EAST KENTUCKY POWER COOPERATIVE

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PUBLIC SERVICE
COMMISSION

August 20, 2007

HAND DELIVERED

Ms. Elizabeth O'Donnell
Executive Director
Public Service Commission
211 Sower Boulevard
Frankfort, KY 40602

Re: PSC Case No. 2006-00472

Dear Ms. O'Donnell:

Please find enclosed for filing with the Commission in the above-referenced case an original and ten copies of the Rebuttal Testimonies of William Bosta, David Eames, Frank Oliva, Ann Wood, Laurence Kirsch, and Daniel Walker, on behalf of East Kentucky Power Cooperative, Inc.

Very truly yours,

Charles A. Lile
Senior Corporate Counsel

Enclosures

Cc: Parties of Record

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BEFORE THE PUBLIC SERVICE COMMISSION

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COOPERATIVE, INC	)	**2006-00472**

REBUTTAL TESTIMONY OF DAVID G. EAMES
ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

Q. Please state your name, business address and occupation.

A. My name is David G. Eames, East Kentucky Power Cooperative (EKPC), 4775 Lexington Road, Winchester, Kentucky 40391. I am Vice-President of Finance for EKPC.

Q. What is the purpose of your testimony?

A. I will rebut the testimony of KIUC witness Kollen regarding his proposed adjustments to legal expenses and the forced outage expenses. I will also address his comments about the continuation of the $19 million interim increase in rates.

Q. On Page 32 of his testimony, Mr. Kollen recommends that the Commission disallow approximately 50% of the legal expense incurred in the test year. Do you agree?

A. No. EKPC has been embroiled in two separate lawsuits with the Environmental Protection Agency for several years. One of the lawsuits, filed in early 2004 by the EPA, related to claims that the modifications made by certain generating units should have triggered new source review permitting. This lawsuit reached settlement and has been submitted to the U. S. Federal District Court-Lexington for review. If approved, the EKPC must adhere to a number of environmental compliance requirements. EKPC anticipates significant legal involvement to ensure that the conditions of the consent decree in that case are met.

The other lawsuit, wherein EPA claimed that EKPC did not include Dale Units 1 & 2 in the acid rain program, remains in a litigation status. While settlement talks are ongoing, legal expenses are likely to continue through the foreseeable future. For these reasons, EKPC anticipates a continuation of this level of legal work and recommends that the Commission retain the test year level of expenses in determining the revenue requirement in this case.

Forced Outage

Q. Page 30 of Mr. Kollen's testimony indicates that the Commission should not adopt EKPC's proposed forced outage adjustment to test year forced outage expense. Do you agree with this?

A. No. Using a five-year average on MWh's is representative of our future forced outages. EKPC applied test-year replacement cost to these average MWh's. Even though the five-year period includes 2004, the year of the Spurlock 1 outage, it also includes some years with low forced outages. As indicated on Exhibit DGE-2, filed with the application, EKPC's forced outage rates are far below the national average.

Q. On pages 4 through 6 of his testimony, Mr. Kollen discusses his recommendation that the Commission continue the $19 million interim rate increase on a permanent basis. Do you agree with this recommendation?

A. No, I do not. My reasons are twofold.

First, maintaining the existing $19 million annual increase would produce a net deficit (loss) for EKPC in the year 2008 of approximately $3.0 million. This loss results in a TIER of 0.98 and a DSCR of 0.94 for the year. Both of these ratios are below the level required by RUS for ratemaking purposes, as prescribed in the RUS Mortgage. Section 4.15 of the RUS Mortgage requires EKPC to "design and implement rates for electric energy and other services furnished by it to provide sufficient revenue (along with other revenue available to the Mortgagor) (i) to pay all fixed and variable expenses when and as due, (ii) to provide and maintain reasonable working capital, and (iii) to maintain, on an annual basis, a TIER not less than 1.05 and a DSC or not less than 1.0." As you can see, continuance of the $19 million increase puts EKPC in a financially precarious position, requiring EKPC to immediately file for another rate increase, in order to be in compliance with the RUS Mortgage.

Mr. Kollen seems to minimize the time, effort, and expense required by all the parties involved in filing an additional request for a rate increase. It does not seem prudent to EKPC to create a situation that will require the filing of an avoidable rate request.

Conversely, the granting of the requested $43 million rate increase is projected to produce a net margin in 2008 of approximately $22 million, resulting in a TIER of 1.14 and a DSCR of 1.05. Even by Mr. Kollen's standards, neither of these ratios is excessive.

Secondly, as discussed by Mr. Daniel Walker in his testimony, Mr. Kollen seems to ignore the principle of capital attraction. The thresholds for G&T financing are higher than they have ever been. EKPC needs to be able to compete for capital at attractive interest rates.

Q. Does this complete your rebuttal testimony?

A. Yes.

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AFFIDAVIT

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

David G. Eames, being duly sworn, states that he has read the foregoing prepared rebuttal testimony and that he would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

David G Eames

Subscribed and sworn before me on this 20th day of August, 2007.

Peggy S. Duffin
Notary Public

My Commission expires: December 8, 2009

COMMONWEALTH OF KENTUCKY

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REBUTTAL TESTIMONY OF DANIEL M. WALKER
ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

Q. Please state your name and address.

A. My name is Daniel M. Walker. I am an advisor on cooperative finance. My business address is 7106 University Drive; Richmond, Virginia, 23229.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to respond to the testimony of Mr. Lane Kollen.

SUMMARY

Q. Would you summarize the major difference between your TIER analysis and the recommendation of Mr. Kollen?

A. My analysis was designed to develop a recommendation for TIER that would assure East Kentucky's financial integrity and allow it to maintain a credit quality similar to "A" rated generation and transmission cooperatives and, thus, attract capital at competitive cost. To accomplish this I developed benchmarks of G&Ts that have been rated by at least one of the three rating agencies. The majority of these benchmarks have had actual financial market experience so they offer a good representation of the financial performance bankers and bondholders would expect in order to advance capital. I believe this is the appropriate regulatory standard the Kentucky Public Service Commission would require to set rates. Based on that standard I have recommended a TIER of 1.35x. Mr. Kollen, on the other hand, abandoned regulatory principle and provides no such analysis and, thus, failed to support his recommendation for a TIER of 1.15x. In addition, Mr. Kollen confused the minimum rate covenant in East Kentucky's mortgage as the standard the financial market would require to lend funds to East Kentucky. The market, on the other hand, would expect East Kentucky to earn TIERs equivalent to other cooperatives with similar risk. I will show that even for RUS G&Ts, the TIERs required by lenders continue to increase far beyond Mr. Kollen's recommended 1.15x level. The cost of capital for East Kentucky is not the same as the minimum rate covenant in its mortgage.

Appropriate Regulatory Standard

Q. Do you believe Mr. Kollen's analyses meet the appropriate regulatory standard for determining a fair rate of return?

A. No I don't. For a cooperative using TIER to set rates, the rate of return is the margin left over after covering all costs, expressed in a ratio of margin to interest cost. In the U.S. Supreme Court's decision in the 1944 Hope Natural Gas Company case, the Court determined the rate of return should "be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. . ." The rate of return should be viewed in its entirety, i.e., the total earnings level of the cooperative, and all that goes into determining it. Mr. Kollen makes recommendations regarding many issues, which when viewed in their entirety, do not place East Kentucky in a strong position in terms of financial integrity and capital attraction. His focus, quite naturally, favors the rates of the industrial customers. However, East Kentucky's focus is much broader, including all of its customers and the providers of its capital.

The basic economic principles of regulation have been reiterated by the Supreme Court over the years as summarized by Dr. Charles F. Phillips in The Regulation of Public Utilities as follows:

> Throughout all of its decisions, the Supreme Court has formulated no specific rules for determining a fair rate of return, but it has enumerated a number of guidelines. . . . The relevant economic criteria enunciated by the Court are three: financial integrity, capital attraction and comparable earnings. Stated another way, the rate of return allowed a public utility should be high enough: (1) to maintain the financial integrity of the enterprise; (2) to enable the utility to attract the new capital it needs to serve the public; and (3) to provide a return on common equity that is commensurate with the returns on investments in other enterprises of corresponding risk. These three economic criteria are interrelated and have been used widely for many years by regulatory commissions throughout the country in determining the rate of return allowed public utilities. (p. 338-339)

Bonbright, Danielson and Kamershein in Principles of Public Utility Rates also emphasize the importance of maintaining the ability to attract capital.

> The criteria of a fair return...include (1) attracting capital, (2) encouraging efficient managerial practice, (3) promoting consumer rationing, (4) ensuring fairness to investors, and (5) providing a reasonably stable and predictable rate level to ratepayers...Among these five criteria a high place, perhaps even first place, must be given to that of capital-attracting efficiency. Judged by this test alone, choice should rest with whatever principles of rate control are best designed to permit well

> managed, soundly financed public utility companies to attract needed capital. (p. 203-204)

As the above-quoted authorities make clear, the public interest is best served when rates are set to maintain a cooperative's financial integrity and to allow it to successfully compete in the capital markets with other borrowers. When I performed my analysis, I was guided by these important tenants of regulation that also guide the Kentucky Public Service Commission. In my opinion, the best set of comparables in this case for East Kentucky is the "A" rated G&Ts. The "A" rated G&Ts have the best opportunity to get the best compensation of interest rates and terms and conditions. I do not believe that either the rating agencies or lenders would agree with Mr. Kollen that a 1.15x TIER would be sufficient to compensate for East Kentucky's risk level. The intervenors' recommendations would place East Kentucky at the bottom of "A" rated G&Ts. On the contrary, East Kentucky's risk level is clearly at least in the middle of the range if not higher.

Q. Do you agree with Mr. Kollen's reliance on 1.15x as a Commission precedent?

A. No, I do not agree for several reasons. First, a regulatory precedent generally refers to a methodology adopted by a regulatory body to determine the cost of service. For example, the Commission now uses TIER to determine a cooperative's cost of capital rather than a return on rate base. The use of TIER in the cost of service would be a Commission precedent, not the value itself. The cost of capital is a component of the cost of service much like other cost such as labor. There is a high probability that labor cost will change from case to case just as the cost of capital will likely change from case to case.

Q. What case does Mr. Kollen rely on to recommend a TIER of 1.15x?

A. Mr. Kollen relies on Case No. 1994 – 00336. This base rate case has a test year of 1993. This case is 14 years old.

Q. Have funding conditions for G&T cooperatives changed since 1993?

A. Absolutely. The world for all utilities has turned upside down over the last five years. As I explained in my original testimony, utilities have been exposed to volatile fuel cost which increases business risk. In addition, as a result of the Enron and World Com debacles and the resulting credit crisis of 2002, lenders no longer consider utilities low risk enterprises. Downgrades of utility credits have exceeded upgrades four to one. Both volatile fuel cost and demanding credit evaluation have also affected East Kentucky. In 1993 the need to hedge volatile fuel cost was barely on the radar screen. In addition, very few G&Ts in 1993 were exposed to commercial credit evaluation in order to acquire capital. A good example is East Kentucky's current credit facility where its pricing is directly related to a credit evaluation similar to that used by the rating agencies. Credit quality and financial performance now go hand-in-hand in determining East Kentucky's cost of capital.

Minimum Rate Covenant

Q. Does Mr. Kollen confuse the relationship between the minimum rate covenant and the market TIER requirement?

A. Yes. A cooperative with a minimum TIER rate covenant of 1.10x cannot issue new debt unless the earned TIER is at least 1.10x. However, merely meeting this minimum is no guarantee a cooperative will be able to access capital and if it can, there is no guarantee the interest rate will be attractive. No one in the financial markets would presume that a cooperative earning a TIER equal to its minimum rate covenant would automatically attract the available capital of a lender.

Q. Are you saying that East Kentucky could not issue debt at the 1.10x TIER level?

A. Under some rare market conditions I believe that East Kentucky could issue debt with a TIER of 1.10x. However, under general market conditions, if East Kentucky earned a TIER of 1.10x, with their risk profile, it would be more difficult and expensive to issue additional debt. Earning a TIER at this level would likely result in a low debt rating and more restrictive covenants which, in turn, would result in higher cost and less flexibility. This would not be in the ratepayers' best interest. In other words, while the rate covenant has a role as a mortgage test, it is not the covenant TIER level lenders focus on to determine capital attraction. They focus on comparable cooperatives, including comparable levels of earned TIERs, and the ability of earned TIERs to address risk.

Q. Can you give me a practical example of market TIERs?

A. Yes. Of the 18 G&Ts listed in Exhibit G-4, Page 18 of 20 (Exhibit DMW-1) of my original testimony and Exhibit DHW-1 of the attached rebuttal testimony, all had a TIER above 1.10x except Square Butte, which is a special purpose company, and Oglethorpe. Each of the "A" rated cooperatives recognizes that to maintain their ratings and have access to financing, they must earn TIERs well above the 1.10x coverage they have in their mortgage. In fact, the average TIER for this group is 1.49x for 2005 and 1.54x for 2006.

Updated Numbers and Current Events for 2006

Q. How have things changed since you filed your testimony?

A. Yes. Attached Exhibit DMW-1 is an update of my testimony and follow up to the response in Staff 3rd Data Request, Item 22. Staff had requested an update once information was available. Not surprisingly lenders expected TIERs have continued to increase. In addition, future generation loans from RUS will require higher standards of credit than ever before.

Q. Would you explain how expected returns have increased?

A. On Exhibit DMW-1, I have updated the earned TIERs for the year 2006. Of the 18 "A" rated G&Ts I have eliminated the highest and the lowest value and then averaged the remaining 16 values. This shows that the average TIER for 2006 is 1.54x. This is 5% higher than the 2005 average TIER computed the same way. The 2005 average TIER is 8% higher than 2004. In my original testimony I computed a three-year average to smooth out any year-to-year fluctuations. The average TIER for the last three years, 2004, 2005, and now 2006 is 1.47x. The mean value of the 16 G&Ts is 1.36x. This further illustrates that Mr. Kollen's recommendation based on the 1993 test year of 1.15x is outdated, not based on an objective study, and should not be considered by the Commission.

Q. What other events have occurred since you filed your testimony that will have an impact on East Kentucky's cost of capital?

A. Even for RUS cooperatives there is more emphasis on credit quality than ever before. President Bush's 2008 budget proposes that base load generation be financed in the commercial markets.

"With the increased need for all aspects of electricity provision and to ensure adequate funding for rural areas, RUS loans will continue to focus on transmission, distribution and up grading generation facilities. Construction of new generation facilities should be financed through the commercial market."[1]

This clearly indicates that credit quality will play a larger role in G&Ts' generation planning and financing. It also indicates that a TIER of 1.15x will no longer be sufficient to attract capital and maintain financial integrity.

This year Congress is likely to require that large generation projects for G&Ts be supported by "AAA" credit backing. The only way East Kentucky could meet this condition is to purchase bond insurance which will require formal ratings and extensive credit evaluations. The pricing of such credit support, if available, would be directly related to East Kentucky's credit quality and financial performance. My opinion is that a TIER of 1.15x would make bond insurance, if available at all, very expensive for East Kentucky and its customers. Alternatively, East Kentucky needs to improve its financial performance with sufficient rates to be rated in the "A" category in order to meet its members' needs as efficiently as possible.

Q. Does this conclude your testimony?

A. Yes, it does.

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[1] Budget of the United States, Fiscal Year – 2008, Appendix, p. 146

Exhibit DMW-1

East Kentucky Power Cooperative

"A" Rated G&T Cooperatives
<u>TIER Analysis</u>
(Updated for 2006 Values)

	Moody's	S&P	Fitch	2004	2005	2006	Average
Golden Spread	---	---	A-	2.68X	6.45X	3.55X	4.23X
Buckeye	A_1	A+	A+	2.88	3.46	2.67	3.00
Brazos	---	A-	A	1.91	1.66	2.07	1.88
Basin	A_1	A+	AA-	1.21	1.79	2.04	1.68
Great River	A_3	BBB+	A-	1.24	1.49	1.83	1.52
Central Iowa	---	A	A-	1.38	1.40	1.61	1.46
Tri-State	Baa_1	A	A	1.43	1.47	1.44	1.45
Dairyland	A_2	A	---	1.24	1.54	1.51	1.43
Arkansas	A_2	AA-	A+	1.22	1.36	1.53	1.37
Western Farmers	---	BBB+	A-	1.39	1.31	1.33	1.34
Central Electric - SC	---	AA	---	1.34	1.32	1.32	1.33
Old Dominion	A_3	A	A	1.20	1.20	1.39	1.26
Associated	A_1	AA	AA	1.32	1.18	1.26	1.25
Georgia Transmission	A_3	AA-	AA-	1.21	1.19	1.18	1.19
Hoosier	A_3	A	---	1.10	1.20	1.20	1.17
Seminole	---	A-	---	1.05	1.14	1.24	1.14
Oglethorpe	A_3	A	A	1.08	1.08	1.08	1.08
Square Butte	A_1	A-	A	1.08	1.08	1.09	1.08
Average				1.38X	1.49X	1.54X	1.47X
Median							1.36X

Source:
- National G&T Accounting and Finance Association Handbook
- Published financial statements for Old Dominion, Oglethorpe, Basin, and Georgia Transmission (these G&T's don't report TIER in the National G&T Accounting and Finance Association Handbook)
- Tri-State TIER data provided directly

Note 1 – The average is computed by removing the highest and lowest value and averaging the remaining 16 values.
Note 2 – Both the ratings and the three-year average have been updated with 2006 results.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

GENERAL ADJUSTMENT OF ELECTRIC RATES OF EAST KENTUCKY POWER COOPERATIVE, INC	)))	**CASE NO. 2006-00472**

AFFIDAVIT

STATE OF VIRGINIA)
)
CITY OF RICHMOND)

Daniel M. Walker, being duly sworn, states that he has read the foregoing prepared rebuttal testimony and that he would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

Subscribed and sworn before me on this 16th day of August, 2007.

7035844
Notary Public

My Commission expires: 5/31/10

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

GENERAL ADJUSTMENT OF ELECTRIC RATES	)	
OF EAST KENTUCKY POWER	)	**CASE NO.**
COOPERATIVE, INC	)	**2006-00472**

REBUTTAL TESTIMONY OF FRANK J. OLIVA
ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

Q. Please state your name, position and business address.

A. My name is Frank J. Oliva, Manager of Finance and Risk Management at East Kentucky Power Cooperative (EKPC), 4775 Lexington Road, Winchester, Kentucky 40391.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to comment on certain aspects of the testimonies of KIUC witness Lane Kollen.

Q. On page 20 of his testimony, Mr. Kollen recommends that annual interest expense be based on the EKPC debt outstanding at March 31, 2007. Does EKPC agree?

A. EKPC agrees that it is reasonable to used annualized interest expense based on the outstanding debt and interest rates as of March 31, 2007. Because the average interest rate on this debt is fairly stable, this seems to be a reasonable approximation of future expense.

Q. How should AFUDC income be calculated?

A. The use of actual CWIP and actual interest rates at March 31, 2007 seems to be a reasonable approach to calculating annualized AFUDC income.

Q. On page 22 of Mr. Kollen's testimony, he suggests that interest expense and TIER requirements be reduced due to a pending refinancing.

Do you agree with this proposed adjustment?

A. No, I do not. This adjustment goes far beyond the March 31, 2007 date Mr. Kollen suggests be used to establish the level of interest expense in the case. This adjustment is also neither known nor measurable for the following reasons. RUS has not yet granted final release of these loan funds and the date of loan clearance is not known. When final clearance is granted, the entire loan amount will not be able to be drawn at one time. RUS will release the funds based on capital expenditures made for the applicable capital projects. Also, the interest rate on drawn funds is unknown, as it is established on the date of each loan draw. For these reasons, this proposed adjustment should not be made.

Q. Mr. Kollen suggests, on page 27 of his testimony, that EKPC's revenue requirement be reduced by $7.242 million to reflect a certain level of interest income in the case.

Do you agree?

A. No. EKPC disagrees with this proposed adjustment. EKPC has suggested since the beginning of this case that interest income is highly variable to the company. As such, EKPC's annual level of interest income fluctuates significantly based on the level of short-term interest rates (since most funds are invested short-term) and is heavily influenced by capital project expenditures and the availability of loan funds. For these reasons, EKPC believes that the level of annualized interest income should be based on a long-term 5-year average. This adjustment more closely normalizes interest income to a level expected to be earned in the future.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY

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COOPERATIVE, INC.	)	**2006-00472**

A F F I D A V I T

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Frank J. Oliva, being duly sworn, states that he has read the foregoing prepared rebuttal testimony and that he would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

Frank J. Oliva

Subscribed and sworn before me on this 20th day of August, 2007.

Peggy S. Duffin
Notary Public

My Commission expires: December 8, 2009

COMMONWEALTH OF KENTUCKY

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REBUTTAL TESTIMONY OF ANN F. WOOD
ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

Q. Please state your name, business address and occupation.

A. My name is Ann F. Wood, East Kentucky Power Cooperative ("EKPC"), 4775 Lexington Road, Winchester, Kentucky 40391. I am the Manager of Accounting for EKPC.

Q. What is the purpose of your rebuttal testimony?

A. I will address one issue raised by Mr. Kollen in his direct testimony.

Early Out

Q. Would you provide the timing of the "early-out" retirement program?

A. Yes. EKPC offered an "early-out" program to employees who were a minimum of age 59. Eligible employees had from March 1 to March 31 to decide whether or not to take the "early-out." The effective date of the "early-out" was April 1, 2007.

Q. Was this "early-out" known and measurable at the time of the filing of the application?

A. No. This "early-out" offer was made to employees after the filing of the application. Additionally, the effective date of the "early-out" program was April 1, 2007; this date was outside the post-test year period.

Q. Did EKPC agree that the savings from the "early-out" program should be considered in this proceeding?

A. Yes. In Response 5 (b)(2) to Staff's Fourth Data Request, EKPC acknowledged that these savings should be considered in these proceedings. Also, in Response 5 (c)(1) to Staff's Fourth Data Request, EKPC reflected the costs associated with this "early-out" program.

Q. On Page 35 of Mr. Kollen's testimony, he states that the "early-out" savings should be reflected in the revenue requirement. In Mr. Kollen's response to Staff's First Data Request 6, he mentions that EKPC has not sought recovery of the costs of the "early-out" program. Why didn't EKPC seek recovery of such costs?

A. As mentioned previously, the "early-out" program was not offered until after the filing of the application. Neither the savings nor the costs of this program were included in the rate case application. However, since this "early-out" program is now being considered as part of the rate case, both the savings and the costs should be considered.

Q. Does this conclude your testimony?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY

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COOPERATIVE, INC.	)	**2006-00472**

AFFIDAVIT

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Ann F. Wood, being duly sworn, states that she has read the foregoing prepared rebuttal testimony and that she would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of her knowledge, information and belief.

Ann F. Wood

Subscribed and sworn before me on this 20th day of August, 2007.

Peggy S. Duffin
Notary Public

My Commission expires: December 8, 2009

COMMONWEALTH OF KENTUCKY

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COOPERATIVE, INC	)	**2006-00472**

REBUTTAL TESTIMONY OF DR. LAURENCE D. KIRSCH ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

Comes now the movant, East Kentucky Power Cooperative, Inc., and submits the following prepared testimony of its witness, Dr. Laurence D. Kirsch.

Q.1. Please state your name, affiliation, and address.

A.1. My name is Laurence D. Kirsch. I am a Senior Consultant with Christensen Associates Energy Consulting, LLC, 4610 University Avenue, Suite 700, Madison, Wisconsin.

Q.2. Please state your educational and other qualifications.

A.2. I hold a Ph.D. in economics from the University of Wisconsin and an A.B. in economics from the University of California.

I have spent the past 25 years specializing in economic analyses of the electric power industry, including studies of bulk power markets, power pool operations, electric power system cost structures, and reliability costs. My clients have included numerous large utilities, small utilities, power system operators, regulatory agencies, and power industry coalitions. Although most of my work has been in the United States, I have also had projects in other countries.

My major interest has been the efficient pricing of electricity services at both the wholesale and retail levels. In the course of my work, I have developed and applied methods for estimating the real-time marginal energy and reliability costs of both generation and transmission; have developed methods for costing and pricing unbundled ancillary services; have evaluated the potential for market power in generation service markets; have participated in the development and implementation of pricing policies for independent power producers; have evaluated the merits of various schemes for auctioning wholesale power; and have assessed a wide variety of utility pricing practices. I have published articles in the *Electricity Journal* and *Public Utilities Fortnightly* on electricity pricing matters. I have previously presented oral and/or written testimony before the Federal Energy Regulatory Commission and before state regulatory commissions.

Exhibit LDK-1 presents my vita.

Q.3. What is the purpose of your testimony?

A.3. The purpose of my testimony is to respond to the testimony that Mr. Geoffrey Young submitted on behalf of the Cumberland Chapter of the Sierra Club, as clarified or extended by Mr. Young's responses to various data or information requests.

Q.4. Please summarize your conclusions.

A.4. Demand-side management (DSM) is a legitimate policy response to the failure of retail electricity prices to reasonably reflect the marginal cost of electricity when loads are high or when there are externalities (like the adverse environmental impacts of power generation) that are not reflected in prices. Kentucky should therefore consider means of implementing DSM in those cases wherein DSM can be demonstrated to have benefits greater than costs. On the other hand, inducing consumer behavior that enhances environmental quality is only one among ratemaking's several goals; and other legitimate goals of ratemaking, such as customer choice and fairness, may sometimes conflict with environmental quality goals.

Decoupling or recoupling programs can, in principle, rectify the sorts of incentive problems that Mr. Young identifies; but there are nonetheless problems with such programs in general and with Mr. Young's proposal for East Kentucky Power Cooperative (EKPC) in particular. In general, there are technical difficulties with implementing decoupling programs, including the "statistical recoupling" approach that Mr. Young prefers. In particular, Mr. Young's proposal for EKPC is vague and is aimed at the wrong kind of entity, namely a non-profit generation and transmission cooperative that lacks the incentives of a profit-making firm and that does not serve the final customers who must participate in DSM programs.

Q.5. How is your testimony organized?

A.5. In sections 1 through 4, I discuss the economic rationale for DSM programs, how DSM fits into the goals of ratemaking, the role of customer choice in ratemaking, and the legitimacy of avoiding cross-subsidies among classes. In sections 5 through 8, I discuss the challenges posed by decoupling programs in general and of "statistical recoupling" in particular, the vagueness of Mr. Young's decoupling proposal, and the inapplicability of Mr. Young's proposal to an entity like EKPC.

1. ENVIRONMENTAL IMPACTS ARE A LEGITIMATE CONCERN IN RATEMAKING; BUT ENVIRONMENTAL PROGRAMS NEED TO PASS LEGITIMATE BENEFIT-COST TESTS.

Q.6. What is the economic justification for DSM programs?

A.6. DSM programs respond to the failure of retail electricity prices to reasonably reflect the marginal costs of electricity. This is important because economic theory states that prices are most efficient when they equal marginal costs. When prices are less than marginal costs, customers tend to consume inefficiently high quantities of a good. When prices exceed marginal costs, customers tend to consume inefficiently low quantities of a good. "Efficiency" is defined according to the relationship between the benefits and costs of consumption: the level of consumption is most "efficient" when the net benefits of consumption (benefits net of costs) are at their maximum.

There are two general types of circumstances that lead to differences between electricity's retail prices and its marginal costs.

First, marginal costs vary over time, tending to be higher when loads are high and lower when loads are low. With the exception of those customers who take service under real-time pricing programs, however, most customers see prices that do not vary over time or (in the case of time-of-use programs) do not accurately follow the time-variance in marginal costs. DSM programs (like programs that directly control air conditioners) can be designed to mitigate the over-consumption that occurs at those times when prices are less than marginal costs. The short-run benefit of such mitigation is that the value of the power system's reduced fuel costs and improved reliability is greater than the value to customers of their reduced consumption. There may be an additional long-term benefit of such mitigation if the DSM programs change load profiles in ways that allow the postponement of new generation investment.

Second, the price of electricity does not reflect the costs of the various externalities associated with fuel production and consumption. These include, for example, the costs arising from emissions of various pollutant gases, nuclear waste disposal, damage to wildlife, oil spills, and military activity to protect fuel supplies and routes. If the price of electricity did reflect these externalities, that price would be higher and customers would consume less electricity. In principle, DSM programs can be designed to mimic the conservation that would occur if prices more accurately reflected these externalities.

DSM programs may also respond to certain "barriers" that prevent customers from responding to the prices that they *do* see. These barriers may include: a) customers' lack of information about load-shifting or conservation opportunities; b) customers' lack of access to financing for capital expenditures that could cost-effectively shift load or conserve electricity; and c) "agency" problems, like landlord-tenant relationships, under which the electricity bill is paid by one party while another party is responsible for conservation-oriented capital expenditures. There has been a great deal of controversy about the extent to which these barriers are real. In at least some cases, customers' failure to pursue load-shifting or conservation opportunities reflects customer preferences for the services of higher-powered appliances or customer recognition of the transactions costs of changing their electricity-consuming habits.

Q.7. Is DSM the only way to induce customers to consume efficient quantities of electricity?

A.7. No. Another way to get customers to consume efficiently is to put taxes on fuels and electricity production that reflect the costs of their externalities, and to set retail rates that accurately reflect the time-varying value of wholesale marginal costs (including the taxes). For some externalities, trading schemes (such as with SO_x) can achieve roughly the same level of net benefit as can taxes.

For a whole variety of practical and political reasons, however, it is difficult to place efficient taxes on fuels and electricity production that reflect the costs of externalities. Consequently, for at least the past three decades, the U.S. electric power industry has had a variety of conservation and load management programs that have attempted to induce consumers to do what they might do if they faced efficient prices that reflect the time-varying value of electricity and the costs of externalities. In other words, DSM is a practical (if imperfect) approach to solving what is in essence a pricing problem.

Q.8. What is the general principle for judging the economic merits of DSM programs?

A.8. A DSM program provides net benefits to society only when its benefits exceed its costs. As a matter of public policy, a DSM program should be subsidized (usually through cross-subsidies among electricity customers) only when it passes legitimate benefit-cost tests.

In his testimony, at page 25, lines 18-19, Mr. Young asserts that "New DSM program ideas should be considered and evaluated using the standard California benefit/cost tests." Although these tests have been widely used throughout the United States, and although EKPC has used these tests as well, the Public Service Commission (hereinafter, the "Commission") should understand that assessing DSM programs using these tests can be problematic. One problem is that these four tests often produce conflicting results, with one or more tests suggesting that a program is beneficial while another suggests the opposite. Another problem is that none of these tests accounts for *all* of the economic benefits and costs that may result from DSM programs: each of these tests ignores some benefits or some costs. The Commission needs to be careful to not repeat erroneous precedent, but to instead employ benefit-cost analyses that count all benefits and all costs.

Q.9. Are Mr. Young's notions of "energy waste" and "energy inefficiency" helpful guides to judging the economic merits of DSM programs?

A.9. No. Beginning on page 5, line 10 of his testimony, Mr. Young refers several times to "energy waste"; and on page 5, line 13, he refers to "energy inefficiency." In the context of his testimony, these are bad things to be avoided; but because their meanings were unclear, I authored Request 2 of EKPC's First Data Request Dated July 25, 2007. In his response, Mr. Young says that "energy waste" and "energy inefficiency" are "equivalent" to one another; and he indicates that these terms mean "any human activity which absorbs resources but creates no value."

Mr. Young's definition of "energy waste" and "energy inefficiency" is so extreme that it applies only to situations wherein somebody has accidentally left the gas on while they go traveling around the world in eighty days. Except in such cases of accident, the use of electricity will almost always create some value, no matter how small. A light left on overnight in a child's bedroom may seem wasteful, but it has some value to the child who is afraid of the dark and to the parents who want to get some sleep. An antiquated energy-guzzling industrial process may also seem wasteful, but if it produces something of value – as it surely must – then it does not meet Mr. Young's definition of "energy waste" and "energy inefficiency." The world is not as black and white as Mr. Young's definition implies. Again, the proper test is to compare the cost of what is consumed to the benefits of that consumption; and those quantities will only rarely be zero.

2. RATEMAKING HAS MULTIPLE GOALS, OF WHICH MANAGING ENVIRONMENTAL IMPACTS IS ONLY ONE.

Q.10. What are the goals of electricity ratemaking?

A.10. Ratemaking has several legitimate goals, which include cost recovery, fairness, rate stability, simplicity, creation of opportunities for customer choice, and encouraging efficient use of electricity services.

Q.11. Can these goals conflict with one another?

A.11. Yes. For example, the most efficient electricity prices tend to vary from hour to hour; but although imposing such real-time pricing on customers would promote the goal of economic efficiency, it may conflict with the goals of rate stability and simplicity.

Another example can be drawn from the Sierra Club's Second Data Request dated 5/30/07. Requests 3 and 4 implicitly raise the question of why $10.2 million per year and $0.4 million per year should be recovered through substation and metering point charges, respectively, rather than through energy charges. The Sierra Club's apparent point is that higher energy charges will possibly have the beneficial effect of discouraging energy consumption while the incentive effects of the substation and metering point charges are unclear. Regardless of the incentive effects, however, these charges may make sense as a matter of fairness because they assign costs to the co-ops whose customers obtain benefits from these facilities. These co-ops then recover the substation and metering point charges from the benefiting customers through some combination of customer, demand, and energy charges; so regardless of the form of the charges by EKPC, these costs may end up being recovered mostly or entirely through the usage charges that the Sierra Club apparently favors. In summary, even if these substation and metering point charges do not encourage efficient use of utility services, they do promote the goal of fairness.

Q.12. Should the Commission and EKPC give priority to environmental goals over the other goals of ratemaking?

A.12. Not necessarily. Environmental goals are important, and the manner in which customers respond to prices and thereby use or conserve electricity is important.

But the Commission and EKPC can and should consider the other ratemaking goals as well.

3. CUSTOMER CHOICE IS A LEGITIMATE GOAL OF RATEMAKING.

Q.13. What is "customer choice"?

A.13. "Customer choice" refers to the availability of options by which customers may use or pay for electricity. For example, customers may enjoy different qualities of service in terms of firmness or interruptibility. Customers may pay prices that vary over time or are fixed over time; and customers may pay bills that vary from month to month or that are fixed for several months at a time.

Q.14. Is customer choice a good thing?

A.14. Customer choice is beneficial if the benefits of offering options exceed the costs of those options. As a general rule, options should not be offered simply for the sake of offering options. For example, if it is cost-effective to put large industrial customers on real-time pricing but not cost-effective to put small residential customers on such pricing, it would be a waste of time and effort to offer a real-time pricing option to residential customers.

Q.15. If customers choose not to take an option, have they been denied choice?

A.15. Of course not. For example, on page 11, lines 27-28 of his testimony, Mr. Young refers to a situation in which "all industrial customers have elected to opt out" of certain DSM programs. This leads Mr. Young to the amazing assertion that "The entire industrial class has consequently been deprived of the opportunity to participate in utility-sponsored DSM programs." Young testimony at page 11, line 41 to page 12, line 1. Mr. Young is saying that if industrial customers were forced to participate in DSM programs, they would have an "opportunity to participate in utility-sponsored DSM programs," while under the actual circumstances in which they have had a choice, they have been deprived of opportunity. This part of Mr. Young's testimony defies logic. The fact is that if customers have chosen not to take an option, they have been given an opportunity and a choice, not denied an opportunity and a choice.

4. AVOIDANCE OF CROSS-SUBSIDIES AMONG CLASSES IS A LEGITIMATE OBJECTIVE OF RATEMAKING.

Q.16. Why is avoidance of cross-subsidies a legitimate objective?

A.16. Cross-subsidies conflict with the goal of fairness, the notion that each group of customers should pay for the costs of its own service.

Q.17. Does Mr. Young advocate cross-subsidies?

A.17. Yes. Mr. Young expresses his wish that the residential and small commercial classes subsidize industrial class DSM programs. He says that the provision of Kentucky law (KRS 278.285) that "in effect, prohibits a utility from using funds collected from one customer class to invest in DSM programs directed toward another customer class... is unnecessarily restrictive... It is possible that if this sentence [provision] had not been included in KRS 278.285, over the past 13 years we might have seen some utilities collecting funds from the residential and commercial classes and using a portion of those funds to expand the industrial DSM programs... The resulting decrease in the utility's total demand might have deferred or eliminated the need for one or more expensive new power plants and thereby might have helped keep the rates lower for all customer classes." Young testimony at page 12, lines 5-17.

Q.18. What are the problems with Mr. Young's reasoning?

A.18. There are three related problems.

First, regardless of whatever environmental benefits might have been created by the missing industrial class DSM programs, these programs are extremely likely to have required a positive net out-of-pocket expense. We know that because the industrial class has elected to not undertake these DSM programs without subsidies. On the reasonable assumption that industrial customers are rational and fairly savvy, it must be the case that industrial customers have figured out that the out-of-pocket expenses of these programs exceed the savings that they will gain from these programs, or that the savings are so small that it is not worth the transactions costs of undertaking these DSM measures.

Second, successful DSM programs reduce sales (as measured by kWh and kW). Because costs are incurred to administer and implement DSM programs, there is a tendency for DSM programs to raise rates by spreading higher costs over fewer sales.

Third, the immediate effect of forcing residential and small commercial customers to subsidize industrial DSM programs will be to raise residential and small commercial rates, while leading to bill savings for the industrial class (if the DSM programs reduce industrial load).

In summary, Mr. Young's assertion that subsidization of industrial class DSM programs "might" defer power plant construction and "might" lower rates for all classes in the long run is speculative at best. It assumes that industrial customers do a poor job of managing their businesses and that Kentucky's utilities are failing to identify the least-cost means of serving their customers; and it ignores the fact that the costs of administering and implementing DSM programs must be recovered from a deliberately shrunken sales base.

Q.19. Can a reasonable argument be made in favor of cross-subsidies?

A.19. Yes, if one is willing to be realistic about the trade-offs among the several goals of ratemaking. For reasons just explained, we should expect that DSM programs require net out-of-pocket expense and that customers will be unwilling to participate in these programs without subsidies. But if these programs have environmental benefits that exceed their expense, they provide net benefits to society. When there are such net benefits, subsidization of DSM would be consistent with the goal of encouraging efficient use of electricity services, which, depending upon circumstances, the Commission may deem more or less important than the conflicting goal of fairness.

Q.20. Are industrial customers as rational and savvy as you assume?

A.20. That is an interesting question, and I believe that it goes to the heart of Mr. Young's argument.

Mr. Young has entered into the record some documents that claim that industrial firms are not rational and savvy. In his Response 2 to EKPC's First Data Request Dated July 25, 2007, Mr. Young submitted a document (Chapter 7 of a book entitled *Natural Capitalism: Creating the Next Industrial Revolution*) that asserts that "five-sixths of the typical custom-house construction schedule is spent in *waiting*… or in *reworking*…" and that "Much if not most air travel would cost less, use less fuel, produce less total noise, and be about twice as fast" if the present hub-and spoke systems were replaced by point-to-point service. These are extreme assertions; and Mr. Young, by placing them in the record, is asking the Commission to seriously consider the possibilities that home construction labor costs six times its efficient level, and that the airline industry was grossly mistaken in its move to the hub-and-spoke system a quarter century ago. In his Response 2a to the First Data Request by Commission Staff to the Cumberland Chapter of the Sierra Club, Mr. Young cites an essay by Amory Lovins that, referring to potential efficiency improvements in industrial processes, figuratively speaks about $100,000 bills lying on industrial shop floors. This, too, is an extreme assertion. Mr. Young believes that we live in a world in which massive efficiency improvements are available for the taking, but in which people are just not smart enough to grab those efficiencies; and he wants the Commission to share this belief and force industrial customers to change how they operate.

There are at least two serious problems with Mr. Young's position.

The first is that, if these massive efficiencies are available for the taking, then industry can make lots of money taking them. If this were true, Mr. Young's desired subsidies for industry's efficiency investments would be unnecessary.

The second serious problem is that, if industry is unable to find these potential improvements in energy efficiencies, then utilities will also be unlikely to find these potential improvements. After all, industry understands its own production processes and its own business opportunities and trade-offs better than utilities do. Do we really expect a utility to be able to walk into an industrial plant and tell that plant's owner how to run their business better? And if some savvy outsiders really can walk into an industrial plant and tell that plant's owner how to run their business better, why do we believe that a utility that is primarily in the business of producing and distributing electricity would be better than an energy management consulting firm at giving industrial energy management advice?

Contrary to Mr. Young's extreme position, it is reasonable to assume that industrial customers are rational and savvy. They know their businesses better than anybody else does. They are competing in a global marketplace in which industrial production has been shifting away from America; so they have strong incentives to undertake cost-effective energy conservation (to the extent that they pay energy prices that reflect marginal costs, including the costs of externalities). An industrial firm that fails to be cost-competitive will ultimately be driven out of business by firms that *are* cost-competitive. Mr. Young has his anecdotes; but he has not explained why profit-making industrial firms would generally fail to find significant cost-effective energy savings, why firms that are more energy-savvy have not driven out of business those firms that are less energy-savvy, and why utilities would be better than industry at managing industrial processes.

5. DECOUPLING PROGRAMS POSE SOME CHALLENGES.

Q.21. What are the positive attributes of decoupling?

A.21. Decoupling mitigates utility disincentives to promote conservation programs and incentives to grow load by increasing customer-level usage. Decoupling can also help stabilize utility revenues and customer bills.

Q.22. Does decoupling destabilize retail electricity prices?

A.22. Decoupling can destabilize retail electricity prices. For support on this point, I wish to cite the document that Mr. Young presents in part in Attachment B of his testimony; but I wish to cite pages that are excluded from Attachment B. The document is Eric Hirst's *Statistical Recoupling: A New Way to Break the Link Between Electric-Utility Sales and Revenues*, Oak Ridge National Laboratory publication ORNL/CON-372, September 1993 (hereinafter the "Hirst Report"). The full document has been put into evidence by Mr. Young in his Response 5a to the First Data Request by Commission Staff to the Cumberland Chapter of the Sierra Club.

The Hirst Report at page 13 shows that California's decoupling mechanism over the years 1982-1991 was responsible, all by itself, for an 8% range of bouncing price changes at Pacific Gas & Electric and Southern California Edison. In some years, rates were 4% higher than without decoupling; while in other years, rates were 4% lower than without decoupling.

The Hirst Report at page 14 mentions that Washington and Maine had "some problems with revenue-per-customer (RPC) decoupling related to price volatility." The Hirst Report at page 15 states that accumulations in Central

Maine Power's decoupling account caused a 5% increase in rates. The Hirst Report at page 17 summarizes the problem by stating that under "some forms of decoupling... electricity prices can be more volatile than under traditional regulation."

Likewise, Mr. Young acknowledges that the decoupling pilot program at Union Light, Heat and Power (ULH&P) ended because management "became concerned about fluctuations in the size of the decoupling balancing account. They also mentioned the possibility that the decoupling formula could be gamed by one or another party." Young testimony at page 19, lines 9-11.

Mr. Young is correct in claiming that statistical recoupling (SR) can mitigate the instability problems associated with the revenue-per-customer decoupling that ULH&P had. He says that "SR addresses these issues and reduces the size of the fluctuations in the balancing account and consequently in electric rates." Young testimony at page 21, lines 14-15. Nonetheless, SR does not eliminate the instability problem.

Q.23. Do decoupling mechanisms generally tend to be significantly affected by factors that have nothing to do with the intent of decoupling?

A.23. Decoupling can be affected by such factors. Again, support can be found in portions of the Hirst Report that are excluded from Attachment B to Mr. Young's testimony.

The Hirst Report at page 14 states that the Washington Utilities and Transportation Commission found that "unusually warm weather" had large impacts on the deferred balance in the decoupling account. The Hirst Report at pages 15-16 states that the 5% rate increase induced by decoupling "was caused in part by non-decoupling factors" specifically including "the prolonged Maine recession", and that the Maine Public Utilities Commission found that "The vast majority [of decoupling accruals] was because the recession had reduced sales."

The Hirst Report at page 18 summarizes the problem as follows: "...when adverse weather and/or a poor economy occur, price changes [i.e., increases] can be important... [W]hen the economy is growing rapidly and/or weather is favorable, decoupling will lead to price decreases..."

Q.24. Does decoupling raise potential gaming problems?

A.24. Yes, it can. An example of this can be found in revenue per customer (RPC) decoupling mechanisms, in which deferrals are based on the difference between allowed and actual revenues per customer multiplied by the current number of customers. Under this system, the utility has the incentive to enroll customers with usage (and therefore revenue) amounts that are less than the allowed level. Each time a "small" customer is added, the RPC decoupling mechanism produces a deferral in the utility's favor in an amount equal to the difference between the allowed per customer revenue amount and the customer's actual revenues. RPC decoupling mechanisms also provide the utility with an incentive to artificially inflate the count of the number of customers, which could be accomplished (for example) by encouraging apartment buildings to move from aggregate to apartment-level metering. Note that statistical recoupling as described by Dr. Hirst contains a customer count variable, and therefore may be described as a form of RPC decoupling that is susceptible to this sort of gaming.

Q.25. What risks might arise if there are errors in the parameters of a decoupling program?

A.25. The number of parameters required by a decoupling mechanism varies according to the design used. The simplest mechanisms require only the setting of the total allowed level of revenues to be recovered by the utility. The RPC decoupling mechanisms just described require the setting of the allowed revenue (or use) per customer and (if use per customer is used instead of revenue per customer) the allowed margin per kilowatt-hour. Statistical recoupling as described by Dr. Hirst requires the development of a statistical model in order to estimate sales. Errors or manipulation in setting these parameters can lead the decoupling mechanism to consistently cause revenue to flow from ratepayers to the utility (or vice versa). For example, if the allowed use per customer under RPC decoupling is set above its "true" value, the decoupling mechanism will, on average, produce deferrals in the utility's favor.

6. MR. YOUNG'S PREFERRED DECOUPLING APPROACH, "STATISTICAL RECOUPLING," HAS IMPLEMENTATION PROBLEMS.

Q.26. What is the basis of your understanding that Mr. Young's preferred decoupling approach is statistical recoupling?

A.26. On page 22, lines 4-5 of his testimony, Mr. Young states, "Statistical decoupling appears to be the decoupling approach that would be most beneficial for Kentucky." Furthermore, Mr. Young devotes a considerable portion of his testimony to discussing statistical recoupling, and has put into the record the Hirst Report, which appears to be the seminal work on statistical recoupling.

Q.27. Please describe statistical recoupling.

A.27. According to the Hirst Report, Dr. Hirst himself is the creator of statistical recoupling: "I developed a new method called statistical recoupling." Hirst Report at page 21.

Dr. Hirst states, "SR involves two steps. The first step decouples revenues from electricity sales. In the second step, revenues are recoupled to statistical estimates of electricity use." Hirst Report at page 21. "Electricity use" is the same thing as electricity sales; and Dr. Hirst uses the term "computed electricity use" to refer to "statistical estimates of electricity use."

Under statistical recoupling, a utility's allowed revenues equal computed electricity use times some fixed price of electricity. The amount of money flowing through a utility's recoupling account equals that fixed electricity price times the difference between actual electricity sales and computed electricity use. Hirst Report at page 21. Thus, any increase or decrease in actual electricity sales has no effect on a utility's allowed revenues, which depend only upon computed electricity use. Instead, the utility's recoupling account will receive any revenue increase arising from an increase in actual electricity sales, and the utility's recoupling account will pay any revenue shortfall arising from a decrease in actual electricity sales; and after a certain period of time, a positive balance in the recoupling account will be returned to customers, and a negative balance will be recovered from customers.

Q.28. How is computed electricity use determined?

A.28. Computed electricity use is determined through a statistical analysis of the relationship between electricity sales and various factors that are likely to influence electricity sales. The Hirst Report at page 21 suggests that electricity sales depend upon weather severity (heating and cooling degree days), economic activity, electricity prices, and numbers of customers; and it further suggests that the statistical dependence of electricity sales on these factors be estimated using historical data for the past ten or fifteen years. The Hirst Report at page 26 indicates that Dr. Hirst has measured "economic activity" according to disposable income, personal income, a wholesale production index, income, employment, industrial output, unemployment rate, and gross state product.

Q.29. How important is computed electricity use to the viability of statistical recoupling?

A.29. Computed electricity use is absolutely central to statistical recoupling. A basic idea of statistical recoupling is that a utility should not receive credit or blame for changes in sales that are due to weather, economic conditions, or other factors that are outside of the utility's control. The purpose of the statistical analysis is to separate the effects of these uncontrollable factors from the effects of the factors (like electricity marketing or DSM) that the utility *can* control. If the statistical analysis is successful, then statistical recoupling will be free of the unstable and somewhat arbitrary price changes that plague other decoupling mechanisms. If the statistical analysis is unsuccessful, then statistical recoupling will share these problems.

Q.30. Is computed electricity use sensitive to the choice of model specification?

A.30. Yes. Again, support can be found in portions of the Hirst Report that are excluded from Attachment B to Mr. Young's testimony. In trying to estimate electricity use for PacifiCorp, the Hirst Report at page 39 shows that some model specifications overestimate electricity use by 5.1% while other specifications underestimate electricity use by 0.9%. Clearly, such misestimates will swamp the sales effects of almost any utility marketing or DSM program, which implies that statistical recoupling is likely to do a poor job of separating the sales effects of utility activities from the effects of all of the other factors that affect sales.

Q.31. Do the estimates of computed electricity use get worse over time?

A.31. Yes. The Hirst Report at page 39 acknowledges that "The range in predictions among models increases from year to year... These results, not surprisingly, show that the accuracy of the models' estimates decreases as one moves further away from the historical estimation period." Consequently, the Hirst Report at page 40 "suggests that these models should be re-estimated every few years."

Q.32. Does statistical recoupling produce satisfactory results when the utility's tariff includes demand charges?

A.32. No. The Hirst Report warns that the presence of demand charges can cause statistical recoupling to inadequately compensate the utility for losses due to DSM programs, reducing the utility's incentive to engage in conservation. "DSM programs typically cut demand by a larger percentage than they cut energy use... Because residential customers pay no demand charge, actual net lost revenues equal those computed with SR models. For the commercial and industrial sectors, which pay both energy and demand charges, the SR models underestimate net lost revenues when the CLF [conservation load factor] of DSM programs is less than the system load factor... This error occurs because the SR models estimate electricity sales (GWh) and are silent with respect to demand (MW). Therefore, changes in demand that do not affect sales have no effect on the amounts of lost revenues estimated by SR models." Hirst Report at page 46.

The danger that statistical recoupling will underestimate lost revenues is real. The conservation load factor – which is defined as average energy savings divided by peak energy savings – will be less than the system load factor whenever DSM programs cut demand by a larger percentage than they cut energy use. Because DSM programs often cut demand by a larger percentage than they cut energy use, statistical recoupling models will typically underestimate net lost revenues for the commercial and industrial classes.

Consider, for example, a DSM program that shifts load from peak hours to off-peak hours but results in no net change in energy use. Such a DSM program is a good thing in that it improves peak-period reliability, reduces fuel costs or power procurement costs, and possibly helps postpone or even eliminate some need for investment in new generation. But because statistical recoupling looks only at energy use, not at demand, statistical recoupling will give the utility no credit for its good work in developing and implementing a load-shifting DSM program if there is no change in energy use. This is a major oversight and weakness of the statistical recoupling approach. This oversight is particularly important in Kentucky, wherein (according to Mr. Young) DSM programs "have harvested miniscule energy savings" but in which "DSM programs designed to shift peak loads to non-peak periods have tended to be somewhat larger and more effective." Young testimony at page 14, lines 6-9. According to his Response 4 to EKPC's First Data Request Dated July 25, 2007, these effective programs include E.ON's direct load control program for residential and commercial customers, which cut 93 MW of demand from the peak and has benefit-cost ratios of 3.75:1 and above; and yet statistical recoupling would penalize E.ON for its success with this program.

7. MR. YOUNG'S DECOUPLING PROPOSAL IS VAGUE.

Q.33. Has Mr. Young clearly addressed the implementation problems just described?

A.33. No. As just explained, the Hirst Report, upon which Mr. Young relies as a primary source of his proposal, acknowledges many weaknesses of the statistical recoupling approach that Mr. Young prefers. Nonetheless, Mr. Young does not explain how he or Kentucky could address these weaknesses. In particular, Mr. Young fails to acknowledge the shortcomings associated with statistical recoupling in the presence of demand charges, even though this problem is described by the Hirst Report that Mr. Young himself put into the record.

Q.34. Has Mr. Young clearly explained the nuts and bolts of how Kentucky can or should implement his decoupling proposal?

A.34. No. For example, the Hirst Report at page 25 indicates that statistical recoupling could be based upon linear, log-log, or log-linear models, and that these models can have lagged dependent variables and dummy variables that represent months or unusual events (like labor strikes). In his testimony, Mr. Young never takes a position on model forms or model variables, or on other details that would need to be worked out to actually implement his proposal. In his Response 9c to the First Data Request by Commission Staff to the Cumberland Chapter of the Sierra Club, however, Mr. Young specifies a linear model form with a lagged dependent variable, but he does not explain: a) why he chose this model form; b) how he proposes to measure the variable "INDOUT"; or c) why he chose to exclude the dummy variables suggested by the Hirst Report.

In his Responses 6b and 9a to the First Data Request by Commission Staff to the Cumberland Chapter of the Sierra Club, Mr. Young implicitly admits that he has never conducted the econometric analysis that would be required to implement statistical recoupling. Quoting Dr. Hirst, Mr. Young indicates his support for an implementation process by which "the utility... develops alternative statistical models. After review of these models, the company and other parties agree on a particular model to use..." This is all new ground, and the going may or may not be so easy as Mr. Young hopes.

In fairness to Mr. Young, I acknowledge that he wishes Kentucky to move in a certain direction, but does not want to be too particular about how Kentucky moves in that direction. For example, he says that "the Sierra Club is not irrevocably wedded to SR. There are other ways to structure EKPC's tariffs so as to decouple revenues from sales, but the drawbacks of these other approaches appear to be greater than the drawbacks of SR." Young testimony at page 25, lines 4-6. The flexibility of Mr. Young's position is understandable: he wants to focus on the big picture of making utility incentives more compatible with DSM, and does not want to become mired in too many of the details of how the new incentive system would actually work. But the consequence is that Mr. Young has left a lot of blanks unfilled, so it is not clear exactly what he is proposing or how well or badly it might actually work in practice.

Q.35. Please summarize your conclusions.

A.35. Mr. Young's proposal is not ready for prime time. In short, it does not appear that Mr. Young has provided a workable decoupling mechanism because he has not addressed the several implementation problems that I describe in Section 6 of this testimony.

Furthermore, Mr. Young acknowledges that he is "not aware of any state regulatory commissions that have adopted the statistical recoupling approach..." Response 5c to the First Data Request by Commission Staff to the Cumberland Chapter of the Sierra Club. This lack of precedent deprives the Commission of concrete experience that might guide the implementation of Mr. Young's proposal.

8. MR. YOUNG'S DECOUPLING PROPOSAL FAILS TO RECOGNIZE EKPC'S BUSINESS SITUATION.

Q.36. Are the incentives for cooperatives are different than those of investor-owned utilities (IOUs)?

A.36. Yes.

EKPC's incentives are affected by the fact that its shareholders and customers are the same people. EKPC *does* need sufficient net revenues to establish and maintain its financial integrity; and it therefore has an incentive to take actions, such as promoting sales during off-peak periods, that will enable it to acquire sufficient revenues. But it does not need net revenues beyond what is required to assure financial integrity, nor does it have an incentive to promote sales to gain such additional net revenues. As Mr. Young himself acknowledges, "EKPC is a not-for-profit cooperative corporation and can return excess net income to its customers." Young testimony at page 22, lines 14-15. Mr. Young thereby acknowledges that there are limits in a coop's incentive to grow load, because if load growth produces net revenues, the coop ultimately returns those net revenues back to the customers.

By contrast, there is in principle no limit to the amount of net revenues that an IOU might want to earn. In practice, regulators place limits on IOUs' rates of return, and will explicitly or implicitly force such utilities to return to customers a portion of earnings when rates of return become high. But shareholders nonetheless stand to potentially gain profits from additional sales, giving IOUs much stronger incentives for promoting sales than cooperatives have.

For a cooperative, a cost-effective DSM program would save money for both shareholders and customers because they are the very same people. For an IOU between rate cases, increasing sales might increase profits as described by Mr. Young; but for a cooperative between rate cases, increasing sales can increase net margins that are ultimately returned, in their entirety, to customers. Aside from the necessity of maintaining its financial integrity, it would make no sense for a cooperative to intentionally increase its profits at the expense of its customer-owners; and it would make no sense for a cooperative to increase sales that will increase the costs of its customer-owners.

Q.37. Does Mr. Young recognize that the incentives for cooperatives are different than those of IOUs?

A.37. Yes and no; but mostly no. On the one hand, Mr. Young acknowledges that "EKPC and its member distribution entities are cooperatives that have been incorporated to serve their ultimate customers rather than profit-seeking investors…" Young testimony at page 9, lines 17-18. On the other hand, Mr. Young states "It is to be expected that EKPC would be concerned with the health of its bottom line, in the same way that an investor-owned utility would… I have seen no indication that the cooperatives are any less interested in net revenue than the IOUs." Young testimony at page 9, lines 21-25.

Portions of Mr. Young's testimony conflate IOUs and cooperatives, failing to distinguish between the two types of utilities. For example, he says "reforming the traditional rate structure was necessary in order to remove the existing massive disincentives for utility companies to operate effective DSM programs that save significant amounts of energy. To fail to reform the rate structures would be to guarantee that each utility's least-cost strategy would diverge widely from its most financially advantageous strategy." Young testimony at page 13, lines 7-11. The foregoing assertion may be true for IOUs, for which the interests of shareholders and customers are not identical; but it is not true for co-ops, whose shareholders and customers are the same people and whose interests therefore *are* identical.

Because of his failure to recognize the different incentives faced by cooperatives and IOUs, Mr. Young asserts "that EKPC has a strong financial incentive to sell more electricity at all times, and has a similarly powerful disincentive to help its ultimate customers improve the efficiency with which they use electricity." Young testimony, page 6, lines 20-22. Although net revenues do increase with sales, the incentive for EKPC to increase sales is muted by its ownership structure.

His failure to recognize cooperatives' business incentives leads Mr. Young to further assert that "Another necessary element of the rate structure is a positive incentive to induce EKPC and its member co-ops to embark on a dramatically different strategy... I recommend that this incentive take the form of a shared savings element, in order to provide an incentive for the utility to operate cost-effective DSM programs." Young testimony at page 23, lines 12. Such a recommendation might make sense for an IOU, for whom owners and customers are different people; but for cooperatives, Mr. Young's recommendation is for nothing more than sharing between the right pockets and left pockets of the same people.

Q.38. How does EKPC's role as a generation and transmission (G&T) company affect the merits of its adoption of a revenue decoupling mechanism?

A.38. As a G&T, EKPC is not well positioned to implement the policies favored by Mr. Young. The problem is that EKPC does not directly serve retail customers, but instead serves only wholesale customers. Consequently, EKPC does not set retail rates. If member cooperatives do not adopt decoupling mechanisms, no purpose would be served by EKPC adopting such a mechanism.

Q.39. How does EKPC's wholesale price structure affect the retail price structures of its sixteen member co-ops?

A.39. In principle, EKPC's wholesale tariff defines the marginal generation and transmission costs of each of its member distributors. For purposes of their own financial stability, member distributors have an incentive to set retail energy prices in ways that somewhat imitate the EKPC's tariff.

To assess the extent to which the rates of EKPC's member cooperatives actually *do* reflect EKPC's rates, I have compared EKPC's rates to those of its five largest members, who together serve over half of the final customers who receive power through EKPC. My main finding is that there is some correspondence between the members' tariffs for larger (industrial) customers and EKPC's tariff, and there is a lesser correspondence between the members' tariffs for smaller customers and EKPC's tariff.

Exhibit LDK-2 summarizes the tariffs. EKPC has monthly charges on metering points and substations, but none on customers themselves for the very good reason that EKPC's costs do not directly depend upon the number of customers. The members, by contrast, have charges on customers, but none on metering points and substations. Apparently and logically, the members recover their payments for metering point and substation charges through other types of charges on their customers; and their customer charges reflect the members' costs (e.g., for distribution and billing) that are related to the number of customers. The customer charges at the low end apply to the residential and/or small commercial classes, while the highest customer charges apply to the largest industrial customers. Interestingly, the customer charges for large industrials vary among the members by the rather large factor of three.

Demand charges are distinguished by those applicable to the peak demand of the current month and those applicable to the peak (ratcheted) demand of the most recent twelve months (including the current month). The current-month demand charges for the members are pretty closely in line with that of EKPC, though Blue Grass Energy has demand charges that are 38% below EKPC's lowest demand charge. The three members that have ratcheted demand charges all share a common rate ($5.53 per kW-month) that is 11% below EKPC's ratcheted demand charge. The other two members have no ratcheted demand charge at all.

Interruption credits are in the form of a demand charge discount. The interruption credits offered by the five members are very similar to that offered by EKPC.

The energy charges are noteworthy in several respects. First, the members' energy charges are always higher than those of EKPC; but the lower energy charges are always paid by large customers who pay demand charges, while the higher energy charges are always paid by smaller customers who do not pay demand charges. The basic story seems to be that the rates paid by larger customers have demand charges and energy charges that more or less follow EKPC's tariff rates, generally with a discount on demand charges and a premium on energy charges; while the rates paid by smaller customers recover EKPC's demand charges through large premiums on energy charges. It therefore appears that smaller customers have plenty of incentive to conserve electrical energy, though not necessarily at the right times; and that industrial customers have plenty of incentive to consume at a high load factor but not necessarily to conserve energy.

Second, there is very little difference between EKPC's on-peak and off-peak energy charges. As a practical matter, it makes little sense for members to put much emphasis on time-differentiated energy rates when EKPC is signaling that its own costs vary little by time period. Nonetheless, all five members offer relatively low-priced off-peak energy to at least some of their customers. Only two of the members offer high-priced on-peak energy to customers.

Third, three of the five members have hours-of-use tariffs for some of their rate schedules, while neither EKPC nor the other two members have such tariffs.

In summary, there is some correspondence between EKPC's tariff and the members' tariffs for larger (industrial) customers, and there is a lesser correspondence between EKPC's tariff and the members' tariffs for smaller customers. EKPC's tariff structure thus appears have some influence on the tariff structures of its members; but that influence is limited. It is therefore questionable whether the adoption of Mr. Young's statistical recoupling proposal will induce the members' to change their tariffs, or whether any such tariff changes by the members will result in retail rate structures that have the incentive effects that Mr. Young seeks.

9. CONCLUSION.

Q.40. Does this conclude your testimony?

A.40. Yes.

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RESUME

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Academic Background

Ph.D., University of Wisconsin, Madison, 1982, Economics
M.S., University of Wisconsin, Madison, 1979, Economics
A.B., University of California, Berkeley, 1972, Economics

Positions

Senior Consultant, Christensen Associates, 1985-present
Consultant, Pacific Gas and Electric Company, San Francisco, 1982-1985
Research Assistant, Madison Consulting Group, Madison, 1981
Teaching Assistant, University of Wisconsin-Madison, 1978-1980
Staff Accountant, Clarence Rainess & Company, CPAs, Beverly Hills, 1973-1974

Professional Experience

I specialize in economic analysis for the electric utility industry, including studies of bulk power markets, power pool operations, electric power system cost structures, and reliability costs. My major interest has been the efficient pricing of electricity services at both the wholesale and retail levels, including the pricing and operating practices of U.S. independent system operators (ISOs) and regional transmission organizations (RTOs). I have developed and applied methods for estimating the real-time marginal energy and reliability costs of both generation and transmission; have developed methods for costing and pricing unbundled ancillary services; have evaluated the potential for market power in generation service markets, including the interaction of market power with transmission congestion; have participated in the development and implementation of pricing policies for independent power producers; have evaluated the merits of various schemes for auctioning wholesale power; and have assessed a wide variety of utility pricing practices. On a variety of electricity pricing issues, I have provided comments and testimony to the Federal Energy Regulatory Commission (FERC) as well as to state regulatory commissions.

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Transmission Interconnection Costs of a New Coal-Fired Generating Plant

Incentives and Rate Designs for Efficiency and Demand Response

RTO Report Card

Review of Offer Caps of the PJM Interconnection

Quantification of the Miscellaneous Benefits of Transmission Investment

Hedging the Long-Term Transmission Pricing Risks Associated with Generation Investments

How Operating Reserve Markets Can Assist in Managing Transmission Congestion

Market Power Analysis of the Kansas City Power & Light Company

Market Power Analysis of Westar

Independent Coordinator of Transmission as an Economic Alternative to RTO Membership

Critique of Historical Contestable Load Analysis of Market Power

Review of the ISO New England and PJM State of the Market Reports

Survey of Market Power Screen Results

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Long-Term Transmission Rights

Valuing and Redesigning a Retail Interruptible Electric Service Program

Approaches for Designing and Pricing Unbundled Transmission and Ancillary Services

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Supply Margin Assessment and Other Market Power Metrics

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Cost-Benefit Analysis of RTO Options

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The Effect of Locational Prices on Retail Pricing Options

Transmission Congestion Analysis

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Curtailable Service and Self-Generation Riders

Encouraging Demand Participation in Texas' Power Markets

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The Market Power Impacts of a Generation Plant Divestiture

Design of Standby, Buyback, and Interruptible Rates

Congestion Charges in the Peruvian Power System

Development of a Purchase Power Agreement Between Generation and Distribution Firms

Seminar on U.S. Power Markets for an Asian Delegation

Analysis of the Readiness for Competition of the Retail Electricity Market in Arkansas

Analysis of an Independent System Operator's Grid Management Charge

Investigation of the Benefits of Expanded Power System Metering

Quantifying the Economic Value of Ancillary Services

Development of Competitive Retail Electricity Products

New Strategies for Electricity Product Development and Wholesale Pricing

Consumer Benefits of Integrating the Generation and Transmission Assets of Municipal Utilities and Investor-Owned Utilities

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Developing New Electricity Products in a Restructured Electricity Market

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Pricing Risk

Review of Draft Ancillary Service Tariffs

The Pricing of Unbundled Electric Power Services

Ancillary Services and the Organization of Electric Power Markets

Pricing Retail Electricity Financial Services

Including Marginal Reliability Costs In Real-Time Prices

Real-Time Pricing Program Development

Costing and Pricing Transmission and Distribution Services

Market Restructuring for Retail Access

Regulatory Reform in Response to Emerging Competition

Retail Market Management and Service Design

Directions for Reactive Power Price Reform

Transmission Pricing Policy

Retail Market Management and Service Design

Transmission Pricing Strategies

Real-Time Pricing Implementation Study

Managing Electric Power Generation in a Competitive Market Environment

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Real-Time Pricing Assessment Study

Forecasting and Measuring Hourly Marginal Costs of Electricity

The Use of Rate Design to Achieve DSM Goals

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Inclusion of Transmission Reliability Costs in Real-Time Pricing Decisions

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"Rate Design for Real-Time Pricing of Electricity," presented at the Rutgers University Advanced Workshop in Public Utility Economics and Regulation, Sagamore, New York, May 1987 (with L. R. Christensen, D. W. Caves, and B. F. Neenan).

"Interpretation of Experimental Results and Implications for Cost Effectiveness," presented at *Proceedings of Niagara Mohawk Workshop on Real-Time Pricing and Load Management Opportunities in New York State,* March 1986 (with D. W. Caves).

"Overview of Electricity Pricing and Service Options," presented at *Proceedings of Niagara Mohawk Workshop on Real-Time Pricing and Load Management Opportunities in New York State*, March 1986 (with D. W. Caves).

"Rate Modeling for Competitive Markets," presented to the American Gas Association Rate Committee Meeting, Orlando, Florida, September 1985.

"The Fundamentals of Gas Marginal Costing," presented to the National Economic Research Associates' Marginal Cost Working Group, San Diego, California, February 1984.

Exhibit LDK-2

COMPARISON OF EKPC'S TARIFFS TO THOSE OF ITS FIVE LARGEST DISTRIBUTORS

	EKPC	Blue Grass Energy	Jackson Electric Cooperative	Owen Electric Cooperative	Salt River Electric	South Kentucky RECC
Monthly Charges ($/month)						
customer charge		4 to 1,097	8 to 1,094	6 to 2,927	8 to 1,595	8 to 3,055
metering point charge	125					
substation charge	944 to 4,605					
Demand Charges ($/kW-month)						
for current-month demand	5.22 to 8.65	3.26 to 8.03	4.95 to 8.00	5.25 to 8.02	5.99 to 8.46	6.15 to 8.02
for 12-month maximum demand	6.22	5.53		5.53		5.53
interruption credit	2.25 to 3.60	2.25 to 3.60	2.25 to 3.60	2.25 to 3.60	2.25 to 3.60	2.25 to 3.60
Energy Charges ($/MWh)						
energy charge [2]						
all hours	27	30 to 74	31 to 74	29 to 69	33 to 67	32 to 79
on-peak	29 to 36			76 to 80	80	
off-peak	29	40	43	41 to 47	36 to 40	40 to 46
Hours-of-Use Tariff	no	yes	no	yes	no	yes

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

GENERAL ADJUSTMENT OF ELECTRIC RATES	**)**	**CASE NO.**
OF EAST KENTUCKY POWER COOPERATIVE, INC.	**)**	**2006-00472**

REBUTTAL TESTIMONY OF DR. LAURENCE D. KIRSCH
ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

AFFIDAVIT

State of North Carolina)
)
County of Orange)

Laurence Kirsch, being duly sworn, states that he has read the foregoing prepared testimony and that he would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of his knowledge, information, and belief.

Laurence D. Kirsch

Subscribed and sworn before me on this 15th day of August, 2007.

Daniela H Adams
Notary Public

My Commission expires: 1/26/09

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

GENERAL ADJUSTMENT OF ELECTRIC RATES	)	
OF EAST KENTUCKY POWER	)	**CASE NO.**
COOPERATIVE, INC	)	**2006-00472**

REBUTTAL TESTIMONY OF WILLIAM A. BOSTA
ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

Q. Please state your name, position and business address.

A. My name is William A. Bosta, Manager of Pricing at East Kentucky Power Cooperative (EKPC), 4775 Lexington Road, Winchester, Kentucky 40391.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to comment on certain aspects of the testimonies of KIUC witnesses Kollen and Higgins, and to rebut issues raised by Mr. Geoffrey Young of the Cumberland Chapter of the Sierra Club. I will also comment on the status of settlement discussions in this proceeding.

Q. On pages 9-13 of Mr. Kollen's testimony, he states that the Company failed to properly synchronize ECR revenue and costs and that an adjustment in EKPC's revenue requirement of approximately $2.1 million is required. Would you comment on this assertion?

A. Yes. EKPC's approach to this issue in this case was to attempt to synchronize the environmental surcharge costs incurred in the test year with the environmental surcharge revenue collected in the test year in order to eliminate the operation of the surcharge in the test period. This adjustment was properly included and shown in Schedule 1, Exhibit F, by excluding the revenue lag so that the surcharge revenues equaled the surcharge expenses. EKPC made no other explicit adjustment for purposes of addressing the environmental surcharge costs and revenues.

EKPC, in its filing, effectively requested a 1.35X TIER on all assets including environmental surcharge assets. This requirement was based on the dire need of the Company to regain its financial footing. EKPC understands that the TIER awarded in the ECR proceeding was 1.15X and that the difference of 1.35X and 1.15X, or 0.20X, is effectively included in the revenue requirement of this case. As Mr. Kollen correctly cites in his response to EKPC-4, the Company did indicate in discovery that it did not intend to roll-in any portion of the ECR into base rates. I do not want the parties to misunderstand EKPC's position on this issue, and Mr. Kollen is correct that one could characterize the 0.20X TIER as a proposed roll-in to base rates.

I believe that EKPC has the right to request the additional 0.20X TIER in its base rates in order to earn the proper TIER on all of its assets. Moreover, while not categorized explicitly as a roll-in to base rates, EKPC's proposal is not unlike what the Commission allowed in the cited LG&E/KU cases.

In the KU case, for example, it is my understanding that the Commission ultimately allowed a higher rate of return on all assets other than for the assets included in the original surcharge application for which a pollution control bond debt rate had been used. This resulted in KU having the average overall return applied to all assets, including environmental surcharge assets (other than the original environmental surcharge assets).

It is my belief that EKPC's filing approach, while not directly comparable to the LG&E/KU cases, essentially follows the same recovery in that EKPC would be given the opportunity to earn the average overall 1.35X TIER on all its assets. As a result, it is my belief that the $2.1 million exclusion proposed by Mr. Kollen is not appropriate.

Q. On page 29 of his testimony, Mr. Kollen indicates that EKPC did not normalize revenues for customer growth. Would you please comment?

A. Yes. EKPC recognized customer growth by developing a revenue annualization based on the number of metering points and number of substations at year end. These two items are the only actual "customers" for EKPC, as it is a wholesale supplier.

Q. Did the Commission recognize retail customer growth in past EKPC rate cases?

A. Yes. As indicated in Mr. Kollen's testimony, the Commission made an adjustment for the number of retail year-end customers in PSC Case 94-336.

Q. Did the Commission make a similar adjustment in PSC Case 8648, the EKPC case preceding the 94-336 case?

A. No. While the Commission fully recognized that the concept was applicable, it did not make an adjustment based on recognizing conditions relevant to that case. The Commission ruled that, although the number of customers had increased, the level of sales had not increased over the prior three years. This was caused by a decline in per customer KWH usage during that three-year period. The Commission concluded that the objective of a sales growth adjustment is to reflect a reasonable level of sales on which to base rates. Based on the level of sales over the three-year period, the Commission did not make an adjustment.

Q. Did customer sales increase for EKPC during the 2004-2006 period?

A. Despite an increase in the number of customers, total KWH sales and KWH sales per customer have fluctuated. This is illustrated below:

	2004	2005	2006
Total EKPC MWH Sales	11,807,384	12,365,466	12,129,142
No. of Retail Customers	489,605	497,372	504,885
KWH Usage Per Customer	24,116	24,862	24,024

Source: EKPC FERC Form 1 for all kwh sold and the RUS Form 7 data for number of customers at retail.

Q. What do you conclude from this information?

A. While there is no question that the number of retail customers has grown, the sales level and usage per customer have both fluctuated. Usage per customer for example, was actually lower in 2006 than in 2004.

Q. Does this three-year trend signify that a test year-end customer adjustment is not warranted?

A. In light of the Commission's reasoning in Case 8648, I do not think that a test year-end retail customer adjustment, as advocated by Mr. Kollen, is warranted.

Q. Have you reviewed the direct testimony and data request responses of KIUC witness Higgins?

A. Yes.

Q. Do you agree with Mr. Higgins' testimony on page 13, lines 22-23, that it is appropriate to view the class cost-of-service analysis solely for informational purposes at this time?

A. Yes. As asserted by Mr. Higgins in this passage of his testimony, EKPC agrees that the issue of the cost-of-service analysis should be viewed as informational only and EKPC took this approach in its Application in this case.

Q. Does Mr. Higgins adhere to his statement on page 13, line 22-23?

A. No. Despite his assertions, he proceeds to include an interruptible cost analysis that would separately assign Gallatin an additional $950,000 annual credit, while increasing EKPC's revenue requirement by the same amount.

Q. Do you agree with his overall approach?

A. No. I agree with his initial assertion that the cost-of-service analysis should be used for information purposes in this proceeding.

Q. Do you concur with Mr. Higgins' statement that revenue apportionment should be based on demand revenues or non-fuel revenues?

A. I have stated that Mr. Higgins' approach (KIUC 1-1) is a feasible alternative. EKPC's approach of an across-the board revenue apportionment was also reasonable when viewed in the context of the overall focus and need for the filing itself.

Q. Should the Special Contracts group, B/C Industrial customers and E class be treated separately as asserted by Mr. Higgins?

A. Yes. EKPC's own proposed rate design takes those classes into account on a separate basis. The load factor and load characteristics for the respective classes are significantly different and warrant separate treatment.

Q. Would it be appropriate to single out each special contract for rate design purposes?

A. Yes. However, in principle, it would also be equally appropriate to develop individual rates for each B/C Industrial customer. EKPC's approach to develop rates by rate class, i.e., Special Contracts, B/C Industrial customers and "E" customers is consistent with past proceedings.

Q. Have you reviewed the testimony and data request responses of Mr. Young from the Sierra Club?

A. Yes.

Q. Would you please identify the issues that EKPC will address?

A. Yes. Dr. Laurence Kirsch of Christensen Associates addresses certain ratemaking issues related to DSM and decoupling. My rebuttal testimony covers various points raised by Mr. Young regarding EKPC's costs, EKPC's management of its capacity expansion plans and its base rates, its DSM programs and the COGEN/SPP Tariff.

Q. On page 8 of his testimony, Mr. Young makes the assertion that "the more electricity EKPC sells, the more money it makes." Do you agree with their statement?

A. No. This statement would be true only when the additional cost associated with producing additional electricity is below EKPC's tariff rates – and, during peak periods such a condition is not currently present on the EKPC system. As indicated in my response to the Sierra Club's First Data Request, Item 9, the answer to this question will vary, depending on the time at which the sale occurs. For example, an increase in EKPC electricity sales at peak hours will result in average embedded cost recovery that is less than both long-run marginal cost and short-run marginal cost. Thus, increased peak electricity sales will result in the need for additional generating units or other resources in the long-term, driving up costs and driving down margins; and it will result in the peak hour costs increasing by more than peak hour revenues thus reducing EKPC's net margins. The revenue recovery in such a situation is based on average embedded cost and the FAC recovery is based on the average FAC cost. Such cost recovery does not cover the long-run or short-run marginal cost caused by the peak sales. It is important for EKPC to reduce or mitigate the growth in its peak demand through Demand Side Management programs that are geared to accomplishing that objective. Shifting load from on-peak to off-peak enables EKPC to mitigate on-peak load growth and limits the need for future generation resources, while improving load factor and helping to cover fixed costs.

Q. On page 25 of his testimony, Mr. Young recommends that EKPC phase out its Electric Thermal Storage (ETS) program. Do you agree?

A. No. Mr. Young's proposal would eliminate a program that has been popular with the retail customers of our Member Systems for many years and has proven to be an efficient form of energy usage. Moreover, as indicated in EKPC's Integrated Resource Plan (Case No. 2006-00471), the ETS program passed the Total Resource Cost (TRC) test. Mr. Young's recommendation would be a radical departure from the Commission's approach to Demand Side Management and is not warranted.

Q. In his response to PSC Staff Request 3, Mr. Young disparages EKPC's Touchstone Energy Home and Touchstone Energy Manufactured Home programs, indicating that the design "leaves much to be desired." Would you please comment?

A. Mr. Young's response to this data request goes well beyond the recommendation in his testimony to eliminate the tariff sheets for these programs. In fact, Mr. Young, as an employee of the Kentucky Department of Energy, attended a meeting at EKPC headquarters on December 1, 2003, to discuss the very program (Touchstone Energy Home) he is now indicting. Mr. Young directly participated in this review of EKPC's Touchstone Energy Home program and offered no changes. These programs were filed under the auspices of the provisions of DSM Statute 278.285, were approved by the Commission as legitimate DSM programs and should remain in place.

Q. On page 14 of his testimony, Mr. Young states that "revenue requirements, electric rates and customers' bills would have been lower if each utility's lowest cost strategy had been implemented." He further indicates in his response to Item EKPC-6 that, if his proposed strategy had been implemented 30 years ago, that "base rates would be lower for customers,

and the average bill per customer would be substantially lower." Do you concur with Mr. Young's comments?

A. No. It is relatively disingenuous of Mr. Young to look back over history and now determine that his strategy would have resulted in lower customer bills. As this Commission is well aware, EKPC has not had a base rate case increase since 1984 and had an 11% <u>decrease</u> in rates in 1995. The proposed increase of 6.6% in base rates is the first time in 23 years that an increase in base rates has even been proposed. Moreover, EKPC was among the last utilities in this state to apply for recovery of environmental costs through the environmental surcharge statute, filing an Application in the fall of 2004, receiving approval in March of 2005 and deferring implementation until July of 2005. Mr. Young's testimony produced no evidence of his assertions, and moreover would have everyone believe that his proposed strategy would have resulted in an even greater decrease in base rates than the 11% decrease our Member Systems actually experienced.

Mr. Young's repeated assertions that EKPC should have invested in DSM programs 20-30 years ago to avoid any new generation is simply Monday-morning quarterbacking. The Public Service Commission, through its comprehensive review of EKPC's proposals to build the new generating units such as Gilbert and Spurlock 4 has engaged in comprehensive reviews of the need for such units under the Certification for Need process. EKPC has routinely solicited proposals for DSM programs, as well as supply side alternatives, when conducting Requests for Proposals for new power supply needs, and has not found economical DSM alternatives sufficient to meet those needs. To assert in

2007 that his proposed strategy would have saved customers more money is unrealistic and unfounded.

EKPC has demonstrated a willingness to listen to alternative points of view on all issues, but is compelled to take a very strong exception to Mr. Young's criticism of EKPC's capacity expansion plans and base rate management.

Q. **On pages 28 through 35, Mr. Young raises several questions regarding EKPC's current COGEN/SPP tariff. When was the current tariff filed and approved by the Commission?**

A. EKPC's current tariff was filed on December 2, 2004, and approved by the Commission for service rendered beginning January 1, 2005.

Q. **How many customers are on the tariff?**

A. One customer is being served under the COGEN/SPP Tariff.

Q. **Were the avoided costs developed in accordance with the approach used in prior filings and approved by the Commission?**

A. Yes.

Q. **Mr. Young makes several comments about the deficiencies of EKPC's COGEN/SPP tariff. Would you please comment?**

A. Yes. EKPC objects to Mr. Young's characterizations that EKPC's COGEN/SPP rates are inappropriate or deficient. The Commission has approved EKPC's existing COGEN/SPP rates. Such suggestions as establishing lower and upper bounds on the rates, establishing different rates based on environmental impacts and having EKPC absorb interconnection costs are not consistent with the approved tariff nor comport with the written requirements set forth in 807 KAR

5:054. EKPC has an obligation to offer COGEN/SPP rates that are based on avoided costs as outlined in the regulation and has complied with that requirement.

Q. Mr. Young believes that EKPC's existing QF tariff contains certain anomalies. Would you please comment?

A. Yes. For example, Mr. Young expresses concern about the fact that EKPC's avoided energy costs for summer are less than in the winter. The avoided cost filing in December 2004 was based on a production cost analysis that compared the hourly variable cost from our expected capacity expansion plan with load at each hour being lower by 100 MW. The price in that analysis was higher in the winter for the following reasons: 1) EKPC is a winter peaking utility, and 2) the last increment of customer loads during peak periods are typically served by combustion turbines (CT's) and/or market purchases. As natural gas prices are generally higher in the winter, it is reasonable to assume that avoided cost will be higher.

Q. Mr. Young also shares concern about the level of the capacity credit. Can you explain the basis of that rate?

A. Yes. The capacity credit for dispatchable QF power stems from the effect on the capacity expansion plan of a decrease in load of 100 MW. In the capacity expansion plan used in that analysis, EKPC had a number of CT's planned to meet forecasted load. Essentially the effect on the capacity expansion plan was a deferral of the need for a year of an already scheduled CT. The per unit cost was based on the present value savings from the deferrals over a ten-year period. As the CT's were already a part of the expansion plan, the effect is fairly minimal.

Q. Mr. Young also makes a comment on Page 30 of his testimony that it "there is no reason whatsoever why EKPC should pay more for capacity that the utility does not dispatch than capacity in does dispatch". Is Mr. Young correct?

A. No. EKPC's capacity credit for non-dispatchable facilities is based on an energy rate because EKPC should not pay a capacity credit for a generation facility whose availability is uncertain. And that is what non-dispatchable means – the generation is not continually available and the on-going capability and output are not known. The $0.0011/kwh energy rate for non-dispatchable power was based on taking the $8.47/KW yearly capacity value and dividing by 7,709 hours (8,760 hours multiplied by .88 capacity factor). The only way the per unit credit for non-dispatchable power would be higher under EKPC's rate is if the load factor for the non-dispatchable power is extremely high. That is highly unlikely given the fact that the facility is not dispatchable.

Q. In light of the issues raised by Mr. Young in this proceeding, what is the next course of action for EKPC?

A. It is EKPC's plan to prepare a new COGEN/SPP rate. I agree with Mr. Young that an update of EKPC's avoided costs is warranted. I believe that this is best accomplished through a separate proceeding and EKPC will meet with the Sierra Club and any other party to this proceeding before filing its updated avoided costs. EKPC certainly understands that the parties may have alternative points of view on this issue and will consider these points prior to filing. EKPC intends to file an updated COGEN/SPP tariff prior to the end of 2007.

Settlement

Q. Have the parties been engaged in settlement discussions to this point in time?

A. Yes. All of the parties have been in discussions to settle this proceeding. EKPC hopes to reach an overall settlement, or to enter into a joint stipulation of the revenue requirement and rate design aspects of the case. EKPC believes that it reasonable to expect that EKPC and some, or all, of the parties will submit documents to the Commission in support of some form of settlement of this case, in the very near future.

Q. Does this complete your rebuttal testimony?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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GENERAL ADJUSTMENT OF ELECTRIC RATES	)	
OF EAST KENTUCKY POWER	)	**CASE NO.**
COOPERATIVE, INC.	)	**2006-00472**

AFFIDAVIT

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

William A. Bosta, being duly sworn, states that he has read the foregoing prepared rebuttal testimony and that he would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

William A. Bosta

Subscribed and sworn before me on this 20th day of August, 2007.

Peggy S. Duffin
Notary Public

My Commission expires: December 8, 2009