco Advanced Materials Co.
Armco Steel
Bethlehem Steel
Connecticut Industrial Energy Consumers
ELCON
Enron Gas Pipeline Company
Florida Industrial Power Users Group
Gallatin Steel
General Electric Company
GPU Industrial Intervenors
Indiana Industrial Group
Industrial Consumers for Fair Utility Rates - Indiana
Industrial Energy Consumers - Ohio
Kentucky Industrial Utility Customers, Inc.
Kimberly-Clark Company
Lehigh Valley Power Committee
Maryland Industrial Group
Multiple Intervenors (New York)
National Southwire
North Carolina Industrial Energy Consumers
Occidental Chemical Corporation
Ohio Energy Group
Ohio Industrial Energy Consumers
Ohio Manufacturers Association
Philadelphia Area Industrial Energy Users Group
PSI Industrial Group
Smith Cogeneration
Taconite Intervenors (Minnesota)
West Penn Power Industrial Intervenors
West Virginia Energy Users Group
Westvaco Corporation

Regulatory Commissions and Government Agencies

Cities in Texas-New Mexico Power Company's Service Territory
Cities in AEP Texas Central Company's Service Territory
Cities in AEP Texas North Company's Service Territory
Georgia Public Service Commission Staff
Kentucky Attorney General's Office, Division of Consumer Protection
Louisiana Public Service Commission Staff
Maine Office of Public Advocate
New York State Energy Office
Office of Public Utility Counsel (Texas)

RESUME OF LANE KOLLEN, VICE PRESIDENT

Utilities

Allegheny Power System
Atlantic City Electric Company
Carolina Power & Light Company
Cleveland Electric Illuminating Company
Delmarva Power & Light Company
Duquesne Light Company
General Public Utilities
Georgia Power Company
Middle South Services
Nevada Power Company
Niagara Mohawk Power Corporation
Otter Tail Power Company
Pacific Gas & Electric Company
Public Service Electric & Gas
Public Service of Oklahoma
Rochester Gas and Electric
Savannah Electric & Power Company
Seminole Electric Cooperative
Southern California Edison
Talquin Electric Cooperative
Tampa Electric
Texas Utilities
Toledo Edison Company

**Expert Testimony Appearances
of
Lane Kollen
As of March 2010**

Date	Case	Jurisdict.	Party	Utility	Subject
10/86	U-17282 Interim	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
11/86	U-17282 Interim Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
12/86	9613	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Revenue requirements accounting adjustments financial workout plan.
1/87	U-17282 Interim	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements, financial solvency.
3/87	General Order 236	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Tax Reform Act of 1986.
4/87	U-17282 Prudence	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
4/87	M-100 Sub 113	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Tax Reform Act of 1986.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements. Tax Reform Act of 1986.
5/87	U-17282 Case In Chief	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Case In Chief Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Prudence Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
7/87	86-524 E-SC Rebuttal	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.

**Expert Testimony Appearances
of
Lane Kollen
As of March 2010**

Date	Case	Jurisdict.	Party	Utility	Subject
8/87	9885	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Financial workout plan.
8/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
10/87	870220-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
11/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Tax Reform Act of 1986.
1/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, rate of return.
2/88	9934	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Economics of Trimble County completion.
2/88	10064	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, O&M expense, capital structure, excess deferred income taxes.
5/88	10217	KY	Alcan Aluminum National Southwire	Big Rivers Electric	Financial workout plan. Corp.
5/88	M-87017 -1C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery.
5/88	M-87017 -2C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery.
6/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Prudence of River Bend 1 economic analyses, cancellation studies, financial modeling.
7/88	M-87017- -1C001 Rebuttal	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery, SFAS No. 92

**Expert Testimony Appearances
of
Lane Kollen
As of March 2010**

Date	Case	Jurisdict.	Party	Utility	Subject
7/88	M-87017--2C005 Rebuttal	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery, SFAS No. 92
9/88	88-05-25	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Excess deferred taxes, O&M expenses.
9/88	10064 Rehearing	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Premature retirements, interest expense.
10/88	88-170-EL-AIR	OH	Ohio Industrial Energy Consumers	Cleveland Electric Illuminating Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	88-171-EL-AIR	OH	Ohio Industrial Energy Consumers	Toledo Edison Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	8800 355-EI	FL	Florida Industrial Power Users' Group	Florida Power & Light Co.	Tax Reform Act of 1986, tax expenses, O&M expenses, pension expense (SFAS No. 87).
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Pension expense (SFAS No. 87).
11/88	U-17282 Remand	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Rate base exclusion plan (SFAS No. 71)
12/88	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87).
12/88	U-17949 Rebuttal	LA	Louisiana Public Service Commission Staff	South Central Bell	Compensated absences (SFAS No. 43), pension expense (SFAS No. 87), Part 32, income tax normalization.
2/89	U-17282 Phase II	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, phase-in of River Bend 1, recovery of canceled plant.

**Expert Testimony Appearances
of
Lane Kollen
As of March 2010**

Date	Case	Jurisdict.	Party	Utility	Subject
6/89	881602-EU 890326-EU	FL	Talquin Electric Cooperative	Talquin/City of Tallahassee	Economic analyses, incremental cost-of-service, average customer rates.
7/89	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87), compensated absences (SFAS No. 43), Part 32.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cancellation cost recovery, tax expense, revenue requirements.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Promotional practices, advertising, economic development.
9/89	U-17282 Phase II Detailed	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
10/89	8880	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Deferred accounting treatment, sale/leaseback.
10/89	8928	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Revenue requirements, imputed capital structure, cash working capital.
10/89	R-891364	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements.
11/89 12/89	R-891364 Surrebuttal (2 Filings)	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements, sale/leaseback.
1/90	U-17282 Phase II Detailed Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements detailed investigation.
1/90	U-17282 Phase III	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in of River Bend 1, deregulated asset plan.
3/90	890319-EI	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.

**Expert Testimony Appearances
of
Lane Kollen
As of March 2010**

Date	Case	Jurisdict.	Party	Utility	Subject
4/90	890319-EI Rebuttal	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Fuel clause, gain on sale of utility assets.
9/90	90-158	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, post-test year additions, forecasted test year.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements.
3/91	29327, et. al.	NY	Multiple Intervenors	Niagara Mohawk Power Corp.	Incentive regulation.
5/91	9945	TX	Office of Public Utility Counsel of Texas	El Paso Electric Co.	Financial modeling, economic analyses, prudence of Palo Verde 3.
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.	Recovery of CAAA costs, least cost financing.
9/91	91-231 -E-NC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Recovery of CAAA costs, least cost financing.
11/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Asset impairment, deregulated asset plan, revenue require-ments
12/91	91-410-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
12/91	10200	TX	Office of Public Utility Counsel of Texas	Texas-New Mexico Power Co.	Financial integrity, strategic planning, declined business affiliations.

Expert Testimony Appearances
of
Lane Kollen
As of March 2010

Date	Case	Jurisdict.	Party	Utility	Subject
5/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, pension expense, OPEB expense, fossil dismantling, nuclear decommissioning.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
9/92	92-043	KY	Kentucky Industrial Utility Consumers	Generic Proceeding	OPEB expense.
9/92	920324-EI	FL	Florida Industrial Power Users' Group	Tampa Electric Co.	OPEB expense.
9/92	39348	IN	Indiana Industrial Group	Generic Proceeding	OPEB expense.
9/92	910840-PU	FL	Florida Industrial Power Users' Group	Generic Proceeding	OPEB expense.
9/92	39314	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	OPEB expense.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy Corp.	Merger.
11/92	8649	MD	Westvaco Corp., Eastalco Aluminum Co.	Potomac Edison Co.	OPEB expense.
11/92	92-1715-AU-COI	OH	Ohio Manufacturers Association	Generic Proceeding	OPEB expense.
12/92	R-00922378	PA	Armco Advanced Materials Co., The WPP Industrial Intervenors	West Penn Power Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
12/92	U-19949	LA	Louisiana Public Service Commission Staff	South Central Bell	Affiliate transactions, cost allocations, merger.

**Expert Testimony Appearances
of
Lane Kollen
As of March 2010**

Date	Case	Jurisdict.	Party	Utility	Subject
12/92	R-00922479	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	OPEB expense.
1/93	8487	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Bethlehem Steel Corp.	OPEB expense, deferred fuel, CWIP in rate base
1/93	39498	IN	PSI Industrial Group	PSI Energy, Inc.	Refunds due to over-collection of taxes on Marble Hill cancellation.
3/93	92-11-11	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	OPEB expense.
3/93	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	Merger. Corp.
3/93	93-01 EL-EFC	OH	Ohio Industrial Energy Consumers	Ohio Power Co.	Affiliate transactions, fuel.
3/93	EC92-21000 ER92-806-000	FERC	Louisiana Public Service Commission	Gulf States Utilities/Entergy Corp.	Merger.
4/93	92-1464-EL-AIR	OH	Air Products Armco Steel Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
4/93	EC92-21000 ER92-806-000 (Rebuttal)	FERC	Louisiana Public Service Commission	Gulf States Utilities/Entergy Corp.	Merger.
9/93	93-113	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Fuel clause and coal contract refund.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers and Kentucky Attorney General	Big Rivers Electric Corp.	Disallowances and restitution for excessive fuel costs, illegal and improper payments, recovery of mine closure costs.
10/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Revenue requirements, debt restructuring agreement, River Bend cost recovery.

Expert Testimony Appearances
of
Lane Kollen
As of March 2010

Date	Case	Jurisdict.	Party	Utility	Subject
1/94	U-20647	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
4/94	U-20647 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Nuclear and fossil unit performance, fuel costs, fuel clause principles and guidelines.
5/94	U-20178	LA	Louisiana Public Service Commission Staff	Louisiana Power & Light Co.	Planning and quantification issues of least cost integrated resource plan.
9/94	U-19904 Initial Post-Merger Earnings Review	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
9/94	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policies, exclusion of River Bend, other revenue requirement issues.
10/94	3905-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Incentive rate plan, earnings review.
10/94	5258-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Alternative regulation, cost allocation.
11/94	U-19904 Initial Post-Merger Earnings Review (Rebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
11/94	U-17735 (Rebuttal)	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, exclusion of River Bend, other revenue requirement issues.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Revenue requirements. Fossil dismantling, nuclear decommissioning.

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Date	Case	Jurisdict.	Party	Utility	Subject
6/95	3905-U Rebuttal	GA	Georgia Public Service Commission	Southern Bell Telephone Co.	Incentive regulation, affiliate transactions, revenue requirements, rate refund.
6/95	U-19904 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
10/95	95-02614	TN	Tennessee Office of the Attorney General Consumer Advocate	BellSouth Telecommunications, Inc.	Affiliate transactions.
10/95	U-21485 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
11/95	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co. Division	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
11/95	U-21485 (Supplemental Direct) 12/95 U-21485 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
1/96	95-299-EL-AIR 95-300-EL-AIR	OH	Industrial Energy Consumers	The Toledo Edison Co. The Cleveland Electric Illuminating Co.	Competition, asset writeoffs and revaluation, O&M expense, other revenue requirement issues.
2/96	PUC No. 14965	TX	Office of Public Utility Counsel	Central Power & Light	Nuclear decommissioning.
5/96	95-485-LCS	NM	City of Las Cruces	El Paso Electric Co.	Stranded cost recovery, municipalization.
7/96	8725	MD	The Maryland Industrial Group and Redland Genstar, Inc.	Baltimore Gas & Electric Co., Potomac Electric Power Co. and Constellation Energy Corp.	Merger savings, tracking mechanism, earnings sharing plan, revenue requirement issues.

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9/96 11/96	U-22092 U-22092 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues, allocation of regulated/nonregulated costs.
10/96	96-327	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental surcharge recoverable costs.
2/97	R-00973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Stranded cost recovery, regulatory assets and liabilities, intangible transition charge, revenue requirements.
3/97	96-489	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental surcharge recoverable costs, system agreements, allowance inventory, jurisdictional allocation.
6/97	TO-97-397	MO	MCI Telecommunications Corp., Inc., MCImetro Access Transmission Services, Inc.	Southwestern Bell Telephone Co.	Pr ce cap regulation, revenue requirements, rate of return.
6/97	R-00973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	R-00973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Depreciation rates and methodologies, River Bend phase-in plan.
8/97	97-300	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. and Kentucky Utilities Co.	Merger policy, cost savings, surcredit sharing mechanism, revenue requirements, rate of return.

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8/97	R-00973954 (Surrebuttal)	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness
10/97	R-974008	PA	Metropolitan Edison Industrial Users Group	Metropolitan Edison Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
10/97	R-974009	PA	Penelec Industrial Customer Alliance	Pennsylvania Electric Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
11/97	97-204 (Rebuttal)	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness of rates, cost allocation.
11/97	U-22491	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
11/97	R-00973953 (Surrebuttal)	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
11/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements, securitization.
11/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.

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12/97	R-973981 (Surrebuttal)	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements.
12/97	R-974104 (Surrebuttal)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
1/98	U-22491 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
2/98	8774	MD	Westvaco	Potomac Edison Co.	Merger of Duquesne, AE, customer safeguards, savings sharing.
3/98	U-22092 (Allocated Stranded Cost Issues)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	8390-U	GA	Georgia Natural Gas Group, Georgia Textile Manufacturers Assoc.	Atlanta Gas Light Co.	Restructuring, unbundling, stranded costs, incentive regulation, revenue requirements.
3/98	U-22092 (Allocated Stranded Cost Issues) (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
10/98	9355-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Affiliate transactions.
10/98	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, other revenue requirement issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/98	U-23327	LA	Louisiana Public Service Commission Staff	SWEPCO, CSW and AEP	Merger policy, savings sharing mechanism, affiliate transaction conditions.
12/98	U-23358 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
12/98	98-577	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
1/99	98-10-07	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, investment tax credits, accumulated deferred income taxes, excess deferred income taxes.
3/99	U-23358 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
3/99	98-474	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements, alternative forms of regulation.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, alternative forms of regulation.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
3/99	99-083	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
4/99	U-23358 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
4/99	99-03-04	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Regulatory assets and liabilities, stranded costs, recovery mechanisms.
4/99	99-02-05	CT	Connecticut Industrial Utility Customers	Connecticut Light and Power Co.	Regulatory assets and liabilities stranded costs, recovery mechanisms.

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Date	Case	Jurisdict.	Party	Utility	Subject
5/99	98-426 99-082 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
5/99	98-474 99-083 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
5/99	98-426 98-474 (Response to Amended Applications)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co. and Kentucky Utilities Co.	Alternative regulation.
6/99	97-596	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Request for accounting order regarding electric industry restructuring costs.
6/99	U-23358	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Affiliate transactions, cost allocations.
7/99	99-03-35	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, regulatory assets, tax effects of asset divestiture.
7/99	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co., Central and South West Corp, and American Electric Power Co.	Merger Settlement and Stipulation.
7/99	97-596 Surrebuttal	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
7/99	98-0452-E-GI	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
8/99	98-577 Surrebuttal	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
8/99	98-426 99-082 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.

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Date	Case	Jurisdict.	Party	Utility	Subject
8/99	98-474 98-083 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
8/99	98-0452-E-GI Rebuttal	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
10/99	U-24182 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
11/99	21527	TX	Dallas-Ft.Worth Hospital Council and Coalition of Independent Colleges and Universities	TXU Electric	Restructuring, stranded costs, taxes, securitization.
11/99	U-23358 Surrebuttal Affiliate Transactions Review	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Service company affiliate transaction costs.
04/00	99-1212-EL-ETP 99-1213-EL-ATA 99-1214-EL-AAM	OH	Greater Cleveland Growth Association	First Energy (Cleveland Electric Illuminating, Toledo Edison)	Historical review, stranded costs, regulatory assets, liabilities.
01/00	U-24182 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
05/00	2000-107	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	ECR surcharge roll-in to base rates.
05/00	U-24182 Supplemental Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate expense proforma adjustments.
05/00	A-110550F0147	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Merger between PECO and Unicom.

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Date	Case	Jurisdict.	Party	Utility	Subject
07/00	22344	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	Statewide Generic Proceeding	Escalation of O&M expenses for unbundled T&D revenue requirements in projected test year.
05/00	99-1658-EL-ETP	OH	AK Steel Corp.	Cincinnati Gas & Electric Co.	Regulatory transition costs, including regulatory assets and liabilities, SFAS 109, ADIT, EDIT, ITC.
07/00	U-21453	LA	Louisiana Public Service Commission	SWEPCO	Stranded costs, regulatory assets and liabilities.
08/00	U-24064	LA	Louisiana Public Service Commission Staff	CLECO	Affiliate transaction pricing ratemaking principles, subsidization of nonregulated affiliates, ratemaking adjustments.
10/00	PUC 22350 SOAH 473-00-1015	TX	The Dallas-Ft. Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU Electric Co.	Restructuring, T&D revenue requirements, mitigation, regulatory assets and liabilities.
10/00	R-00974104 Affidavit	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, capital costs, switchback costs, and excess pension funding.
11/00	P-00001837 R-00974008 P-00001838 R-00974009	PA	Metropolitan Edison Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, regulatory assets and liabilities, transaction costs.
12/00	U-21453, U-20925, U-22092 (Subdocket C) Surrebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Stranded costs, regulatory assets.
01/01	U-24993 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
01/01	U-21453, U-20925, U-22092 (Subdocket B) Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Industry restructuring, business separation plan, organization structure, hold harmless conditions, financing.
01/01	Case No. 2000-386	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Recovery of environmental costs, surcharge mechanism.
01/01	Case No. 2000-439	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Recovery of environmental costs, surcharge mechanism.
02/01	A-110300F0095 A-110400F0040	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance	GPU, Inc. FirstEnergy Corp/	Merger, savings, reliability.
03/01	P-00001860 P-00001861	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co. and Pennsylvania Electric Co.	Recovery of costs due to provider of last resort obligation.
04 /01	U-21453, U-20925, U-22092 (Subdocket B) Settlement Term Sheet	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on overall plan structure.
04 /01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.
05 /01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues Transmission and Distribution Rebuttal	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, Separations methodology.

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Date	Case	Jurisdict.	Party	Utility	Subject
07/01	U-21453, U-20925, U-22092 Subdocket B Transmission and Distribution Term Sheet	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on T&D issues, agreements necessary to implement T&D separations, hold harmless conditions, separations methodology.
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Company	Revenue requirements, Rate Plan, fuel clause recovery.
11/01	14311-U Direct Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
11/01	U-25687 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, capital structure, allocation of regulated and nonregulated costs, River Bend uprate.
02/02	25230	TX	Dallas Ft.-Worth Hospital Council & the Coalition of Independent Colleges & Universities	TXU Electric	Stipulation. Regulatory assets, securitization financing.
02/02	U-25687 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
03/02	14311-U Rebuttal Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, earnings sharing plan, service quality standards.
03/02	14311-U Rebuttal Panel with Michelle L. Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Co.	Revenue requirements. Nuclear life extension, storm damage accruals and reserve, capital structure, O&M expense.
04/02	U-25687 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
04/02	U-21453, U-20925 and U-22092		Louisiana Public Service Commission	SWEPCO	Business separation plan, T&D Term Sheet, separations methodologies, hold harmless

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Date	Case	Jurisdict.	Party	Utility	Subject
	(Subdocket C)		Staff		conditions.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and The Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
08/02	U-25888	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. and Entergy Louisiana, Inc.	System Agreement, production cost disparities, prudence.
09/02	2002-00224 2002-00225	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Line losses and fuel clause recovery associated with off-system sales.
11/02	2002-00146 2002-00147	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Environmental compliance costs and surcharge recovery.
01/03	2002-00169	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Power Co.	Environmental compliance costs and surcharge recovery.
04/03	2002-00429 2002-00430	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co	Extension of merger surcredit, flaws in Companies' studies.
04/03	U-26527	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, Capital structure, post test year Adjustments.
06/03	EL01-88-000 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
06/03	2003-00068	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Environmental cost recovery, correction of base rate error.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Unit power purchases and sale cost-based tariff pursuant to System Agreement.

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11/03	ER03-583-000, ER03-583-001, and ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001, and ER03-682-002 ER03-744-000, ER03-744-001 (Consolidated)	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Market-Ing, L.P, and Entergy Power, Inc.	Unit power purchase and sale agreements, contractual provisions, projected costs, levelized rates, and formula rates.
12/03	U-26527 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, Capital structure, post test year adjustments.
12/03	2003-0334 2003-0335	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Earnings Sharing Mechanism.
12/03	U-27136	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Purchased power contracts between affiliates, terms and conditions.
03/04	U-26527 Supplemental Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post test year adjustments.
03/04	2003-00433	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	SOAH Docket 473-04-2459, PUC Docket	TX	Cities Served by Texas-New Mexico Power Co.	Texas-New Mexico Power Co.	Stranded costs true-up, including including valuation issues, ITC, ADIT, excess earnings.

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05/04	29206 04-169- EL-UNC	OH	Ohio Energy Group, Inc.	Columbus Southern Power Co. & Ohio Power Co.	Rate stabilization plan, deferrals, T&D rate increases, earnings.
06/04	SOAH Docket 473-04-4555 PUC Docket 29526	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Stranded costs true-up, including valuation issues, ITC, EDIT, excess mitigation credits, capacity auction true-up revenues, interest.
08/04	SOAH Docket 473-04-4556 PUC Docket 29526 (Suppl Direct)	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Interest on stranded cost pursuant to Texas Supreme Court remand.
09/04	Docket No. U-23327 Subdocket B	LA	Louisiana Public Service Commission Staff	SWEPCO	Fuel and purchased power expenses recoverable through fuel adjustment clause, trading activities, compliance with terms of various LPSC Orders.
10/04	Docket No. U-23327 Subdocket A	LA	Louisiana Public Service Commission Staff	SWEPCO	Revenue requirements.
12/04	Case No. 2004-00321 Case No. 2004-00372	KY	Gallatin Steel Co.	East Kentucky Power Cooperative, Inc., Big Sandy Recc, etal.	Environmental cost recovery, qualified costs, TIER requirements, cost allocation.
01/05	30485	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric, LLC	Stranded cost true-up including regulatory Central Co. assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
02/05	18638-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements.
02/05	18638-U Panel with Tony Wackerly	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Comprehensive rate plan, pipeline replacement program surcharge, performance based rate plan.
02/05	18638-U Panel with Michelle Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Energy conservation, economic development, and tariff issues.

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03/05	Case No. 2004-00426 Case No. 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric	Environmental cost recovery, Jobs Creation Act of 2004 and § 199 deduction, excess common equity ratio, deferral and amortization of nonrecurring O&M expense.
06/05	2005-00068	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, margins on allowances used for AEP system sales.
06/05	050045-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Co.	Storm damage expense and reserve, RTO costs, O&M expense projections, return on equity performance incentive, capital structure, selective second phase post-test year rate increase.
08/05	31056	TX	Alliance for Valley Healthcare	AEP Texas Central Co.	Stranded cost true-up including regulatory assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
09/05	20298-U	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Revenue requirements, roll-in of surcharges, cost recovery through surcharge, reporting requirements.
09/05	20298-U Panel with Victoria Taylor	GA	Georgia Public. Service Commission Adversary Staff	Atmos Energy Corp.	Affiliate transactions, cost allocations, capitalization, cost of debt.
10/05	04-42	DE	Delaware Public Service Commission Staff	Artesian Water Co.	Allocation of tax net operating losses between regulated and unregulated.
11/05	2005-00351 2005-00352	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co. Louisville Gas and Electric Co.	Workforce Separation Program cost recovery and shared savings through VDT surcredit.
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	System Sales Clause Rider, Environmental Cost Recovery Rider. Net Congestion Rider, Storm damage, vegetation management program, depreciation, off-system sales, maintenance normalization, pension and OPEB.
03/06 05/06	31994 31994 Supplemental	TX	Cities	Texas-New Mexico Power Co.	Stranded cost recovery through competition transition or change. Retrospective ADFIT, prospective ADFIT.

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03/06	U-21453, U-20925, U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.
3/06	NOPR Reg 104385-OR	IRS	Alliance for Valley Health Care and Houston Council for Health Education	AEP Texas Central Company and CenterPioint Energy Houston Electric	Proposed Regulations affecting flow-through to ratepayers of excess deferred income taxes and investment Tax credits on generation plant that Is sold or deregulated.
4/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	2002-2004 Audit of Fuel Adjustment Clause Filings. Affiliate transactions.
07/06	R-00061366, Et. al	PA	Met-Ed Ind. Users Group Pennsylvania Ind. Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Recovery of NUG-related stranded costs, government mandated programs costs, storm damage costs.
07/06	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co.	Revenue requirements, formula rate plan, banking proposal.
08/06	U-21453, U-20925 U-22092 (Subdocket J)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.
11/06	05CVH03-3375 Franklin County Court Affidavit	OH	Various Taxing Authorities (Non-Utility Proceeding)	State of Ohio Department of Revenue	Accounting for nuclear fuel assemblies as manufactured equipment and capitalized plant.
12/06	U-23327 Subdocket A Reply Testimony	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co..	Revenue requirements, formula rate plan, banking proposal.
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc., Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
03/07	33309	TX	Cities	AEP Texas Central Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	33310	TX	Cities	AEP Texas North Co.	Revenue requirements, including functionalization of transmission and distribution costs.

Expert Testimony Appearances
of
Lane Kollen
As of March 2010

Date	Case	Jurisdict.	Party	Utility	Subject
03/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Interim rate increase, RUS loan covenants, credit facility requirements, financial condition.
03/07	U-29157	LA	Louisiana Public Service Commission Staff	Cleco Power, LLC	Permanent (Phase II) storm damage cost recovery.
04/07	U-29764 Supplemental And Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
04/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and state income tax effects on equalization remedy receipts
04/07	ER07-684-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Fuel hedging costs and compliance with FERC USOA.
05/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and account 924 effects on MSS-3 equalization remedy payments and receipts.
06/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, LLC Entergy Gulf States, Inc.	Show cause for violating LPSC Order on fuel hedging costs.
07/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Revenue requirements, post test year adjustments, TIER, surcharge revenues and costs, financial need.
07/07	ER07-956-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Storm damage costs related to Hurricanes Katrina and Rita and effects of MSS-3 equalization payments and receipts.

**Expert Testimony Appearances
of
Lane Kollen
As of March 2010**

Date	Case	Jurisdict.	Party	Utility	Subject
10/07	05-UR-103 Direct	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	05-UR-103 Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	25060-U Direct	GA	Georgia Public Service Commission Public Interest Adversary Staff	Georgia Power Company	Affiliate costs, incentive compensation, consolidated income taxes, §199 deduction.
11/07	06-0033-E-CN Direct	WV	West Virginia Energy Users Group	Appalachian Power Company	IGCC surcharge during construction period and post-in-service date.
11/07	ER07-682-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.
01/08	ER07-682-000 Cross Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Fuctionalization and allocation of intangible and general plant and A&G expenses.
01/08	07-551-EL-AIR Direct	OH	Ohio Energy Group, Inc.	Ohio Edison Company, Cleveland Electric Illuminating Company, Toledo Edison Company	Revenue Requirements.
02/08	ER07-956-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses in account 923; storm damage expense and accounts 924, 228.1, 182.3, 254 and 407.3; tax NOL carrybacks in account 165 and 236; ADIT; nuclear service lives and effect on depreciation and decommissioning.

Expert Testimony Appearances
of
Lane Kollen
As of March 2010

Date	Case	Jurisdict.	Party	Utility	Subject
03/08	ER07-956-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses in account 923; storm damage expense and accounts 924, 228.1, 182 3, 254 and 407.3; tax NOL carrybacks in account 165 and 236; ADIT; nuclear service lives and effect on depreciation and decommissioning.
04/08	2007-00562 2007-00563	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co. Louisville Gas and Electric Co.	Merger surcredit.
04/08	26837 Direct Panel with Thomas K. Bond, Cynthia Johnson, Michelle Thebert	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Rebuttal Panel with Thomas K. Bond, Cynthia Johnson, Michelle Thebert	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Supplemental Rebuttal Panel with Thomas K. Bond, Cynthia Johnson, Michelle Thebert	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
06/08	2008-00115	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Environmental surcharge recoveries, incl costs recovered in existing rates, TIER
07/08	27163 Direct	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Revenue requirements, incl projected test year rate base and expenses.
07/08	27163 Panel with Victoria Taylor	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Affiliate transactions and division cost allocations, capital structure, cost of debt.
08/08	6680-CE-170 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Nelson Dewey 3 or Colombia 3 fixed financial parameters.

Expert Testimony Appearances
of
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As of March 2010

Date	Case	Jurisdict.	Party	Utility	Subject
08/08	6680-UR-116 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	CWIP in rate base, labor expenses, pension expense, financing, capital structure, decoupling.
08/08	6680-UR-116 Rebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Capital structure.
08/08	6690-UR-119 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, incentive compensation, Crane Creek Wind Farm incremental revenue requirement, capital structure.
09/08	6690-UR-119 Surrebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, Section 199 deduction.
09/08	08-935-EL-SSO 08-918-EL-SSO	OH OH	Ohio Energy Group, Inc.	First Energy	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	08-917-EL-SSO	OH	Ohio Energy Group, Inc.	AEP	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	2007-564 2007-565 2008-251 2008-252	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky Utilities Company	Revenue forecast, affiliate costs, depreciation expenses, federal and state income tax expense, capitalization, cost of debt.
11/08	EL08-51	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities, regulatory asset and bandwidth remedy.
11/08	35717	TX	Cities Served by Oncor Delivery Company	Oncor Delivery Company	Recovery of old meter costs, asset ADFIT, cash working capital, recovery of prior year restructuring costs, levelized recovery of storm damage costs, prospective storm damage accrual, consolidated tax savings adjustment.
12/08	27800	GA	Georgia Public Service Commission	Georgia Power Company	AFUDC versus CWIP in rate base, mirror CWIP, certification cost, use of short term debt and trust preferred financing, CWIP recovery, regulatory incentive.
01/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.

Expert Testimony Appearances
of
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As of March 2010

Date	Case	Jurisdict.	Party	Utility	Subject
01/09	ER08-1056 Supplemental Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Blytheville leased turbines; accumulated depreciation.
02/09	EL08-51 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities regulatory asset and bandwidth remedy.
02/09	2008-00409 Direct	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Revenue requirements.
03/09	ER08-1056 Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
03/09	U-21453,U-20925 U-22092 (Subdocket J)		Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
04/09	U-21453, U-20925 U-22092 (Subdocket J) Rebuttal		Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
04/09	2009-00040 Direct-Interim (Oral)	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Emergency interim rate increase; cash requirements.
04/09	36530	TX	State Office of Administrative Hearings	Oncor Electric Delivery Company, LLC	Rate case expenses.
05/09	ER08-1056 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
06/09	2009-00040 Direct-Permanent	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Revenue requirements, TIER, cash flow.
07/09	080677-EI	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Multiple test years, GBRA rider, forecast assumptions, revenue requirement, O&M expense, depreciation expense, Economic Stimulus Bill, capital structure.
08/09	U-21453, U-20925 U-22092 (Subdocket J) Supplemental Rebuttal		Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.

**Expert Testimony Appearances
of
Lane Kollen
As of March 2010**

Date	Case	Jurisdict.	Party	Utility	Subject
08/09	8516 and 29950	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Modification of PRP surcharge to include infrastructure costs.
09/09	05-UR-104 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company	Revenue requirements, incentive compensation, depreciation, deferral mitigation, capital structure, cost of debt.
09/09	09AL-299E	CO	CF&I Steel, Rocky Mountain Steel Mills LP, Climax Molybdenum Company	Public Service Company of Colorado	Forecasted test year, historic test year, proforma adjustments for major plant additions, tax depreciation.
09/09	6680-UR-117 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Power and Light Company	Revenue requirements, CWIP in rate base, deferral mitigation, payroll, capacity shutdowns, regulatory assets, rate of return.
10/09	09A-415E	CO	Cripple Creek & Victor Gold Mining Company, et al.	Black Hills/CO Electric Utility Company	Cost prudence, cost sharing mechanism.
10/09	EL09-50 Direct	LA	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.
10/09	2009-00329	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Trimble County 2 depreciation rates.
12/09	PUE-2009-00030	VA	Old Dominion Committee for Fair Utility Rates	Appalachian Power Company	Return on equity incentive.
12/09	ER09-1224 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical v. actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
01/10	ER09-1224 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical v. actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
01/10	EL09-50 Rebuttal	LA	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.
02/10	ER09-1224 Final	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical v. actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.

Expert Testimony Appearances
of
Lane Kollen
As of March 2010

Date	Case	Jurisdict.	Party	Utility	Subject
02/10	30442 Wackerly-Kollen Panel	GA	Georgia Public Service Commission Staff	Atmos Energy Corporation	Revenue Requirement issues.
02/10	30442 McBride-Kollen Panel	GA	Georgia Public Service Commission Staff	Atmos Energy Corporation	Affiliate/division transactions, cost allocation, capital structure.
02/10	2009-00353	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Ratemaking recovery of wind power purchased power agreements.
03/10	2009-00545	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Ratemaking recovery of wind power purchased power agreement.
03/10	E015/GR-09-1151	MN	Large Power Interveners	Minnesota Power	Revenue requirement issues, cost overruns on environmental retrofit project.

EXHIBIT ____ (LK-2)

Kentucky Power Company

REQUEST

Refer to page 2 of the Company's response to Staff 1-29.

a. Please describe the plant additions to account 312 in the test year.

b. Please describe the plant additions to account 314 in the test year.

c. Please describe the plant additions to account 362 in the test year. Please quantify the plant additions and retirements due to storm events during the test year.

d. Please describe the plant additions to account 364 in the test year. Please quantify the plant additions and retirements due to storm events during the test year.

e. Please describe the plant additions to account 365 in the test year. Please quantify the plant additions and retirements due to storm events during the test year.

f. Please describe the plant additions to account 368 in the test year. Please quantify the plant additions and retirements due to storm events during the test year.

g. Please describe the plant additions to account 369 in the test year. Please quantify the plant additions and retirements due to storm events during the test year.

RESPONSE

See pages 2-4 of this response for a description of the plant additions.

The Company does not maintain the detail of plant additions and retirements associated with storm events separately from other plant additions and retirements. The Company follows the FERC Uniform System of Accounts (USA). The USA does not require KPCo to keeps its accounting records in this level of detail and KPCo has not kept its records in that level of detail.

WITNESS: Ranie K Wohnhas

Kentucky Power Company
Description of Plant Additions
For the Test Year October 1, 2008 Through September 30, 2009

Line No.	Funding Proj No.	Description	Amount
		31200 - Boiler Plant Equipment	
1	X00000002	WS-CI-KEPCo-G PPB	$5,622,846.74
2	000012426	Repl SSH Outlet T91 tubes	$5,493,121.48
3	BSU1CI002	Replace lower furnace U1	$4,603,672.04
4	BSU1CI001	Repl Secondary SH inlet U1	$2,400,286.58
5	BSU1CI006	Air Heater Basket Repl U1	$1,167,668.31
6	000013508	AOD & SCR Year Round Oper Rev	$912,976.93
7	BSU2CI013	BS2 Lwr Furnace Sidewall Rpl	($1,953.73)
8	BSPPBS235	South MainTurb Oil Cooler U2	($4,047.21)
9		Total Boiler Plant Equipment	$20,194,571.14
		31400 - Turbogenerator Units	
10	000012376	Big Sandy Unit 1 Turbine Retrofit	$33,809,312.29
11	X00000002	WS-CI-KEPCo-G PPB	$563,529.24
12		Total Turbogenerator Units	$34,372,841.53
		36200 - Station Equipment	
13	DP7KY014B	KY/Hitchins Rebuild Station	$2,944,308.81
14	DP7KY006B	KY/Soft Shell Sta 138-34kV	$2,403,806.33
15	DP7KY015B	KY/Busseyville Sta Add 2nd Xfm	$2,035,088.95
16	000012012	KYP-2006-2007 Relay Rehab Projects	$1,012,563.73
17	X00000646	ET-CI-KyPCo-T Drvn D Asset Imp	$491,194.23
18	000015593	DS/KYP/Metering Upgrade KY	$302,186.95
19	000013935	DS/KYPCO/Purchase-Rebuild Eq	$291,331.00
20	DP7KY121B	KY/Princess Station D20	$152,018.13
21	000016691	DS/KY/Replace&Refurbish	$136,103.80
22	X00000051	ED-CI-KEPCo-D AST IMP	$201.04
23	000011949	Circuit Breaker Rehab Program-KYP	($0.11)
24		Total Station Equipment	$9,768,802.86

Kentucky Power Company
Description of Plant Additions
For the Test Year October 1, 2008 Through September 30, 2009

Line No.	Funding Proj No.	Description	Amount
		36400 - Poles, Towers and Fixtures	
1	X00000073	ED-CI-KEPCo-D CUST SERV	$3,242,574.06
2	X00000692	KyPCo-D Service Restoration BI	$1,745,539.25
3	X00000051	ED-CI-KEPCo-D AST IMP	$1,564,178.09
4	EDN014680	Ds-Kp-Ai Pole Replacement	$794,229.48
5	DP7KY121A	KY/Cannonsburg Distr Auto	$648,370.99
6	X00000716	KyPCo-D Third Party Work Blkt	$541,845.81
7	DP7KY006A	KY/Soft Schell Sta 34kV Fdrs	$509,124.11
8	DP7KY112A	KP/Beaver Ck Svc Black Diamond	$483,708.53
9	DP7KY103E	KY/Busseyville Sta Torchlight	$183,111.97
10	DP7KY015A	KY/Busseyville Sta Feeders	$159,893.08
11	DP7KY014A	KY/Hitchins Sta Relocate Fdrs	$102,731.52
12	DP7KY005A	KP/Salisbury Sta Feeder Impr	$38,627.36
13	DP8KY014A	KY/Collier Sta 34kV to Equitab	$19,617.17
14	EDN014720	Ds-Kp-Ai Recloser Replacement	$2,801.21
15	X00000704	KyPCo-D Small Cap Adds Blkt	$2,666.12
16	DR6CH068A	KY/Elwood Sta - Dorton Fdr Imp	$1,066.90
17	DP7KY103A	KY/Busseyville Sta Louisa Fdr	$742.72
18	DP7KY002A	KY/Beaver Creek Ligon Fdr	$0.02
19	X00000095	ED-CI-KEPCo-D PPR	($241,233.75)
20		Total Poles, Towers and Fixtures	$9,799,594.64
		36500 - Overhead Conductors and Devices	
21	000009160	KP/2004-2006 R/W Widening	$3,943,808.68
22	X00000073	ED-CI-KEPCo-D CUST SERV	$2,361,019.27
23	X00000692	KyPCo-D Service Restoration BI	$2,250,630.16
24	EDN014720	Ds-Kp-Ai Recloser Replacement	$1,863,145.41
25	X00000051	ED-CI-KEPCo-D AST IMP	$1,513,624.37
26	X00000716	KyPCo-D Third Party Work Blkt	$789,524.50
27	DP7KY006A	KY/Soft Schell Sta 34kV Fdrs	$702,396.53
28	000016528	KY/Cutout-Arrester 2008-9	$375,528.89
30	DP7KY112A	KP/Beaver Ck Svc Black Diamond	$360,074.50
31	DP7KY103E	KY/Busseyville Sta Torchlight	$288,121.02
32	EDN014680	Ds-Kp-Ai Pole Replacement	$252,983.77
33	DP7KY015A	KY/Busseyville Sta Feeders	$169,360.50
34	DP7KY014A	KY/Hitchins Sta Relocate Fdrs	$156,961.91
35	DP7KY121A	KY/Cannonsburg Distr Auto	$138,121.06
36	DP7KY005A	KP/Salisbury Sta Feeder Impr	$68,301.12
37	DP8KY014A	KY/Collier Sta 34kV to Equitab	$13,771.00
38	X00000704	KyPCo-D Small Cap Adds Blkt	$4,004.12
39	DP7KY002A	KY/Beaver Creek Ligon Fdr	($0.02)
40	DP7KY103A	KY/Busseyville Sta Louisa Fdr	($794.04)
41	DR6CH068A	KY/Elwood Sta - Dorton Fdr Imp	($1,516.65)
42	X00000095	ED-CI-KEPCo-D PPR	($207,511.32)
43		Total Overhead Conductors and Devices	$15,041,554.78

Kentucky Power Company
Description of Plant Additions
For the Test Year October 1, 2008 Through September 30, 2009

Line No.	Funding Proj No.	Description	Amount
		36800 - Line Transformers	
1	X00000084	ED-CI-KEPCo-D LN TRNSF	$3,416,114.54
2	X00000051	ED-CI-KEPCo-D AST IMP	$594,198.01
3	X00000692	KyPCo-D Service Restoration Bl	$589,550.85
4	X00000073	ED-CI-KEPCo-D CUST SERV	$552,198.29
5	000016528	KY/Cutout-Arrester 2008-9	$488,320.94
6	DP7KY121A	KY/Cannonsburg Distr Auto	$180,541.06
7	DP7KY112A	KP/Beaver Ck Svc Black Diamond	$147,197.08
8	DP7KY103E	KY/Busseyville Sta Torchlight	$131,093.20
9	DP8KY014A	KY/Collier Sta 34kV to Equitab	$112,094.35
10	X00000716	KyPCo-D Third Party Work Blkt	$73,418.44
11	EDN014680	Ds-Kp-Ai Pole Replacement	$51,634.13
12	DP7KY006A	KY/Soft Schell Sta 34kV Fdrs	$28,273.89
13	X00000704	KyPCo-D Small Cap Adds Blkt	$24,303.29
14	DP7KY014A	KY/Hitchins Sta Relocate Fdrs	$2,960.44
15	EDN014720	Ds-Kp-Ai Recloser Replacement	$1,953.56
16	DP7KY015A	KY/Busseyville Sta Feeders	$1,832.74
17	DP7KY005A	KP/Salisbury Sta Feeder Impr	$696.15
18	DR6CH068A	KY/Elwood Sta - Dorton Fdr Imp	$537.64
19	DP7KY103A	KY/Busseyville Sta Louisa Fdr	($1.81)
20	X00000095	ED-CI-KEPCo-D PPR	($8,094.10)
21		Total Line Transformers	$6,388,822.69
		36900 - Services	
22	X00000073	ED-CI-KEPCo-D CUST SERV	$2,643,440.23
23	X00000692	KyPCo-D Service Restoration Bl	$953,116.19
24	X00000051	ED-CI-KEPCo-D AST IMP	$75,951.90
25	X00000716	KyPCo-D Third Party Work Blkt	$23,961.77
26	EDN014680	Ds-Kp-Ai Pole Replacement	$9,041.97
27	DP7KY112A	KP/Beaver Ck Svc Black Diamond	$2,062.51
28	DP7KY006A	KY/Soft Schell Sta 34kV Fdrs	$1,876.12
29	X00000095	ED-CI-KEPCo-D PPR	$894.85
30	DR6CH068A	KY/Elwood Sta - Dorton Fdr Imp	$706.54
31	DP7KY014A	KY/Hitchins Sta Relocate Fdrs	$247.24
32		Total Services	$3,711,299.32

EXHIBIT ____ (LK-3)

Kentucky Power Company

REQUEST

Refer to the Company's response to KIUC 1-75 for account 314.

a. Please describe in detail the Big Sandy Unit 1 turbine retrofit, including, but not limited to, the scope of work performed and the start and completion dates.

b. Please describe in detail any resulting increases in output as a result of the turbine retrofit and quantify any increases in mW capacity and in energy output on an annualized basis.

c. Please provide the fuel expense on a per mWh basis for all energy produced by Big Sandy 1 and by Big Sandy 2 during the test year.

d. Please provide the non-fuel incremental variable expense on a per mWh basis for all energy produced by Big Sandy 1 and by Big Sandy 2 during the test year.

e. Please provide the capacity factor, capacity in mW, and energy generation (mWh) for each month at Big Sandy 1 and at Big Sandy 2 from January 2004 through January 2010.

RESPONSE

a. The HP(high pressure) turbine rotor, inner and outer shell, throttle and governor valves were replaced. The IP/SFLP (intermediate pressure/single flow low pressure all on one rotor) rotor and inner shell also were replaced. The high pressure oil control system was replaced with a electro hydraulic control system run by Ovation (computer control). This work started in June 2009 while the Unit was still running and was completed in late December 2009. The fall outage was from September 19, 2009 and returned to service on December 13, 2009.

b. Improvements at Big Sandy Unit 1 have increased summer and winter ratings of the unit by 13 MW and 18 MW respectively, consistent with NERC region reporting. For AEP Interconnection Agreement ("East Pool") capacity settlements, Big Sandy Unit 1 was increased by 17 MW. In addition, for a given capacity factor, the unit will produce approximately 5% to 7% more energy. The first actual AEP Interconnection Agreement ("East Pool") capacity settlement statement reflecting this change will be the February 2010 Actual which will be available the first week in April 2010. The Company is obligated to provide this information when available pursuant to the Staff 1st Set Item No. 43.

c. On a per MWh basis, the fuel expense for Big Sandy 1 and 2 during the test year was $29.85/MWh.

d. On a per MWh basis, the non-fuel (variable O&M) expense for Big Sandy 1 and 2 during the test year was $4.67/MWh.

e. Please refer to the attached pages for the Monthly Capacity Factor (%), Capability (MW), and Generation (MWh) for Big Sandy 1 and Big Sandy 2 from January 2004-January 2010.

WITNESS: Errol K Wagner

KENTUCKY POWER COMPANY
BIG SANDY PLANT
ACTUAL UNIT PERFORMANCE - CAPACITY FACTOR
(Percent %)

DP925

NIT		Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	YTD
G SANDY 1	260	90.87	94.35	81.72	33.25	79.23	46.86	60.96	40.83	34.96	39.74	73.34	59.94	61.31
G SANDY 2	800	90.27	94.31	39.42	90.50	79.45	77.76	79.60	82.16	75.76	58.56	42.44	70.39	73.29

NIT		Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	YTD
IG SANDY 1	260	65.50	79.32	73.29	70.46	-	56.06	77.84	79.78	76.18	77.65	79.39	78.47	67.71
IG SANDY 2	800	64.61	90.40	92.22	81.47	84.25	84.30	86.04	77.72	85.16	86.23	72.65	89.18	82.81

NIT		Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	YTD
IG SANDY 1	260	77.63	75.51	82.45	82.08	77.69	73.30	82.03	76.15	62.96	64.91	83.98	77.53	76.37
IG SANDY 2	800	84.55	90.12	87.05	63.47	18.85	83.39	82.05	79.79	84.76	89.54	86.54	81.50	77.51

INIT		Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	YTD
IG SANDY 1	260	80.78	92.03	84.26	31.89	64.50	78.29	53.94	89.97	78.24	88.87	87.06	67.41	74.69
IG SANDY 2	800	85.34	75.86	90.41	83.04	51.45	83.14	87.26	94.39	86.74	78.56	89.59	92.44	83.22

JNIT		Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	YTD
3IG SANDY 1	260	83.45	83.92	89.50	85.68	58.48	69.95	67.02	66.48	38.48	-	-	17.94	54.99
3IG SANDY 2	800	93.45	63.32	96.61	76.53	-	48.76	80.76	55.68	85.61	72.70	66.68	73.55	67.81

JNIT		Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	YTD
BIG SANDY 1	260	53.10	54.86	66.19	66.42	61.14	44.92	38.46	51.28	44.93	60.58	69.21	93.18	58.75
BIG SANDY 2	800	88.32	81.72	81.34	81.40	50.64	72.54	41.98	74.40	43.70	75.18	80.28	72.69	70.26

UNIT		Jan-10
BIG SANDY 1	260	92.85
BIG SANDY 2	800	91.93

KENTUCKY POWER COMPANY
BIG SANDY PLANT
ACTUAL UNIT PERFORMANCE - CAPABILITY
(MW)

DP925

IIT	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04
3 SANDY 1	260	260	260	260	260	260	260	260	260	260	260	260
G SANDY 2	800	800	800	800	800	800	800	800	800	800	800	800

NIT	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
G SANDY 1	260	260	260	260	260	260	260	260	260	260	260	260
G SANDY 2	800	800	800	800	800	800	800	800	800	800	800	800

NIT	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06
IG SANDY 1	260	260	260	260	260	260	260	260	260	260	260	260
IG SANDY 2	800	800	800	800	800	800	800	800	800	800	800	800

INIT	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07
IG SANDY 1	260	260	260	260	260	260	260	260	260	260	260	260
IG SANDY 2	800	800	800	800	800	800	800	800	800	800	800	800

JNIT	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08
3IG SANDY 1	260	260	260	260	260	260	260	260	260	260	260	260
3IG SANDY 2	800	800	800	800	800	800	800	800	800	800	800	800

JNIT	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09
3IG SANDY 1	260	260	260	260	260	260	260	260	260	260	260	260
3IG SANDY 2	800	800	800	800	800	800	800	800	800	800	800	800

UNIT	Jan-10
BIG SANDY 1	260
BIG SANDY 2	800

KENTUCKY POWER COMPANY
BIG SANDY PLANT
ACTUAL UNIT PERFORMANCE - GENERATION
(MWh)

OP925

IT	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Annual
; SANDY 1	175,782	170,741	158,080	62,242	153,269	87,727	117,925	78,985	65,444	76,866	137,290	115,941	**1,400,292**
; SANDY 2	537,316	525,128	234,654	521,258	472,892	447,882	473,776	488,989	436,366	348,545	244,457	418,954	**5,150,217**

IT	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Annual
; SANDY 1	126,702	138,593	141,767	131,723	-	104,935	150,577	154,323	142,612	150,402	148,620	151,800	**1,542,054**
; SANDY 2	384,586	486,001	548,911	468,595	501,448	485,559	512,127	462,613	490,531	513,949	418,454	530,796	**5,803,570**

IT	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Annual
3 SANDY 1	150,158	131,936	159,487	153,448	150,293	137,209	158,677	147,303	117,856	125,739	157,211	149,979	**1,739,296**
3 SANDY 2	503,261	484,491	518,144	365,098	112,167	480,335	488,359	474,925	488,213	533,649	498,465	485,102	**5,432,209**

IIT	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Annual
3 SANDY 1	156,266	160,798	162,989	59,707	124,776	146,562	104,340	174,046	146,465	171,902	162,975	130,399	**1,701,225**
3 SANDY 2	507,964	407,839	538,137	478,283	306,256	478,858	519,370	561,837	499,616	467,565	516,063	550,210	**5,831,998**

IIT	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Annual
G SANDY 1	161,431	151,859	173,134	160,399	113,120	130,955	129,650	128,607	72,026	-	-	34,708	**1,255,889**
G SANDY 2	556,200	352,571	575,023	440,803	-	280,830	480,711	331,425	493,127	432,728	384,078	437,797	**4,765,293**

NIT	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Annual
G SANDY 1	102,724	95,847	128,036	124,339	118,262	84,097	74,395	99,198	84,108	117,185	129,559	180,255	**1,338,005**
G SANDY 2	525,683	439,341	484,158	468,866	301,385	417,830	249,854	442,809	251,717	447,477	462,416	432,624	**4,924,160**

NIT	Jan-10
G SANDY 1	179,611
IG SANDY 2	547,150

EXHIBIT ____ (LK-4)

Kentucky Power Company

REQUEST

Provide the dollar amounts the company has earned in off-system sales for each of the past five (5) years.

a. Provide any and all analyses the company has conducted regarding forecasts for off-system sales in dollar amounts for the next five (5) years.

RESPONSE

Page 2 of this response provides the dollar amount the company has earned in off-system sales for each of the past five (5) years.

a. The off-system sales forecast for 2010-2013 is shown on Page 3 of this response. At this time we have not conducted forecasts beyond 2013.

WITNESS: Errol K Wagner

Kentucky Power Company
Off System Sales Margins
Years 2005 to 2009

Month	Year 2009	Year 2008	Year 2007	Year 2006	Year 2005
January	1,559,042	5,144,466	3,936,280	4,187,099	3,674,868
February	1,405,018	4,273,413	2,911,080	4,049,188	1,840,112
March	1,328,862	3,075,288	4,277,970	4,437,747	(389,264)
April	797,692	3,283,321	3,765,051	3,357,274	3,333,982
May	646,768	3,636,818	2,954,780	3,104,186	3,622,195
June	2,162,000	5,385,019	5,653,449	4,994,179	3,151,393
July	1,858,472	7,763,492	6,014,017	7,227,394	2,571,386
August	1,753,385	6,557,531	5,448,132	6,462,817	2,163,651
September	1,566,609	3,697,501	5,647,635	3,011,963	2,755,486
October	1,471,103	1,602,812	3,631,657	3,269,198	2,355,770
November	1,272,675	563,591	4,111,374	2,516,000	2,559,653
December	1,301,625	369,904	2,933,668	3,274,713	5,525
Total	17,123,251	45,353,156	51,285,093	49,891,758	27,644,757

Kentucky Power Company
Off System Sales
Years 2010 to 2013
($000)

Month	Year 2010	Year 2011	Year 2012	Year 2013
January	1,882	2,352	3,995	5,745
February	2,015	1,829	3,302	4,926
March	1,682	2,634	2,612	4,355
April	1,796	2,715	3,231	3,620
May	1,420	2,089	2,969	4,100
June	3,004	2,953	4,228	6,962
July	3,985	4,208	5,572	8,884
August	4,497	5,179	6,588	10,341
September	2,040	2,432	3,096	6,955
October	1,257	727	2,077	4,412
November	1,608	802	2,296	4,960
December	1,610	1,574	3,671	5,342
Total	26,796	29,494	43,637	70,602

EXHIBIT ____ (LK-5)

Kentucky Power Company

REQUEST

Refer to page 17 line 20 to page 18 line 7 of Mr. Myers' Direct Testimony wherein he provides a list of the AEPSC technology investments and staffing requirements necessary for AEPSC to engage in trading and other activities that generate OSS margins. Please confirm that AEPSC costs to engage in OSS, including investment costs and the operating expenses such as salaries and benefits, are allocated entirely to KPCo and the other AEP utilities and none of these costs are retained by AEPSC.

RESPONSE

AEPSC does not retain any of the costs related to the activities that generate OSS margins. All AEPSC costs are allocated to the AEP operating companies, including KPCo.

WITNESS: Thomas M. Myers

EXHIBIT ____ (LK-6)

Kentucky Power Company

REQUEST

Refer to page 10 line 21 of Mr. Everett Phillips' Direct Testimony and the claim of "increasing customer expectations." Is this a general observation that customers always want better customer service or reliability or is there some specific evidence that Mr. Phillips relies on that customers are demanding better customer service or reliability? If the latter, then please identify all such evidence that customers are demanding better customer service or reliability that Mr. Phillips relied on for this statement.

RESPONSE

The results provided in testimony are the result of one question included in the surveys conducted with 200 residential and 200 commercial customers by third-party vendor MSI in 2008. In addition, please refer to the response to Staff 2nd Set Item No. 45 for the 2008 MSI survey report.

WITNESS: Everett G Phillips

EXHIBIT ____ (LK-7)

Kentucky Power Company

REQUEST

Refer to the Company's response to AG 1-32. Please describe and identify the baseline and metrics proposed by the Company to measure "the cost effectiveness" of the Company's Enhanced Vegetation Management Initiative. Please do not cite reliability indices or customer satisfaction unless the Company can convert these reliability and satisfaction metrics into "cost effectiveness" metrics.

RESPONSE

The baseline metrics to measure the cost-effectiveness of vegetation management spending include measures of the tree crews' productivity such as trees trimmed or removed, the amount of brush cut and the line miles cleared in a given period of time.

These metrics, however, do not address the effectiveness or the cost-effectiveness of the vegetation management program for which these activities are undertaken. To properly evaluate the effectiveness of a vegetation management program, one must look at tree-caused outages and how they affect both reliability indices such as SAIFI and SAIDI as well as customer satisfaction. This explains the Company's opening statement in its response to AG 1-32.

WITNESS: Everett G Phillips

EXHIBIT ____ (LK-8)

Kentucky Power Company

REQUEST

Refer to the Company's response to Staff 1-12, page 7 of 19.

a. Please explain all reasons why FERC Account 593, Maintenance of Overhead Lines, increased by $13.411 million for the 12 months ended September 30, 2009 compared to the 12 months ended September 30, 2008.

b. Please provide the annual amounts booked to FERC Account 593, Maintenance of Overhead Lines for each calendar year from 2004 through 2008 and each 12 months ended September 30, 2004 through 2008.

c. Please indicate whether the Company included a proforma adjustment in its filing to normalize costs booked during the test year to FERC Account 593, Maintenance of Overhead Lines. If so, identify the proforma adjustment in the filing. If not, explain in detail why the Company did not include a proforma adjustment for this purpose.

d. Please indicate whether the Company considers the increase of $13.411 million in FERC Account 593 a recurring level of expense. If so, please explain in detail why this amount or some subset of this amount is recurring.

RESPONSE

a. Other than the normal day to day activities of maintaining overhead lines, the increase of $13.411 million in FERC account 593, Maintenance of Overhead Lines from the 12 months ended September 30, 2008 to the 12 months ended September 30, 2009 is primarily due to significant storm restoration expenses related to severe storms in January 2009, February 2009 and May 2009.

b. The annual amounts booked to FERC Account 593, Maintenance of Overhead Lines for each calendar year from 2004 through 2008 and each 12 months ended September 30, 2004 through 2008 are as follows:

Calendar Year Ended:	Amount
2004	$ 13,965,041.89
2005	11,851,456.39
2006	14,024,573.23
2007	14,372,082.91
2008	15,612,653.87

12 Months Ended September 30:	Amount
2004	$ 13,282,201.40
2005	12,062,182.15
2006	14,052,195.08
2007	14,138,828.44
2008	16,003,896.72

c. Yes. Please see Section V, Workpaper S-4, Page 15 of the filing. In responding to this data request we discovered an error in the original filing. We inadvertently inserted the current storm amount in base rates in column 3, line 1 versus the actual amount for the 12 month ended period 9/30/09 of $12,423,094 . Please see page 2 of this response for a corrected Section V, Workpaper S-4, Page 15.

d. The Company believes that some portion of the increase to FERC Account 593 is a recurring level of expense as shown by a three year average on Line 5 of the corrected Section V, Workpaper S-4, Page 15 attached as page 3 of this response.

WITNESS: Ranie K Wohnhas

Kentucky Power Company
Normalization of Major Storms Adjustment
Test Year Twelve Months Ended 9/30/2009

Section V
Workpaper S-4
Page 15
Revised 2/12/10

Ln No (1)	Description (2)	Storm Damage Expense Excl. In-House Labor (3)	Constant Dollar Index [1/] (4)	Expense in 2009 Dollars (5)
1	12 ME September 30, 2009	$12,423,094	1.00	$12,423,094
2	12 ME September 30, 2008	$51,497	1.03	$53,042
3	12 ME September 30, 2007	$461,822	1.18	$544,950
4	Three Year Total Storm Damage			$13,021,086
5	Three Year Average (Ln 4/ Ln 3)			$4,340,362
6	Test Year Storm Damage Expense			$12,423,094
7	Adjustment to O&M for Storm Damage Normalization			($8,082,732)
8	Allocation Factor - GP-TOT			0.991
9	KPSC Jurisdictional Amount (Ln 7 X Ln 8)			($8,009,987)

[1/] Handy-Whittman Contract Labor Index
Reference E-2 Line 42

January, 2009	535
January, 2008	518
January, 2007	453

Witness: R. K. Wohnhas

EXHIBIT ____ (LK-9)

Kentucky Power Company

REQUEST

For each incentive compensation plan, please provide the test year expense amount incurred through charges to the Company from AEPSC and incurred directly by the Company for its employees.

RESPONSE

A breakdown of test year incentive amounts by each incentive compensation plan broken down between those charges from AEPSC and directly incurred by Kentucky Power employees is as follows:

Incentive Compensation Plan	Kentucky Power Employees	From AEPSC(a)
Kentucky Power Company	$ 1,142,899	$ 0
Generation	$ 844,526	$ 306,575
Transmission	$ 147,174	$ 276,221
Shared Services	$ 109,826	$ 229,970
Customer & Distribution Services	$ 0	$ 347,375
Long Term Incentive	($ 85,422)	$ 8,157
Sr. Officer	$ 0	$ 117,361(a)
Finance	$ 0	$ 0(a)
Environmental, Safety, Health & Facilities	$ 18,636	$ 0(a)
Corporate Communications	$ 0	$ 0(a)
Corporate	$ 0	$ 475,926
Commercial Operations	$ 0	$ 384,039
Total	$ 2,177,639	$ 2,145,624

(a) Test year AEPSC incentive compensation is funded through monthly accruals which record expense, and offsetting liabilities, based upon monthly estimates of the year end incentive targets. The accrued expense is recorded as a loading on employee labor and is not necessarily segregated by each available plan, but rather is segregated by AEPSC department. The Sr. Officer, Finance, Environmental and Corporate Communication plans are all combined in the monthly accruals.

In responding to this request the Company discovered an error of Exhibit RKW-1 of the Direct Testimony of Ranie K. Wohnhas. The sign was incorrect on the test year incentive amount of KPCo employees under LTIP. A corrected Exhibit RKW-1 is attached as page 3 of this response.

WITNESS: Ranie K Wohnhas

Exhibit RKW-1
Revised 2/12/10

Kentucky Power Company
Summary of ICP/LTIP Adjustment to 1.0 Target Payout
Test Year 12ME 9/30/2009

Type of Incentive	Calculated Incentive @ 1.0 Payout	Test Year Incentive	Adjustment
ICP			
KPCo Employees	$ 2,658,577	$ 2,263,061	$ 395,516
AEPSC Employees	$ 2,992,070	$ 2,137,467	$ 854,603
Total ICP	$ 5,650,647	$ 4,400,528	$ 1,250,119
LTIP			
KPCo Employees	$ 206,705	$ (85,422)	$ 292,127
AEPSC Employees	$ 784,153	$ 8,157	$ 775,996
Total LTIP	$ 990,858	$ (77,265)	$ 1,068,123
Total ICP/LTIP	$ 6,641,505	$ 4,323,263	$ 2,318,242

EXHIBIT ____ (LK-10)

Kentucky Power Company

REQUEST

Refer to page 34 of the Wagner Testimony and Section V, Workpaper S-4, page 8.

Explain why an adjustment to include this below-the-line item in the company's cost of service is appropriate.

RESPONSE

The interest income recorded in Account 4190005 is a direct result of the interest earned as a result of the Company being in a "cash long position" from the Kentucky operations. Therefore, the ratepayers should receive the benefit of this interest income.

The interest expense recorded in Account 4300003 should not have been included in this adjustment due to the fact that the interest expense amount of $1,923,535 was also included in the $2,056,695 reflected on Section V, Workpaper S-3, Page 2 of 3, Line Number 16.

WITNESS: Errol K Wagner

EXHIBIT ____ (LK-11)

Exhibit 1
Reference Schedule 1.44
Sponsoring Witness: Miller

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustment for Domestic Production Activities Deduction
For the Twelve Months Ended October 31, 2009

	Electric
1. Test year federal taxable income	$ 92,877,360
2. Percent of production assets to total	51.7%
3. Qualified Production Activities income (Line 1 x Line 2)	$ 48,017,595
4. Production Activities Deduction rate (effective January 1, 2010)	9.0%
5. Production Activities Deduction (Line 3 x Line 4)	$ 4,321,584
6. Production Activities Deduction in test year	1,083,365
7. Adjustment for Production Activities Deduction (Line 5 - Line 6)	$ 3,238,219
8. Statutory tax rate	38.9%
9. Production Activities Deduction tax amount (line 7 x Line 8)	$ 1,259,667
10. Production Activities Deduction tax adjustment	$ (1,259,667)

EXHIBIT ____ (LK-12)

Kentucky Power Company Revenue Requirement
KIUC Recommendation to Reflect Section 199 Domestic Production Activities Deduction
Case No. 2009-00459
For the Test Year Ended September 30, 2009
($ Millions)

Line		
1	Test Year Federal Taxable Income	68.804
2	Percent of Production Assets to Total	34.3%
3	Qualified Production Activities Income (Line 1 x Line 2)	23.613
4	Production Activities Deduction Rate	9.0%
5	Production Activities Deduction (Line 3 x Line 4)	2.125
6	Production Activities Deduction in Test Year	-
7	Adjustment for Production Activities Deduction (Line 5 - Line 6)	2.125
8	Statutory Tax Rate	39.05%
9	Production Activities Deduction Tax Amount (Line 7 x Line 8)	0.830
10	Production Activities Deduction Tax Adjustment	(0.830)
11	Revenue Requirement for Production Activities Deduction Tax Adjustment (Line 10/(1-Line 8)	(1.362)

EXHIBIT ____ (LK-13)

Kentucky Power Company

Monthly Period	Account No. 4190005 Interest Income		Account No. 4300003 Interest Expense	
Sep-09	$	3,119	$	72
Aug-09	$	3,790	$	122
Jul-09	$	114	$	2,388
Jun-09	$	11,419	$	82,885
May-09	$	-	$	125,170
Apr-09	$	812	$	160,794
Mar-09	$	1,069	$	190,364
Feb-09	$	396	$	202,299
Jan-09	$	-	$	222,000
Dec-08	$	-	$	352,811
Nov-08	$	2,133	$	314,549
Oct-08	$	-	$	270,082
Sep-08	$	-	$	168,841

Note: The source for Account Nos. 4190005 and 4300003 is the Utility Money Pool.

EXHIBIT ____ (LK-14)

Kentucky Power Company

REQUEST

Refer to Section V Schedule 3 and Section V Workpaper S-3 page 2 of 3.

a. Please explain why the Company used the September 30, 2009 balance of short term debt and did not use the 13 month average of short term debt on Schedule 3 that it computed on Workpaper S-3. Cite all precedent and/or other authorities relied on for this position.

b. Please provide the Company's balance of short term debt for each month subsequent to September 2009 by type of such debt, e.g., AEP Utility Money Pool, bank borrowings or credit facilities.

c. Please confirm that the Company's financing plans include short term debt.

d. Please provide a copy of the Company's operating and capital budgets, and the resulting budgeted financial statements for calendar year 2010. Provide all assumptions, data, computations and electronic spreadsheets with formulas intact. In addition, provide a copy of all narratives that accompanied such budgets, including presentations to the Company's Board of Directors and/or the AEP Board of Directors.

RESPONSE

a. In case numbers 8429, 8734, 91-066 and 2005-00341 KPCo consistently used the short term debt value at the end of the test year for capitalization purposes . The 13 month average short term debt value on Schedule 3 was computed for the purpose of calculating the average short term debt interest rate during the test year.

The KIUC or its predecessor was a party to most if not all of the above proceedings and should have a copy of the relevant documents.

b. All of Kentucky Power's short-term debt is sourced from the utility money pool. Kentucky Power does not have any bank lines of their own to borrow short-term debt. Month-end balances amounts are as follows:

Month and Year	End of Month Balances
October 2009	$0
November 2009	$0
December 2009	$485,337
January 2010	$805,286

c. Yes. The Company's financing plan does include short-term debt.

d. Please see page 2 for the capital budget and pages 3-4 for the O&M budget and financial statements for calendar year 2010. We are not aware of any narratives or presentations to the Company's Board of Directors and/or the AEP Board of Directors for these budgets.

WITNESS: Errol K Wagner/Ranie K Wohnhas

EXHIBIT ____ (LK-15)

KIUC Adjustments to KPCO Capitalization and Cost of Capital
Test Year Ending 9/30/2009

I. KPCO Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Per Filing

	Per Book Balance	KPCO Proforma Adjustments	KPCO Adjusted Capitalization	KPCO Reapportioned Adjusted Capitalization	Kentucky Jurisdictional Factor	KPCO Reapportioned Kentucky Adjusted Capitalization	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement
Short Term Debt	-	(21,660,796)	(21,660,796)	(21,701,938)	99.10%	(21,506,621)	-2.16%	2.29%	-0.0495%	-0.0497%	(494,784)
Long Term Debt	548,680,094	(1,522,076)	547,158,018	548,197,288	99.10%	543,263,512	54.62%	6.48%	3.5412%	3.5562%	35,372,784
Accts Receivable Financing	46,477,902	-	46,477,902	46,566,182	99.10%	46,147,086	4.64%	2.99%	0.1387%	0.1393%	1,385,617
Common Equity	431,042,090	(1,195,740)	429,846,350	430,662,799	99.10%	426,786,833	42.91%	11.75%	5.0415%	8.3062%	82,621,148
Sub Total	1,026,200,086	(24,378,612)	1,001,821,474	1,003,724,330		994,690,811	100.00%		8.67%	11.95%	118,884,766
Job Development Tax Credit	1,902,856		1,902,856								
Total Capital	1,028,102,942	(24,378,612)	1,003,724,330	1,003,724,330		994,690,811	100.00%		8.67%	11.95%	118,884,766

II. KPCO Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Adjusting Capitalization for:
Capitalization Adjustment 1 - Reflect 13 Month Average Short Term Debt

	KPCO Reapportioned Adjusted Capitalization	KIUC Proforma Adjustment 1	KIUC Adjusted Reapportioned Capitalization After Adjustment 1	Kentucky Jurisdictional Factor	KIUC Reapportioned Kentucky Adjusted Capitalization	KIUC Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	(21,701,938)	89,884,847	68,182,909	99.10%	67,569,262	6.79%	2.29%	0.1556%	0.1563%	1,554,506	2,049,289
Long Term Debt	548,197,288	(89,884,847)	458,312,441	99.10%	454,187,629	45.66%	6.48%	2.9606%	2.9731%	29,572,906	(5,799,878)
Accts Receivable Financing	46,566,182	-	46,566,182	99.10%	46,147,086	4.64%	2.99%	0.1387%	0.1393%	1,385,617	-
Common Equity	430,662,799	-	430,662,799	99.10%	426,786,833	42.91%	11.75%	5.0415%	8.3062%	82,621,148	-
Total Capital	1,003,724,330	-	1,003,724,330		994,690,811	100.00%		8.30%	11.57%	115,134,177	(3,750,589)

III. KPCO Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Adjusting Short Term Debt Rate to 1.0%.

	KIUC Adjusted Reapportioned Capitalization After Adjustment 1	KIUC Proforma Adjustment 2	KIUC Adjusted Reapportioned Capitalization After Adjustment 2	Kentucky Jurisdictional Factor	KIUC Reapportioned Kentucky Adjusted Capitalization	KIUC Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	68,182,909	-	68,182,909	99.10%	67,569,262	6.79%	1.00%	0.0679%	0.0682%	678,543	(875,963)
Long Term Debt	458,312,441	-	458,312,441	99.10%	454,187,629	45.66%	6.48%	2.9606%	2.9731%	29,572,906	-
Accts Receivable Financing	46,566,182	-	46,566,182	99.10%	46,147,086	4.64%	2.99%	0.1387%	0.1393%	1,385,617	-
Common Equity	430,662,799	-	430,662,799	99.10%	426,786,833	42.91%	11.75%	5.0415%	8.3062%	82,621,148	-
Total Capital	1,003,724,330	-	1,003,724,330		994,690,811	100.00%		8.21%	11.49%	114,258,214	(875,963)

KIUC Adjustments to KPCO Capitalization and Cost of Capital
Test Year Ending 9/30/2009

IV. KPCO Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Adjusting Short Term Debt Rate to 1.0%.
Capitalization Adjustment 2 - Apply Big Sandy Coal Stock Adjustment to all Capital Components Other than A/R Financing
The Big Sandy Capitalization Adjustment to Short Term Debt was $21,531,864 on a Total Company Basis Per Section V Schedule 3 in Filing

	KIUC Adjusted Reapportioned Capitalization After Adjustment 1	KIUC Proforma Adjustment 2	KIUC Adjusted Reapportioned Capitalization After Adjustment 2	Kentucky Jurisdictional Factor	KIUC Reapportioned Kentucky Adjusted Capitalization	KIUC Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	68,182,909	19,554,678	87,737,587	99.10%	86,947,948	8.74%	1.00%	0.0874%	0.0878%	873,147	194,604
Long Term Debt	458,312,441	(10,081,442)	448,230,999	99.10%	444,196,920	44.66%	6.48%	2.8955%	2.9077%	28,922,395	(650,512)
Accts Receivable Financing	46,566,182	-	46,566,182	99.10%	46,147,086	4.64%	2.99%	0.1387%	0.1393%	1,385,617	-
Common Equity	430,662,799	(9,473,236)	421,189,562	99.10%	417,398,856	41.96%	11.75%	4.9306%	8.1235%	80,803,741	(1,817,407)
Total Capital	1,003,724,330	-	1,003,724,330		994,690,811	100.00%		8.05%	11.26%	111,984,900	(2,273,315)

V. KPCO Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Adjusting Capitalization for:
Capitalization Adjustment 3 - Remove Company's Proposed Reliability Capital Adjustment

	KIUC Adjusted Reapportioned Capitalization After Adjustment 2	KIUC Proforma Adjustment 3	KIUC Adjusted Reapportioned Capitalization After Adjustment 3	Kentucky Jurisdictional Factor	KIUC Reapportioned Kentucky Adjusted Capitalization	KIUC Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	87,737,587	(426,770)	87,310,817	99.10%	86,525,019	8.78%	1.00%	0.0878%	0.0882%	868,900	(4,247)
Long Term Debt	448,230,999	(5,038,095)	443,192,904	99.10%	439,204,168	44.57%	6.48%	2.8901%	2.9022%	28,597,308	(325,086)
Accts Receivable Financing	46,566,182	-	46,566,182	99.10%	46,147,086	4.68%	2.99%	0.1400%	0.1406%	1,385,617	-
Common Equity	421,189,562	(3,957,919)	417,231,643	99.10%	413,476,559	41.96%	11.75%	4.9306%	8.1234%	80,044,428	(759,313)
Total Capital	1,003,724,330	(9,422,784)	994,301,546		985,352,832	100.00%		8.05%	11.25%	110,896,253	(1,088,646)

VI. KPCO Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Adjusting Return on Common Equity to 10.1%.

	KIUC Adjusted Reapportioned Capitalization After Adjustment 3	Kentucky Jurisdictional Factor	KIUC Reapportioned Kentucky Adjusted Capitalization	KIUC Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	87,310,817	99.10%	86,525,019	8.78%	1.00%	0.0878%	0.0882%	868,900	-
Long Term Debt	443,192,904	99.10%	439,204,168	44.57%	6.48%	2.8901%	2.9022%	28,597,308	-
Accts Receivable Financing	46,566,182	99.10%	46,147,086	4.68%	2.99%	0.1400%	0.1406%	1,385,617	-
Common Equity	417,231,643	99.10%	413,476,559	41.96%	10.10%	4.2382%	6.9827%	68,804,147	(11,240,281)
Total Capital	994,301,546		985,352,832	100.00%		7.36%	10.11%	99,655,972	(11,240,281)

EXHIBIT ____ (LK-16)

Kentucky Power Company

REQUEST

Refer to page 7 line 24 through page 8 line 2 of Mr. Myers' Direct Testimony wherein he states that the Company's proposal provides "AEPSC with an incentive mechanism to optimize the margins in such a manner that will benefit KPCo customers."

a. Please explain in detail how AEPSC will manage the System's OSS any differently with or without the SSC either in its present form or in the modified form proposed by the Company. Provide all evidence in support of each change in AEPSC management of the System's OSS.

b. Please explain how the SCC either in its present form or in the modified form proposed by the Company provides an "incentive" to optimize the margins so that they will benefit KPCo customers as opposed to simply providing a mechanism to share OSS margins over a baseline between customers and KPCo.

RESPONSE

a. Business decisions regarding how AEPSC will optimize OSS margins are made on an AEP s ystem basis and not on an individual operating company basis. In the event that the company determines that the cumulative weight of all commission decisions in the various jurisdictions does not provide adequate incentive, the company would likely scale back OSS activities such as participation in competitive energy supply auctions. AEPSC has no specific plans to alter the management of the System's OSS based on the outcome of this proceeding, but will evaluate future activities accordingly.

b. The proposed system sales clause provides an incentive to optimize OSS margins so that they will benefit KPCo customers by aligning the interests of both the company and the customer. Because OSS margins would be shared 50/50, both KPCo customers and the company benefit from optimizing those margins. The proposed incentive structure also aligns the interests of both the company and the customer in regards to risk management. Because the company has the daily responsibility to actively manage OSS risks, the incentive structure places the greater exposure on the company. The KPCo customers receive an embedded rate regardless of whether OSS margins reach that level and have no limit on their equal sharing to the upside.

WITNESS: Thomas M. Myers

EXHIBIT ____ (LK-17)

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2009

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _________ to_________

Commission File Number	Registrants; States of Incorporation; Address and Telephone Number	I.R.S. Employer Identification Nos.
1-3525	AMERICAN ELECTRIC POWER COMPANY, INC. (A New York Corporation)	13-4922640
1-3457	APPALACHIAN POWER COMPANY (A Virginia Corporation)	54-0124790
1-2680	COLUMBUS SOUTHERN POWER COMPANY (An Ohio Corporation)	31-4154203
1-3570	INDIANA MICHIGAN POWER COMPANY (An Indiana Corporation)	35-0410455
1-6543	OHIO POWER COMPANY (An Ohio Corporation)	31-4271000
0-343	PUBLIC SERVICE COMPANY OF OKLAHOMA (An Oklahoma Corporation)	73-0410895
1-3146	SOUTHWESTERN ELECTRIC POWER COMPANY (A Delaware Corporation)	72-0323455
	1 Riverside Plaza, Columbus, Ohio 43215	
	Telephone (614) 716-1000	

Indicate by check mark if the registrants American Electric Power Company, Inc., Appalachian Power Company and Ohio Power Company, is each a well-known seasoned issuer, as defined in Rule 405 on the Securities Act. Yes ☒ No. ☐

Indicate by check mark if the registrants Columbus Southern Power Company, Indiana Michigan Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company, are well-known seasoned issuers, as defined in Rule 405 on the Securities Act. Yes ☐ No. ☒

Indicate by check mark if the registrants are not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes ☐ No. ☒

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No. ☐

Indicate by check mark whether American Electric Power Company, Inc. has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No. ☐

Indicate by check mark whether Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company have submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☐ No. ☐

Jurisdiction	Percentage of AEP System Retail Revenues (1)	Percentage of OSS Profits Shared with Ratepayers	AEP Utility Subsidiaries Operating in that Jurisdiction	Authorized Return on Equity (2)
Ohio	33%	No sharing included in ESPs	OPCo	(3)
			CSPCo	(3)
Texas	12%	Not Applicable in ERCOT	TCC (4)	9.96%
			TNC (4)	9.96%
		90% in SPP	SWEPCo	15.70%
Virginia	12%	75%	APCo	10.20%
West Virginia	10%	100%	APCo	10.50%
			WPCo	10.50%
Oklahoma	10%	75%	PSO	10.50%
Indiana	10%	50% after certain level (5)	I&M	10.50%
Kentucky	5%	60% to 70% after certain levels (6)	KPCo	10.50%
Louisiana	3%	50% to 100% after certain levels (7)	SWEPCo	10.57%
Arkansas	2%	50% to 100% after certain levels (8)	SWEPCo	10.25%
Michigan	2%	100% in one area, 0% in the other area	I&M	13.00%
Tennessee	1%	Not Applicable	Kingsport	12.00%

(1) Represents the percentage of revenues from sales to retail customers from AEP utility companies operating in each state to the total AEP System revenues from sales to retail customers for the year ended December 31, 2009.

(2) Identifies the predominant authorized return on equity and may not include other, less significant, permitted recovery. Actual return on equity varies from authorized return on equity.

(3) CSPCo's and OPCo's generation revenues are governed by its Electric Security Plans (ESP) filed and approved by the PUCO. Starting in April 2009, the ESP became effective which authorized rate increases during the ESP period, subject to caps that limit the rate increases for CSPCo to 7% in 2009, 6% in 2010 and 6% in 2011 and for OPCo to 8% in 2009, 7% in 2010 and 8% in 2011. Some rate components and increases are exempt from the cap limitations. The ESP also provided for a fuel adjustment clause for the three-year period of the ESP. CSPCo and OPCo provide distribution services at cost based rates approved by the PUCO. Transmission services are provided at OATT rates based on rates established by the FERC.

(4) Operating in the ERCOT region of Texas and consists of distribution and transmission functions. Generation operations were divested in compliance with the Texas electric restructuring.

(5) There is an annual $37.5 million credit established for off-system sales in base rates. If the off-system sales profits exceed the amount built into base rates, I&M reimburses ratepayers 50% of the excess.

(6) There is an annual $24.9 million credit established for off-system sales in base rates. If the monthly off-system sales profits do not meet the monthly level built into base rates, ratepayers reimburse KPCo 70% of the shortfall. If the monthly off-system sales profits exceed the monthly base amount built into base rates, KPCo reimburses ratepayers 70% of the excess up to and including $30 million annually. After $30 million, the percentage drops to 60%.

(7) Below $0.874 million, 100% is shared with customers; from $0.874 million to $1.3 million, 85% is shared with customers; above $1.3 million, 50% is shared with customers.

(8) Below $0.759 million, 100% is shared with customers; from $0.759 million to $1.2 million, 85% is shared with customers; above $1.2 million, 50% is shared with customers.

FERC

Under the FPA, the FERC regulates rates for interstate power sales at wholesale, transmission of electric power, accounting and other matters, including construction and operation of hydroelectric projects. The FERC regulations require AEP to provide open access transmission service at FERC-approved rates. The FERC also regulates unbundled transmission service to retail customers. The FERC also regulates the sale of power for resale in interstate commerce by (i) approving contracts for wholesale sales to municipal and cooperative utilities and (ii) granting authority to public utilities to sell power at wholesale at market-based rates upon a showing that the seller lacks the ability to improperly influence market prices. Except for wholesale power that AEP delivers within its control area of the SPP, AEP has market-rate authority from the FERC, under which much of its wholesale marketing activity takes place. The FERC requires each public utility that owns or controls interstate transmission facilities to, directly or through an RTO, file an open access network and point-to-point transmission tariff that offers services comparable to the utility's own uses of its transmission system. The FERC also requires all transmitting utilities, directly or through an RTO, to establish an OASIS, which electronically posts transmission information such as available capacity and prices, and requires utilities to comply with Standards of Conduct that prohibit utilities' transmission employees from providing non-public transmission information to the utility's marketing employees.

The FERC oversees RTOs, entities created to operate, plan and control utility transmission assets. Order 2000 also prescribes certain characteristics and functions of acceptable RTO proposals. The AEP East Companies are members of PJM. SWEPCo and PSO are members of SPP.

The FERC has jurisdiction over the issuances of securities of our public utility subsidiaries, the acquisition of securities of utilities, the acquisition or sale of certain utility assets, and mergers with another electric utility or holding company. In addition, both the FERC and state regulators are permitted to review the books and records of any company within a holding company system. EPACT gives the FERC limited "backstop" transmission siting authority as well as increased utility merger oversight.

COMPETITION

The public utility subsidiaries of AEP, like the electric industry generally, face competition in the sale of available power on a wholesale basis, primarily to other public utilities and power marketers. The Energy Policy Act of 1992 was designed, among other things, to foster competition in the wholesale market by creating a generation market with fewer barriers to entry and mandating that all generators have equal access to transmission services. As a result, there are more generators able to participate in this market. The principal factors in competing for wholesale sales are price (including fuel costs), availability of capacity and power and reliability of service.

AEP's public utility subsidiaries also compete with self-generation and with distributors of other energy sources, such as natural gas, fuel oil and coal, within their service areas. The primary factors in such competition

EXHIBIT ____ (LK-18)

Kentucky Power Company

REQUEST

Please identify all changes in AEP System trading activities that were adopted when West Virginia re-established the ENEC for APCo with 100% of the OSS margins inuring to ratepayers. Please describe why each such change was initiated and demonstrate that it was initiated due to the lack of any "incentive" mechanism in West Virginia for APCo.

RESPONSE

There were no changes in AEP System trading activities that resulted from the elimination of OSS margin sharing when the ENEC was reinstated in APCo West Virginia. As stated in KIUC 1st Set, Item No. 48 part a., the Company evaluates OSS activities based on the aggregate incentives on the AEP system.

WITNESS: Thomas M. Myers