East Kentucky Po...r Cooperative, Inc.

Case No. 2008-00409
Fully Forecasted Test Period Filing Requirements
Table of Contents

Volume	Tab	Filing Requirement	Description	Sponsoring Witness(es)
1	1	807 KAR 5:001 Section 10(1)(b)(1)	A statement of the reason the adjustment is required.	Robert M. Marshall David G. Eames
1	2	807 KAR 5:001 Section 10(1)(b)(2)	A statement that the utility's annual reports, including the annual report for the most recent calendar year, are on file with the commission in accordance with 807 KAR 5:006, Section 3(1).	Ann F. Wood
1	3	807 KAR 5:001 Section 10(1) (b)(3) and (5)	If the utility is incorporated, a certified copy of the utility's articles of incorporation and all amendments thereto or out of state documents of similar import. If the utility's articles of incorporation and amendments have already been filed with the Commission in a prior proceeding, the application may state this fact making reference to the style and case number of the prior proceeding and a certificate of good standing or certificate of authorization dated within sixty (60) days of the date the application is filed.	Ann F. Wood
1	4	807 KAR 5:001 Section 10(1)(b)(4) and (5)	If applicant is a limited partnership, a certified copy of the limited partnership agreement or if the agreement was filed with the PSC in a prior proceeding, a reference to the style and case number of the prior proceeding and a certificate of good standing or certificate of authorization dated within sixty (60) days of the date the application is filed.	Ann F. Wood
1	5	807 KAR 5:001 Section 10(1)(b)(6)	A certified copy of a certificate of assumed name as required by KRS 365.015 or a statement that such a certificate is not necessary.	Ann F. Wood
1	6	807 KAR 5:001 Section 10(1)(b)(7)	The proposed tariff in form complying with 807 KAR 5:011 with an effective date not less than thirty (30) days from the date the application is filed.	Ann F. Wood
1	7	807 KAR 5:001 Section 10(1)(b)(8)	Proposed tariff changes shown either by providing present and proposed tariffs in comparative form or indicating additions by italicized inserts or underscoring and striking over deletions in a copy of the current tariff.	Ann F. Wood
1	8	807 KAR 5:001 Section 10(1)(b)(9)	Statement that notice given, see subsections (3) and (4) of 807 KAR 5:001, Section 10 with copy.	Ann F. Wood
1	9	807 KAR 5:001 Section 10(2)	If gross annual revenues exceed $1,000,000 written notice of intent filed at least four (4) weeks prior to application. Notice shall state whether the application will be supported by historical or a fully forecasted test period.	Ann F. Wood
1	10	807 KAR 5:001 Section 10 (3)	Form of notice to customers. Every utility filing an application pursuant to this section shall notify all affected customers in the manner prescribed herein. The notice shall include the following information: (a) Amount of change requested in dollar amounts and percentage for each customer classification to which change will apply.	Ann F. Wood

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Volume	Tab	Filing Requirement	Description	Sponsoring Witness(es)
			(b) Present and proposed rates for each customer class to which change would apply. (c) Electric, gas, water and sewer utilities - the effect upon average bill for each customer class to which change will apply. (d) Local exchange companies - include effect upon average bill for each customer class for change in basic local service. (e) A statement that the rates contained in this notice are the rates proposed by (name of utility); however, the Public Service Commission may order rates to be charged that differ from the proposed rates contained in this notice; (f) A Statement that any corporation, association, or person with a substantial interest in the matter may, by written request, within thirty (30) days after publication or mailing of this notice of the proposed rate changes request to intervene; Intervention may be granted beyond the thirty (30) day period for good cause shown. (g) A statement that any person who has been granted intervention by the commission may obtain copies of the rate application and any other filings made by the utility by contacting the utility through a name and address and phone number stated in this notice; (h) A statement that any person may examine the rate application and any other filings made by the utility at the main office of the utility or at the commission's office indicating the addresses and telephone numbers of both the utility and the commission; and (i) The commission may grant a utility with annual gross revenues greater than $1,000,000, upon written request, permission to use an abbreviated form of published notice of the proposed rates provided the notice includes a coupon which may be used to obtain all of the information required herein.	
1	11	807 KAR 5:001 Section 10(4)(a)	Manner of notification. Sewer utilities shall give the required typewritten notice by mail to all of their customers pursuant to KRS 278.185.	Ann F. Wood
1	12	807 KAR 5:001 Section 10(4)(b)	Manner of notification. Applicant has 20 customers or less, written notice of proposed rate changes and estimated amount of increase per customer class shall be mailed to each customer no later than date of application.	Ann F. Wood
1	13	807 KAR 5:001 Section 10(4)(c)	Except for sewer utilities, applicants with more than twenty (20) customers affected by the proposed general rate adjustment shall give the required notice by	Ann F. Wood

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Volume	Tab	Filing Requirement	Description	Sponsoring Witness(es)
3	24	807 KAR 5:001 Section 10(9)(b)	Most recent capital construction budget containing at minimum 3 year forecast of construction expenditures.	Gary T. Crawford Craig A. Johnson Ricky L. Drury
3	25	807 KAR 5:001 Section 10(9)(c)	Complete description, which may be in prefiled testimony form, of all factors used to prepare forecast period. All econometric models, variables, assumptions, escalation factors, contingency provisions, and changes in activity levels shall be quantified, explained, and properly supported.	Frank J. Oliva
3	26	807 KAR 5:001 Section 10(9)(d)	Annual and monthly budget for the 12 months preceding filing date, base period and forecasted period.	Frank J. Oliva
3	27	807 KAR 5:001 Section 10(9) (e)	Attestation signed by utility's chief officer in charge of Kentucky operations providing: 1. That forecast is reasonable, reliable, made in good faith and that all basic assumptions used have been identified and justified; and 2. That forecast contains same assumptions and methodologies used in forecast prepared for use by management, or an identification and explanation for any differences; and 3. That productivity and efficiency gains are included in the forecast;	Robert M. Marshall
3	28	807 KAR 5:001 Section 10(9)(f)	For each major construction project constituting 5% or more of annual construction budget within 3 year forecast, following information shall be filed: 1. Date project began or estimated starting date; 2. Estimated completion date; 3. Total estimated cost of construction by year exclusive and inclusive of Allowance for Funds Used During Construction ("AFUDC") or Interest During Construction Credit; and 4. Most recent available total costs incurred exclusive and inclusive of AFUDC or Interest During Construction Credit;	Gary T. Crawford Craig A. Johnson Ricky L. Drury
3	29	807 KAR 5:001 Section 10(9)(g)	For all construction projects constituting less than 5% of annual construction budget within 3 year forecast, file aggregate of information requested in paragraph (f) 3 and 4 of this subsection;	Craig A. Johnson Ricky L. Drury
3	30	807 KAR 5:001 Section 10(9)(h)	Financial forecast for each of 3 forecasted years included in capital construction budget supported by underlying assumptions made in projecting results of operations and including the following information: 1. Operating income statement (exclusive of dividends per share or earnings per share);	James C. Lamb, Jr. Frank J. Oliva

Volume	Tab	Filing Requirement	Description	Sponsoring Witness(es)
			2. Balance sheet; 3. Statement of cash flows; 4. Revenue requirements necessary to support the forecasted rate of return; 5. Load forecast including energy and demand (electric); 6. Access line forecast (telephone); 7. Mix of generation (electric); 8. Mix of gas supply (gas); 9. Employee level; 10. Labor cost changes; 11. Capital structure requirements; 12. Rate base; 13. Gallons of water projected to be sold (water); 14. Customer forecast (gas, water); 15. MCF sales forecasts (gas); 16. Toll and access forecast of number of calls and number of minutes *(telephone); and* 17. A detailed explanation of any other information provided.	
3	31	807 KAR 5:001 Section 10(9)(i)	Most recent FERC or FCC audit reports;	Ann F. Wood
3	32	807 KAR 5:001 Section 10(9)(j)	Prospectuses of most recent stock or bond offerings;	Ann F. Wood
3	33	807 KAR 5:001 Section 10(9)(k)	Most recent FERC Form 1 (electric), FERC Form 2 (gas), or the Automated Reporting Management Information System Report (telephone) and PSC Form T (telephone);	Ann F. Wood
4	34	807 KAR 5:001 Section 10(9)(l)	Annual report to shareholders or members and statistical supplements for the most recent 5 years prior to application filing date;	Ann F. Wood
5	35	807 KAR 5:001 Section 10(9)(m)	Current chart of accounts if more detailed than Uniform System of Accounts chart;	Ann F. Wood
5	36	807 KAR 5:001 Section 10(9)(n)	Latest 12 months of the monthly managerial reports providing financial results of operations in comparison to forecast;	Ann F. Wood
5	37	807 KAR 5:001 Section 10(9)(o)	Complete monthly budget variance reports, with narrative explanations, for the 12 months prior to base period, each	Frank J. Oliva

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Volume	Tab	Filing Requirement	Description	Sponsoring Witness(es)
			based on current and reliable data from single time period.	
5	45	807 KAR 5:001 Section 10(9)(w)	Local exchange carriers with fewer than 50,000 access lines need not file cost of service studies, except as specifically directed by PSC. Local exchange carriers with more than 50,000 access lines shall file: 1. Jurisdictional separations study consistent with Part 36 of the FCC's rules and regulations; and 2. Service specific cost studies supporting pricing of services generating annual revenue greater than $1,000,000 except local exchange access: a. Based on current and reliable data from single time period; and b. Using generally recognized fully allocated, embedded, or incremental cost principles.	Ann F. Wood
5	46	807 KAR 5:001 Section 10(10)(a)	Jurisdictional financial summary for both base and forecasted periods detailing how utility derived amount of requested revenue increase;	David G. Eames William Steven Seelye
5	47	807 KAR 5:001 Section 10(10)(b)	Jurisdictional rate base summary for both base and forecasted periods with supporting schedules which include detailed analyses of each component of the rate base;	William Steven Seelye
5	48	807 KAR 5:001 Section 10(10)(c)	Jurisdictional operating income summary for both base and forecasted periods with supporting schedules which provide breakdowns by major account group and by individual account;	Ann F. Wood
5	49	807 KAR 5:001 Section 10(10)(d)	Summary of jurisdictional adjustments to operating income by major account with supporting schedules for individual adjustments and jurisdictional factors;	Ann F. Wood
5	50	807 KAR 5:001 Section 10(10)(e)	Jurisdictional federal and state income tax summary for both base and forecasted periods with all supporting schedules of the various components of jurisdictional income taxes;	Ann F. Wood
5	51	807 KAR 5:001 Section 10(10)(f)	Summary schedules for both base and forecasted periods (utility may also provide summary segregating items it proposes to recover in rates) of organization membership dues; initiation fees; expenditures for country club; charitable contributions; marketing, sales, and advertising; professional services; civic and political activities; employee parties and outings; employee gifts; and rate cases;	Ann F. Wood
5	52	807 KAR 5:001 Section 10(10)(g)	Analyses of payroll costs including schedules for wages and salaries, employees benefits, payroll taxes straight time and overtime hours, and executive compensation by title;	Ann F. Wood

East Kentucky Power Cooperative, Inc.

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East Kentucky Power Cooperative, Inc.
Case No. 2008-00409
Fully Forecasted Test Period
Volume 2, Tab 23

Filing Requirement
807 KAR 5:001 Section 10(9)(a)
Sponsoring Witness: Ann F. Wood

Description of Filing Requirement:

Prepared testimony of each witness supporting its application including testimony from chief officer in charge of Kentucky operations on the existing programs to achieve improvements in efficiency and productivity, including an explanation of the purpose of the program.

Response:

Prepared testimonies of the following witnesses are included as attachments in this volume.

Robert M. Marshall
David G. Eames
Jonathon Andrew Don
Daniel M. Walker
Frank J. Oliva
Gary T. Crawford
James C. Lamb, Jr.
Craig A. Johnson
Ricky L. Drury
Ann F. Wood
William Steven Seelye

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

GENERAL ADJUSTMENT OF ELECTRIC RATES	)	PSC CASE NO.
OF EAST KENTUCKY POWER	)	2008-00409
COOPERATIVE, INC.	)	

TESTIMONY OF
ROBERT M. MARSHALL
PRESIDENT AND CHIEF EXECUTIVE OFFICER
EAST KENTUCKY POWER COOPERATIVE

Filed: October 31, 2008

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

A. My name is Robert M. Marshall and my business address is East Kentucky Power Cooperative (EKPC), 4775 Lexington Road, Winchester, Kentucky 40391. I am President and Chief Executive Officer.

Q. How long have you been employed by East Kentucky Power Cooperative, Inc. ("EKPC")?

A. I have been employed by EKPC since January 1, 2007. Prior to being named President and CEO at EKPC, I was President and CEO at Owen Electric Cooperative ("Owen") in Owenton, Kentucky.

Q. Please state your education and professional experience.

A. I received a bachelor of science degree in civil engineering from the Clemson University. I also completed a program in management development from the Harvard Business School. I have been employed in the utility industry for thirty-nine years, serving in a variety of management positions at Florida Power & Light and as President and CEO at Coosa Valley Electric Cooperative in Alabama. I was President and CEO at Owen for about seven years.

Q. Please provide a brief description of your duties at EKPC.

A. The Board of Directors has given me, as CEO, the responsibility for managing the Cooperative's business on a day-to-day basis. I develop and recommend to the Board EKPC's objectives and policies, short- and long-range plans, and annual budgets and work plans. I administer the Board's approved wage and salary plan, authorize prudent investments, administer the budget, implement policies, plans and programs established by the Board, ensure an appropriate organizational structure, negotiate contracts, and submit periodic and special reports to the Board on operations, financial issues, budgets, power supply, rates, construction, and other areas. This is just a sampling of the responsibilities established for the president and CEO in EKPC Board policy.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present an overview of EKPC's Application for an increase in base rates, a discussion of the need for the rate increase, an introduction of the witnesses, and a description of the proposed rate design phase-in that includes a pass-through of the proposed increase in base rates to EKPC's Member Systems when the new rates initially go into effect with a transition to cost based rates in 2010.

Q. Are you supporting certain information required by Commission Regulations 807 KAR 5:001, Section 10?

A. Yes. I am sponsoring the following schedules for the corresponding Filing Requirements:

Filing Requirement	Description	Volume	Tab #
Section 10(1)(b)(1)	A statement of the reason the adjustment is required.	Vol. 1	Tab 1

Filing Requirement	Description	Volume	Tab #
Section 10(9)(e)	Attestation by utility's chief officer in charge of Kentucky operations providing: 1) that forecast is reasonable, reliable, made in good faith and that all basic assumptions used have been identified and justified; 2) that forecast contains same assumptions and methodologies used in forecast prepared for use by management, or an identification and explanation for any difference; and 3) that productivity and efficiency gains are included in the forecast.	Vol. 3	Tab 27

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring Exhibit RMM-1, which is the resolution from the EKPC Board of Directors approving the application for a rate increase.

Q. What increase is EKPC seeking and why is EKPC requesting an increase in base rates at this time?

A. EKPC is requesting an increase in base rates that will result in approximately $67.9 million in additional annual revenues, which is an increase of 7.8%, to address the recovery of the costs related to the Spurlock 4 Unit going into service and to address serious challenges regarding its financial condition. As discussed in Mr. Seelye's testimony, the $67.9 million request differs slightly from the Board-approved amount of $67.7 million. The reason for this is that in the presentation to the Board the rates were applied to billing determinants for the 12 months ended April 30, 2010, but in the rate case application the Board-approved rates were applied to the billing determinants for 12 months ended May 31, 2010.

Without rate relief, EKPC's interest and debt coverage ratios will be inadequate to meet the requirements set forth in the mortgage and credit facility loan agreements with its lenders after Spurlock 4 goes into commercial operation on April 1, 2009. Spurlock 4 is a 278 MW circulating fluidized bed, coal-fired generating unit which will cost $528 million. EKPC has not yet included the Construction Work In Progress ("CWIP") or any of the costs for Spurlock 4 in rate base. Because it has been accruing an Allowance for Funds Used During Construction on its construction expenditures, EKPC is currently not recovering interest expenses associated with Spurlock 4 through base rates. Once Spurlock 4 is placed into commercial operation, EKPC will experience a significant increase in its non-fuel operation and maintenance expenses, depreciation expenses and current interest expenses. Although Spurlock 4 will result in fuel and purchased power cost savings, those savings will be automatically passed along to its members through the application of the monthly fuel adjustment clause. Therefore, the fuel cost savings will not off-set the negative impact on EKPC's net income from placing Spurlock 4 in service nor will it offset the significant increases in its non-fuel operation and maintenance expenses, depreciation expenses and current interest expenses that EKPC will incur. When EKPC begins incurring these increases in non-fuel operation and maintenance expenses, depreciation expenses and current interest expenses, EKPC's interest and debt coverage ratios will be inadequate to meet the requirements set forth in the mortgage and credit facility loan agreements with its lenders. This is why EKPC is requesting an increase in its base rates and is using a forward test year in this proceeding. It is critical that EKPC's revenues from the application of wholesale rates be sufficient to cover these significant increases in expenses beginning April 1, 2009. Even a delay of a month or two could result in EKPC failing to meet its 2009 debt covenants. Additionally, with the current crisis in the credit market, it is essential that EKPC increase its equity percentage and financial strength in order to have the ability to attract capital in the future.

EKPC failed to meet its debt covenants in 2006 and had to request a waiver from its lenders in 2006. EKPC is also very close to failing to meet its debt covenants in 2008 and may need to request a waiver again this year. When EKPC requests a waiver of its debt covenants from its lenders, the lenders charge EKPC a waiver fee to cover their legal costs, due diligence expenses, and to compensate them for EKPC's increased perceived risk. These anticipated fees would cost EKPC between $1.5 million and $2 million in incremental expense.

Q. What effective date is EKPC proposing to implement the rate increase proposed in this Application?

A. As noted above, it is essential that EKPC begin recovering additional revenue in some form beginning April 1, 2009. This can occur either by establishing a regulatory asset that would allow EKPC to record the additional revenues that it would have collected in April and May 2009, if EKPC's new rates were to have gone into effect on April 1, 2009, or through increased wholesale rates going into effect on April 1, 2009, subject to refund of any excess over the rates finally approved by the Commission. This is described in more detail in testimony submitted by Mr. Steve Seelye in support of the motion filed by EKPC, along with its Application in this case, for authority to establish such a regulatory asset. EKPC would prefer to address this problem by establishing a regulatory asset.

Q. Why does EKPC need recovery of costs associated with Spurlock 4 to begin by April 1, 2009?

A. EKPC is requesting authority to recover additional costs associated with Spurlock 4 through the establishment and subsequent amortization of a regulatory asset because of the deterioration of its financial condition that will otherwise result after Spurlock 4 goes into commercial service, and in order to demonstrate to the financial community that it is taking action to strengthen its financial condition and to meet its loan covenants. In its Order in case No. 2006-00472, the Commission recognized the financial pressure that Spurlock 4 going into service could cause and ordered EKPC to file a base rate case within nine months of Spurlock 4 going into service. This rate case complies with the requirements of that Order.

Q. What recent cost savings measures has EKPC initiated?

A. Currently, EKPC is purchasing a significant portion of the power necessary to meet its members' needs. The additional generating capacity that EKPC is constructing will help EKPC to avoid these purchases and reduce the delivered cost of power to its members. EKPC's other cost containment initiatives include: reduction in the defined benefit plan level, increase in employee medical plan contributions, elimination of salary increases in 2007, improvements in the competitive bidding process, materials standardization, and improvements in power plant efficiencies.

EKPC is also deferring a computer software upgrade. Even with these cost cutting measures, revenues from current base rates will be insufficient to meet debt covenants after April 1, 2009.

Q. When was EKPC's last base rate increase?

A. EKPC received an interim increase of $19 million annually beginning in April 2007 in case No. 2006-00472. This interim increase was made permanent in December 2007. EKPC had originally requested an increase of $43.4 million in that proceeding.

Q. Please list EKPC's witnesses who will provide detailed testimony supporting the proposed increase in base rates.

A. (1) Mr. David G. Eames, Chief Financial Officer at EKPC, will describe the overall financial condition of EKPC, the basis of the requested increase in base rates, and the need for additional equity. Mr. Eames will also sponsor the financial forecast for the test year.

(2) Mr. Jonathon Andrew Don, Vice-President of Capital Markets-Member Products, National Rural Utilities Cooperative Finance Corporation ("CFC"), will discuss EKPC's need to build equity, EKPC's credit strengths and weaknesses, and environment in which EKPC will need to raise capital.

(3) Mr. Dan Walker, President of Walker and Associates, will prepare an independent appraisal of EKPC's cost of capital requirements and recommend TIER and equity levels that will enable EKPC to maintain its financial integrity.

(4) Mr. Frank Oliva, Manager of Finance at EKPC, will provide an overview of EKPC's budgeting process and will also provide a detailed explanation of the

methodology and assumptions used to forecast items other than projections of major construction projects and projections of capital and operations and maintenance expenses for the power production and power delivery functions.

(5) Mr. Gary Crawford, Vice-President, Construction, at EKPC, will describe the Spurlock 4 circulating fluidized bed, coal-fired generating unit, the combustion turbine No's. 8 and 9, and the Smith 1 circulating fluidized bed, coal-fired generating unit that EKPC is in the process of constructing. He will discuss the in-service dates and estimated costs of these generating units and describe the methodology and assumptions used to develop these cost estimates.

(6) Mr. James C. Lamb, Jr. Senior Vice President of Power Supply at EKPC, will explain the methodology and assumptions used to prepare the load, sales and revenue forecasts.

(7) Mr. Craig Johnson, Vice-President of Production at EKPC, will explain the methodology and assumptions used to prepare EKPC's generation operations and maintenance expenses and capital expenditures forecasts. He will compare EKPC's O&M costs to industry averages and discuss EKPC's forced outage rates.

(8) Mr. Ricky L. Drury, Manager of Engineering at EKPC, will explain the methodology and assumptions used to prepare EKPC's power delivery operations and maintenance expenses and capital expenditures forecasts.

(9) Ms. Ann Wood, Manager, Regulatory Services, will discuss the regulatory requirements in this Application and will sponsor a number of filings requirements for the rate case application.

(10) Mr. Steve Seelye, Principal and Senior Consultant at The Prime Group LLC, will explain the revenue requirement calculation, discuss the cost-of-service study and the methodology used to develop this study, discuss the rate design and tariff changes that EKPC is proposing, and explain how the base rate increase will be passed through to EKPC's Member Systems.

Q. Please describe the proposed rate design phase-in that includes a pass through of the proposed increase in base rates to EKPC's Member Systems when the new rates initially go into effect with a transition to cost-based rates in 2010.

A. The member systems recognize that it is necessary to evolve to a rate structure where fixed costs are recovered through demand charges and variable costs are recovered through energy charges. To accommodate the need for immediacy in implementing the proposed rate increase and to help provide time for the member systems to adapt to a new cost-based rate design, the EKPC Board decided to pass through the increase in base rates on a proportional basis when the new rates go into effect and to adopt a new cost-based rate structure beginning one year later. Mr. Seelye's testimony will more fully describe this proposed phase-in of cost-based rates.

Q. Will EKPC's base rate increase be passed through by the Member Systems?

A. As discussed by Mr. Seelye in his testimony, the increase will be passed through by EKPC's Member Systems pursuant to KRS 278.455(2) when the rates go into effect. Fourteen of the sixteen Member Systems are filing for approval of the pass-through. The remaining two Member Systems are filing their own base rate cases.

Q. Please summarize EKPC's request in this case.

A. EKPC is seeking an additional $67.9 million in annual revenues in order to improve its financial condition and meet its loan covenants. This increase, coupled with EKPC's cost containment efforts, will enable EKPC to become a more financially solvent entity and will help to grow equity, which is going to be necessary to meet the more stringent lending requirements that are likely to result from the current credit crisis.

Q. Does this conclude your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In re the Matter of:

THE APPLICATION OF EAST KENTUCKY	)	
POWER COOPERATIVE, INC. FOR A	)	**CASE NO. 2008-00409**
GENERAL ADJUSTMENT OF ITS	)	
WHOLESALE ELECTRIC RATES	)	

AFFIDAVIT

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Robert M. Marshall, 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.

Subscribed and sworn before me on this 24th day of October, 2008.

Claudia A. Embs
Notary Public

My Commission expires: March 23, 2011

FROM THE MINUTE BOOK OF PROCEEDINGS OF THE BOARD OF DIRECTORS OF EAST KENTUCKY POWER COOPERATIVE, INC.

At a regular meeting of the Board of Directors of East Kentucky Power Cooperative, Inc. held at the Headquarters Building, 4775 Lexington Road, located in Winchester, Kentucky, on Tuesday, September 9, 2008, at 9:30 a. m., EDT, the following business was transacted:

File Rate Application

Upon recommendation of management and the Operations, Services and Support Committee and after review and discussion of the applicable information, a motion was made by Wade May and, there being no further discussion, passed to approve the following:

Whereas, East Kentucky Power Cooperative, Inc. ("EKPC") continues to experience financial challenges;

Whereas, There is a possibility that, without continued improvement in its financial condition, EKPC will not satisfy the debt covenant requirements under the Rural Utilities Service ("RUS")/National Rural Utilities Cooperative Finance Corporation ("CFC") Mortgage and the Credit Facility Agreement;

Whereas, EKPC's financial condition also concerns the Public Service Commission ("Commission");

Whereas, EKPC intends to file the rate adjustment application with the Commission using a fully forecasted test period and seeks to increase annual revenues by approximately $67.7 million, or an 7.76 percent increase; and

Whereas, EKPC plans to file the application on October 31, 2008, and will seek actual implementation of the proposed rates for service rendered on or after June 1, 2009; now, therefore, be it

Resolved, That the EKPC Board of Directors ("Board") hereby grants approval to file a rate increase application for an annual increase of $67.7 million, or 7.76 percent, to be effective for service rendered on or after December 1, 2008, which would support an actual implementation date of June 1, 2009, after the statutory suspension period; and that the Board authorizes EKPC to seek RUS and CFC approval for this application.

The foregoing is a true and exact copy of a resolution passed at a meeting called pursuant to proper notice at which a quorum was present and which now appears in the Minute Book of Proceedings of the Board of Directors of the Cooperative, and said resolution has not been rescinded or modified.

Witness my hand and seal this 9th day of September 2008.

A. L. Rosenberger, Secretary

Corporate Seal

A. L. Rosenberger

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

GENERAL ADJUSTMENT OF ELECTRIC RATES	)	PSC CASE NO.
OF EAST KENTUCKY POWER	)	2008-00409
COOPERATIVE, INC.	)	

TESTIMONY OF
DAVID G. EAMES
CHIEF FINANCIAL OFFICER
EAST KENTUCKY POWER COOPERATIVE

Filed: October 31, 2008

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

A. My name is David G. Eames and my business address is East Kentucky Power Cooperative (EKPC), 4775 Lexington Road, Winchester, Kentucky 40391. I am Chief Financial Officer for EKPC.

Q. Please state your education and professional experience.

A. I received a Bachelor's degree in Engineering from Northeastern University in 1971 and a Master's degree in Business Administration in 1976 from the University of Michigan. I am a licensed professional engineer and a certified public accountant in the Commonwealth of Kentucky. In addition, I have attended and participated in several seminars and supplemental training courses over the years. I have been employed by EKPC since January 1979 and have occupied my current position within the EKPC organization since September 1985.

Q. Please provide a brief description of your duties at EKPC.

A. I am responsible for all aspects of finance, accounting, performance measures and risk management at EKPC.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the overall financial condition of East Kentucky Power Cooperative, the basis of the requested increase in base rates, and the need for additional equity.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring Eames Exhibit-1. This exhibit summarizes EKPC's financial forecast for the fully-forecasted test year used to support EKPC's proposed revenue increase. It is utilized by Mr. Steve Seelye, Principal and Senior Consultant at the Prime Group, L.L.C., in his direct testimony in this case (Application Tab 23), to determine EKPC's revenue deficiency.

Q. Are you supporting certain information required by Commission Regulations 807 KAR 5:001, Section 10?

A. Yes. I am sponsoring the following schedules for the corresponding Filing Requirements:

Filing Requirement	Description	Volume	Tab #
Section 10(1)(b)(1)	*A statement of the reason the adjustment is required.*	Vol. 1	Tab 1
Section 10(10)(a)	Jurisdictional financial summary for both base and forecasted periods detailing how utility derived amount of requested revenue increase.	Vol. 5	Tab 46
Section 10(10)(j)	Cost of capital summary for both base and forecasted periods with supporting schedules providing details on each component of the capital structure.	Vol. 5	Tab 55

Q. What is the basis for the requested $67.9 million increase in base rates?

A. EKPC is short of base load capacity because of load growth on its system. As a result of this shortfall, EKPC has been meeting member needs by purchasing power in the market. To more cost effectively meet this demand, the Spurlock 4 generating unit, a 278 MW circulating fluidized bed, coal-fired generating unit, is scheduled to be placed into commercial operation in April 2009. The capital cost of Spurlock 4 is projected to be approximately $528 million. EKPC is also scheduled to add two combustion turbines ("CTs"), CT 9 and CT10, at Smith Station in October 2009 at a cost of approximately $156 million. EKPC cannot support the costs associated with these capital additions without a base rate increase.

Q. What costs will EKPC incur once Spurlock 4 is placed in commercial operation?

A. EKPC will incur increased interest, depreciation, and non-fuel operating and maintenance expense once Spurlock 4 is placed in operation. If these increased costs are not recovered through base rates, EKPC's compliance with its Times Interest Earned Ratio ("TIER"), Debt Service Coverage ("DSC") ratio, and equity debt covenant requirements will be in jeopardy, resulting in EKPC not meeting its Rural Utilities Service ("RUS") and National Rural Utilities Cooperative Finance Corporation ("CFC") Mortgage and private financing Credit Facility loan covenants for 2009.

Q. What TIER is EKPC seeking in this proceeding?

A. EKPC is seeking a TIER of 1.45, which is supported by the testimony of Mr. Dan Walker, President of Walker and Associates (Application Tab 23).

Q. What are the forecasted TIER and DSC for the test year ending May 31, 2010 without the increase in base rates?

A. As reflected in the attached Eames Exhibit 1, both the TIER and DSC without rate relief are forecasted to be 0.941.

Q. Is a TIER level of 1.45 necessary to allow EKPC to meet its objective of building equity?

A. Yes. The Commission granted EKPC a TIER level of 1.35 in PSC Case No. 2006-00472. However, EKPC has been unable to significantly improve its equity level since the rates granted in that case went into effect. EKPC revenues continue to be subject to weather and economic conditions, and EKPC continues to face the on-going risk of substantial unrecoverable costs due to forced outages. A TIER of 1.45, and a corresponding annual rate increase of $67.9 million are needed, based on those risks, to allow EKPC to start to rebuild its equity level and meet its financial obligations pursuant to the RUS/CFC Mortgage Agreement and the Credit Facility Agreement.

Q. Has EKPC ever failed to meet the covenants for the RUS Mortgage and the Credit Facility Agreement?

A. Yes. EKPC failed the covenants for RUS purposes in 2006 and would have failed to meet the minimum requirements in 2006 for the Credit Facility Agreement if a waiver had not been obtained from the lenders.

Q. How did EKPC resolve those situations with its lenders?

A. EKPC presented a plan of action to the RUS, which included the rate increase requested in PSC Case No. 2006-00472 and the many cost reduction efforts taken by EKPC in the past few years. RUS did not declare EKPC to be in default of its Mortgage covenants, based on its continuing efforts to improve its net margins and equity level, but RUS continues to monitor EKPC's financial condition carefully. The lenders under the Credit Facility granted EKPC the necessary waiver, based on similar assurances of efforts to improve its financial performance and the payment of the waiver fee. The waiver cost to EKPC was $794,000, which represents additional fees and interest expenses

Q. Does EKPC expect to meet the loan covenants in 2008?

A. EKPC expects to meet the covenants for RUS/CFC purposes but does not believe it will meet the covenants for the Credit Facility Agreement without the relief requested in PSC Case No. 2008-00436.

Q. What is the reason for possibly failing the Credit Facility Agreement covenants?

A. EKPC has had to absorb $12 million of forced outage costs as of September 30, 2008, and had several unexpected maintenance projects at its Spurlock Station, all of which has put it $10 million over budget so far for 2008.

Q. What are the consequences of EKPC not satisfying the DSC requirements of the Mortgage Agreement and the Credit Facility Agreement?

A. If EKPC does not meet the loan covenants, the Credit Facility lenders can place EKPC in default, and refuse to advance additional funds, or could demand immediate payment of the loan funds outstanding. This would be a very serious development, since EKPC does not have surplus funds to pay the loans, if called. At the very least, EKPC would need another waiver, which in today's market could cost several million dollars. If rate relief is not granted in this case, EKPC would also be in potential default of the RUS mortgage. Consequently, RUS could refuse to advance any additional funds, and could implement other remedies available to it under the Mortgage. Under cross-default provisions, any default declared by RUS would be a default of the Credit Facility, as well.

Q. Why is it important for EKPC to build equity?

A. A strong equity position is critical for EKPC to meet its loan covenants and to be able to obtain future financing. EKPC expects to need short term private financing at least through 2019, for its capital expansion program. Having the appropriate amount of equity is essential for access to such financing, and will significantly reduce the cost of future borrowings. EKPC's equity as a percent of assets as of August 2008 was 6.34%, far below the level EKPC needs to be considered to be in a strong credit position by the investment community.

Q. When does the Credit Facility Agreement mature?

A. The Credit Facility Agreement expires on September 2, 2010.

Q. In testimony in Commission Case No. 2006-00472, EKPC stated that it anticipated an increasing need to rely on private financing for generation projects in the future. Has there been any change in this situation?

A. No, not at all. The RUS is still not lending for coal-fired or nuclear base load generation. It is unknown whether this suspension of generation loans will be lifted at any point in the future. EKPC is investigating private financing alternatives for the Smith CFB Unit 1 project, which will be more expensive than the loans guaranteed by the RUS in the past.

Q. Based on EKPC's current financial condition, do you anticipate any difficulty in renewing the Credit Facility Agreement in 2010?

A. If EKPC does not show significant improvement in its financial position, it will be very difficult or impossible to secure a replacement Credit Facility Agreement similar to the one currently in place, and any replacement will be much more expensive. This risk is discussed further in the testimony of Mr. Jonathon Andrew Don, Vice-President of Capital Markets-Member Products, of CFC.

Q. EKPC is proposing to establish a regulatory asset as a means of providing cost recovery for Spurlock Unit 4 in April and May 2009. Based on EKPC's current financial condition, how important is it for this regulatory asset treatment to be granted?

A. It is extremely important. As indicated in my testimony and the testimonies of Mr. Walker, Mr. Don, and Mr. Seelye, EKPC's equity is extremely low. The inability to obtain rate recovery concurrent with the commercial operation of Spurlock Unit 4 would place even more financial distress on EKPC. I strongly support EKPC's proposal to establish a regulatory asset for this purpose.

Q. EKPC has another case (No. 2008-00436) before the Commission concerning establishing a regulatory asset for unrecovered forced outage replacement power costs. If the Commission approves the establishment of a regulatory asset in that proceeding, how will the decision impact this Application for a general rate increase?

A. Upon Commission approval of the regulatory asset treatment outlined in Case No. 2008-00436, EKPC will amend this filing (No. 2008-00409) and request an adjustment to consider the amortization of the regulatory asset for unrecovered forced outage replacement power costs.

Q. Does this conclude your testimony?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In re the Matter of:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A GENERAL ADJUSTMENT OF ITS WHOLESALE ELECTRIC RATES	))))	**CASE NO. 2008-00409**

AFFIDAVIT

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

David G. Eames, 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.

David G Eames

Subscribed and sworn before me on this 23rd day of October, 2008.

Peggy S. Griffin
Notary Public

My Commission expires: December 8, 2009

EAST KENTUCKY POWER COOPERATIVE

Budgeted Statement of Operations

Forecasted Test Year June 2009 - May 2010

	STATEMENT OF OPERATIONS	June 2009	July 2009	August 2009	September 2009	October 2009	November 2009	December 2009	January 2010	February 2010	March 2010	April 2010	May 2010	Totals
	Electric Energy Revenues													
1	Power Sales-Member Coops - Basic Rate	51,785,981	58,174,842	57,165,523	50,166,265	45,672,574	52,826,789	64,293,059	68,630,721	59,352,634	56,992,109	46,358,215	47,937,042	659,355,754
2	Power Sales-Member Coops - Fuel Clause	4,839,308	5,695,708	9,418,926	7,092,765	4,579,464	4,936,575	12,775,630	12,408,150	12,056,270	11,385,749	6,637,509	5,791,586	97,617,640
3	Power Sales-Member Coops - Env Surcharge	7,767,296	8,888,698	9,507,524	8,197,366	7,038,178	7,838,500	10,742,159	11,429,314	9,559,858	9,230,840	7,236,952	7,288,484	104,725,169
4	Power Sales-Member Coops - Steam	861,269	860,969	933,981	905,265	964,278	912,316	1,147,638	1,136,189	1,082,146	1,083,028	965,690	947,268	11,800,037
5	Power Sales - Off System	1,332,340	1,119,946	1,159,704	1,311,731	1,001,815	253,615	272,436	398,354	439,280	1,096,284	866,814	734,687	9,987,006
6	Wheeling Revenue	201,540	197,760	223,545	198,933	173,994	176,604	188,281	279,490	214,328	178,513	173,754	182,381	2,389,123
7	Other Operating Revenue - Income	30,467	30,467	30,467	30,467	30,767	30,767	30,767	39,307	39,307	39,307	39,307	27,646	399,043
8	Total Operating Revenue & Patronage Capital	66,818,201	74,968,390	78,439,670	67,902,792	59,461,070	66,975,166	89,449,970	94,321,525	82,743,823	80,005,830	62,278,241	62,909,094	886,273,772
9														
10	Operation Expenses													
11	Production Costs Excluding Fuel - Dale	477,104	469,997	469,184	463,716	479,841	464,416	640,107	488,372	510,420	495,218	483,466	486,527	5,928,368
12	Production Costs Excluding Fuel - Cooper	557,426	552,584	561,302	539,761	511,439	499,980	804,349	581,184	517,271	539,935	524,800	527,535	6,717,566
13	Production Costs Excluding Fuel - Spurlock	2,158,225	2,183,518	2,332,563	2,247,311	2,052,564	2,266,813	2,986,644	2,241,025	2,313,730	2,460,945	2,212,164	2,412,475	27,867,977
14	Production Costs Excluding Fuel - Gilbert & Unit #4	1,374,399	1,396,093	1,401,168	1,199,684	1,231,260	1,373,908	1,829,238	1,611,141	1,544,243	1,650,955	1,582,465	1,289,805	17,484,359
15	Production Costs Excluding Fuel - Smith	311,289	326,539	322,352	313,687	326,984	305,960	384,450	365,610	367,110	376,117	411,167	364,290	4,175,555
16	Production Costs Excluding Fuel - Dist. Generation	153	153	153	153	153	153	154	143	143	143	143	143	1,787
17	Production Costs Excluding Fuel - Landfill Gases	50,083	49,886	50,284	49,706	50,341	50,347	86,825	52,070	56,974	59,352	57,000	58,190	671,058
18	Production Costs Excluding Fuel - Allowances	801,662	984,403	960,270	723,776	511,628	768,152	838,169	230,884	199,796	185,781	117,482	298,867	6,620,870
19	Fuel-Dale	2,288,615	3,295,610	3,109,849	2,033,868	2,164,900	3,418,382	3,345,152	4,145,336	3,543,148	3,014,705	1,761,213	2,252,758	34,373,536
20	Fuel-Cooper	4,411,534	5,446,015	5,317,069	3,840,413	3,194,767	5,541,300	6,007,884	7,248,205	6,257,236	5,678,807	3,202,800	5,272,808	61,418,838
21	Fuel-Spurlock	14,145,642	14,903,387	14,925,454	13,936,695	15,091,507	11,329,378	16,102,554	17,475,018	15,660,028	16,864,338	15,932,923	14,955,227	181,322,151
22	Fuel - Gilbert & Unit #4	8,372,066	8,490,319	8,686,413	8,177,557	5,841,837	7,147,048	8,789,917	9,025,075	7,977,677	8,825,489	6,955,397	6,359,150	94,647,945
23	Fuel-Smith	1,770,513	5,375,556	3,909,124	2,018,749	1,380,452	5,529,129	6,045,764	5,427,273	4,226,393	2,369,864	1,647,992	1,427,582	41,128,391
24	Fuel-Distributive Generation	534	534	534	534	534	534	794	266	534	534	534	534	6,400
25	Fuel-Landfill Gas	40,548	7,817	(456,001)	40,687	4,885	(10,275)	42,188	9,428	(5,061)	41,793	8,475	(11,754)	(287,270)
26	Fuel Handling	1,189,333	1,175,217	1,170,849	1,168,233	1,034,919	1,169,731	1,233,858	1,244,890	1,286,210	1,284,707	1,277,848	1,091,699	14,327,494
29	Other Power Supply	4,691,895	6,182,885	6,037,943	4,568,392	4,460,144	8,322,164	8,404,411	10,316,391	7,896,440	5,019,813	4,519,617	4,283,122	74,703,217
30	Other Power Supply-ACES Fees	207,000	207,000	207,000	207,000	207,000	207,000	207,000	207,000	207,000	207,000	207,000	207,000	2,484,000
31	Transmission Wheeling	1,405,070	1,346,746	1,377,196	1,305,222	1,214,810	1,296,902	1,319,317	2,198,733	1,548,283	875,710	929,816	815,145	15,632,950
32	Transmission Expense	934,015	950,027	933,555	931,043	1,248,363	935,152	1,041,326	1,192,816	1,029,009	1,062,322	1,032,744	1,061,082	12,351,454
33	Distribution Expense	80,153	99,467	79,095	78,540	79,871	79,132	92,111	92,502	84,294	80,351	86,164	89,946	1,021,626
34	Customer Accounts	0	0	0	0	0	0	0	0	0	0	0	0	0
35	Customer Service and Information	137,026	134,417	136,972	138,785	138,738	137,263	173,049	171,473	147,411	157,978	143,017	148,461	1,764,590
36	Sales	833	833	833	833	833	833	1,253	417	833	833	833	833	10,000
37	Administrative and General	2,133,529	3,042,756	1,782,730	2,071,089	1,858,633	2,092,466	1,867,540	3,357,943	2,249,476	2,546,210	1,844,206	1,828,751	26,675,329
38	Total Operation Expenses	47,538,647	56,621,759	53,315,891	46,055,434	43,086,403	52,925,868	62,244,054	67,683,195	57,618,598	53,798,900	44,939,266	45,220,176	631,048,191

Eames Exhibit 1
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EAST KENTUCKY POWER COOPERATIVE

Budgeted Statement of Operations

Forecasted Test Year June 2009 - May 2010

STATEMENT OF OPERATIONS	June 2009	July 2009	August 2009	September 2009	October 2009	November 2009	December 2009	January 2010	February 2010	March 2010	April 2010	May 2010	Totals
Maintenance Expenses													
1 Production - Dale	2,091,803	731,612	742,442	420,074	331,994	307,082	362,163	236,856	284,756	409,515	290,934	778,659	6,987,890
2 Production - Cooper	716,861	715,809	714,325	1,056,730	3,061,490	1,460,136	903,078	465,387	610,957	619,026	613,670	618,257	11,555,726
3 Production - Spurlock	1,544,862	1,369,329	1,550,929	1,586,066	1,614,960	1,447,080	1,477,484	1,305,840	1,390,642	1,484,017	1,921,692	1,379,292	18,072,193
4 Production - Gilbert & Unit #4	487,920	492,860	461,523	452,920	536,883	974,948	436,051	394,237	621,662	596,867	399,926	1,819,538	7,675,335
5 Production - Smith	69,605	69,591	69,741	69,605	603,010	70,112	88,383	50,719	65,734	395,777	436,761	116,734	2,105,772
6 Production - Dist. Generation	3,912	3,911	3,920	3,912	3,966	3,913	4,016	3,940	3,921	3,923	3,922	3,921	47,177
7 Production - Landfill Gases	85,749	101,540	104,339	92,349	387,640	259,303	396,405	89,140	306,105	181,937	120,126	105,605	2,230,238
8 Transmission Expense	486,784	396,736	396,264	396,524	400,679	395,546	522,563	274,312	391,158	393,311	391,510	393,658	4,839,045
9 Distribution Expense	81,855	81,841	82,000	81,855	84,805	81,862	102,816	64,565	81,665	81,961	80,946	81,665	987,836
10 General Plant	103,942	159,232	77,590	79,242	78,137	77,888	135,638	91,937	136,098	88,620	141,369	76,098	1,245,791
11 Total Maintenance Expenses	5,673,293	4,122,461	4,203,073	4,239,277	7,103,564	5,077,870	4,428,597	2,976,933	3,892,698	4,254,954	4,400,856	5,373,427	55,747,003
12													
13													
14													
15													
16 Fixed Costs													
17 Depreciation/Amortization	5,723,016	5,723,300	5,723,363	6,063,468	6,109,495	6,109,495	6,450,578	6,318,749	6,320,249	6,335,160	6,335,491	6,345,947	73,558,311
18 Taxes	0	0	0	0	0	0	0	0	0	800	0	0	800
19 Interest on Long-Term Debt	10,667,749	11,140,546	11,139,513	11,027,355	11,290,717	11,168,148	11,288,671	11,420,418	11,096,753	11,562,532	11,921,671	12,059,814	135,783,887
20 Interest During Construction	0	0	0	0	0	0	0	0	0	0	0	0	0
21 Other Interest Expense	3,288	3,397	3,397	3,288	3,397	3,288	3,397	3,397	3,068	3,397	3,288	3,397	39,999
22 Other Deductions	224,378	224,386	223,747	223,728	224,014	223,616	259,251	190,156	223,980	223,876	223,674	(101,100)	2,363,706
23 Total Fixed Costs	16,618,431	17,091,629	17,090,020	17,317,839	17,627,623	17,504,547	18,001,897	17,932,720	17,644,050	18,125,765	18,484,124	18,308,058	211,746,703
24													
25													
26 Total Cost of Electric Service	69,830,371	77,835,849	74,608,984	67,612,550	67,817,590	75,508,285	84,674,548	88,592,848	79,155,346	76,179,619	67,824,246	68,901,661	898,541,897
27													
28 Operating Margins	(3,012,170)	(2,867,459)	3,830,686	290,242	(8,356,520)	(8,533,119)	4,775,422	5,728,677	3,588,477	3,826,211	(5,546,005)	(5,992,567)	(12,268,125)
29													
30													
31 Non-Operating Items													
32 Interest Income	336,637	348,197	348,066	344,753	347,842	344,532	347,623	320,752	311,008	320,467	317,133	320,179	4,007,189
33 Allowance for Funds used for Construction	0	0	0	0	0	0	0	0	0	0	0	0	0
34 Other Non-Operating Income	(2,150)	(2,100)	(2,103)	(2,219)	(2,194)	(2,116)	(2,586)	(2,856)	(2,470)	(2,626)	(2,222)	(2,270)	(27,912)
35 Other Capital Credits/Patronage Dividends	4,166	4,166	204,166	4,166	4,166	4,166	4,174	4,166	4,166	4,166	4,166	4,166	250,000
36 Total Non-Operating Items	338,653	354,463	554,335	351,138	354,202	350,814	354,383	327,774	317,644	327,259	323,521	326,615	4,229,277
37													
38													
39 Net Patronage Capital & Margins(Deficits)	(3,350,823)	(3,221,922)	3,276,351	(60,896)	(8,710,722)	(8,883,933)	4,421,039	5,400,903	3,270,833	3,498,952	(5,869,526)	(6,319,182)	(8,038,848)
40													
41 TIER													0.941
42													
43 DSC													0.941

Eames Exhibit 1
Page 2 of 2

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.	)	2008-00409

TESTIMONY OF
JONATHAN ANDREW DON
ON BEHALF OF
EAST KENTUCKY POWER COOPERATIVE, INC.

Filed: October 31, 2008

Q. Please state your name and business address.

A. My name is Jonathon Andrew Don. My business address is 2201 Cooperative Way, Herndon, Virginia 20171.

Q. Please state your occupation and place of employment.

A. I am employed by National Rural Utilities Cooperative Finance Corporation (CFC) as the Vice President of Capital Market Relations. In that capacity I am responsible for the structuring and execution of loan syndication activities and loan transactions on behalf of CFC's borrowers, as well as the banking and investor relations functions of CFC.

Q. What is the purpose of your testimony?

A. I will discuss EKPC's need to build equity, EKPC's credit strengths and weaknesses, and the environment in which EKPC will need to raise capital.

Q. Please explain CFC's relationship with East Kentucky.

A. CFC has had a long term credit relationship with East Kentucky going back to 1970. CFC's current credit exposure consists of providing credit enhancement for $98 million of tax-exempt bond financing and almost $151 million of loans. CFC also arranged for a $650 million unsecured revolving credit facility for East Kentucky in 2005.

Q. Did you recently have an opportunity to review East Kentucky's credit in connection with a potential financing?

A. Yes. East Kentucky, like many other large Generation & Transmission (G&T) cooperatives, has a huge need for capital in order to manage daily operations, as well as for interim bridge financing of construction expenditures before the placement of long-term permanent financings. In the past, East Kentucky has primarily been obtaining its long-term loan funds from the RUS. A loan request to RUS for permanent financing may take 18 months to 4 years before funding is available. In addition, in early 2008, the RUS announced that it has instituted a moratorium in regard to loan applications from electric cooperatives in connection with the financing of any coal-fired or nuclear base load electric generation. The RUS moratorium , coupled with cash requirements from normal or abnormal operations and the long lead time to obtain financing from the RUS, can severely impact cash resources.

Q. Was this the case with East Kentucky?

A. Yes. East Kentucky has been using its $650 million syndicated bridge credit facility to finance its capital expenditure needs. The credit facility will mature in September 2010. To refinance the credit facility, East Kentucky will need to consider establishing diversified funding sources (other than RUS and CFC). In addition, in order to continue funding future capital expenditure needs, East Kentucky will likely need to establish another syndicated bridge credit facility when the current one matures.

Q. What is the primary factor in obtaining future financing?

A. Credit quality of the borrower is the primary factor in securing any attractive financing package in the capital markets.

Q. Would you explain?

A. In order to both attract capital markets' participants and establish a pricing schedule for the interest rate and fees, it is necessary to develop a credit profile for

East Kentucky. This can be done by evaluating East Kentucky's credit strengths and challenges.

Q. What were some of East Kentucky's credit strengths?

A. A very important strength supporting East Kentucky's credit is their all-requirements contract with their member cooperatives. East Kentucky's financial performance also shows some improvement since 2004.

Q. What risks have you identified?

A. Lenders will be most concerned about East Kentucky's weak equity position. Specifically, East Kentucky's asset-to-equity ratio was approximately 6.8% as of December 31, 2007. Our credit evaluation of East Kentucky resulted in a rating that would be in the range of BBB to BBB-. Since lenders expect to be compensated for risk, the loan pricing and fees would be based on this rating.

Q. Why must East Kentucky be concerned about attracting capital?

A. As many borrowers are experiencing in the current credit markets (in October 2008), the ability to attract capital may be very challenging and only available to companies with strong credit profiles. There are no guarantees that capital will be available at reasonable pricing levels and with reasonable terms and conditions when it is needed by East Kentucky. East Kentucky must compete for capital like any other utility. Lenders by their nature are risk adverse and, as such, look to avoid lending into an unstable or uncertain credit situation. In an unstable credit situation, it is often difficult for a lender to fully understand their risk exposure and determine what compensation is appropriate to accept that risk, if at all. Alternatively, given the vast opportunities to lend into stable credit situations, lenders naturally move their available capital to "safe harbors" where their risk and rewards are more certain. Thus, East Kentucky must improve its financial position in order to improve its credit assessment to provide lenders a stable lending environment. With a stable credit environment, lenders can more effectively evaluate their risk. Thus, with improved credit, East Kentucky will have the greatest opportunity to finance with competitive pricing and reasonable terms and conditions.

Q. Would a higher equity level provide East Kentucky lower cost financing?

A. Absolutely. A stronger equity position is a key ingredient to a better credit score. Exhibit JAD-1 is the actual pricing guideline for a syndicated facility that was closed in September 2008, when the credit markets were in a more "normal" mode. You can clearly see from Schedule 1 that the credit assessment drives the cost of financing. For example, the indicated London Interbank Offered Rate ("LIBOR") pricing spread for a BBB/BBB- rated utility was 130-150 bps over the 3-month LIBOR. (LIBOR is the rate used in EKPC's credit facility.) However, for a A/A- rated utility, the pricing spread would only be around 90-100 bps. This indicates that if East Kentucky can obtain an "A/A-" rating, East Kentucky's borrowing costs would be substantially reduced by 40-50 bps This represents an interest expense savings of $3.25 million a year on a $650 million credit facility, or $16.25 million over the five-year financing period. It is very important to note that there has been a significant widening in pricing due to adverse market conditions since September 2008. While this may change in calendar year 2009, as of October 21, 2008 credit market conditions have worsened considerably from

September 2008, and there is very limited capital available from the banking system. I believe that if East Kentucky were to seek financing as of October 20, 2008, it would have to pay a credit spread of at least 300 bps over LIBOR with closing fees of an additional 2% of the total to secure financing, if it could obtain financing at all. This would also be for a term of one year only, as compared to East Kentucky's current credit facility term of 5 years.

Q. What expected returns and financial performance do you believe are necessary for East Kentucky to attract capital at reasonable prices and terms?

A. Before lending capital, bankers go through their own credit profile analysis. The lenders closely evaluate the expected returns of the borrowers and their risk exposure. If the borrowers' credit challenges exceed their credit strengths, the lenders will require higher interest rates and fees to compensate for the increased exposure. If they believe the risk exposure is too great, they will not participate in the financing. This will be extremely important if East Kentucky is to refinance the current credit facility. East Kentucky must start now to get their credit house in order. I believe that East Kentucky needs rates sufficient to allow it to gradually build its equity-to-asset ratio to a minimum of 10%.

Q. Does this conclude your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In re the Matter of:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A GENERAL ADJUSTMENT OF ITS WHOLESALE ELECTRIC RATES	))))	**CASE NO. 2008-00409**

<u>AFFIDAVIT</u>

STATE OF VIRGINIA)
)
COUNTY OF FAIRFAX)

Jonathon Andrew Don, 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.

[signature]

Subscribed and sworn before me on this 24 day of October, 2008.

Elizabeth C. Mikschae
Notary Public

My Commission expires:

ELIZABETH C. MIKSCHE
Notary Public
Commonwealth of Virginia
7120373
My Commission Expires Sep 30, 2011

INDICATIVE MARKET PRICING IN SEPTEMBER 2008

Credit Rating	Commitment Fee BPS	LIBOR Margin BPS
A	17.5	90
A-	20	100
BBB+	25	120
BBB	30	130
BBB-	35	150
BB+	50	300

Exhibit JAD-1

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

GENERAL ADJUSTMENT OF ELECTRIC RATES	)	**PSC CASE NO.**
OF EAST KENTUCKY POWER	)	**2008-00409**
COOPERATIVE, INC.	)	

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

Filed: October 31, 2008

Q. Please state your name and business 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. Please describe your relevant experience and educational background.

A. I hold a Bachelor's degree from Appalachian State University and a Master of Business Administration degree from the University of Richmond. I have published articles in the College of William & Mary Business Review, EPRI Research Journal, and Public Utilities Fortnightly on regulation. I have served as Director of Public Utility Accounting and Finance for the Virginia State Corporation Commission and as a public utility consultant, testifying in civil and administrative cases in Virginia, Florida, Kentucky, Ohio, Arizona, and Alaska. In addition, I have served as the Chief Financial Officer for Old Dominion Electric Cooperative for 21 years. In that capacity, I have been directly responsible for the issuance of approximately $3 billion of cooperative financings. Also, in that capacity I have testified on behalf of Old Dominion and its members before the Virginia State Corporation Commission, the Maryland Public Service Commission, the Delaware Public Service Commission, and the Federal Energy Regulatory Commission. As an advisor to G&Ts, I have assisted in placing over $2.5 billion of financing in the capital markets.

Q. What is the purpose of your testimony?

A. I have been asked by East Kentucky Power Cooperative to prepare an independent appraisal of East Kentucky's cost of capital and to recommend Times Interest Earned Ratio (TIER) and equity levels for ratemaking that are fair to East Kentucky and its member/owners that will allow East Kentucky to attract capital on reasonable terms and to maintain its financial integrity.

Q. Please summarize your testimony and recommendations.

A. I developed a recommendation for East Kentucky based on TIER and equity metrics from BBB+ to A+ rated G&Ts. Because of the changing credit environment and East Kentucky's current less than favorable credit position, it is critical that they have in place rates which will produce an earned TIER sufficient to attract capital.

Q. How did you estimate East Kentucky's cost of capital?

A. First, I evaluated East Kentucky's credit using the same techniques that the debt rating agencies use. Second, I selected a proxy group of cooperatives that are comparable to East Kentucky with regard to risk. The regulatory principle of a "fair rate of return" requires that the cost of capital be determined by comparing achieved earnings of companies with corresponding risk. Third, I averaged the proxy group's earned TIER's for the last three reporting years. Fourth, I narrowed the proxy group of cooperatives to those cooperatives that have been evaluated and given a debt rating of BBB+ to A+ rating from at least one of the three major rating agencies. I call these G&Ts the "Reference Group."

Cost of Capital

Q. How do you define the required rate of return or cost of capital used to set rates for a cooperative?

A. In the regulatory arena the cost of capital is a measure of a "fair" rate of return.

> "At a minimum a public utility must be afforded the opportunity not only of assuring its financial integrity so that it can maintain its credit standing and attract additional capital as needed, but also of achieving earnings (margins) comparable to those of other companies having corresponding risk."[1]

This is a fundamental principle of finance whether the utility is regulated or unregulated. For a cooperative using TIER (interest coverage) 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 determining a rate level, capital-attracting adequacy is properly considered a basic test of a fair return. A utility must be able to attract capital at a reasonable cost in order to build and maintain physical plants and to meet its public service obligations. Failure to maintain the financial integrity of a cooperative is against the interest of its members as well as the lenders of capital. The first step in determining cost of capital is to establish risk parameters.

Q. How do you determine the appropriate risk parameters?

A. The most important sources of an independent evaluation of risk and credit are the three major rating agencies: Standard & Poor's (S&P), Moody's Investors Service (Moody's), and Fitch. It is fundamental that expected returns are directly related to the perceived risk of an investment. It follows that a similarity of risk between a particular cooperative and other rated cooperatives implies that their respective cost of capital should be similar. In most cases, to determine the cost of capital for a cooperative you would compare its

[1] Charles Phillips, Jr., "The Regulation of Public Utilities," Public Utilities Reports, Inc., p. 331.

financial performance with cooperatives of similar risk as determined by the three major rating agencies. In other words, to attract capital it is reasonable to assume the lenders would expect cooperatives with similar risk to have similar financial performance.

Q. Does this model work for East Kentucky?

A. Yes. This model is especially important to East Kentucky because they must improve their credit position to attract capital. To restore positive credit credentials, East Kentucky must earn a TIER on a consistent basis that would result in a credit assessment equivalent to the BBB+ to A+ range.

Q. Is East Kentucky currently rated?

A. No. However, by applying the principles used by the rating agencies, a proxy rating can be determined.

Q. Could you briefly explain what factors are considered important by the rating agencies in assessing a cooperative's risk?

A While each of the rating agencies has a different rating methodology, they tend to concentrate their evaluation of cooperatives in several areas. A "credit negative" in one agency may also be a credit concern in the other agencies. General areas of evaluation are:

(1) Financial Performance
(2) Flexibility to Change Rates/Regulatory Environment
(3) Long-Term Wholesale Contract with Members
(4) Member Profile
(5) Size

The above list is ranked in the general order of importance given by the particular rating agency's committees in developing credit ratings.

1. Financial Performance

The bottom line indicator on how well a cooperative has dealt with its risk is the financial results of its operations. The agencies analyze a variety of indicators and ratios to measure the ability to cover fixed and variable obligations. The key ratios analyzed are interest or debt service coverages, liquidity, and equity. For the purposes of my study I have concentrated on TIER and equity since the Kentucky Public Service Commission uses these indicators to set rates. The rating agencies also apply stress to financial results to test the ability of cooperatives to deal with uncertainties in their financial operations. The reason financial performance is given the most weight by lenders is that financial performance demonstrates the cooperative's ability to service its obligation, which could have a direct impact on the value of the lender's investment. For example, a downgrade in a credit rating of a cooperative could decrease the value of that cooperative's bonds held in a bondholder's portfolio. The bondholder is concerned about a cooperative's credit at both the time of issuance and on an ongoing basis.

2. Flexibility to Change Rates/Regulatory Environment

Most of the cost exposure to cooperatives, such as fuel, is unregulated in the U.S. The cooperative needs the flexibility to raise or lower rates in order to track dramatic changes in cost levels. This holds true also for environmental requirements and capital investments to provide service. Not all cooperatives are regulated. Cooperatives that serve in states that are regulated have more difficulty raising rates compared to peers who are only subject to their board of directors for authority to change rates. An unsupportive regulatory jurisdiction is a credit negative and leaves cooperatives with less flexibility to raise rates if needed. Of the 21 rated G&T cooperatives, only two are state regulated for rates, and three are regulated by the Federal Energy Regulatory Commission (FERC). The FERC regulated co-ops use a flexible automatic adjustment formula to adjust rates. In Moody's evaluation of risk, financial performance and rate flexibility account for 60% of the credit evaluation.

3. Long-term Wholesale Contracts

The contracts between cooperatives and their members provide a high degree of assurance that cost and capital investments can be recovered in rates. The trend in the industry is to extend existing contracts for 30 or more years. Cooperatives such as Oglethorpe have extended their member contract to 2050. Most lenders, either in the capital market or RUS, are generally not issuing new loans beyond the maturity date of existing wholesale power contracts. Shorter maturities result in fewer numbers of years to recover fixed cost, thus increasing the cost per year. This situation is considered a credit negative by the rating agencies. Generally, the longer the contract, the greater assurance the cost of assets will be recovered and the debt repaid.

4. Member Profile

The member profile is important because it is the members that are the primary source of cash flow. The credit strength of the members, whether they are "end-of-line" member consumers or purchase for resale distribution members of a G&T cooperative, is an important factor to the credit strength of the cooperative. If a cooperative has members with poor credit fundamentals, it is a credit negative for the system.

5. Size

This factor, while the least important, still matters. The larger the entity, the greater the ability to withstand unexpected events. Also, the greater the size, the greater the ability to take advantage of economic diversity such as fuel mix and new generation. On the other hand, smaller utilities or utilities that have sufficient load loss have difficulty adjusting to significant events.

Listed below are the cooperatives that have investment grade ratings as of December 31, 2007:

Cooperatives with Investment-Grade Ratings

Cooperative	**Moody's**	**S&P**	**Fitch**
G&T's			
Alabama Electric Cooperative	---	BBB+	BBB+
Arkansas Electric Cooperative	A2	AA- (Neg.)	A+
Associated Electric	A1	AA	AA
Basin Electric Power	A1	A+	AA-
Brazos	---	A-	A
Buckeye Power	A1	A+	A+
Central Electric – South Carolina	---	AA	---
Central Iowa	---	A	A-
Chugach Electric Association	A2	A-	A-
Dairyland Power Cooperative	A2	A	---
Georgia Transmission Cooperative	A3	AA-	AA-
Golden Spread	A3	A	A-
Great River Energy	A3	BBB+	A-
Hoosier Energy Rural	A3	A-	---
Oglethorpe Power	A3	A	A
Old Dominion Electric	A3	A	A
Seminole Electric Cooperative	---	A-	---
Square Butte Electric Cooperative	A1	A-	---
Tri-State G&T Association	Baa2	A	A-
Western Farmers	---	BBB+	A-
Wabash Valley	---	BBB+	---

Q. Would you explain how credit positives and credit negatives work in particular applications?

A. Each utility has its own "basket of risks" to manage and still provide service on a daily basis. Most experts would agree that each utility has a collection of factors that are either credit positives or credit negatives. Since the credit crisis following the collapse of Enron, the ability to maintain credit standing has become demanding and difficult. In 2002, subsequent to the Enron collapse, there were substantially greater downgrades than upgrades by S&P. The challenges for a utility are to mitigate credit negatives and improve credit positives when possible. Unfortunately, each utility has some credit negatives that are outside their ability to control. Weather and unexpected economic conditions that impact demand are good examples.

Within a rating category, each cooperative has different credit negatives and positives. For example, two cooperatives may have the exact same letter credit rating. Cooperative (A) may build into rates a higher TIER that could be a credit positive, however have a credit negative in that rate flexibility may be limited, such as with rate regulation. Cooperative (B), on the other hand, may build into rates a lower TIER coverage, which by itself would be a credit negative. However, this credit negative could be mitigated if the cooperative has the flexibility to adjust rates when needed to cover changing cost levels. Old Dominion Electric Cooperative (a G&T serving Virginia, Maryland, and Delaware) is a good example of how credit negatives can be offset against credit positives. Old Dominion is regulated by the Federal Energy Regulatory Commission (FERC). Old Dominion each year develops rates sufficient to achieve a TIER of 1.20X. Its FERC tariff states that if the 1.20X is not achieved, then rates can automatically be increased to achieve a 1.20X coverage. In other words, Old Dominion has accepted a fixed TIER in exchange for assurance from the regulator that a 1.20X level can be achieved on an annual basis without regulatory lag. If actual financial performance produces a TIER greater than 1.20X, then the Old Dominion member cooperatives have the option of whether to receive a refund, use the difference to mitigate other costs, or post higher margins to build equity in order to offset risk. Financial performance and the flexibility to adjust rates are intricately linked and are evaluated together.

The key in any credit evaluation is whether the credit negatives outweigh the credit positives and to what degree the lenders are exposed to a cooperative's risk.

Q. How important is it to maintain a good credit position?

A: Failure to maintain a good credit position is against the interest of consumers as well as lenders.

> "An immediate effect of low earnings and earnings of low quality is to increase the financial risks of investors, and thus lead to the downgrading of securities by the rating agencies. Downrating, in turn, means that the bonds must carry higher interest rates, a charge which is passed along to customers. Such downgrading has become a familiar phenomenon in the utility scene . . . The bonds of many utilities are now rated at levels so low that many institutional investors are barred by law from purchasing them, and interest rates must be raised in order to sell the securities within a much smaller market. These additional capital costs force rate increases which otherwise would not be necessary, without improving the financial condition of the utilities or their ability to raise money on a low cost basis. An equally serious result of limited capability to raise money is the inability of the utilities to make the investments required in order to achieve the optimum economies of service."[2]

In today's utility credit environment, the basis for capital attraction is the credit evaluation process. Whether the lenders are program lenders (CFC, CoBank), bond investors, commercial banks, or trade vendors, all rely on an evaluation of credit to determine if capital or credit should be advanced. In addition, this evaluation may also determine the nature of terms and conditions for capital or credit.

[2] Report of an Informal Task Force to the Energy Transition Team, "Recommendations for Restoration of Financial Health to the U.S. Electric Power Industry" (mimeographed, December 17, 1980), pp. 11-12.

Q. You said that the first step is to determine East Kentucky's credit profile. What does it show?

A. If rated today by the three major rating agencies, East Kentucky most likely would not achieve an investment grade rating. Certainly their credit position is currently below all the "BBB" rated cooperatives listed above.

Q. Would you explain further?

A. There are currently five G&T cooperatives that have at least a "BBB" debt rating from one of the three major debt-rating agencies.

	Three-Year (2005-2007) Average TIER	Equity Percentage
Great River	1.53X	12.08%
Western Farmers	1.41X	13.87%
Tri-State	1.38X	18.60%
Wabash Valley	1.26X	10.14%
Alabama Electric	1.24X	9.98 %
East Kentucky	**.96X**	**6.83%**

Of this group, East Kentucky's financial performance is substantially below the "BBB" rated cooperatives.

Q. Could you give me an example of how East Kentucky's weakened credit position could impact its cost and ability to attract capital on reasonable terms in the future?

A. East Kentucky currently has in place a $650 million credit facility to help bridge its capital needs until permanent financing is available. The level of interest cost and other fees are directly tied to an assessment of its credit profile. When this facility was established, the pricing was based on a credit position of a BBB- to BBB credit rating. This evaluation was just barely in the investment grade category. The continued weakness in East Kentucky's credit position has threatened its ability to meet the debt covenants of the credit facility and has called into question its ability to structure a similar credit facility when this arrangement matures in 2010. Even if they could find willing banks to participate, not only will the financing be more expensive, but also the terms and conditions could be highly restrictive. For example, lenders could require a direct guarantee from East Kentucky members before funds could be advanced. In addition, the longer the credit position remains weak, the more likely their permanent lenders, RUS and CFC, may impose more difficult terms and conditions that would reduce East Kentucky's flexibility for years to come.

Q. What is your recommendation regarding East Kentucky's credit condition?

A. Stronger financial performance would substantially improve East Kentucky's risk assessment and, therefore, improve its credit position. I believe East Kentucky should strive to achieve financial performance, on a consistent basis, to support a debt rating in the BBB+ to A+ rating category. This would yield the best combination of cost and flexible terms and conditions. As such, the cost of capital awarded by the Kentucky Public Service Commission should be consistent with other G&T cooperatives with ratings in the BBB+ to A+ range.

Q. Since the last rate case, has East Kentucky achieved the level of financial performance necessary to obtain capital at reasonable cost?

A. No. On the surface it would appear that the 1.41x TIER posted in 2007 would be a step in the right direction. However, 76% of East Kentucky's earnings in 2007 were either non-recurring or non cash AFUDC. Credit analysts would discount both these items in their analysis thus leaving East Kentucky with a coverage ratio of only 1.10x rather than 1.41x. In today's credit environment it is highly unlikely that East Kentucky will be able to replace its $ 650 million bank syndicated facility in 2010 without strong financial performance in 2008 and 2009. This facility has been heavily used by East Kentucky with frequent balances well over $500 million. The inability to renew this facility could cause severe liquidity problems for East Kentucky.

Q. Could you explain your concerns?

A. We are now in the worst credit crisis since World War II. The credit crisis has produced fewer lending institutions and substantially higher requirements to obtain credit now and in the future. The "flight to quality" has even made it difficult for "A" rated credits to borrow. While most analysts believe this condition will hopefully improve in the future, it is likely East Kentucky will find a much tougher lending environment in 2010 than was available in 2005 when the syndicated facility was first arranged. East Kentucky is running out of time to achieve a credit profile and financial performance that would attract capital on reasonable terms. It is thus critical, that earnings improve in order for East Kentucky to have a fighting chance to arrange liquidity financing when the current $650 million facility matures in 2010.

Q. How did you select the proxy group of rated G&T cooperatives?

A. I gathered information from various sources comparable to BBB+ and A+ rated G&T cooperatives from across the United States. I analyzed the data first by grouping all the BBB+ to A+ rated G&T cooperatives together and determined the average and median TIER. To remove any bias from year to year fluctuation, I averaged three years of data for the period 2005 to 2007 for each G&T cooperative. In addition, I removed the highest average TIER (Golden Spread) and the lowest average TIER (Square Butte) to further smooth the average.

Q. Would you summarize the results of your analysis?

A. Before discussing the cost of capital, it is important to acknowledge that the true cost of capital for East Kentucky is not the TIER of 1.05x contained in East Kentucky's debt covenant of its mortgage. This is a minimum TIER requirement with potential penalties if East Kentucky's TIER drops below this level. Most mortgages or indentures have some form of debt covenant. The lenders generally view this covenant as a market entry test that must be achieved in order to avoid default. In other words, a minimum threshold must be achieved before additional bonds can be issued. The 1.05x TIER threshold does not mean East Kentucky can actually attract capital with margins at this level. The market after an assessment of risk as addressed above will determine what level above 1.05x is necessary to attract capital.

Exhibit DMW-1 lists the rated G&Ts and their achieved TIER. The TIER coverage for each G&T was calculated using an average of 2005, 2006, and 2007 TIER data. In column (H) I have included just those G&T's that are rated in the BBB+ to A+ range. This represents a reasonable credit range for East Kentucky. A review of East Kentucky's credit profile would suggest that if East Kentucky achieved financial performance similar to the "Reference G&T's" in column (H), they would likely also have similar ratings.

Using the earned TIER's for BBB+ to A+ rated G&Ts in column (H) of Exhibit DMW-1, the G&Ts can be divided into four groups.

	TIER
Level IV	1.63X to 2.84X
Level III	1.39X to 1.53X
Midpoint	1.385X
Level II	1.29X to 1.38X
Level I	1.10X to 1.27X

This grouping is useful to evaluate East Kentucky's need to improve its credit position. As stated above, a utility's credit position is made up of credit positives and credit negatives.

The debt ratings are derived by the ability of the cooperative to offset credit negatives. The cooperatives in Level I have a tendency to earn relatively low TIER's. In evaluating their credit, their financial performance is actually a credit negative. This credit negative is offset by certain significant credit positives. For example, Oglethorpe is not regulated and can adjust all its charges to its members on a monthly basis to insure timely collection of cost. Thus, there is little risk of under-recovery of either fuel, operational, or fixed cost. Second, several years ago Oglethorpe and its members modified their contracts, which effectively fixes the power requirements of its members from Oglethorpe. As a result of this contract change, Oglethorpe is relieved of the obligation and corresponding risk of building or acquiring power supplies to meet members' growth. Therefore, the member's load growth is the responsibility of the individual member, not the G&T.

Having the ability to immediately recover changes in cost levels and not having to incur risk related to capital acquisition are significant credit positives, thus allowing Oglethorpe to earn lower TIER's and equity ratios and still retain an "A" rating. By comparison, East Kentucky is limited by regulation in its ability to change its rates to recover cost and also is obligated as a public service company to provide for its members' load growth. To compensate for these risks, East Kentucky must earn a higher TIER than Oglethorpe to attract capital.

To compensate for its "basket of risk" East Kentucky should earn a <u>consistent</u> TIER above the midpoint of the TIER earned by the BBB+ to A+ G&T cooperatives. To be more specific, before their next financing, East Kentucky should post annual financial performance within the upper end of Level III (1.39x to 1.53x) on a consistent basis. This would demonstrate that East Kentucky's credit position has improved and stabilized.

Q. Was this the same methodology you used in East Kentucky's last rate case?

A. The methodology between the studies in the last case and this case is essentially the same. In the last case I used a three-year average of earned TIERs of G&Ts with debt ratings between BBB+ and A+ for the years of 2004, 2005, and 2006. In this case I updated the data and used a three-year average of TIERs for essentially the same G&Ts for the years 2005, 2006, and 2007. The updated study does have an additional data point. In the current study, I included Arkansas in the Reference Group since, as a result of a downgrade by Fitch (AA- to A+), they now have the majority of their ratings in the "A" category. In the last case the majority of Arkansas' ratings were outside the Reference Group range of BBB+ to A+. With the additional data, each of the four levels have an equal number of data points.

Q. Are you surprised that the cost of capital for G&Ts has continued to increase?

A. No, I am not surprised. The overall business risk in our industry continues to increase thus requiring higher financial performance in order to maintain credit quality. Whenever possible, G&Ts are taking steps to deal with credit issues by improving earnings, equity, and liquidity levels. The new credit environment for years to come will certainly demand even higher credit standards.

Q. Where would you recommend the Commission actually set the TIER for making rates in this case?

A. In Order No. 2006-00472, the Commission used a TIER of 1.35x to set rates which was the bottom of my recommended Level III range. There are a number of reasons why the bottom of my current recommended Level III range (1.39x to 1.53x) will not work in this case. Conditions surrounding East Kentucky in this case are far different than the credit environment in the last case.

Q. What has changed since the last case?

A. First, as I have stated above, we are in the greatest credit crisis since World War II. For years to come we will witness the results of a "flight to quality" in which lenders will demand higher credit standards. East Kentucky will feel the real world impact of tougher lending requirements when it tries to solicit banks to replace the current $650 million credit facility in 2010. While the exact nature of these requirements may not be known at this time, it is safe to say that East Kentucky must not only improve the quality of its earnings (higher portion of cash earnings to AFUDC earnings) but also increase the level of its earnings. Second, the time frame to prepare for this financing has been dramatically reduced. When the last case was filed, we were more than three years away from the maturity of the $650 million facility. We now have very little time to demonstrate to new creditors that East Kentucky can support a new loan with sufficient credit standards. The bottom line is that East Kentucky is facing significant refinancing risk.

Q. Based on the above concerns where do you recommend the Commission set the TIER within your recommended range of 1.39x to 1.53x?

A. Without the benefit of a projected test year, the Commission would need to set the TIER in the upper portion of that range to provide East Kentucky the best opportunity to replace its financing in 2010.

Q. How does the use of a projected test year impact your recommendations?

A. A projected test year combined with a timely rate order is a risk reduction factor. While it is difficult to precisely quantify the value of this, I believe it would be reasonable to reduce the allowed TIER to around the mid-point of the 1.39x to 1.53x range, or 1.45x.

Q. What comments do you have on East Kentucky's equity ratio?

A. The equity ratio is a key component in supporting a utility credit profile. As credit standards tighten, required equity levels will increase. Since the test period in the last rate case, East Kentucky's equity has made some improvement. However, as can be seen from Exhibit DMW-2, the average equity level of the Reference Group is 14.35% compared to East Kentucky's current level of 6.83%. East Kentucky still has a considerable way to go to reach an acceptable level.

Q. Would you explain Exhibit DMW-3, "Capital Structure as of May 31, 2010"?

A. Yes, Exhibit DMW-3 shows the projected capital structure and a TIER requirement of 1.45x. By using these components the overall cost of capital for rate making would be 7.36%. This would allow EKPC to earn its required return and over time increase its equity position to a level sufficient to attract capital.

Q. Does that conclude your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In re the Matter of:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A GENERAL ADJUSTMENT OF ITS WHOLESALE ELECTRIC RATES	))))	**CASE NO. 2008-00409**

AFFIDAVIT

STATE OF VIRGINIA)
)
CITY OF RICMOND)

Daniel M. Walker, 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.

Subscribed and sworn before me on this day of October, 2008.

Notary Public

My Commission expires: 2/28/11

TAWYANA ATHEY
NOTARY PUBLIC
COMMONWEALTH OF VIRGINIA
MY COMMISSION EXPIRES FEB. 28, 2011
COMMISSION #7151046

East Kentucky Power Cooperative
Rated G&T Cooperatives
TIER Analysis

	Moody's (A)	S&P (B)	Fitch (C)	2005 (D)	2006 (E)	2007 (F)	Average (G)	Reference Group of BBB+ to A+ G&T's (H)
Golden Spread	A3	A	A-	2.01x	2.68x	6.45x	5.34x	
Buckeye	**A1**	**A+**	**A+**	**3.46**	**2.67**	**2.40**	**2.84**	**2.84**
Brazos	**---**	**A-**	**A**	**1.66**	**2.07**	**1.76**	**1.83**	**1.83**
Basin	**A1**	**A+**	**AA-**	**1.76**	**2.04**	**1.13**	**1.64**	**1.64**
Central Iowa	**---**	**A**	**A-**	**1.40**	**1.61**	**1.89**	**1.63**	**1.63**
Great River	**A3**	**BBB+**	**A-**	**1.49**	**1.83**	**1.27**	**1.53**	**1.53**
Dairyland	**A2**	**A**	**---**	**1.54**	**1.51**	**1.41**	**1.49**	**1.49**
Western Farmers	**---**	**BBB+**	**A-**	**1.31**	**1.33**	**1.58**	**1.41**	**1.41**
Arkansas	**A2**	**AA-(Neg.)**	**A+**	**1.36**	**1.53**	**1.29**	**1.39**	**1.39**
Tri-State	**Baa1**	**A**	**A-**	**1.47**	**1.44**	**1.23**	**1.38**	**1.38**
Hoosier Energy	**A3**	**A-**	**---**	**1.29**	**1.39**	**1.31**	**1.33**	**1.33**
Chugach	**A2**	**A-**	**A-**	**1.42**	**1.41**	**1.12**	**1.32**	**1.32**
Central Electric - SC	---	AA	---	1.32	1.32	1.30	1.31	
Old Dominion	**A3**	**A**	**A**	**1.20**	**1.39**	**1.27**	**1.29**	**1.29**
Wabash Valley	**---**	**BBB+**	**---**	**1.27**	**1.23**	**1.31**	**1.27**	**1.27**
Associated	A1	AA	AA	1.18	1.26	1.32	1.25	
Alabama Electric	**---**	**BBB+**	**BBB+**	**1.19**	**1.29**	**1.25**	**1.24**	**1.24**
GTC	A3	AA-	AA-	1.19	1.18	1.21	1.19	
Seminole	**---**	**A-**	**---**	**1.14**	**1.24**	**1.18**	**1.19**	**1.19**
Oglethorpe	**A3**	**A**	**A**	**1.10**	**1.10**	**1.10**	**1.10**	**1.10**
Square Butte	A_1	A-	A	1.06	1.08	1.08	1.07	
Average								**1.48x**
Median								**1.385x**
East Kentucky								**.96x**

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 – "Reference Group" data in bold

Exhibit DMW-1

East Kentucky Power Cooperative
Equity Ratios of Reference Group

Arkansas	40.25%
Buckeye	30.23%
Chugach	30.18%
Basin	28.23%
Tri-State	18.69%
Old Dominion	18.48%
Central Iowa	16.72%
Brazos	15.59%
Western Farmers	13.87%
Hoosier	13.76%
Oglethorpe	12.48%
Great River	12.08%
Dairyland	11.45%
Wabash Valley	10.14%
Alabama	9.98%
Seminole	7.25%
Average	18.08%
Median	14.73%
East Kentucky	**6.83%**

Source:
- 2008 National G&T Accounting and Finance Association Handbook

East Kentucky Power Cooperative
Capital Structure as of May 31, 2010

	Balance 5/31/10	Interest Rate	Ratio	Cost of Capital
Tax-Exempt Debt:				
Spurlock	58,200,000	4.5000%	2.100%	0.095%
Smith	7,625,000	5.2500%	0.275%	0.014%
Cooper	7,700,000	3.2500%	0.278%	0.009%
Intermediate Debt – General	650,000,000	4.0000%	23.454%	0.938%
CFC Long-Term Debt	15,509,130	4.7175%	0.560%	0.026%
CFC Other:				
Inland	4,500,000	7.7000%	0.162%	0.013%
Fast Track (CT9-10)	205,722,000	5.2060%	7.423%	0.386%
CREB's	7,401,838	0.4000%	0.267%	0.001%
RUS Notes	34,329,651	5.0170%	1.239%	0.062%
FFB Notes	1,780,340,381	5.5000%	64.241%	3.533%
Total Debt	2,771,328,000		100.000%	5.078%
TIER Requirement				1.45
				7.363%

Exhibit DMW-3

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

GENERAL ADJUSTMENT OF ELECTRIC RATES	)	**PSC CASE NO.**
OF EAST KENTUCKY POWER	)	**2008-00409**
COOPERATIVE, INC.	)	

TESTIMONY OF
FRANK J. OLIVA
MANAGER OF FINANCE
EAST KENTUCKY POWER COOPERATIVE, INC.

Filed: October 31, 2008

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

A. My name is Frank J. Oliva and my business address is East Kentucky Power Cooperative (EKPC), 4775 Lexington Road, Winchester, Kentucky 40391. I am Manager of Finance.

Q. Please state your education and professional experience.

A. I have a Bachelor's degree in Accounting from the University of Kentucky and a Master's degree in Business Administration from Xavier University. I have been employed by EKPC for 30 years. I served as General Accounting Supervisor from 1978 to 1985 and Finance Manager from 1985 to present.

Q. Please provide a brief description of your duties at EKPC.

A. My responsibilities include finance and related treasury functions for the cooperative. I report directly to the Chief Financial Officer.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of EKPC's budgeting process. I will also provide a detailed explanation of the methodology and assumptions used to forecast items other than projections of major construction projects and projections of capital and operations and maintenance expenses for the power production and power delivery functions.

Q. Are you supporting certain information required by Commission Regulations 807 KAR 5:001, Section 10?

A. Yes. I am sponsoring the following schedules for the corresponding Filing Requirements:

Filing Requirement	Description	Volume	Tab #
Section 10(8)(a)	Financial data for forecasted period presented as pro forma adjustments to base period.	Vol. 1	Tab 19
Section 10(9)(c)	Complete description, which may be in prefiled testimony form, of all factors used to prepare forecast period. All econometric models, variables, assumptions, escalation factors, contingency provisions, and changes in activity levels shall be quantified, explained, and properly supported.	Vol. 3	Tab 25
Section 10(9)(d)	Annual and monthly budget for the 12 months preceding filing date, base period and forecasted period.	Vol. 3	Tab 26
Section 10(9)(h)	Financial forecast for each of 3 forecasted years included in capital construction budget supported by underlying assumptions made in projecting results of operations and including the following information: 1. Operating income statement (exclusive of dividends per share or earnings per share); 2. Balance sheet; 3. Statement of cash flows; 4. Revenue requirements necessary to support the forecasted rate of return; 5. Load forecast including energy and demand (electric); 6. Access line forecast (telephone); 7. Mix of generation (electric); 8. Mix of gas supply (gas); 9. Employee level; 10. Labor cost changes; 11. Capital structure requirements; 12. Rate base; 13. Gallons of water projected to be sold (water); 14. Customer forecast (gas, water); 15. MCF sales forecasts (gas); 16. Toll and access forecast of number of calls and number of minutes (telephone); and 17. A detailed explanation of any other information provided.	Vol. 3	Tab 30
Section 10(9)(o)	Complete monthly budget variance reports, with narrative explanations, for the 12 months prior to base period, each month of base period, and subsequent months, as available;	Vol. 5	Tab 37
Section 10(10)(i)	Comparative income statements (exclusive of dividends per share or earnings per share), revenue statistics and	Vol. 5	Tab 54

	sales statistics for 5 calendar years prior to application filing date, base period, forecasted period, and 2 calendar years beyond forecast period;		
Section 10(10)(k)	Comparative financial data and earnings measures for the 10 most recent calendar years, base period, and forecast period;	Vol. 5	Tab 56

Q. What is your role in the overall budgeting process at EKPC?

A. I am responsible for coordinating the budgeting process. This involves distributing budget instructions to departments throughout the organization. Each department is responsible for preparing preliminary budget estimates which are reviewed by senior management. Upon approval by senior management, I am responsible for integrating the departmental budgets and other budget items for which I am directly responsible into EKPC's budgeting system so that the company's financial performance can be analyzed prospectively. The testimonies of Mr. Crawford, Mr. Jonhson, Mr. Drury, and Mr. Lamb describe the budgeting processes for their specific areas of responsibility.

Q. How is the member cooperative revenue budget developed?

A. The Planning Department provides a load forecast including MW's and MWh's for each rate class and large commercial load. Current rates are applied to each of these rate classes and commercial loads to develop the total revenue for demand and energy. Revenue from metering points and load center charges are based on current information and any new substations projected to be added in the budget years. The new substation additions are provided by the power delivery expansion department.

The fuel adjustment revenue budget is based on projected monthly estimates of fuel costs, power purchases, and off-system sales. If this monthly estimate is greater than the fuel base included in base rates, the difference is factored into the revenue budget as fuel adjustment revenue.

Q. How is the off-system sales revenue budget developed?

A. The Planning Department provides MW's and MWh's for contract and projected other sales on the market. The EKPC planning model provides the contract price and EKPC's system cost which is used to compute the incremental cost of off-system sales. An expected margin is applied to this incremental cost to provide off-system sales revenue.

Q. How are the labor and payroll tax budgets derived?

A. Payroll personnel calculate the current annual compensation amount for all full-time employees. The Human Resources area determines a projected rate for performance increases. Payroll applies this rate to the current annual compensation amount to arrive at a projected compensation level. This analysis is done at the department level, by individual employee. Payroll also projects an appropriate level of shift differential. New/replacement/temporary/part-time employees are provided by each department and included in the labor totals.

From the projected compensation amount, Payroll calculates taxes on each employee for FICA, Medicare, FUTA (Federal Unemployment) and SUTA (State Unemployment) based on the amounts/rates in effect by the appropriate taxing agencies (IRS, Commonwealth of Kentucky).

Adjustments to the current annual compensation amount are made based on anticipated retirements and projected new hires. These adjustments are reflected on a pro-rata basis.

Q. How is interest expense budgeted?

A. Finance personnel develop an annual monthly cash flow to show advances that will be needed to keep a positive cash position for the two budget years. Finance personnel also develop an assumption schedule showing the advances that will be needed and project interest rates that will be assigned to each budgeted advance. Individual loan amortization schedules are prepared, based on projected advances and their respective interest rates, to calculate the total interest expense amount and principal payments by month/quarter/year.

Q. How are fuels and emissions budgeted?

A. The Fuels and Emissions Department (F&E) provides the Planning Department a weighted average cost of fuel and quantity for each of EKPC's generating units taking into account contract quantities/pricing, projected usage, historical usage, and spot price estimates/quantities. F&E also provides pricing for emission allowances.

The preliminary forecasts of price and quantity are inputs used in the generation planning model to project the MWhs generated for each of EKPC's generating units. F&E reviews these projections with the Planning Department and with Production personnel. Any changes in methodology, unit characteristics or costs, outage rates, etc. are revised by Planning and a final run is made for projected MWh for each of EKPC's generating units. F&E then combines Inland steam sales equivalent MWhs with the generation projections to arrive at total MWhs. F&E converts these MWhs into forecasted fuel usage to use in its budget preparation. F&E uses the usage tons for coal, usage MMBtu for natural gas, and tons of emissions for SO2 and NOx along with contract quantities/pricing and spot pricing and any adjustments to arrive at an average cost per MMBtu for each source. Oil for the combustion turbines is calculated as a percentage of the combustion turbine usage. Oil for start-up and flame stability for the other plants is based on each plant's production forecast. The pricing for any spot quantities are taken from an independent outside forecast with EKPC adjustments based on current market information from bid solicitations and forward market pricing. Limestone quantities are based on the plant's projections based on historical and projected use and the pricing is developed from actual market information with the outside fuel forecast as a reasonableness check.

Usage in MWh's and tons, price per MMBtu for each of the units, and total fuel dollars and dollars/MWh are provided to Finance based on the above information. Fuel costs and emission allowance costs are recoverable through the fuel adjustment clause and environmental surcharge, respectively.

Q. How is the miscellaneous revenue budget developed?

A. For those miscellaneous revenue items that have an associated contract, Accounting personnel review current contract information to make the future projections.

If the miscellaneous revenue item does not have an associated contract, Accounting personnel review historical activity in the general ledger and make projections based on historical data.

Q. How is property insurance budgeted?

A. Property exposures are evaluated continuouly, but beginning in January of each year, an assessment is made of EKPC's property exposures. What has changed, what is planned for the next year or more and what additional exposures such as terrorism potentials, flood potentials, environmental exposures, transportation issues, etc. are just some of the factors considered. EKPC's Plant Accounting group accumulates detailed property valuations from the previous year to give an accurate determination of property values to insure. From the property valuations received and considering potential additional exposures, the budget is derived.

Q. How is depreciation expense budgeted?

A. For existing plant, Plant Accounting calculates the most recent month's depreciation expense then annualizes that amount to arrive at the budgeted expense for the year. For new plant, Plant Accounting analyzes budgeted capital additions, categorizes these additions into the appropriate asset account noting the date the project is to be completed or the asset is to be placed in service, then calculates depreciation with the rate associated with the asset account. EKPC's last depreciation study was approved by the Commission in Case No. 2006-00236. A summary of depreciation rates is included under tab 41.

Q. How is property tax budgeted?

A. Property taxes are based on the net book value of plant as of December 31 of the previous year. For existing plant, Plant Accounting projects the net book value through the end of that year. Plant Accounting also projects the net book value through year-end for any budgeted capital additions. Plant Accounting then classifies the net book value information by account and applies the appropriate property tax rate (i.e. real estate, manufacturing machinery, intangible, local) to those accounts.

Q. How are benefits budgeted?

A. There are several components to the benefits budget as described below.

- Defined Benefit Plan—The Benefits area annualizes base pay for all employees eligible for this plan. Benefits personnel multiply total base pay by the current plan contribution rate provided by NRECA, the plan administrator.
- Sick Leave Liability—The Accounting area provides this information based on historical charges to this budget code.
- Dental and Vision—The Benefits area reviews historical claims history and applies an inflation rate to determine budgeted expense.
- 401K Employer Match—The budgeted projected base wage is multiplied by the applicable company match, to determine the budget.
- LTD Insurance—The budget is based on a rate of $.675 per $100 of budgeted base wages per month.

- Business Travel Insurance—This premium is fixed at approximately $1,500 per year and includes coverage for all full-time employees and the Board of Directors.
- Employee Safety Awards, Vending Supplies, Employee Food Certificates, Employee Relocation, Board and Retiree Lunches, Employee Safety Awards, Employee Recognition Dinner, Key Contributor Awards— the Benefits area budgets these items based on historic usage.
- Group Term Life & AD&D—This benefit is equal to 2 times an employee's salary. The budget is determined based on budgeted salary data at a rate of $.210 per $1,000 of coverage.
- Postretirement Medical and Life—The actuary that performs the FAS 158 calculation provides budget projections.
- Postemployment, Long-Term Disability, and Workers Compensation—The Accounting area estimates these expenses based on historic usage.
- Employee Recruiting/Relocation—The Benefits area arrives at this budget amount by factoring in the number of retirements from professional positions that will require replacement.
- Executive Retirement—This benefit is available to the CEO and Executive Staff. The budget amount is derived from estimated premium amounts and the present value of future benefits.

- Employee Assistance Program—Budget is based on $2.75 per month for eligible employees.
- Wellness Program—This program has just been implemented. Budgeted amounts include the costs of a health risk assessment and blood work for eligible employees.
- Medical Surveillance, CDL Physicals, CDL Drug/Alcohol Testing, Corporate Drug/Alcohol Testing—These are based on fixed annual costs, plus 3 percent for inflation.
- Medical Insurance—the Benefits area reviews the previous year's claims history and applies a medical inflation rate to determine the budgeted amounts needed.

Q. Does this conclude your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In re the Matter of:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A GENERAL ADJUSTMENT OF ITS WHOLESALE ELECTRIC RATES	))))	**CASE NO. 2008-00409**

AFFIDAVIT

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Frank J. Oliva, 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.

Frank J. Oliva

Subscribed and sworn before me on this 28th day of October, 2008.

Peggy S. Griffin
Notary Public

My Commission expires: December 8, 2009

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

GENERAL ADJUSTMENT OF ELECTRIC RATES	)	PSC CASE NO.
OF EAST KENTUCKY POWER	)	2008-00409
COOPERATIVE, INC.	)	

TESTIMONY OF
GARY T. CRAWFORD
VICE-PRESIDENT, CONSTRUCTION
EAST KENTUCKY POWER COOPERATIVE

Filed: October 31, 2008

I. INTRODUCTION

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

A. My name is Gary T. Crawford, and I am Vice-President, Construction at East Kentucky Power Cooperative (EKPC) located at 4775 Lexington Road, Winchester, Kentucky 40391.

Q. How long have you been employed by East Kentucky Power Cooperative, Inc. ("EKPC")?

A. I have been employed at EKPC since June 1977, a period of over 31 years.

Q. Please state your education and professional experience.

A. I received a Bachelor of Science degree in Civil Engineering from the University of Kentucky in 1974 and a Master of Business Administration from Morehead State University in 1999. Before joining EKPC in 1977, I worked in the consulting engineering and manufacturing industries. I have been a Licensed Professional Engineer in Kentucky since 1978.

Q. Please provide a brief description of your duties at EKPC.

A. As Vice President, Construction at EKPC, I am responsible for project management, engineering, and construction management of all major retrofit and new generation capital projects for EKPC. My responsibilities include both budget and schedule accountability.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the Spurlock 4 circulating fluidized bed, coal-fired generating unit, the Smith 9 and 10 combustion turbines and the Smith 1 circulating fluidized bed, coal-fired generating unit that EKPC is in the process of constructing. I will discuss the in-service dates and estimated costs of these generating units and describe the methodology used to develop these cost estimates. I will also explain why the cost estimates that are used in the 2009 and 2010 budgets, as well as in the forecasted test year, are reasonable.

Q. Are you supporting certain information required by Commission Regulations 807 KAR 5:001, Section 10?

A. Yes. I am sponsoring the following schedules for the corresponding Filing Requirements:

Filing Requirement	Description	Volume	Tab #
807 KAR 5:001 Section 10(9)(b)	Most recent capital construction budget containing at minimum 3 year forecast of construction expenditures.	Vol. 3	Tab 24
807 KAR 5:001 Section 10(9)(f)	For each major construction project constituting 5% or more of annual construction budget within 3 year forecast, following information shall be filed: 1. Date project began or estimated starting date; 2. Estimated completion date; 3. Total estimated cost of construction by year exclusive and inclusive of Allowance for Funds Used During Construction ("AFUDC") or Interest During Construction Credit; and Most recent available total costs incurred exclusive and inclusive of AFUDC or Interest During Construction Credit;	Vol. 3	Tab 28

Q. Please describe the Spurlock 4 Generating Unit.

A. Spurlock 4 is a state-of-the-art circulating fluidized bed (CFB) coal-fired generating unit which employs the latest technology to achieve some of the lowest emissions of any coal-fired plant in the United States. In fact, it is widely acknowledged to be one of the cleanest coal-fired power generation plants in the U.S. It is currently under construction at EKPC's

Spurlock Station near Maysville, Kentucky. Spurlock 4 will have a net generating capacity of 278 MW when completed in 2009 and is fully dedicated to serving the needs of EKPC's sixteen member system distribution cooperatives and over 500,000 of their retail members. The unit is provided with an Alstom CFB boiler supplying 2,018,142 lb/hr of steam to a General Electric turbine-generator set with a maximum gross capability of 305,846 kW, (net expected capacity of 278,000 kW). The turbine operates at an inlet throttle pressure of 2400 psi at 1000 °F. The CFB will burn approximately 187.5 tons of fuel per hour and use over 40 tons of limestone per hour at maximum load and can burn biomass and tires in addition to coal. The unit is equipped with a dry scrubber and baghouse to remove sulfur dioxide and particulate matter. Nitrogen oxides are removed in the furnace of the CFB with a post-combustion polishing selective non-catalytic reduction (SNCR) system, and meets or exceeds all current environmental emission standards. The plant is equipped with the normal complement of auxiliaries including coal and limestone unloading, ash and waste handling, water make-up and treatment facilities, pumps, fans, a cooling tower, and a 650 foot tall stack.

Q. When is the Spurlock 4 Generating Unit expected to begin commercial operation?

A. Spurlock 4 is scheduled to begin commercial operation on April 1, 2009.

Q. What is the total estimated cost of the Spurlock 4 Generating Unit?

A. The total Spurlock 4 cost estimate included in the 2009 Budget is $532,220,813. (See Exhibit GTC-A.)

Q. Please explain the methodology for arriving at this cost estimate and why this cost estimate is reasonable.

A. The estimate is based on an accumulation of project costs which identifies each major equipment and construction contract in the project scope. This process tracks the original contract cost and adjusts for additions which occur as a result of change orders, labor or material escalation, and forecasted cost changes. This process also incorporates additional contingency, Owner's Costs, and estimated Interest During Construction. In the case of Spurlock 4, all contract costs are the result of negotiated agreements with suppliers and contractors who have supplied identical equipment and services for EKPC's E.A. Gilbert Unit ("Gilbert"), a twin to the Spurlock 4 unit at the same location. The Gilbert unit was placed into service in early 2005. By duplicating the scope of work on each contract and incorporating lessons learned in the erection of Gilbert, significant engineering and construction cost is saved due to the inherent knowledge of the contractor of the exact scope of their work. A high confidence in the cost estimate is the result. The only real variables are managing construction labor productivity, and escalation in the cost of materials and labor due to the timing differences in the schedule for constructing Spurlock 4 as opposed to Gilbert.

Q. Since EKPC's 2009 budget was approved, have there been any changes to the construction schedule and estimated cost of Spurlock 4?

A. The construction schedule has not changed since the 2009 budget was approved. We expect that Spurlock 4 will be placed into commercial service on April 1, 2009. However, there have been adjustments to the estimated cost at completion (EAC).

The current EAC is $528,088,436. Each month, an updated forecast of the cost of each contract in the project cost model is made. The sum of all contracts is the updated EAC. (See Exhibit GTC-B.) This updated cost estimate is the result of changes that were incorporated after the 2009 budget was developed and approved by EKPC's Board.

Q. Please explain why these changes are necessary and why they are reasonable.

A. The changes in the most recent EAC in the amount of $4,132,377 were necessary as a result of additions associated with individual contract change orders, and adjustments for costs that were included in the Spurlock 4 Project estimate, which should have been included in other project estimates.

Q. Please describe the Smith 9 and 10 Combustion Turbines.

A. The Smith 9 and 10 Combustion Turbines are aero-derivative simple cycle combustion turbines (Model LMS100's) supplied by GE Packaged Power Inc. (GE) of Houston, TX. These units are a relatively new design offered by GE to be used during periods of peak load on the EKPC system. They will be fueled exclusively by natural gas due to air permitting limitations and will be state-of-the-art in lowest air emissions. The units are composed of a low-pressure compressor, an interstage cooler, a high pressure compressor and a combustion turbine producing a maximum nominal capacity of 100,000 kW. The units also will be fitted with a carbon monoxide and nitrogen oxide reduction system.

Q. When are the Smith 9 and 10 Combustion Turbines expected to begin commercial operation?

A. The scheduled Commercial Operation for both Smith 9 and Smith 10 is October 1, 2009.

Q. What is the total estimated cost of the Smith 9 and 10 Combustion Turbines?

A. The total estimated cost of the Smith 9 and 10 Combustion Turbines, as included in the 2009 approved budget, is $162,500,632. (See Exhibit GTC-C.)

Q. Please explain the methodology for arriving at this cost estimate and why this cost estimate is reasonable.

A. This estimate is based on a EKPC Board of Directors approved contract with GE in the amount of $73,837,445 for the supply of the combustion turbine equipment and the balance of plant (BOP) engineering, and an estimated amount of $88,663,187 for the BOP equipment and installation costs. The BOP equipment and installation costs are estimated based on GE experience in providing equipment and installation services on other LMS100 projects adjusted to meet the specific Smith 9 and 10 conditions.

Q. Since EKPC's 2009 budget was approved, have there been any changes to the construction schedule and estimated cost of Smith 9 and 10?

A. Yes, the current estimated cost of the project is $155,800,000. (See Exhibit GTC-D.)

Q. Please explain why these changes are necessary and why they are reasonable.

A. The current estimate is based on actual procurement activity to date since the 2009 budget was developed and completion of detailed engineering for the BOP equipment. As such, a much more definitive cost can now be assigned to each component part of the project scope.

Q. Please describe the Smith 1 Generating Unit.

A. The Smith 1 Generating Unit is a state-of-the-art circulating fluidized bed (CFB) coal-fired generating unit which employs the latest technology to achieve some of the lowest emissions of any coal-fired plant in the United States. In fact, it is widely acknowledged to be one of the cleanest coal-fired power generation plants in the U.S. It is a twin to the Spurlock 4 unit at Maysville, Kentucky. Smith 1 will also have a net generating capacity of 278 MW when completed in 2013 and is fully dedicated to serving EKPC's sixteen member system distribution cooperatives and their retail members.

The unit is provided with an Alstom CFB boiler supplying 2,018,142 lb/hr of steam to a General Electric turbine-generator set with a maximum gross capability of 305, 846 kW, (net expected capacity of 278,000 kW). The turbine operates at an inlet throttle pressure of 2400 psi at 1000 °F. The CFB will burn approximately 187.5 tons of fuel per hour and use over 40 tons of limestone per hour at maximum load. The unit is equipped with a dry scrubber and baghouse to remove sulfur dioxide and particulate matter, respectively, in accordance with all current environmental standards. Nitrogen oxides are removed in the furnace of the CFB and with a post-combustion polishing selective non-catalytic reduction (SNCR) system. The plant is equipped with the normal complement of auxiliaries including coal and limestone unloading, ash and waste handling, water make-up and treatment facilities, pumps, fans, a cooling tower, and a 475 foot tall stack.

Q. Please explain the permitting and construction process for the Smith 1 Generating Unit if RUS financing is used for this generating unit.

A. Smith 1 is currently undergoing an extensive environmental review process in accordance with the National Environmental Policy Act (NEPA) rules. This process is necessitated by EKPC's need for federal approval of a loan guarantee by the Rural Utilities Service (RUS). A Supplemental Environmental Impact Statement (SEIS) has been prepared for the project and is in the final stages of RUS staff review prior to public notice. It is referred to as "Supplemental" because the Smith site has been the subject of two other EIS efforts. The first was finalized by RUS in 1980 for a proposed coal fired unit at that time. The second was an effort by the Department of Energy in 2003 to site an integrated gasified combined cycle project at the site. Neither of these projects was completed. Upon completion of public review of this latest SEIS process, RUS will issue a Record of Decision of its findings. In parallel with the NEPA work by RUS, EKPC has filed the necessary air, water, and other permits and permissions from appropriate regulatory agencies and has received approval or is actively pursuing such approval. A complete listing of permit and other approvals is provided in Exhibit GTC-E.

Q. Please explain the permitting and construction process for the Smith 1 Generating Unit if RUS financing is not used for this generating unit.

A. In the event RUS financing is not used for the Smith 1 project, it is EKPC's intent to request a Lien Accommodation from RUS and seek financing from another party. RUS has developed procedures for an expedited approval of requests for lien accommodations which are normally processed within 90 days of receipt of the application from an RUS borrower. EKPC intends to file under this process in early

November 2008.

RUS is currently in litigation with the Sierra Club over granting a lien accommodation in a case involving Sunflower Electric Cooperative G&T in Kansas wherein the Sierra Club challenges RUS' determination that granting a lien accommodation does not trigger the provisions of NEPA. This case is before the federal court at this time. In the Sunflower case, RUS did not prepare an EIS for the proposed project. In the EKPC Smith 1 case, a draft SEIS has been prepared by RUS. EKPC continues to work with RUS in the finalization of the SEIS.

In the event non-RUS financing is used, the issuance of other federal permits could trigger the application of NEPA rules for the Smith 1 project. EKPC is reviewing the possible impact of a number of non-RUS financing alternatives on the permitting of Smith 1. In the case of non-RUS financing, the major issue affecting the permitting and construction process is the timing of receiving the final environmental clearances needed to start construction. Construction is targeted to begin in January 2010.

Q. Please explain how the different sources for financing that EKPC might use for Smith 1 could affect the permitting and construction costs for the Smith 1 Generating Unit that are included in the test year.

A. Construction costs included in the test year are very dependent on the actual start of construction of the project. A detailed cash flow for the project based on a January 2010 construction start has been developed. If start of construction is delayed, the cash flow will be offset by the period of the delay. Nevertheless, the sources of financing for the project do not change the requirement to obtain all permits prior to beginning construction. Financing from RUS or others will be conditioned on EKPC's satisfactory demonstration that all approvals are in place.

Q. **What is the estimated project balance of the Smith 1 Generating Unit at May 31, 2010?**

A. Based on commencing construction in January 2010, the estimated costs incurred by the end of the test year will be $163,964,186 (See Exhibit GTC-F).

Q. **Please explain the methodology for arriving at this cost estimate.**

A. This estimated cost was derived from the recorded expenditures as of September 30, 2008, plus the estimated expenditures through May 30, 2010 (the end of the test year).

Q. **What assumptions has EKPC used in estimating the permitting and construction costs for the Smith 1 Generating Unit that are included in the test year and why are these assumptions reasonable?**

A Test year construction costs are based on the assumed start of construction date of January 2010 and the accumulated budgeted cash flow for all contracts and Owner's costs that are expected to be incurred by the end of the forecasted test year.

Q. **Since EKPC's 2009 budget was approved, have there been any changes to the construction schedule and estimated cost of Smith 1?**

A. The schedule has not changed. However, EKPC has updated the Smith 1 cost to reflect the addition of a make-up water reservoir and financing costs. (See Exhibit GTC-G.) These changes result in a revised total Smith 1 cost estimate of $766,678,878, compared to the previous cost estimate of $804,000,000. However, the estimated expenditures during the test year are not expected to change from what was approved in the 2009 budget.

Q. **Please explain why these changes are necessary and why they are reasonable.**

A. These changes are necessary to reflect changes in construction cost estimates after the 2009 and 2010 budgets were approved for the Smith 1 project.

Q. **Does this conclude your testimony?**

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In re the Matter of:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A GENERAL ADJUSTMENT OF ITS WHOLESALE ELECTRIC RATES	)	**CASE NO. 2008-00409**

AFFIDAVIT

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Gary T. Crawford, 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.

Gary T. Crawford

Subscribed and sworn before me on this 24th day of October, 2008.

Gregory S. Duffin
Notary Public

My Commission expires: December 8, 2009

SPURLOCK UNIT 4 PROJECT
Project Cost Estimate
2009 Budget Basis

Contract Description	Estimate at Completion
Turbine Generator Equipment	$26,318,986
Turbine Generator Installation	$8,088,946
Site Preparation	$0
Feedwater Heaters	$1,126,645
Deaerator	$302,460
Condenser	$2,288,620
Circulating Water Pumps	$1,566,200
Condensate Pumps	$323,505
Boiler Feed Pumps	$2,327,395
Distributed Controls System	$3,988,437
Fans & Motors	$2,771,607
Ash Handling Equipment	$3,171,350
Alloy Piping	$3,940,498
Large Transformers	$3,170,552
Medium Transformers	$1,358,300
Iso-Phase Buss	$725,700
Switchgear	$5,710,196
Boiler Island	$196,778,030
Emissions Monitoring	$300,000
Coal/Limestone Handling	$16,210,400
Chimney	$6,701,000
Cooling Tower	$3,230,954
Circulating Water Pipe	$10,742,620
Piling	$9,270,142
Substructure	$22,569,192
Ash Silos	$8,000,000
Balance of Plant	$26,059,279
Balance of Plant	$76,257,606
Roofing	$621,777
Painting	$2,718,750
Engineering	$9,695,000
Construction Mgmt	$6,700,000
	$463,034,147
Owners Cost	$20,000,000
Environmental	$0
Misc. Communications	$0
	$0
	$483,034,147
Estimated IDC	$49,186,666
	$532,220,813

Spurlock Unit 4 Project
Project Cost Estimate
Current EAC Basis

Contract Description	*Estimated Cost to EKPC at Completion*
Turbine Generator Equipment	$26,318,986
Turbine Generator Installation	$8,128,894
Site Preparation	$0
Feedwater Heaters	$1,126,645
Deaerator	$302,460
Condenser	$2,160,413
Circulating Water Pumps	$694,200
Condensate Pumps	$323,505
Boiler Feed Pumps	$2,327,395
Distributed Controls System	$3,861,237
Fans & Motors	$2,771,607
Ash Handling Equipment	$3,171,350
Alloy Piping	$3,940,498
Large Transformers	$3,106,434
Medium Transformers	$1,358,300
Iso-Phase Buss	$725,700
Switchgear	$4,103,046
Boiler Island	$200,187,000
Emissions Monitoring	$300,000
Coal/Limestone Handling	$13,440,765
Chimney	$6,701,000
Cooling Tower	$3,230,954
Circulating Water Pipe	$10,742,620
Piling	$9,270,142
Substructure	$20,726,604
Ash Silo	$12,000,000
Balance of Plant	$27,287,303
Balance of Plant	$71,231,501
Roofing	$621,777
Painting	$1,866,433
Engineering	$10,175,000
Construction Mgmt	$6,700,000
	$458,901,770
Owners Cost	$20,000,000
Environmental	$0
Misc. Communications	$0
	$0
	$478,901,770
Estimated IDC	$49,186,666
	$528,088,436

Smith 9 & 10
2009 Budget & Project Cost Estimate

Contract Description	2009 Budget	Project Cost Estimate
CT901Equip. & Engineer.	$73,837,445	$62,400,000
CT901 Installation	60,501,203	n/a
CT901		11,440,466
Balance of Plant (est.)		81,917,766
Spare Part	2,445,000	Incl. In BOP
Emission Monitoring	700,000	Incl. In BOP
Site Preparation	500,000	Incl. In BOP
Nox Water Improve.	200,000	Incl. In BOP
Control Room Mod.	546,400	Incl. In BOP
GSU Transformer	2,500,000	Incl. In BOP
Gas Supply Piping	546,400	Incl. In BOP
EK Proj. Mgt.	750,000	Incl. In BOP
Contingency 10%	14,275,201	Incl. In BOP
Owner's Cost*	5,698,983	Incl. In BOP
Project Total	**$162,500,632**	**$155,758,232**
		155,800,000

Smith 9 & 10
Project Cost Estimate as of 10.15.08

Description	Current Amount
15kv switchgear	568,410.00
5kv switchgear	378,400.00
Station Serv. & Aux Xfmer	635,026.00
Ammonia Tank & Fwdg Pump Skid	289,985.00
Power Control Module	604,600.00
Simplex Gas Filter & Coalescer Skid	169,580.00
Instrument Air Compressor	472,153.40
Motor Control Center	464,580.04
IsoPhase Bus Duct	634,746.00
Dry PCM Bldg	100,350.00
Demin Water Forward Pump	267,782.00
Gas Turbine Fixators	42,870.00
SCS- OPEN	Pending
Waste & Expansion Tanks	214,373.98
Conical Shoes	61,616.00
Production Piling	1,840,434.95
UPS - OPEN	Pending
	6,744,907.37
1 GSU Transformer	2,185,000.00
2 LMS 100 Packages & Engineering	73,840,466.00
Simple Cycle Catalyst System	7,786,760.00
Dry Secondary Coolers	4,321,176.00
Gas Compressor	2,200,440.00
GC Substructures	14,747,220.00
Above Ground Construction	Pending
TOTAL LMS 100 & BOP Awarded	**111,825,969.37**
CEMS Bldgs	349,591.00
Consulting Services	129,205.50
Eng. Construction Observation	86,030.00
Rock	50,650.00
Test Pile Program	579,510.00
Pre-Engineered Building	533,300.00
Portable radios for site	4,079.88
Temporary Drain for Trailer	2,500.00
Total To Date	**113,560,835.75**
Forecasted:	
Construction (estimate)	30,000,000.00
Supervisory Control System (estimate)	600,000.00
UPS	50,000.00
Spare Parts (estimate)	2,445,000.00
Owner's Cost	1,701,620.12
Contingency	8,828,905.58
Current Forecasted Total	**155,800,000.00**

Smith CFB Permits a..d Approvals from SEIS

Appendix B -- Relevant Federal and State Environmental Laws and Regulations

Standard, Requirement, Criteria, or Limitation	Citation	Description	Administration and Permitting	Compliance
Federal				
Clean Water Act (Federal Water Pollution Control Act), as amended [33 USCA Sect. 1251 et seq.]				
Section 404 of the Clean Water Act	33 USC 1344	Section 404 grants authority to USACE to regulate activities in federal Waters of the United States, including jurisdictional wetlands.	The Section 404 permit program is administered by the USACE in Kentucky.	EKPC would be required to obtain a permit under Section 404 for any impacted Waters of the United States, including jurisdictional wetlands.
Section 401 of the Clean Water Act	33 USC 1341	The states are granted authority to review activities in waterways and wetlands and to issue water quality certifications, under Section 401.	The Section 401 Water Quality Certification is issued by the Kentucky Division of Water.	EKPC would be required to obtain a Section 401 Water Quality Certification for impacted Waters of the United States, and for construction of the dam for the emergency water supply reservoir.
Section 316(b) of the Clean Water Act	33 USC 1326	Requires for cooling water intake structures that the location, design, construction, and capacity reflect the best technology available for minimizing adverse environmental impact.	Kentucky Pollution Discharge Elimination System (KPDES) permit, issued by the Kentucky Division of Water.	EKPC would be required to modify its existing KPDES permit for Smith Station.

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Appendix B -- Relevant Federal and State Environmental Laws and Regulations

Standard, Requirement, Criteria, or Limitation	Citation	Description	Administration and Permitting	Compliance
National Pollutant Discharge Elimination System (NPDES) Regulations	40 CFR Part 122, 125	Establishes procedures for determination of effluent limitations for point source discharges of chemicals, and requires permits for discharges of pollutants from any point source, to Waters of the Untied States, protective of beneficial uses.	Kentucky Pollution Discharge Elimination System (KPDES) permit, issued by the Kentucky Division of Water.	EKPC would be required to modify its existing KPDES permit for Smith Station.
Steam Electric Power Generating Point Source Category	40 CFR 423	Federal effluent limitations, performance standards, and pretreatment standards of any surface water discharged by a Steam Electric Power Generating Point Source.	Kentucky Pollution Discharge Elimination System (KPDES) permit, issued by the Kentucky Division of Water.	EKPC would be required to modify its existing KPDES permit for Smith Station.

Appendix B -- Relevant Federal and State Environmental Laws and Regulations

Standard, Requirement, Criteria, or Limitation	Citation	Description	Administration and Permitting	Compliance
Requirements Applicable to Cooling Water Intake Structures	40 CFR 125 Subpart I	The purpose of these requirements is to establish the best technology available for minimizing adverse environmental impact associated with the use of cooling water intake structures.	Kentucky Pollution Discharge Elimination System (KPDES) permit, issued by the Kentucky Division of Water.	EKPC would be required to modify its existing KPDES permit for Smith Station.
Storm water Runoff Requirements	40 CFR Sect. 122.26(b)(14)	Requires that storm water runoff be monitored and controlled on construction sites greater than one acre.	Kentucky Division of Water, construction storm water KPDES permit	EKPC would be required to obtain a storm water permit, which would include a storm water pollution prevention plan (SWPPP).
Ambient Water Quality Criteria	40 CFR Part 131 Quality Criteria for Water, 1976, 1980, 1986	Requires states to establish ambient water quality criteria for surface water based on use classifications and the criteria stated under Section 304(a) of the Clean Water Act.	Kentucky Division of Water.	Preferred Alternative would comply.

Appendix B -- Relevant Federal and State Environmental Laws and Regulations

Standard, Requirement, Criteria, or Limitation	Citation	Description	Administration and Permitting	Compliance
Oil Pollution Prevention	40 CFR 112	Establishes rules to prevent impacts from oil spills.	EPA	Spill Prevention, Control and Countermeasure (SPCC) Plan would be required for fuel oil tanks and other petroleum products in tanks. EKPC to include in contract specifications.
National Environmental Policy Act (NEPA)	**42 U.S.C. 4321-4347**	Requires federal agencies to evaluate the environmental impacts of their actions, and integrate such evaluations into their decision-making processes.	CEQ/lead agency	This draft SEIS fully complies with NEPA.

Appendix B -- Relevant Federal and State Environmental Laws and Regulations

Standard, Requirement, Criteria, or Limitation	Citation	Description	Administration and Permitting	Compliance
Council on Environmental Quality (CEQ) Regulations	40 CFR 1500-1518	These regulations implement NEPA and establish two different levels of environmental analysis: the environmental assessment (EA) and the EIS. An EA determines whether significant impacts may result from a Proposed Action. If significant environmental impacts are identified, and EIS is required to provide the public with a detailed analysis of alternative actions, their impacts, and mitigation measure if necessary.	CEQ	The draft SEIS fully complies with the CEQ regulations for implementing NEPA.
Safe Drinking Water Act	**42 U.S.C. Subchapter XII**	Establishes procedures to ensure the safety of public water supply systems and protection of underground sources of drinking water.	Through Kentucky laws and regulations.	Preferred alternative would comply. EKPC receives its potable water from a local water district and would continue to do so.

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Appendix B -- Relevant Federal and State Environmental Laws and Regulations

Standard, Requirement, Criteria, or Limitation	Citation	Description	Administration and Permitting	Compliance
Sole Source Aquifers	40 CFR 149	Establishes protections for aquifers that are a sole source of drinking water.	EPA	No designated sole source aquifers are located anywhere near the preferred alternative area (none in Kentucky).
Transportation—42 U.S.C. 4916				
Railroad Noise Emission Compliance Regulations	49 CFR 210	Establishes standards for noise emissions from railroads.	Federal Railroad Administration.	Railroads would need to comply.
Environmental Quality Improvement Act, as amended	**42 U.S.C. 4371-4375**	The Act creates the Office of Environmental Quality to support the work of the Council of Environmental Quality and is further intended to assure that each federal department and agency involved with programs affecting the environment implement appropriate policies.	CEQ	Preferred alternative complies.

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Appendix B -- Relevant Federal and State Environmental Laws and Regulations

Standard, Requirement, Criteria, or Limitation	Citation	Description	Administration and Permitting	Compliance
Farmland Protection Policy Act [7 USC 4201-4209]				
Farmland Protection Policy Act	7 CFR 658	Requires federal agencies to use criteria to identify and take into account the adverse effects of their programs on the preservation of farmland, to consider alternative actions that could decrease adverse effects, and to ensure that their programs are compatible with state and local government and private programs and policies to protect farmland.	Natural Resources Conservation Service (NRCS) administrates through Farmland Conversion Impact Rating	RUS has submitted the rating form to NRCS; preferred alternative would comply.

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Appendix B -- Relevant Federal and State Environmental Laws and Regulations

Standard, Requirement, Criteria, or Limitation	Citation	Description	Administration and Permitting	Compliance
Fish and Wildlife Coordination Act, as amended	**16 USC 661-667**	Provides that whenever the waters or a channel of a body of water are modified by a department or agency of the U.S., the department or agency first shall consult with the U.S. Fish and Wildlife Service and with the head of the agency exercising administration over the wildlife resources of the state where construction would occur, with a view to the conservation of wildlife resources.	Coordination through NEPA process.	Preferred alternative would comply.

Appendix B -- Relevant Federal and State Environmental Laws and Regulations

Standard, Requirement, Criteria, or Limitation	Citation	Description	Administration and Permitting	Compliance
Migratory Bird Treaty Act	**16 USC 703-712**	This law implements the treaties that the US has signed with a number of countries protecting birds that migrate across national boarders. It makes illegal the taking, possessing or selling of protected species.	Coordination through NEPA	Preferred alternative would comply.
Bald and Golden Eagle Protection Act	**16 USC 668-668d**	The Act prohibits the taking or possession of and commerce in bald and golden eagles, with limited exceptions.	FWS	Preferred alternative would comply.
The U.S. Rivers and Harbors Act [33 USC Sect 401 et seq.]				
Section 10 of the U.S. Rivers and Harbors Act	**33 USC 403**	Regulates activities (e.g., construction, soil disturbance) that occur below the Ordinary High Water elevation of navigable waters of the United States.	The Section 10 permit program is administered by the USACE in Kentucky. The USACE also establishes the Ordinary High Water elevation.	EKPC would obtain a Section 10 permit for the Kentucky River intake structure.

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Appendix B -- Relevant Federal and State Environmental Laws and Regulations

Standard, Requirement, Criteria, or Limitation	Citation	Description	Administration and Permitting	Compliance
Protection and Enhancement of Environmental Quality	Executive Order 11514	Protection of environment provides leadership for protecting and enhancing the quality of the Nation's environment to sustain and enrich human life.	Addressed through NEPA process	Preferred alternative would comply.
Intergovernmental Review of Federal Programs	Executive Order 12372	Directs federal agencies to consult with and solicit comments from state and local government officials whose jurisdictions would be affected by federal actions.	Addressed through NEPA process.	RUS is conducting consultation with state and local officials.
Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations	Executive Order 12898	Requires federal actions to achieve environmental justice by identifying and addressing disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority and low-income populations.	Addressed through NEPA process	Preferred alternative would comply, as documented in this draft SEIS.

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Appendix B -- Relevant Federal and State Environmental Laws and Regulations

Standard, Requirement, Criteria, or Limitation	Citation	Description	Administration and Permitting	Compliance
Protection of Children From Environmental Health Risks and Safety Risks	Executive Order 13045	Requires federal actions and policies to identify and address disproportionately adverse risks to the health and safety of children.	N/A	The preferred alternative does not entail particular risks to health and safety of children.
Responsibilities of Federal Agencies To Protect Migratory Birds	Executive Order 13186	Directs executive departments and agencies to take certain actions to further implement the Migratory Bird Treaty Act.	Addressed through NEPA process	Preferred alternative would comply, as documented in this draft SEIS.

Appendix B -- Relevant Federal and State Environmental Laws and Regulations

Standard, Requirement, Criteria, or Limitation	Citation	Description	Administration and Permitting	Compliance
Floodplain Management and Protection of Wetlands [Executive Orders 11988 and 11990]				
Floodplain Management and Protection of Wetlands	44 CFR 9	These executive orders, regulations, and guidance establish procedures for avoidance of actions that would exacerbate flooding, evaluation of impacts, and involvement of the public and affected homeowners in the decision-making process.	Addressed through NEPA process, Section 404 permitting, and Floodplain permit from county	Preferred alternative would comply.
Noise Control Act of 1972, as amended by the Quiet Communities Act of 1978	**42 U.S.C. 4901 to 4918**	Requires compliance with state and local noise laws and ordinances.	No permit required; administered through RUS regulations.	Preferred alternative would comply.
Noise Abatement and Control	24 CFR 51 Subpart B	Establishes noise protection standards.	HUD regulations specified by RUS.	To be included in EKPC specifications for contractor.
Noise Emission Standards for Transportation Equipment; Interstate Rail Carriers	40 CFR 201	Establishes noise emission standards for railroads.	EPA	Railroad connectors would need to comply.

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Appendix B -- Relevant Federal and State Environmental Laws and Regulations

Standard, Requirement, Criteria, or Limitation	Citation	Description	Administration and Permitting	Compliance
Federal Aviation Act of 1958, as amended [49 USC 1101, et seq.]				
Objects Affecting Navigable Airspace	14 CFR Part 77	Requires compliance with the Federal Aviation Administration (FAA) to identify any potential impacts, such as emissions or height of construction, on air safety and navigable airspace.	FAA regulations. If any part of the project exceeds notification criteria under FAR Part 77, notice should be filed at least 30 days prior to the proposed construction date.	Preferred alternative would comply. Plant stack (chimney) would have lighting in accordance with FAA requirements. Air fields were avoided through the original siting process.
Resource Conservation and Recovery Act RCRA (Solid Waste Disposal Act) as amended [42 USC Sect. 6901-6992K]				
Criteria for Classification of Soil Waste Disposal Facilities and Practices (Subtitle D)	40 CFR Part 257	Established criteria for use in determining which solid waste disposal facilities and practices pose a reasonable probability of adverse effects on health and the environment	Kentucky Environment and Public Protection Cabinet.	EKPC would need to meet the established criteria for its landfill.

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Appendix B -- Relevant Federal and State Environmental Laws and Regulations

Standard, Requirement, Criteria, or Limitation	Citation	Description	Administration and Permitting	Compliance
Identification and Listing of Hazardous Waste (Subtitle C)	40 CFR Part 261	Defines characteristics of hazardous wastes and provides lists of hazardous wastes. Identifies solid wastes which are subject to regulation as hazardous wastes under CFR Parts 124, 262-265, 268, 270, and 271	Kentucky Environment and Public Protection Cabinet.	EKPC to include in contract specifications.
Releases from Solid Waste Management Units	40 CFR Part 264.94	Subpart F (264.94) gives concentration limits in groundwater for hazardous constituents from a regulated unit.	Kentucky Environment and Public Protection Cabinet.	EKPC would need to meet the established criteria for its landfill.
Guidelines for the Land Disposal of Solid Wastes	40 CFR Part 241	Delineates minimum levels of performance required of any solid waste land disposal site operation; provides mandates for federal agencies. Primarily addresses design and operation of solid waste landfills.	Kentucky Environment and Public Protection Cabinet.	EKPC would need to meet the established criteria for its landfill.

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Appendix B -- Relevant Federal and State Environmental Laws and Regulations

Standard, Requirement, Criteria, or Limitation	Citation	Description	Administration and Permitting	Compliance
Hazardous Waste Management Systems General	Subtitle C 40 CFR Part 260	Provides definitions, general standards, and information applicable to 40 CFR Parts 260-265, 268.	EPA, Kentucky Environment and Public Protection Cabinet.	EKPC to include in contract specifications.
Standards Applicable to Generators of Hazardous Waste	Subtitle C 40 CFR Part 262	Establishes standards for generators of hazardous waste.	EPA, Kentucky Environment and Public Protection Cabinet.	EKPC to include in contract specifications.
Standards Applicable to Transporters of Hazardous Waste	Subtitle C 40 CFR Part 263	Establishes standards which apply to transporting hazardous waste within the U.S. if the transportation requires a manifest under 40 CFR Part 262.	EPA, Kentucky Environment and Public Protection Cabinet.	EKPC to include in contract specifications.
Hazardous Waste Permit Program	40 CFR Part 270	Establishes provisions covering basic EPA permitting requirements.	EPA, Kentucky Environment and Public Protection Cabinet.	EKPC to include in contract specifications.

Appendix B -- Relevant Federal and State Environmental Laws and Regulations

Standard, Requirement, Criteria, or Limitation	Citation	Description	Administration and Permitting	Compliance
Clean Air Act (CAA), as amended [42 USCA Sect. 7401-7671Q]				
National Primary and Secondary Ambient Air Quality Standards (NAAQS)	40 CFR Part 50	Establishes ambient air quality standards for certain "criteria pollutants" to protect public health and welfare.	Kentucky Department for Environmental Protection Division for Air Quality (DAQ).	EKPC has applied for an air permit.
National Emission Standards for Hazardous Air Pollutants (NESHAPS)	40 CFR Part 61	Provides standards for emissions of designated hazardous air pollutants, including mercury, beryllium, asbestos, and inorganic arsenic, from certain activities	Kentucky Department for Environmental Protection Division of Air Quality (DAQ).	EKPC has applied for an air permit.
Asbestos Projects—abatement, registration, certification, notification.	10 CSR 10-6.240 to 10-6.250	Requirements for Asbestos projects including demolition.	Kentucky Department for Environmental Protection Division of Air Quality (DAQ).	EKPC to include in contract specifications if applicable.
Hazardous Materials Transportation Act [40 USCA Sect. 1801-1813]				
Hazardous Materials Transportation Regulations	40 CFR Parts 107, 171-177	Regulates transportation of hazardous materials	USDOT	EKPC to include in contract specifications.

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Appendix B -- Relevant Federal and State Environmental Laws and Regulations

Standard, Requirement, Criteria, or Limitation	Citation	Description	Administration and Permitting	Compliance
Occupation Safety and Health Act of 1970 [PL 91-956, 29 USCA Sect. 651-678]				
Occupational Safety and Health Standards	29 CFR Part 1910	Establishes safety and health requirements for personnel working with hazardous materials and hazardous waste.	OSHA	EKPC to include in contract specifications.
Safety and Health Regulations for Construction	29 CFR Part 1926	Establishes protection standards (e.g., hazard communication, excavation and trenching requirements) for workers involved in hazardous waste operations.	OSHA	EKPC to include in contract specifications.
National Historic Preservation Act of 1966		Requires establishment of a National Register of Historic Places (NRHP). Section 106 requires federal agencies to take into account the effects of their actions on properties on or eligible for the NRHP.	National Park Service; implemented through State Historic Preservation Officer.	Concurrence from SHPO on NRHP eligibility and required actions. SHPO has indicated concurrence with conclusion of no adverse impacts; final report to be reviewed. See Appendix F correspondence.

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Appendix B -- Relevant Federal and State Environmental Laws and Regulations

Standard, Requirement, Criteria, or Limitation	Citation	Description	Administration and Permitting	Compliance
National Register of Historic Places.	36 CFR Part 60 to 63	Authorizes Secretary of Interior to establish NRHP and identifies procedures to determine eligibility.		
Advisory Council on Historic Preservation Regulations.	36 CFR Part 800	Implementation of Section 106 of the National Historic Preservation Act.	Kentucky Heritage Council State Historic Preservation Officer (SHPO)	Concurrence from SHPO on NRHP eligibility and required actions. SHPO has indicated concurrence with conclusion of no adverse impacts; final report to be reviewed. See Appendix F correspondence.
Archaeological and Historic Preservation Act of 1974	**16 USCA 469 36 CFR Part 65 40 CFR 6301(c)**	Established procedures to provide for preservation of historical and archaeological data which might be destroyed through alteration of terrain as a result of a federal construction project or a federally licensed activity or program.	Kentucky Heritage Council State Historic Preservation Officer (SHPO)	Concurrence from SHPO on NRHP eligibility and required actions. SHPO has indicated concurrence with conclusion of no adverse impacts; final report to be reviewed. See Appendix F correspondence.

Appendix B -- Relevant Federal and State Environmental Laws and Regulations

Standard, Requirement, Criteria, or Limitation	Citation	Description	Administration and Permitting	Compliance
Native American Graves Protection and Repatriation Act	**PL 101-601**	Requires that if Native American remains or cultural items are found on federal lands, the appropriate tribe must be notified, and all activity in the area of discovery must cease.	Kentucky Heritage Council/tribal coordination	Notification and compliance with Act.
Endangered Species Act	**16 USC 1531-1544** **50 CFR part 200** **50 CFR Part 402**	Protects endangered species and the critical habitats upon which endangered species depend.	USFWS by coordination through NEPA process; consultation may be required.	On-going coordination with USFWS is occurring.
Wild and Scenic Rivers Act	**16 U.S.C. 1271**	Protects designated rivers.	The only Wild and Scenic River in Missouri, the Eleven Point, is administered by the U.S. Forest Service.	Preferred alternative is not near any Wild and Scenic Rivers.

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Appendix B -- Relevant Federal and State Environmental Laws and Regulations

Standard, Requirement, Criteria, or Limitation	Citation	Description	Administration and Permitting	Compliance
National Historic Preservation Act of 1966, Section 106	**16 USC 470**	Provides the framework for federal review and protection of cultural resources, and to ensure they are considered during federal project planning and execution. The implementing regulations for Section 106 process (36 CFR 800) have been developed by the Advisory Council on Historic Preservation. The Secretary of the Interior maintains a National Register of Historic Places and sets forth significance criteria for inclusion in the register. Cultural resources included in the NRHP, or determined eligible for inclusion, are considered "historic properties" for the purpose of consideration by federal undertakings.	Kentucky Heritage Council SHPO	Concurrence from SHPO on NRHP eligibility and required actions. SHPO has indicated concurrence with conclusion of no adverse impacts; final report to be reviewed. See Appendix F correspondence.

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Appendix B -- Relevant Federal and State Environmental Laws and Regulations

Standard, Requirement, Criteria, or Limitation	Citation	Description	Administration and Permitting	Compliance
National Flood Insurance Act of 1968	**42 USC 4001**	Establishes the National Flood Insurance Program (NFIP), which enables property owners to purchase insurance as protection against flood losses in exchange for state and community floodplain management regulations that reduce future flood damages.	Federal Emergency Management Agency (FEMA) and State of Kentucky.	The project will comply with NFIP requirements.
FEMA regulations	44 CFR Chapter I	Implements the NFIP; establishes requirements for construction and permitting in floodplains.	State of Kentucky.	Floodplain construction permit and "no-rise certification" from the State of Kentucky would be needed for the river intake structure.
State				
Act related to flood control and water resources.	**KRS 151.125**	Requires establishment of regulations for flood control and water resources.	Kentucky Environmental and Public Protection Cabinet (EPPC).	Preferred alternative will comply, through various regulations implemented under the Act.
Act related to floodplain management.	**KRS 151.230**	Authorizes EPPC to establish minimum standards for floodplain management.	Kentucky Environmental and Public Protection Cabinet (EPPC).	Preferred alternative will comply, through various regulations implemented under the Act.

Exhibit GTC-E
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Appendix B -- Relevant Federal and State Environmental Laws and Regulations

Standard, Requirement, Criteria, or Limitation	Citation	Description	Administration and Permitting	Compliance
Act related to plans for dams, levees, etc.	**KRS 151.250**	Assigns authority for regulating and permitting dam construction to the Department for Natural Resources.	Kentucky Department for Natural Resources (DNR).	Dam for emergency drought storage reservoir would require a permit.
Environmental Protection Act	**KRS 224**	Establishes authority for air quality, noise control, waste, and water quality.	Environmental Quality Commission.	Preferred alternative will comply, through various regulations implemented under the Act.
Act Related to Kentucky River Authority	**KRS 151.700 to 151.730**	Establishes the Kentucky River Authority (KRA) and responsibilities.	KRA is responsible for establishing a long-range water resource plan for management of the Kentucky River.	Through NEPA coordination process.
Stream construction criteria.	401 KAR 4:060	Establishes requirements for construction in floodplains and floodways.	Kentucky Division of Water.	EKPC would be required to obtain a stream construction permit and no-rise certification for the proposed intake structure.
Regulations on groundwater protection plans.	401 KAR 5:037	Establishes regulations to prevent groundwater pollution.	Kentucky Environmental and Public Protection Cabinet (EPPC).	EKPC would be required to develop and implement a groundwater protection plan addressing potential impacts from the CCB landfill and from chemicals stored on-site (e.g., ammonia).

Exhibit GTC-E
Page 22 of 24

Appendix B -- Relevant Federal and State Environmental Laws and Regulations

Standard, Requirement, Criteria, or Limitation	Citation	Description	Administration and Permitting	Compliance
KPDES permitting program regulations.	401 KAR 5:050 to 5:080	Establishes requirements for discharge of waste water.	Kentucky Pollution Discharge Elimination System (KPDES) permit, issued by the Kentucky Division of Water.	EKPC would be required to modify its existing KPDES permit for Smith Station. EKPC would be required to obtain a storm water permit, which would include a storm water pollution prevention plan (SWPPP).
Section 401 Water Quality Certification Requirements.	401 KAR Chapter 9	The states are granted authority to review activities in waterways and wetlands and to issue water quality certifications, under Section 401.	The Section 401 Water Quality Certification is issued by the Kentucky Division of Water.	EKPC would be required to obtain a Section 401 Water Quality Certification for impacted Waters of the United States, and for construction of the dam for the emergency water supply reservoir.
Water Quality Standards	401 KAR Chapter 10	Water quality standards established for various water bodies must not be violated.	Kentucky Division of Water.	Preferred alternative would comply, through the KPDES point discharge and storm water permit program.
Hazardous Waste Regulations	401 KAR Chapters 31 to 40	Defines and regulates hazardous wastes.	Kentucky EPPC	Proposed alternative would comply; hazardous wastes are not anticipated.
Underground Storage Tank Regulations	401 KAR Chapter 42	Defines and regulates underground storage tanks.	Kentucky EPPC	Proposed alternative would comply; no underground storage tanks are planned.

Exhibit GTC-E
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Appendix B -- Relevant Federal and State Environmental Laws and Regulations

Standard, Requirement, Criteria, or Limitation	Citation	Description	Administration and Permitting	Compliance
Special Waste Regulations	401 KAR Chapter 45	Defines and regulates special waste. CCB is defined as a special waste.	Kentucky EPPC	CCB as structural fill is regulated at 401 KAR 45:060 (special waste permit-by-rule); CCB in landfill is regulated at 401 KAR 45:110 and 130. Preferred alternative would comply.
Air Quality Regulations	401 KAR Chapters 50 - 63	Includes general regulations and regulations specific to NAAQS, hazardous air pollutants, and New Source Performance Standards.	Kentucky DAQ	Enforced through the air permit application process; EKPC has applied for their air permit.
Kentucky Heritage Commission enabling legislation.	KRS 171.3801 to 171.384	Established what is now the Kentucky Heritage Council. The director of the Heritage Council is the SHPO.	Kentucky Heritage Council, SHPO.	Concurrence from SHPO on NRHP eligibility and required actions. SHPO has indicated concurrence with conclusion of no adverse impacts; final report to be reviewed. See Appendix F correspondence.

Exhibit GTC-E
Page 24 of 24

J. K. Smith Unit 1
Estimated Project Balance at May 31, 2010

Recorded Expenditures as of 9/30/08[1]	$122,094,127.99
Owner's Cost as of 9/30/08	2,009,878.26
Estimated Cash Flow Oct. - Dec. 2008[2]	553,551.00
Estimated Cash Flow Jan. - Dec. 2009	7,347,004.00
Estimated Cash Flow Jan.- May 2010	31,959,625.00
Total Estimated Project Balance at May 31, 2010	$163,964,186.25

1Excluding IDC

2Source: SCI 8/13/08 Cash Flow due to Jan. 2010 start of construction

SMITH STATION UNIT 1
ESTIMATED PROJECT COSTS - AUGUST 2008
(EK revised 9/25/08)

CONTRACT		UNIT 1 ESTIMATE AUG 2008
TURBINE GENERATOR	$	38,000,000
SITE IMPROVEMENTS	$	6,100,000
FEEDWATER HEATERS	$	1,684,665
DEAERATOR	$	450,000
CONDENSER	$	2,661,835
CIRCULATING WATER PUMPS	$	1,100,000
CONDENSATE PUMPS	$	450,000
BOILER FEED PUMPS	$	2,962,378
DISTRIBUTED CONTROL SYSTEM	$	2,650,000
FANS	$	4,400,000
ASH HANDLING EQUIPMENT	$	5,200,000
TURBINE BRIDGE CRANE	$	650,000
ALLOY PIPING	$	4,400,000
LARGE POWER TRANSFORMERS	$	3,400,000
MEDIUM POWER TRANSFORMERS	$	1,600,000
SMALL POWER DISTRIBUTION TRANSFORMERS	$	850,000
GENERATOR BREAKER & ISOPHASE	$	3,300,000
SWITCHGEAR	$	6,000,000
BOILER ISLAND	$	264,000,000
EMISSIONS MONITORING	$	450,000
COAL/LIMESTONE HANDLING	$	55,400,000
CHIMNEY	$	7,500,000
COOLING TOWER	$	3,900,000
CIRCULATING WATER PIPE	$	5,500,000
DAM & WATER RESERVOIR / PUMP HOUSE	$	**33,200,000**
SUBSTRUCTURE I and II	$	34,500,000
ASH SILOS	$	12,700,000
TURBINE BUILDING STRUCTURAL STEEL	$	8,900,000
BALANCE OF PLANT		
BUILDING & MECHANICAL WORK	$	109,700,000
ASH HANDLING INSTALLATION	$	4,600,000
RIVER WATER INTAKE & PUMPHOUSE	$	6,800,000
ELECTRICAL & INSTRUMENTATION WORK	$	28,500,000
PAINTING	$	4,200,000
SUBTOTAL	$	665,706,878
PERMANENT PLANT MOBILE EQUIPMENT	$	-
G201 BOILER CONTINGENCY #	$	13,200,000
G281 BOP & G311 ELEC CONTINGENCY #	$	13,820,000
MISC CONTINGENCY (EXCL G1,G6, G11, G21, G201,G281, G311) #	$	21,820,000
SUBTOTAL	$	48,840,000
ENGINEERING COST		
ORIGINAL DESIGN	$	14,580,000
MISC. STUDIES	$	50,000
CM ASSISTANCE	$	7,500,000
PERFORMANCE TEST	$	-
FINANCE COSTS	$	**3,000,000**
OWNERS COST	$	20,000,000
SUBTOTAL	$	45,130,000
TOTAL	$	759,678,878
IDC	$	2,000,000
PROJECT TOTAL	$	761,678,878
PROJECT TOTAL COST PER KW (excluding substation)	$	2,740
SUBSTATION (BY EKPC PD)	$	5,000,000
TRANSMISSION (BY EKPC PD)	$	-
UNIT 1 TOTAL PROJECT COST	$	766,678,878
PROJECT TOTAL COST PER KW	$	2,758

PRICING BASED ON DUPLICATE EQUIPMENT AS SPURLOCK UNIT 4
UNIT WILL HAVE NET CAPACITY OF 278 MW
INCLUDED WITH CONTRACT 131A
INCLUDES $5 MILLION FOR COND & SW TANKS, NH3 STORAGE, POTABLE WATER TREAT
CO2, H2, N2 STORAGE, MAINTENANCE SHOP, CONTROL ROOM 7 OTHER OCCUPIED SPACES
ADJUSTMENTS FOR AUGUST 2008 UPDATE: MATERIAL - 3% / YR TO FEBRUARY 2008, THEN 10% / YR; LABOR - 5% / YR.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

GENERAL ADJUSTMENT OF ELECTRIC RATES OF EAST KENTUCKY POWER COOPERATIVE, INC.	) PSC CASE NO.) 2008-00409)

TESTIMONY OF
JAMES C. LAMB, JR.
SENIOR VICE PRESIDENT OF POWER SUPPLY
EAST KENTUCKY POWER COOPERATIVE, INC.

Filed: October 31, 2008

I. INTRODUCTION AND PURPOSE

Q. Please state your name and business address.

A. James C. Lamb, Jr., and my business address is East Kentucky Power Cooperative, Inc., 4775 Lexington Road, P.O. Box 707, Winchester, Kentucky, 40392-0707.

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

A. I am employed by East Kentucky Power Cooperative, Inc., ("EKPC") as the Senior Vice President of Power Supply.

Q. Please provide a brief summary of your educational and professional background.

A. I have a B.S. in Economics from Centre College and an MBA from the University of Kentucky. I have been employed at EKPC since 1981 and worked in System Planning, Control Area Operations, and Market Research. I assumed my current position in February 2007.

Q. What are your responsibilities at EKPC in your position?

A. I am responsible for Resource Planning, Transmission Planning, Mid-Term Planning, Market Forecasting & Analysis, Generation Dispatch, Strategic Planning, Fuels & Emissions, Rates & Regulatory Filings, and Financial Forecasts.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of this testimony is to describe the process and methodologies currently utilized by EKPC and its member systems to forecast load, sales and revenues. Billing determinants used in this proceeding were developed based on the load and sales forecast.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring Exhibits JCL-1 through JCL-9.

Q. Are you sponsoring certain information required by Commission Regulations 807 KAR 5:001, Section 10?

A. Yes. I am sponsoring the following schedules for the corresponding Filing Requirements:

Filing Requirement	Description	Volume	Tab #
807 KAR 5:001 Section 10(9)(h)	Financial forecast for each of 3 forecasted years included in capital construction budget supported by underlying assumptions made in projecting results of operations and including the following information: 1. Operating income statement (exclusive of dividends per share or earnings per share); 2. Balance sheet; 3. Statement of cash flows; 4. Revenue requirements necessary to support the forecasted rate of return; 5. Load forecast including energy and demand (electric); 6. Access line forecast (telephone); 7. Mix of generation (electric); 8. Mix of gas supply (gas); 9. Employee level; 10. Labor cost changes; 11. Capital structure requirements; 12. Rate base; 13. Gallons of water projected to be sold (water); 14. Customer forecast (gas, water); 15. MCF sales forecasts (gas); 16. Toll and access forecast of number of calls and number of minutes (telephone); and 17. A detailed explanation of any other information provided.	Vol. 3	Tab 30
807 KAR 5:001 Section 10(10)(i)	Comparative income statements (exclusive of dividends per share or earnings per share), revenue statistics and sales statistics for 5 calendar years prior to application filing date, base period, forecasted period, and 2 calendar years beyond forecast period;	Vol. 5	Tab 54

II. <u>LOAD FORECAST</u>

II. A. <u>GENERAL DESCRIPTION</u>

Q. What is the load forecast?

A. The load forecast is a projection of future energy and peak demand that reflects both changes in usage per customer and customer growth. The forecast is based on economic and demographic trends, weather data, and appliance saturation data. The forecast is the basis for calculating all capital expansion costs, operational expenses and projected revenues. It is required every two years by the Rural Utilities Services (RUS).

Q. How are the load forecast values used in calculation of rates and other elements of this rate case?

A. The load forecast is the basis for calculating projected revenue for the 2009 and 2010 budget years. The load forecast is also used to develop the test year billing determinants used in this proceeding.

Q. How is East Kentucky Power Cooperative's load forecast developed?

A. EKPC's forecast of system peak demand and total energy requirements is the summation of the load forecasts for EKPC's 16 member systems. A process flow chart is provided in Exhibit JCL-1. Every two years, EKPC is required by RUS to submit a Work Plan for developing the following year's forecast. This plan describes, in detail, how the forecast will be developed, resources to be used, as well as a timeline. In November of 2007, the EKPC Board of Directors approved the 2007 Work Plan to be adhered to for the development of the 2008 Load Forecast. RUS then reviewed and approved the Load Forecast Work Plan. Following approval of the Work Plan, EKPC prepares a preliminary load forecast for the 16 member systems. This preliminary forecast for each system is based on customer and retail sales projections for six classes of customers - residential, residential seasonal, commercial and industrial (C&I) less than or equal to 1 MW (small C&I or small commercial), commercial and industrial greater than 1 MW (large C&I or large commercial), public authorities or public buildings, and street lighting. Note that not all member systems report data for each of these classes (see Exhibit JCL-2). Historical sales data for each member system is taken from each member system's RUS Form 7. For each class, retail sales and the number of customers are projected based on historical trends, appliance saturations and efficiencies, and economic/demographic variables such as employment and population growth. EKPC's sales to member systems are then determined by adding distribution losses to the sum of total retail sales for all 16 member systems. EKPC's total requirements are calculated by adding transmission losses to total retail sales. Winter and Summer peak demands are then determined based on normal EKPC peak day weather.

II. B. LOAD FORECAST RESULTS

Q. What are the results of the forecast?

A. The average annual growth rate for EKPC's total requirements for the five-year period 2008 to 2013 is 2.3%. For the ten-year period, average growth is 2.1% per year. Exhibits JCL-3 and JCL-4 show the historical and forecasted winter and summer peak demands and total energy requirements, respectively.

Q. **How does this compare with growth rates of surrounding utilities?**

A. EKPC growth rates for total energy requirements are projected to be higher than those of surrounding utilities. According to the 2008 Joint Integrated Resource Plan ("IRP") of Louisville Gas and Electric Company (LGE) and Kentucky Utilities Company (KU), annual growth rates for total requirements are projected to be 1.1% for LGE and 1.2% for KU for the 2008 to 2012 period. According to Duke Energy-Kentucky's most recent IRP, also prepared in 2008, the growth rate is 0.8% for the same time period. The most recent Big Rivers IRP (2005) shows a 1.1% growth rate for the five year period.

Q. To what do you attribute EKPC's higher growth rates?

A. EKPC member system retail customers tend to use more electricity than the national average for the following reasons. There is relatively little natural gas available in the service territory of the member systems, and electric heat is the heating method of choice. Approximately 60% of all retail customers have electric heat, and around 90% have electric water heaters. New homes coming on to the system tend to be larger than the existing stock of homes. There is also a relatively high number of mobile homes in the service territory of the member systems – the typical installed heating system is an electric furnace. While efficiency gains are being seen with respect to heat pumps, refrigerators, washers, and dryers, and while such gains have been incorporated into the load forecast, homeowners continue to add appliances such as computers and large screen televisions. The net result is that use per customer has continued to increase. EKPC believes that use per customer will continue to grow, albeit at a reduced rate relative to historical usage levels.

Q. How does the growth in the 2008 Load Forecast compare to previous load forecasts and what are the major factors causing the differences?

A. Exhibit JCL-5 shows that the 2008 Load Forecast is lower than the 2006 Forecast. In the 2008 Load Forecast, the projections reflect the implementation of a direct load control program. This program results in 15 MW being clipped off the winter peak due to controlling water heaters and the summer peak being reduced by 60 MW due to air conditioning and water heating control.

III. METHODOLOGY AND TECHNIQUE DETAILS

Q. What is the role of each individual member system during the load forecast process?

A. EKPC prepares a preliminary load forecast for each member system and then meets with them to discuss the preliminary forecast. Member system personnel present at the meetings include the Manager and other key staff members from the areas of Finance, Engineering, Member Services, and Operations. During the meeting, preliminary projections are reviewed and, if necessary, revised as mutually agreed upon.

Q. Why would revisions be necessary?

A. Distribution cooperatives are local area providers. As such, they monitor and are very aware of local area business conditions. EKPC takes advantage of this local knowledge and incorporates factors raised by the member systems into the forecast.

Q. Specifically, what data does the member system provide?

A. Member systems provide EKPC with data for individual large C&I customers, both existing and planned. This data includes monthly sales and monthly peak demand projections for three years. The member systems also work with EKPC to develop a rate forecast to be used in the models.

Q. Please describe how the service area economic forecasts are developed.

A. EKPC has divided its members' service areas into seven economic regions based on the member system service territorial boundaries. EKPC subscribes to Global Insight, Inc. in order to analyze regional economic performance. Global Insight, Inc. is a widely used consulting firm with expertise in more than 170 industries and over 200 countries, including the utility industry. They collect and monitor data, provide forecasts and analysis, and offer consulting advice to clients in business, financial, and government organizations. Global Insight collects historical county level data, develops forecasting models based on the data, and provides the resulting forecasts to EKPC. County data provided to EKPC include: population, income, employment levels, wages, labor force, and unemployment rate. Consistent regional forecasts for population, income, and employment are developed and provided to EKPC by Global Insight. These projections of regional economic activity are needed because they greatly impact the sales forecasting and strategic planning of EKPC. Changes in regional employment and income are important determinants of customer and sales growth. Economic models for these seven economic regions provide EKPC with a way of linking the electricity needs of a service area to the rest of the service area's economy in a consistent and reasonable manner.

Q. How are the energy forecasts developed?

A. Energy forecasts are prepared at the member system level by customer class, which for the purposes of the 2008 Load Forecast include residential, residential seasonal, small C&I, large C&I, public authorities, and street lighting. Not all member systems report all classifications; See Exhibit JCL-2. EKPC reports Gallatin Steel separately due to its size and because most of its load is interruptible.

Q. What are the primary factors affecting energy use?

A. In general, the number of customers, weather and local area economic conditions are major factors that affect energy use. Specifically for the residential class, population growth and household formation, energy price, weather, appliance saturation and efficiencies are all key elements that are incorporated in the forecast. The residential class is the largest class. See Exhibit JCL-6. Electricity use per customer tends to decrease as electric prices increase. Improvements in appliance efficiencies also reduce usage per customer. Electric use per customer tends to increase as appliance saturations increase, particularly electric space heating and water heating. Commercial and industrial classes are impacted by employment and electric price. The lighting sector is correlated with the number of residential customers.

Q. Please describe the method used to prepare the residential class load forecast.

A. The general approach to forecasting the residential class is to multiply the number of customers in the residential class by average electric usage per residential customer. The number of residential customers is forecasted using a regression model with regional economic and demographic variables as the independent variables in the analysis. Additional explanatory variables are used for member systems in order to account for regional differences in local economies. Two variables that are significant in these regressions are a) the number of households by county in each member system's economic region and b) percent of total households served by the member system. The latter, also referred to as market share of total households, is based on RUS Form 7 data. EKPC uses statistically adjusted end-use (SAE) models in order to project sales. These models are constructed with average energy use per customer as the dependent variable and heating, cooling, water heating and other energy usage as the independent variables. Using this approach, EK can combine end-use level concepts into a total residential sales forecast. Because SAE models use end-use level data, detailed information about appliance saturation, appliance use, appliance efficiencies, household characteristics, weather characteristics, and demographic and economic information is required. The SAE approach segments the average household use into end-use components.

$$\boxed{Use_{y,m} = Heat_{y,m} + Cool_{y,m} + Water\ Heat_{y,m} + Other_{y,m}}$$

Formulas for the cooling end-use component are provided in Exhibit JCL-7. The heating, water heating and other end-use components have the same basic structure. There is an index variable and a usage variable. The index variable is developed using appliance efficiency and appliance saturation trends. The usage variable is constructed using normal weather and trends with respect to household size, household income, and the price of electricity. The index and use variables are multiplied by each other which produces the end-use component's energy contribution to the average use per customer. For example, the index for cooling energy usage may be defined as a function of appliance saturation, efficiency of the appliance, and usage of the appliance. Annual end-use indices and a usage variable are constructed and used to develop a variable to be used in least squares regression in the model. These variables are constructed for heating, cooling, water heating, and an 'Other' variable, which includes lighting and other miscellaneous usage.

The Cool, Heat, Water Heat, and Other variables are then used in a least squares regression which results in estimates for annual and monthly use per household.

Q. Describe other data needed for this process.

A. Twenty years of historical appliance saturation data are used to forecast saturation of appliances. Every two years since 1981, EKPC member systems have surveyed their residential customers. The most recent survey was conducted in the Fall of 2007.

Member systems gather appliance, insulation, heating and cooling, economic, and demographic data. Appliance holdings of survey respondents are analyzed in order to better understand their electricity consumption and to project future appliance saturations.

Q. How are appliance efficiencies considered?

A. Increased appliance efficiencies due to government standards have been accounted for in the model. As the efficiency ratings increase for appliances, new households install the higher efficiency appliances and existing households in the market for new appliances replace the older less efficient appliances with these more efficient units. The different efficiency ratings are an input to the forecast models.

Q. How does EKPC track appliance efficiencies?

A. EKPC is a member of the Energy Forecasting Group (EFG), which is a collaboration of electric utilities coordinated by Itron, Inc., a consulting firm with expertise in many areas including forecasting. As a member, EKPC receives a summary of the latest Energy Information Administration (EIA) Annual Energy Outlook and a summary of the EIA's recently published Residential Energy Consumption Survey. Itron works closely with EIA to embed these equipment saturation and efficiency trend forecasts in regional models they develop for EFG members. EKPC tailors regional trends to its member system service territories. The resulting indices pertaining to appliance efficiency trends and usage are used to construct electric energy models based on heating, cooling, water heating and other electric use for the residential class. Various demographic and socioeconomic factors that affect appliance choice and appliance use are used to model appliance efficiencies. These include the changing shares of urban and rural customers relative to total customers, number of people living in the household, as well as square footage of the house and the thermal integrity of the house.

Q. Please describe other data used to prepare residential class forecast.

A. Lastly, weather is an integral input. EKPC subscribes to a service of DTNMeteorlogix, which provides actual weather data including daily high and low temperatures, hourly temperatures, humidity, sunshine minutes, and wind chill. EKPC currently maintains six weather databases for different regions of the state of Kentucky. Each member system's model uses the weather station that most closely reflects the local weather.

Q. Please describe the method used to prepare the residential seasonal class load forecast.

A. This class includes any customer reported on the RUS Form 7 by the member systems as residential seasonal. Only 1 member system reports this class. The approach to forecasting residential seasonal class is to multiply number of customers in the residential seasonal class by electric usage per residential customer. Customers are modeled first, followed by sales. Customers are analyzed by means of regression model with regional economic and demographic variables as the independent variables in the analysis. The resulting coefficients used to prepare customer projections. Energy use per customer is projected using the same SAE methodology described for the residential class. Total sales is the result of multiplying the number of customers by the energy use per customer.

Q. Please describe the method used to prepare the public authorities class load forecast.

A. This class includes any customer reported on the RUS Form 7 by member systems as Sales to Public Authorities. Only 2 member systems report this class. The approach to forecasting sales to public authorities differs from the residential and seasonal classes in that customers are modeled and total energy use instead of use per customer. Customers are modeled first, followed by sales. Customers are analyzed by means of a regression model with regional economic and demographic variables as the independent variables in the analysis. The resulting coefficients are used to prepare customer projections. Residential customer projections are a significant driver for customers in the public authorities class. Total sales for this class are projected with the independent variables being the forecasted number of customers resulting from the previous customer model, electric price, employment, and weather.

Q. Please describe the method used to prepare the Small C&I Class load forecast.

A. The Small C&I Class includes any customer with demand less than 1 MW. The Small C&I Class load forecast depends on the number of customers and the total electric usage. This class is analyzed by means of regression analysis, and the resulting coefficients are used to prepare sales and customer forecasts. The Small C&I customer regression model typically consists of residential customers, unemployment rate, or time as the independent variables. The regression model for total C&I sales typically consists of price, weather, and some measure of the local or national economy and a seasonal dummy variable to account for the seasonal changes in electric use. Different explanatory variables may be used for different member systems, in order to account for regional differences in local area economies. For example, the Eastern Region is directly impacted by the mining industry whereas the Central Region is not

Q. Please describe the method used to prepare the Large C&I Class load forecast.

A. The Large C&I Class includes customers with demand greater than 1 MW. EKPC and its members utilize a two-part method for making projections for the Large C&I Class: a forecast of existing customer sales and a forecast of new customer sales. Forecasts of existing customers are made directly by the member system that serves the load. Member systems maintain working relationships with these customers and are in regular contact with them. Each member system prepares a three-year projection for each of their customers whose demand exceeds 1 MW. Load forecasts beyond the three-year horizon for existing large C&I customers are modeled using regression analysis and input from the member system. Any potential large C&I customer that has contacted the member system and discussed plans to locate within the member system territory is included in the forecast. Due to normal construction lead times, the ability to predict additions in the near term is strong. The only exception to this is with respect to coal mine loads. Coal mine operations can move equipment from place to place in a relatively short time period, making a forecast of their location difficult.

Q. How is the longer term forecast for the Large C&I Class produced?

A. Over the long term, regression analysis is used to forecast new large C&I customers. Because there are so few customers in this class, analysis is initially done at the EKPC level to forecast total new customers. These new customers are then allocated overall to the member systems via a probabilistic model. This provides an analytical basis for locating large loads on the EKPC system. The model is spreadsheet based and uses @RISK. The model probabilistically distributes the forecast of new large C&I customers to member systems based on their regional economic outlook, share of county served and historical success in attracting new customers.

Once the number of new large C&I customers is determined, energy projections are developed. Based on historical data, the characteristics of a new generic large C&I customer in the 2008 Load Forecast are: a peak load of 1.8 MW with a 70 percent load factor.

Q. Please describe the method used to prepare the street lighting class load forecast.

A. This class includes any customer reported on the RUS Form 7 by member systems as street lighting. Eleven member systems report this class. As with the other classes, customers are modeled first, followed by sales. The street lighting customer regression model typically includes the resulting residential class customer forecast or a trend variable as the independent variable. The regression model for total street lighting energy sales typically consists of seasonal variables to account for winter and summer changes in lighting usage patterns and/or a measure of the number of hours of light per day.

Q. Please describe the method used to produce the Gallatin Steel forecast.

A. Gallatin Steel is a large industrial customer and is served by an EKPC member system. Gallatin Steel management provides any planned operational changes as well as planned maintenance schedules. This information combined with the historical hourly load data is used to construct hourly forecast data.

Q. Are there any adjustments made to the forecast derived from the econometric models?

A. Model output is scaled up due to transmission and distribution losses. Losses make up approximately 8% of total energy requirements on the EKPC system.

Q. Please explain how the peak forecasts are developed.

A. EKPC's peak demand forecast is a bottom-up approach, meaning that member system peaks are summed to obtain the EKPC peak. Member system peaks are developed by applying load factors to forecasted energy sales. Model outputs are hourly demand for winter peak day and hourly demand for summer peak day. Peak demands are based on typical peak day temperature profiles for winter and summer. The resulting peaks are explicitly linked to energy projections.

Q. Does the energy and peak load forecast include the impact of existing DSM?

A. Yes, the impacts of existing DSM programs that have been implemented by EKPC and member systems are reflected in the forecast. The historical data used to develop the forecast contains the impact of those existing programs. See Exhibit JCL-8.

Q. Does the energy and peak forecast include the impact from the implementation of new DSM programs?

A. Yes. The energy and peak load forecast includes the impact of a Direct Load Control Program (DLC), that is currently being implemented. Electric water heaters and/or central air conditioning units will be controlled during peak demand periods via switches installed on the participant's home. Over a five year period, the implementation plan is for a total of 50,000 participants, 10,000 each year. Due to the installation of equipment, energy and peak savings are not expected until the summer of 2009. Based upon a pilot project conducted in 2007, projected energy and peak savings for the next 5 years are shown in Exhibit JCL-9.

Q. Are there other peak load reductions that are included in the forecast?

A. Yes. The peak load forecast has been reduced due to the customers on a special contract or interruptible rate, totaling 128 MW for winter peak and summer peak.

Q. Does this conclude your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In re the Matter of:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A GENERAL ADJUSTMENT OF ITS WHOLESALE ELECTRIC RATES	))))	**CASE NO. 2008-00409**

AFFIDAVIT

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

James C. Lamb, Jr., 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.

James C. Lamb Jr.

Subscribed and sworn before me on this 29th day of October, 2008.

Peggy S. Griffin
Notary Public

My Commission expires: December 8, 2009

Phase 1	EKPC and RUS Approved Work Plan
Phase 2	Data collection: -billing history -weather -load research -appliance saturations
	Econometric data development: -population -households -employment -wages -energy price
Phase 3	Energy forecasts by Member System -by RUS Form 7 classifications -sales and customers using regression analysis
Phase 4	Peak Demand Forecasts -winter and summer by Member System -monthly and hourly for EKPC system
Phase 5	EKPC and RUS Approved

Class		**Total Number of Member Systems Reporting**
Residential		16
Residential Seasonal		1
Small C&I		16
Large C&I		16
Public Authorities		2
Street Light		11

Peak Demands and Total Requirements
Historical and Projected

Season	Firm Winter Peak Demand (MW)	Year	Firm Summer Peak Demand (MW)	Year	Total Requirements (MWh)	Load Factor (%)
1989 - 90	1,449	1990	1,079	1990	5,489,092	43%
1990 - 91	1,306	1991	1,164	1991	5,958,422	52%
1991 - 92	1,383	1992	1,131	1992	6,099,308	50%
1992 - 93	1,473	1993	1,309	1993	6,860,902	53%
1993 - 94	1,788	1994	1,314	1994	6,917,414	44%
1994 - 95	1,621	1995	1,518	1995	7,761,980	55%
1995 - 96	1,990	1996	1,540	1996	8,505,621	49%
1996 - 97	2,004	1997	1,650	1997	8,850,394	50%
1997 - 98	1,789	1998	1,675	1998	9,073,950	58%
1998 - 99	2,096	1999	1,754	1999	9,825,866	54%
1999 - 00	2,169	2000	1,941	2000	10,521,400	55%
2000 - 01	2,322	2001	1,980	2001	10,750,900	53%
2001 - 02	2,238	2002	2,120	2002	11,456,830	58%
2002 - 03	2,568	2003	1,996	2003	11,568,314	51%
2003 - 04	2,610	2004	2,052	2004	11,865,797	52%
2004 - 05	2,719	2005	2,180	2005	12,527,829	53%
2005 - 06	2,599	2006	2,196	2006	12,331,272	54%
2006 - 07	2,840	2007	2,354	2007	13,080,367	53%
2007 - 08	3,051	2008	2,302	2008	13,172,654	49%
2008 - 09	2,962	2009	2,363	2009	13,647,057	53%
2009 - 10	3,029	2010	2,406	2010	13,959,302	53%
2010 - 11	3,087	2011	2,442	2011	14,217,198	53%
2011 - 12	3,143	2012	2,475	2012	14,511,928	53%
2012 - 13	3,215	2013	2,529	2013	14,777,060	52%
2013 - 14	3,275	2014	2,579	2014	15,050,207	52%
2014 - 15	3,345	2015	2,630	2015	15,335,690	52%
2015- 16	3,408	2016	2,680	2016	15,657,979	52%
2016 - 17	3,482	2017	2,737	2017	15,930,390	52%
2017 - 18	3,547	2018	2,790	2018	16,221,635	52%
2018 - 19	3,617	2019	2,843	2019	16,526,826	52%
2019-20	3,680	2020	2,893	2020	16,855,275	52%
2020-21	3,760	2021	2,957	2021	17,158,239	52%
2021-22	3,833	2022	3,016	2022	17,479,553	52%
2022-23	3,904	2023	3,071	2023	17,784,014	52%
2023-24	3,965	2024	3,121	2024	18,106,328	52%
2024-25	4,052	2025	3,186	2025	18,422,561	52%
2025-26	4,125	2026	3,248	2026	18,751,416	52%
2026-27	4,204	2027	3,311	2027	19,099,314	52%
2027-28	4,283	2028	3,419	2028	19,447,211	52%

Peak Demand and Energy Consumption

Year	Firm Winter Peak Demand (MW)	Firm Summer Peak Demand (MW)	Total Requirements (MWh)	Annual Load Factor (%)
2005	2,719	2,180	12,527,829	53%
2006	2,599	2,196	12,331,272	54%
2007	2,840	2,354	13,080,367	53%
Forecast				
2008	**3,051**	2,302	13,172,654	49%
2009	2,962	2,363	13,647,057	53%
2010	3,029	2,406	13,959,302	53%
2011	3,087	2,442	14,217,198	53%
2012	3,143	2,475	14,511,928	53%
2017	3,482	2,737	15,930,390	52%
2022	3,833	3,016	17,479,553	52%
2027	4,204	3,311	19,099,314	52%

Note: 2008 Firm Winter Peak Demand is actual data.

Table 2
Energy and Peak Growth Rates

	2008-2012	**2008-2018**	**2008-2028**
Total Energy Requirements	2.3%	2.1%	2.0%
Residential Sales	2.0%	2.0%	2.0%
Total Commercial and Industrial Sales (Excluding Gallatin Steel)	3.3%	2.8%	2.3%
Firm Winter Peak Demand	1.1%	1.5%	1.7%
Firm Summer Peak Demand	1.9%	1.9%	2.0%

EKPC Total Member System Energy Sales

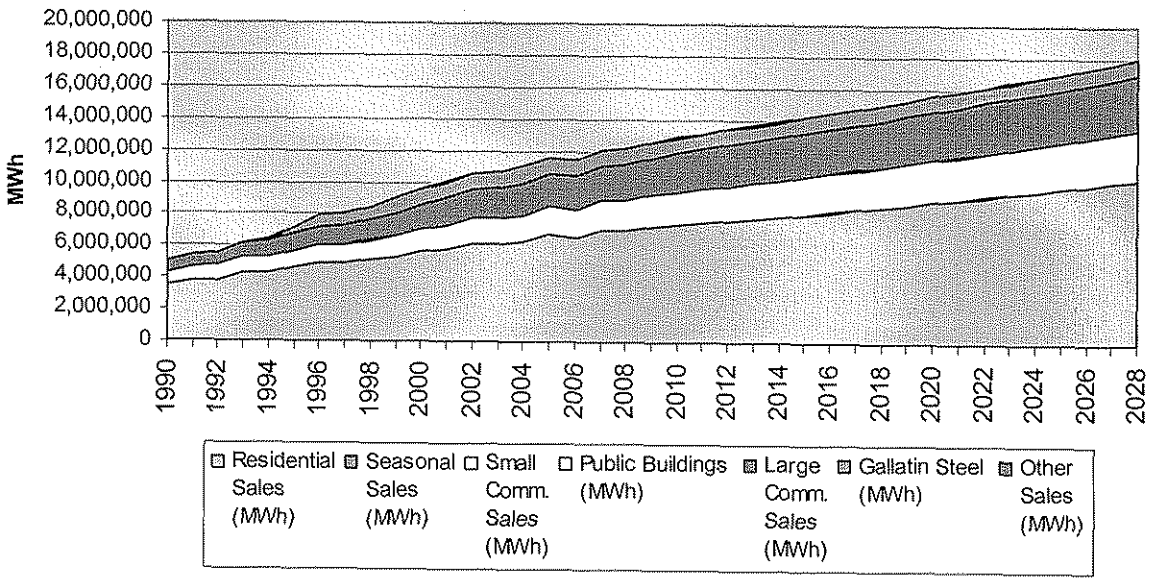
Year	Residential Sales (MWh)	Seasonal Sales (MWh)	Small Comm. Sales (MWh)	Public Buildings (MWh)	Large Comm. Sales (MWh)	Gallatin Steel (MWh)	Other Sales (MWh)	Total Retail Sales (MWh)
1990	3,497,574	9,094	813,371	9,096	653,502	0	3,737	4,986,373
1991	3,770,962	9,423	868,031	9,871	725,419	0	4,029	5,387,735
1992	3,813,577	9,756	913,599	11,586	776,268	0	4,304	5,529,089
1993	4,230,486	10,144	980,301	13,779	968,345	0	5,081	6,208,135
1994	4,285,099	10,280	1,014,549	14,240	1,026,927	0	4,156	6,355,251
1995	4,592,909	11,066	1,097,729	15,889	1,119,361	294,835	5,042	7,136,833
1996	4,875,662	12,342	1,138,469	16,785	1,188,760	640,756	5,555	7,878,329
1997	4,901,058	11,888	1,163,683	16,272	1,256,829	755,279	5,663	8,110,671
1998	5,109,002	11,476	1,230,450	17,315	1,345,859	696,051	5,601	8,415,754
1999	5,320,858	11,496	1,336,957	17,765	1,415,128	901,685	5,756	9,009,646
2000	5,626,500	12,479	1,446,958	18,280	1,503,523	906,171	6,160	9,520,072
2001	5,797,895	12,769	1,505,480	18,865	1,666,141	992,438	6,545	10,000,133
2002	6,166,723	14,076	1,577,590	20,453	1,798,352	1,005,491	7,107	10,589,793
2003	6,205,364	13,445	1,550,248	21,754	1,874,104	1,007,676	7,447	10,680,038
2004	6,337,737	13,846	1,598,111	22,974	1,989,780	1,047,466	7,498	11,017,413
2005	6,751,547	14,501	1,733,390	22,530	2,020,875	992,824	7,713	11,543,379
2006	6,548,160	13,882	1,777,897	22,196	2,078,245	978,939	8,236	11,427,556
2007	6,998,554	14,679	1,861,952	26,427	2,137,525	986,518	8,457	12,034,113
2008	7,032,311	14,723	1,911,640	27,542	2,214,381	967,738	8,721	12,177,056
2009	7,240,039	15,203	2,005,467	28,093	2,345,827	969,012	10,580	12,614,222
2010	7,374,611	15,683	2,059,958	28,667	2,443,048	969,150	10,821	12,901,939
2011	7,493,203	16,065	2,114,817	29,256	2,506,190	968,960	11,061	13,139,552
2012	7,646,800	16,585	2,169,237	29,837	2,569,877	967,411	11,298	13,411,045
2013	7,773,389	16,975	2,223,152	30,404	2,632,834	967,031	11,533	13,655,317
2014	7,903,386	17,368	2,277,104	30,963	2,698,010	968,462	11,769	13,907,062
2015	8,059,377	17,855	2,331,968	31,516	2,748,980	968,404	12,004	14,170,103
2016	8,233,250	18,401	2,387,430	32,073	2,814,845	968,850	12,239	14,467,087
2017	8,387,245	18,846	2,442,770	32,622	2,857,240	966,792	12,474	14,717,988
2018	8,540,177	19,298	2,498,092	33,159	2,916,374	966,524	12,707	14,986,331
2019	8,713,969	19,857	2,553,229	33,693	2,967,431	966,412	12,940	15,267,531
2020	8,899,636	20,436	2,608,961	34,232	3,025,391	968,439	13,173	15,570,267
2021	9,059,814	20,908	2,665,418	34,773	3,086,839	968,256	13,405	15,849,412
2022	9,230,462	21,444	2,722,020	35,323	3,154,493	968,089	13,637	16,145,470
2023	9,401,535	21,959	2,778,618	35,874	3,207,786	966,278	13,870	16,425,919
2024	9,580,822	22,490	2,835,490	36,428	3,267,396	966,171	14,102	16,722,900
2025	9,760,214	23,033	2,892,717	36,982	3,321,197	965,789	14,334	17,014,264
2026	9,943,341	23,561	2,949,880	37,536	3,381,009	967,464	14,566	17,317,357
2027	10,134,762	24,089	3,007,348	38,080	3,451,076	967,782	14,797	17,637,935
2028	10,352,048	24,667	3,064,451	38,623	3,495,898	967,782	15,028	17,958,497

EKPC Energy Sales and Total Requirements

Year	Total Retail Sales (MWh)	Office Use (MWh)	% Loss	EKPC Sales to Members (MWh)	EKPC Office Use (MWh)	Transmission Loss (%)	Total Requirements (MWh)
1990	4,986,373	5,087	5.7	5,295,459	6,287	3.5	5,489,092
1991	5,387,735	5,333	6.3	5,755,588	6,798	3.4	5,958,422
1992	5,529,089	5,242	6.2	5,903,267	7,559	3.2	6,099,308
1993	6,208,135	5,552	6.0	6,612,688	8,026	3.6	6,860,902
1994	6,355,251	5,614	5.5	6,727,959	8,541	2.7	6,917,414
1995	7,136,833	5,711	5.5	7,558,452	9,197	2.6	7,761,980
1996	7,878,329	6,167	5.0	8,301,379	8,856	2.4	8,505,621
1997	8,110,671	6,349	5.2	8,559,022	8,505	3.3	8,850,394
1998	8,415,754	6,121	4.5	8,821,630	7,236	2.8	9,073,950
1999	9,009,646	6,040	4.8	9,468,916	8,157	3.7	9,825,866
2000	9,520,072	6,606	5.0	10,027,205	7,862	4.8	10,521,400
2001	10,000,133	6,793	4.0	10,426,995	8,205	3.0	10,750,900
2002	10,589,793	7,562	4.3	11,071,862	8,818	3.4	11,456,830
2003	10,680,038	7,681	4.5	11,190,870	9,123	3.3	11,568,314
2004	11,017,413	8,289	4.4	11,537,505	9,106	2.8	11,865,797
2005	11,543,379	8,617	4.2	12,060,460	8,902	3.8	12,527,829
2006	11,427,556	8,924	3.8	11,892,304	7,568	3.6	12,331,272
2007	12,034,113	10,291	4.3	12,582,260	7,491	3.9	13,080,367
2008	12,177,056	9,925	4.3	12,729,876	8,080	3.3	13,172,654
2009	12,614,222	9,984	4.3	13,188,540	8,165	3.3	13,647,057
2010	12,901,939	9,984	4.3	13,490,439	8,205	3.3	13,959,302
2011	13,139,552	9,984	4.3	13,739,781	8,250	3.3	14,217,198
2012	13,411,045	9,984	4.3	14,024,740	8,295	3.3	14,511,928
2013	13,655,317	9,984	4.3	14,281,078	8,339	3.3	14,777,060
2014	13,907,062	9,984	4.3	14,545,167	8,384	3.3	15,050,207
2015	14,170,103	9,984	4.3	14,821,184	8,429	3.3	15,335,690
2016	14,467,087	9,984	4.3	15,132,793	8,473	3.3	15,657,979
2017	14,717,988	9,984	4.3	15,396,169	8,518	3.3	15,930,390
2018	14,986,331	9,984	4.3	15,677,759	8,562	3.3	16,221,635
2019	15,267,531	9,984	4.4	15,972,833	8,607	3.3	16,526,826
2020	15,570,267	9,984	4.4	16,290,399	8,652	3.3	16,855,275
2021	15,849,412	9,984	4.4	16,583,321	8,696	3.3	17,158,239
2022	16,145,470	9,984	4.4	16,893,987	8,741	3.3	17,479,553
2023	16,425,919	9,984	4.4	17,188,356	8,786	3.3	17,784,014
2024	16,722,900	9,984	4.4	17,499,989	8,830	3.3	18,106,328
2025	17,014,264	9,984	4.4	17,805,742	8,875	3.3	18,422,561
2026	17,317,357	9,984	4.4	18,123,700	8,919	3.3	18,751,416
2027	17,637,935	9,984	4.4	18,460,072	8,964	3.3	19,099,314
2028	17,958,497	9,984	4.4	18,796,444	9,009	3.3	19,447,211

Forecast Comparison 2008 Versus 2006					
	Year	2008	2006	Difference 2008 and 2006	
Total Requirements, MWh	2010	13,959,302	14,138,674	-179,372	-1.3%
	2015	15,335,690	15,787,203	-451,513	-2.9%
	2020	16,855,275	17,601,161	-745,886	-4.2%
	2025	18,422,561	19,519,545	-1,096,984	-5.6%
Net Winter Peak MW	2010	3,087	3,021	66	2.2%
	2015	3,345	3,398	-53	-1.6%
	2020	3,680	3,804	-124	-3.3%
	2025	4,052	4,248	-196	-4.6%
Net Summer Peak MW	2010	2,406	2,403	3	0.1%
	2015	2,630	2,674	-44	-1.6%
	2020	2,893	2,968	-75	-2.5%
	2025	3,186	3,298	-112	-3.4%

Total Retail Sales by Member Systems



The SAE approach segments the average household use into end-use components as follows:

$$Use_{y,m} = Heat_{y,m} + Cool_{y,m} + Water\ Heat_{y,m} + Other_{y,m}$$

Where, y=year
m=month

$$CoolIndex_y = \sum_{Type} Wgt^{Type} * \left(\frac{CoolShare_y^{Type} / Eff_y^{Type}}{CoolShare_{98}^{Type} / Eff_{98}^{Type}} \right)$$

$$CoolUse_{y,m} = \left(\frac{CDD_{y,m}}{NormCDD}\right) * \left(\frac{HHSize_y}{HHSize_{by}}\right) * \left(\frac{Income_y}{Income_{by}}\right) * \left(\frac{Price_{y,m}}{Price_{by}}\right)^{-.30}$$

Where, by=base year

$$Cool_{y,m} = CoolIndex_y * CoolUse_{y,m}$$

The Cool, Heat, Water Heat, and Other variables are then used in a least squares regression which results in estimates for annual and monthly use per household.

EKPC reported the following DSM Impacts in the 2006 Integrated Resource Plan:

Load Impacts of Existing Programs

(negative value= reduction in load)

Year	Impact on Energy Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
1998	7,545	-40.6	-7.3
1999	8,139	-44.3	-8.2
2000	9,393	-48.3	-9.2
2001	9,487	-51.2	-10.1
2002	9,131	-53.3	-11.0
2003	8,712	-54.8	-12.0
2004	7,765	-55.7	-13.0
2005	7,807	-57.2	-13.8
2006	7,671	-58.7	-14.7
2007	7,671	-58.7	-14.7
2008	7,671	-58.7	-14.7
2009	7,671	-58.7	-14.7
2010	7,671	-58.7	-14.7
2011	7,671	-58.7	-14.7
2012	7,671	-58.7	-14.7
2013	7,671	-58.7	-14.7
2014	7,671	-58.7	-14.7
2015	7,671	-58.7	-14.7
2016	7,671	-58.7	-14.7
2017	7,671	-58.7	-14.7
2018	7,671	-58.7	-14.7
2019	7,671	-58.7	-14.7
2020	7,671	-58.7	-14.7
2021	7,671	-58.7	-14.7

Impact of Direct Load Control Program

Year	Winter Peak Demand Savings (MW)	Summer Peak Demand Savings (MW)	Energy Savings (MWh)
2009		24	3,381
2010	9	36	5,099
2011	12	48	6,831
2012	15	60	8,379
2013	15	60	8,324

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

GENERAL ADJUSTMENT OF ELECTRIC RATES	)	PSC CASE NO.
OF EAST KENTUCKY POWER	)	2008-00409
COOPERATIVE, INC.	)	

TESTIMONY OF
CRAIG A. JOHNSON
VICE-PRESIDENT, PRODUCTION
EAST KENTUCKY POWER COOPERATIVE

Filed: October 31, 2008

I. INTRODUCTION

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

A. My name is Craig A. Johnson and my business address is East Kentucky Power Cooperative, Inc. ("EKPC"), 4775 Lexington Road, Winchester, Kentucky 40391. I am the Vice President of Production in the Generation and Transmission Operations Division of East Kentucky Power Cooperative, Inc.

Q. Please state your education and professional experience.

A. I received a Bachelor's degree in Engineering from West Virginia Institute of Technology and a Master's of Science degree in Engineering from the University of Kentucky. I am a licensed professional engineer in the Commonwealth of Kentucky. I have been employed by EKPC since September 1989 and have occupied my current position within the EKPC organization since May 2007.

Q. Please provide a brief description of your duties at EKPC.

A. I am responsible for all operational and maintenance functions at EKPC's three coal fired power plants, combustion turbine plant, and landfill gas operations. I report to the Senior Vice President of G&T Operations.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the methodology and assumptions used to prepare EKPC's generation operations and maintenance expenses and capital expenditures forecasts. I will also compare EKPC's O&M costs to industry averages and discuss EKPC's forced outage rates.

Q. Are you supporting certain information required by Commission Regulations

807 KAR 5:001, Section 10?

A. Yes. I am sponsoring the following schedules for the corresponding Filing Requirements:

Filing Requirement	Description	Volume	Tab #
Section 10(9)(b)	Most recent capital construction budget containing at minimum 3 year forecast of construction expenditures	Vol. 3	Tab 24
Section 10(9)(f)	For each major construction project constituting 5% or more of annual construction budget within 3 year forecast, following information shall be filed: 1. Date project began or estimated starting date; 2. Estimated completion date; 3. Total estimated cost of construction by year exclusive and inclusive of Allowance for Funds Used During Construction ("AFUDC") or Interest During Construction Credit; and 4. Most recent available total costs incurred exclusive and inclusive of AFUDC or Interest During Construction Credit	Vol. 3	Tab 28
Section 10(9)(g)	For each major construction project constituting 5% or more of annual construction budget within 3 year forecast, file aggregate of information requested in paragraph (f) 3 and 4 of this subsection.	Vol. 3	Tab 29

Q. Please explain how the power plant operation and maintenance expenses were estimated for the forecasted test year.

A. The operation and maintenance expenses that are included in the forecasted test year are based on 2009 and 2010 budgets for EKPC. These budgets are divided into budget codes for each generating facility. Each electric generating plant has its own responsibility center. The responsibility centers are then divided into individual budget codes for operational items, maintenance items and capital items. The budget codes are standardized among the facilities to the maximum extent possible. There are budget codes that are unique to individual power plants and, in some cases, by the type of generating unit. The methods that were used in estimating the budget allocation for each expense item include: 1) historical usage, 2) price escalation, 3) maintenance schedules, 4) vendor quotes, and 5) generation models.

Q. Please describe the various budget codes and the methodology used to develop the expenses that are included in Plant Operations?

A. The budget codes that are included in Plant Operations include: 1) Travel, 2) Routine Operating Material and Supplies, 3) Operations, 4) Utilities, 5) Equipment Rental, 6) Maintenance and Service Agreements, 7) Outside Professional and Consulting Services, 8) Subscriptions, 9) Annual Dues and Memberships, and 10) Education, Seminars, and Conferences. The costs included in these budget codes are estimated based on the historical usage, the type of maintenance planned for the upcoming year, the level of education and training required for the work force, and the escalation in the cost of commodities. EKPC's Supply Chain Department is responsible for determining budgetary unit price estimates for commodities with the exception of fuel and limestone.

Q. Please describe the various budget codes and the methodology used to develop the expenses that are included in Distributive Generator (Cagles)?

A. The budget codes that are included in Distributive Generator (Cagles) include: 1) Fuel, 2) Fuel Oil and 3) Lubricants. Cooper Power Station budgets for the Cagles Distributive

Generators. The costs included in these budget codes are estimated based on historical usage and anticipated price escalation. The price of fuel is based upon the budgetary unit price estimate provided by the Fuel Department.

Q. Please describe the various budget codes and the methodology used to develop the expenses that are included in Lime – Operations?

A. Lime is used as an additive in the combustion process for Spurlock Units No. 1 and No. 2 to reduce the potential for arsenic damage to the SCR catalyst. The amount of lime is based upon the historical usage and any planned outages. The price per ton of lime is based upon the estimate provided by the EKPC's Fuel Department.

Q. Please describe the various budget codes and the methodology used to develop the expenses that are included in Limestone and Magnesium Hydroxide – Operations?

A. Limestone is required for the scrubbing process for the removal of sulfur dioxide from flue gas from Spurlock Units No. 1, No. 2, No. 3, and No. 4. Magnesium Hydroxide is a chemical additive mixed with the spray water for the Units No. 1 and No. 2 wet electrostatic precipitators used to remove particulates from the flue gas. The costs of these items are recovered through the environmental surcharge. The quantity of limestone for Spurlock Unit No. 3 is based upon historical usage and the amount of generation estimated from the Planning Department's Generation Model. The amount of sulfur in coal that the Fuel Department is purchasing for Spurlock Unit No. 3 is also taken into consideration. Usage for Unit No. 4 is based upon the historical usage in Unit No. 3. Usage for Spurlock Units No. 1 and No. 2 are based upon the type of coal being purchased, the manufacturer estimate of limestone required, and the amount of generation predicted. The Fuel Department supplies a cost per ton for limestone. The Supply Chain Department supplies the cost per gallon for magnesium hydroxide.

Q. Please describe the various budget codes and the methodology used to develop the expenses that are included in Operations.

A. The budget codes that are included in Operations include: 1) Employee Recognitions, 2) Temporary Office Clerks, 3) Boiler Contractor License, 4) Landfill Manager Certifications, and 5) Employee Uniforms. Estimates for these expense items are based on historical usage.

Q. Please describe the various budget codes and the methodology used to develop the expenses that are included in Maintenance.

A. The maintenance functions at each plant are divided into systems. This allows EKPC to track the costs associated with certain systems and equipment. Maintenance budgets are driven by several factors. EKPC utilizes a computerized maintenance management system (CMMS) to track and to forecast maintenance activities and costs. All equipment at Dale, Cooper, Spurlock, and Smith are identified in the CMMS. The CMMS records the historical activities associated with equipment maintenance and the cost of performing these activities and can be used to predict future maintenance needs and costs. This provides for a systematic approach to maintenance activities. Steam turbine/generator overhauls are budgeted on 10- year cycles. Annual routine inspections are performed on the coal fired boilers with major inspections done at the time of the major turbine generator overhauls. The major overhauls on the combustion turbines are done based upon manufacturer's guidelines for the number of starts or operating hours. Major overhauls on the landfill gas units are based on the number of hours operated. All other maintenance activities, which are routine in nature, are based upon historical cost, predicted generation, and anticipated material pricing.

EKPC performs planned outages in the spring and fall on its coal fired units. The activities that can only be performed during a planned outage are identified in the CMMS. This information is used to schedule the duration of the planned outages. The risk associated with a forced outage is a factor that is used in determining when maintenance will be performed. This is especially true when planning activities associated with the boiler, which is a major driver of forced outages. The cost of replacement power for a forced outage causes EKPC to have a low tolerance for risk. This level of maintenance done on an annual basis helps to avoid the risk of forced outages.

Q. Please describe how the costs of Capital/Work Orders, Tools and Equipment Greater than $5,000, and Licensed & Motorized Vehicle are forecasted.

A. Capital improvements have their own planning and justification process outside of the operation and maintenance budgeting process. EKPC has a program for planning and justifying asset improvements called the MEAGER plan. MEAGER is an acronym for Maintaining Electric and Generation Equipment Reliability. The MEAGER identifies large capital improvements and large maintenance items over a 20 year planning horizon. The capital improvements and large maintenance that fall in a particular year are included in the relevant annual budget. Budgeting for tools and equipment is based on a proven need or the replacement of worn items. Vehicles are justified based on a demonstrated need and replaced using the following guidelines: (1) Five Years of Age, (2) Over 150,000 miles, and (3) percentage of repairs.

Q. Please compare EKPC's O&M costs to industry averages.

A. EKPC's total O&M costs ranged between $19.10 per megawatt hour in 2002 to $31.89 per megawatt hour in 2007. The national average during the same time period ranged from $18.68 per megawatt hour in 2002 to $25.83 per megawatt hour in 2007. EKPC's costs are comparable to industry averages.

Q. Please discuss EKPC's forced outage rate and compare it to industry averages.

A. EKPC's coal-fired generating forced outage rate ("FOR") is typically lower than the national average. The latest information for national averages comes from the 2002 - 2006 Generating Availability Report (GADS) published in November of 2007. This report, a portion of which was submitted in Commission Case No. 2008-00436, is published by the North American Electric Reliability Council (NERC) and is a compilation of operating histories from more than 230 utilities in the United States and Canada. The following table compares each EKPC coal-fired unit to the national average for a coal-fired unit in its size class.

Unit	EKPC Average FOR 2002-2006	National Average FOR 2002-2006
Dale 1	2.1%	5.2%
Dale 2	1.6%	5.2%
Dale 3	2.0%	5.2%
Dale 4	1.7%	5.2%

Cooper 1	2.2%	4.5%
Cooper 2	2.1%	4.7%
Spurlock 1	0.3% (avg. yrs 02, 03, 05 & 06)	4.2%
Spurlock 2	1.7%	5.1%
Gilbert	13.2%	4.7%

Note that the average FOR for Spurlock 1 does not include 2004, when an unusually long forced outage, the circumstances of which were discussed in detail in PSC Case No. 2006-00472, contributed to a 32 % annual FOR. Also, note that the average FOR for the Gilbert Unit reflects less than two years of experience during its initial months of operation, since that unit went into commercial operation in March 2005. The generating data collected by NERC does not distinguish between the different types of coal boilers and groups Gilbert, a CFB, with pulverized coal units. The reasons why a CFB plant differs from a pulverized coal plant with respect to FOR were discussed in detail in Case No. 2008-00436.

Q. Does this conclude your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In re the Matter of:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A GENERAL ADJUSTMENT OF ITS WHOLESALE ELECTRIC RATES	))))	**CASE NO. 2008-00409**

AFFIDAVIT

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Craig A. Johnson, 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.

Craig A Johnson

Subscribed and sworn before me on this 27th day of October, 2008.

Peggy S. Driffin
Notary Public

My Commission expires: December 8, 2009

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

GENERAL ADJUSTMENT OF ELECTRIC RATES	)	**PSC CASE NO.**
OF EAST KENTUCKY POWER	)	**2008-00409**
COOPERATIVE, INC.	)	

TESTIMONY OF
RICKY L. DRURY
MANAGER OF ENGINEERING
EAST KENTUCKY POWER COOPERATIVE

Filed: October 31, 2008

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

A. My name is Ricky L. Drury and my business address is East Kentucky Power Cooperative ("EKPC"), 4775 Lexington Road, Winchester, Kentucky 40391. I am the Manager of Engineering for EKPC.

Q. Please state your education and professional experience.

A. I received a Bachelor's Degree in Electrical Engineering from the University of Kentucky in 1979 and a Master's Degree in Business Administration in 1986 also from the University of Kentucky. I am a licensed Professional Engineer in the Commonwealth of Kentucky. In addition, I have attended and participated in several seminars and supplemental training courses over the years. I have been employed by EKPC since January 1980 and have occupied several engineering and management positions associated with planning, designing and maintaining the transmission system. In July 2008, I became Manager of Engineering at EKPC.

Q. Please provide a brief description of your duties at EKPC.

A. As Manager of Engineering, I am responsible for managing the design and construction of all transmission facilities and providing general engineering services for others throughout the organization. I report directly to the Senior Vice President of G&T Operations.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the methodology and assumptions used to prepare EKPC's power delivery operations and maintenance expenses and capital expenditures forecasts.

Q. Are you supporting certain information required by Commission Regulations 807 KAR 5:001, Section 10?

A. Yes. I am sponsoring the following schedules for the corresponding Filing Requirements:

Filing Requirement	Description	Volume	Tab #
Section 10(9)(b)	Most recent capital construction budget containing at minimum 3 year forecast of construction expenditures	Vol. 3	Tab 24
Section 10(9)(f)	For each major construction project constituting 5% or more of annual construction budget within 3 year forecast, following information shall be filed: 1. Date project began or estimated starting date; 2. Estimated completion date; 3. Total estimated cost of construction by year exclusive and inclusive of Allowance for Funds Used During Construction ("AFUDC") or Interest During Construction Credit; and 4. Most recent available total costs incurred exclusive and inclusive of AFUDC or Interest During Construction Credit	Vol. 3	Tab 28
Section 10(9)(g)	For each major construction project constituting 5% or more of annual construction budget within 3 year forecast, file aggregate of information requested in paragraph (f) 3 and 4 of this subsection.	Vol. 3	Tab 29

Q. Please explain the process that was used to develop the costs that were included in the power delivery capital budget used in the forecasted test year.

A. The transmission capital budget is developed using computer models of the transmission system that simulate future transmission system conditions and that are used in transmission system planning. These models identify system problems and alternative actions and system upgrades that could cost effectively and reliably resolve these problems. These studies were used to develop a work plan that was used by EKPC's Engineering Department to budget and schedule upcoming transmission projects. Additionally, EKPC's Member Distribution Systems use similar models to identify problems on the distribution system and work with EKPC Planning Engineers to determine the best solution to these problems. Solutions to these distribution system problems may require distribution substations and associated transmission tap lines that would also be included in the capital budget. Finally, some telecommunications and transmission capital projects may be included in the budget by either the Engineering or Operations Department to replace aging transmission or telecommunications infrastructure that is obsolete or in poor condition.

Cost estimates that are included in the capital budget are based on historic EKPC costs and generic cost estimates of similar projects. An inflation rate derived from the publication "Power Planner" published by Global Insight was used to escalate the cost estimates to the year the project is planned to be placed in service. For projects that span multiple years, timeline for the transmission projects were used to assign the portion of the total project cost to the appropriate year in the budget.

Q. Please explain the process that was used to develop the costs that were included in the power delivery maintenance budget.

A. The primary driver for development the maintenance budget was the work plan for maintenance of the transmission and telecommunications systems. The work plan includes various inspections of the transmission system that are routinely performed to identify the condition of system components. Intervals for performing these inspections were developed by a panel of internal subject experts led by an external expert that is familiar with industry norms. These intervals form the basis for the inspections included in the work plan. The amount of maintenance required as a result of each inspection is based on EKPC's experience with the types of problems that the inspections identify. The estimates for all the work plan items for each type of maintenance (ex: substation, right of way, line) are summed to determine the total budget for inspecting and maintaining the transmission system. These estimates are compared to historic maintenance costs and the expected labor costs to see if these estimates are reasonable. Differences between historic maintenance costs and maintenance cost estimates are analyzed and appropriate adjustments are then made to derive the final budget values.

Q. Please explain the process that was used to develop the costs that were included in the power delivery operations budget.

In addition to the above transmission and telecommunications budgets for inspection and maintenance, the transmission Operations Department also has an operating budget associated with metering, control and operation of the transmission system. This budget is primarily based on historic data along with appropriate adjustments for any expected upgrades of the equipment and systems for this purpose.

Finally, each department's operating budget also includes necessary administrative costs. Examples of these administrative costs include items such as safety equipment, computers, training, office supplies, tools and other miscellaneous administrative costs. Budgets for these expenses are primarily based on historic values.

Q. Does this conclude your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In re the Matter of:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A GENERAL ADJUSTMENT OF ITS WHOLESALE ELECTRIC RATES	))))	**CASE NO. 2008-00409**

<u>AFFIDAVIT</u>

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Ricky L. Drury, 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.

Ricky L. Drury

Subscribed and sworn before me on this 24th day of October, 2008.

Peggy S. Griffin
Notary Public

My Commission expires: December 8, 2009

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

GENERAL ADJUSTMENT OF ELECTRIC RATES	)	PSC CASE NO.
OF EAST KENTUCKY POWER	)	2008-00409
COOPERATIVE, INC.	)	

TESTIMONY OF
ANN F. WOOD
MANAGER OF REGULATORY SERVICES
EAST KENTUCKY POWER COOPERATIVE

Filed: October 31, 2008

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

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

Q. Please state your education and professional experience.

A. I received a B.S. Degree in Accounting from Georgetown College in 1987. After graduation I accepted an audit position with Coopers & Lybrand in the Lexington office. My responsibilities ranged from performing detailed audit testing to managing audits. In October 1995, I started working for Lexmark International, Inc. as an analyst. In May 1997, I joined EKPC and held various management positions in the accounting and internal auditing areas. In August 2008, I became Manager of Regulatory Services at EKPC. I am a certified public accountant in Kentucky.

Q. Please provide a brief description of your duties at EKPC.

A. As Manager of Regulatory Services, I am responsible for managing all filings with the Public Service Commission ("Commission.") I report directly to the Senior Vice President of Power Supply.

Q. Are you supporting certain information required by Commission Regulations 807 KAR 5:001, Section 10?

A. Yes. I am sponsoring the following schedules for the corresponding Filing Requirements:

Filing Requirement	Description	Volume	Tab #
Section 10(1)(b)(2)	A statement that the utility's annual reports, including the annual report for the most recent calendar year, are on file with the commission in accordance with 807 KAR 5:006, Section 3(1).	Vol. 1	Tab 2
Section 10(1)(b)(3) and (5)	If the utility is incorporated, a certified copy of the utility's articles of incorporation and all amendments thereto or out of state documents of similar import. If the utility's articles of incorporation and amendments have already been filed with the Commission in a prior proceeding, the application may state this fact making reference to the style and case number of the prior proceeding <u>and</u> a certificate of good standing or certificate of authorization dated within sixty (60) days of the date the application is filed.	Vol. 1	Tab 3
Section 10(1)(b)(4) and (5)	If applicant is a limited partnership, a certified copy of the limited partnership agreement <u>or</u> if the agreement was filed with the PSC in a prior proceeding, a reference to the style and case number of the prior proceeding <u>and</u> a certificate of good standing or certificate of authorization dated within sixty (60) days of the date the application is filed.	Vol. 1	Tab 4
Section 10(1)(b)(6)	A certified copy of a certificate of assumed name as required by KRS 365.015 or a statement that such a certificate is not necessary.	Vol. 1	Tab 5
Section 10(1)(b)(7)	The proposed tariff in form complying with 807 KAR 5:011 with an effective date not less than thirty (30) days from the date the application is filed.	Vol. 1	Tab 6
Section 10(1)(b)(8)	Proposed tariff changes shown either by providing present and proposed tariffs in comparative form or indicating additions by italicized inserts or underscoring and striking over deletions in a copy of the current tariff.	Vol. 1	Tab 7
Section 10(1)(b)(9)	Statement that notice given, see subsections (3) and (4) of 807 KAR 5:001, Section 10 with copy.	Vol. 1	Tab 8

Section 10(2)	If gross annual revenues exceed $1,000,000 written notice of intent filed at least four (4) weeks prior to application. Notice shall state whether the application will be supported by historical or a fully forecasted test period.	Vol. 1	Tab 9
Section 10(3)	Form of notice to customers. Every utility filing an application pursuant to this section shall notify all affected customers in the manner prescribed herein. The notice shall include the following information: (a) Amount of change requested in dollar amounts and percentage for each customer classification to which change will apply. (b) Present and proposed rates for each customer class to which change would apply. (c) Electric, gas, water and sewer utilities - the effect upon average bill for each customer class to which change will apply. (d) Local exchange companies - include effect upon average bill for each customer class for change in basic local service. (e) A statement that the rates contained in this notice are the rates proposed by (name of utility); however, the Public Service Commission may order rates to be charged that differ from the proposed rates contained in this notice; (f) A Statement that any corporation, association, or person with a substantial interest in the matter may, by written request, within thirty (30) days after publication or mailing of this notice of the proposed rate changes request to intervene; Intervention may be granted beyond the thirty (30) day period for good cause shown. (g) A statement that any person who has been granted intervention by the commission may obtain copies of the rate application and any other filings made by the utility by contacting the	Vol. 1	Tab 10

	utility through a name and address and phone number stated in this notice; (h) A statement that any person may examine the rate application and any other filings made by the utility at the main office of the utility or at the commission's office indicating the addresses and telephone numbers of both the utility and the commission; and (i) The commission may grant a utility with annual gross revenues greater than $1,000,000, upon written request, permission to use an abbreviated form of published notice of the proposed rates provided the notice includes a coupon which may be used to obtain all of the information required herein.		
Section 10(4)(a)	Manner of notification. Sewer utilities shall give the required typewritten notice by mail to all of their customers pursuant to KRS 278.185.	Vol. 1	Tab 11
Section 10(4)(b)	Manner of notification. Applicant has 20 customers or less, written notice of proposed rate changes and estimated amount of increase per customer class shall be mailed to each customer no later than date of application.	Vol. 1.	Tab 12
Section 10(4)(c)	Except for sewer utilities, applicants with more than twenty (20) customers affected by the proposed general rate adjustment shall give the required notice by one (1) of the following methods: 1. A typewritten notice mailed to all customers no later than the date the application is filed with the commission; 2. Publishing the notice in a trade publication of newsletter which is mailed to all customers no later than the date on which the application is filed with the commission; or 3. Publishing the notice once a week for three (3) weeks in a prominent manner in a newspaper of general circulation in the utility's service area, the first publication to be made within seven(7) days of the filing of the application with the Commission	Vol. 1	Tab 13

Section 10(4)(d)	If the notice is published, an affidavit from the publisher verifying the notice was published, including the dates of the publication with an attached copy of the published notice, shall be filed with the commission no later than forty-five (45) days of the filed date of the application.	Vol. 1	Tab 14
Section 10(4)(e)	If the notice is mailed, a written statement signed by the utility's chief officer in charge of Kentucky operations verifying the notice was mailed shall be filed with the commission no later than thirty (30) days of the filed date of the application.	Vol. 1	Tab 15
Section 10(4)(f)	All utilities, in addition to the above notification, shall post a sample copy of the required notification at their place of business no later than the date on which the application is filed which shall remain posted until the commission has finally determined the utility's rates.	Vol. 1	Tab 16
Section 10(4)(g)	Compliance with this subsection shall constitute compliance with 807 KAR 5:051, Section 2.	Vol. 1	Tab 17
Section 10(5)	Notice of hearing scheduled by the commission upon application by a utility for a general adjustment in rates shall be advertised by the utility by newspaper publication in the areas that will be affected in compliance with KRS 424.300.	Vol. 1	Tab 18
Section 10(8)(a)	Financial data for forecasted period presented as pro forma adjustments to base period.	Vol. 1.	Tab 19
Section 10(8)(f)	The utility shall provide a reconciliation of the rate base and capital used to determine its revenue requirements.	Vol. 1	Tab 22
Section 10(9)(a)	Prepared testimony of each witness supporting its application including testimony from chief officer in charge of Kentucky operations on the existing programs to achieve improvements in efficiency and productivity, including an explanation of the purpose of the program.	Vol. 2	Tab 23
Section 10(9)(i)	Most recent FERC or FCC audit reports;	Vol. 3	Tab 31
Section 10(9)(j)	Prospectuses of most recent stock or bond offerings;	Vol. 3	Tab 32
Section 10(9)(k)	Most recent FERC Form 1 (electric), FERC Form 2 (gas), or the Automated Reporting Management Information System Report (telephone) and PSC Form T (telephone);	Vol. 3	Tab 33

Section 10(9)(l)	Annual report to shareholders or members and statistical supplements for the most recent 5 years prior to application filing date;	Vol. 4	Tab 34
Section 10(9)(m)	Current chart of accounts if more detailed than Uniform System of Accounts chart;	Vol. 5	Tab 35
Section 10(9)(n)	Latest 12 months of the monthly managerial reports providing financial results of operations in comparison to forecast;	Vol. 5	Tab 36
Section 10(9)(p)	SEC's annual report for most recent 2 years, Form 10-Ks and any Form 8-Ks issued during prior 2 years and any Form 10-Qs issued during past 6 quarters;	Vol. 5	Tab 38
Section 10(9)(q)	Independent auditor's annual opinion report, with any written communication which indicates the existence of a material weakness in internal controls;	Vol. 5	Tab 39
Section 10(9)(r)	Quarterly reports to the stockholders for the most recent 5 quarters;	Vol. 5	Tab 40
Section 10(9)(s)	Summary of latest depreciation study with schedules itemized by major plant accounts, except that telecommunications utilities adopting PSC's average depreciation rates shall identify current and base period depreciation rates used by major plant accounts. If information has been filed in another PSC case, refer to that case's number and style.	Vol. 5	Tab 41
Section 10(9)(t)	List all commercial or in-house computer software, programs, and models used to develop schedules and work papers associated with application. Include each software, program, or model; its use; identify the supplier of each; briefly describe software, program, or model; specifications for computer hardware and operating system required to run program.	Vol. 5	Tab 42
Section 10(9)(u)	If the utility had any amounts charged or allocated to it by an affiliate or general or home office or paid any monies to an affiliate or general or home office during the base period or during the previous three (3) calendar years, the utility shall file: 1. Detailed description of method of calculation and amounts allocated or charged to utility by affiliate or general or home office for each allocation or payment; 2. Method and amounts allocated during	Vol. 5	Tab 43

	base period and method and estimated amounts to be allocated during forecasted test period; 3. Explain how allocator for both base and forecasted test period was determined; and 4. All facts relied upon, including other regulatory approval, to demonstrate that each amount charged, allocated or paid during base period is reasonable.		
Section 10(9)(w)	Local exchange carriers with fewer than 50,000 access lines need not file cost of service studies, except as specifically Directed by PSC. Local exchange carriers with more than 50,000 access lines shall file: 1. Jurisdictional separations study consistent with Part 36 of the FCC's rules and regulations; and 2. Service specific cost studies supporting pricing of services generating annual revenue greater than $1,000,000 except local exchange access: a. Based on current and reliable data from single time period; and b. Using generally recognized fully allocated, embedded, or incremental cost principles.	Vol. 5	Tab 45
Section 10(10)(c)	Jurisdictional operating income summary for both base and forecasted periods with supporting schedules which provide breakdowns by major account group and by individual account;	Vol. 5	Tab 48
Section 10(10)(d)	Summary of jurisdictional adjustments to operating income by major account with supporting schedules for individual adjustments and jurisdictional factors;	Vol. 5	Tab 49
Section 10(10)(e)	Jurisdictional federal and state income tax summary for both base and forecasted periods with all supporting schedules of the various components of jurisdictional income taxes;	Vol. 5	Tab 50
Section 10(10)(f)	Summary schedules for both base and forecasted periods (utility may also provide summary segregating items it proposes to recover in rates) of organization membership dues; initiation fees; expenditures for country	Vol. 5	Tab 51

	club; charitable contributions; marketing, sales, and advertising; professional services; civic and political activities; employee parties and outings; employee gifts; and rate cases;		
Section 10(10)(g)	Analyses of payroll costs including schedules for wages and salaries, employees benefits, payroll taxes straight time and overtime hours, and executive compensation by title;	Vol. 5	Tab 52
Section 10(10)(i)	Comparative income statements (exclusive of dividends per share or earnings per share), revenue statistics and sales statistics for 5 calendar years prior to application filing date, base period, forecasted period, and 2 calendar years beyond forecast period;	Vol. 5	Tab 54
Section 10(10)(k)	Comparative financial data and earnings measures for the 10 most recent calendar years, base period, and forecast period;	Vol. 5	Tab 56

Q. Have you reviewed the above requirements and found the responses to be complete and accurate?

A. Yes. These requirements were prepared by me or under my supervision. To the best of my knowledge, the responses to these requirements are accurate.

Q. Were you responsible for managing the rate case application in this proceeding?

A. Yes. I also prepared a number of key schedules and exhibits in the application, gathered much of the financial and accounting data used to prepare Mr. Seelye's exhibits, and worked closely with Mr. Seelye in analyzing the revenue deficiency.

Q. Does this conclude your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In re the Matter of:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A GENERAL ADJUSTMENT OF ITS WHOLESALE ELECTRIC RATES	))))	**CASE NO. 2008-00409**

AFFIDAVIT

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Ann F. Wood, being duly sworn, states that she has read the foregoing prepared 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 24th day of October, 2008.

Peggy S. Giffin
Notary Public

My Commission expires: December 8, 2009

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In re the Matter of:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A GENERAL ADJUSTMENT OF ITS WHOLESALE ELECTRIC RATES	))))	CASE NO. 2008-00409

TESTIMONY OF
WILLIAM STEVEN SEELYE
PRINCIPAL & SENIOR CONSULTANT
THE PRIME GROUP, LLC

Filed: October 31, 2008

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is William Steven Seelye and my business address is The Prime Group, LLC, 6001 Claymont Village Drive, Suite 8, Crestwood, Kentucky, 40014.

Q. By whom are you employed?

A. I am a senior consultant and principal for The Prime Group, LLC, a firm located in Crestwood, Kentucky, providing consulting and educational services in the areas of utility marketing, regulatory analysis, cost of service, rate design and depreciation studies.

Q. On whose behalf are your testifying?

A. I am testifying on behalf of East Kentucky Power Cooperative, Inc. ("EKPC").

Q. What is the purpose of your testimony?

A. The purpose of my testimony is (i) to present the financial summary and supporting exhibits detailing how EKPC derived the amount of the requested revenue increase, (ii) describe EKPC's proposed pro-forma revenue, expense, and rate base adjustments, (iii) describe the calculation of EKPC's adjusted net margin and revenue deficiency for the fully forecasted test period ended May 31, 2010, (iv) describe the calculation of the 13-month average of EKPC's rate base and capitalization for the fully forecasted test period; (v) to sponsor the fully allocated class cost of service studies based on EKPC's cost of providing service for the 12 months ended May 31, 2010; and (vi) to support EKPC's proposed wholesale rates to its members.

Q. Please summarize your testimony.

A. EKPC is proposing a rate increase which is designed to produce additional revenues of approximately $67.9 million. EKPC's proposed rate increase is supported by a fully forecasted test period corresponding to the 12 months ended May 31, 2010. The level of the increase is supported by an analysis of EKPC's revenue deficiency based on the pro-forma financial results for the forecasted test period. EKPC's revenue requirement was determined based on net margin requirements necessary to produce a 1.45 Times Interest Earned Ratio ("TIER"). The $67.9 million proposed increase, which was approved by EKPC's Board of Directors, is less than the $70.0 million revenue deficiency determined using a 1.45 TIER.

EKPC's proposed rates will allow it to begin gradually rebuilding its equity, which is currently at a dangerously low level. EKPC's equity as a percentage of total capitalization is expected to drop to around 6.8 percent prior to the implementation of the new rates. It is important to realize, however, that even with the new rates, EKPC's equity as a percentage of total capitalization is projected to only be 9.67 percent in December 2011, which will still not be adequate. One of the main reasons that its equity position will not improve more than this is because EKPC will continue to add assets to its balance sheet in support of its effort to install sufficient generation facilities to meet the needs of its members.

A class cost of service study was performed for the purpose of assisting EKPC in designing its proposed rates. In order to transition to cost-based rates, EKPC is proposing a phased-in approach consisting of *Phase I* rates – which would be placed into effect upon approval by the Kentucky Public Service Commission ("Commission"), which presumably will be at the end of the suspension period in this proceeding, and "Phase II" rates – which would go into effect 12 months later. Although both Phase I and Phase II rates are designed to produce approximately the same overall revenue, the proposed Phase II rates include unit charges that more accurately track the results of the cost of service study.

Q. Are you supporting certain information required by Commission Regulations 807 KAR 5:001, Section 10?

A. Yes. I am sponsoring the following schedules for the corresponding Filing Requirements:

Filing Requirement	Description	Volume	Tab #
Section 10(8)(b)	Forecasted adjustments shall be limited to the 12 months immediately following the suspension period.	Vol. 1	Tab 20
Section 10(8)(c)	Capitalization and net investment rate base shall be based on a 13 month average for the forecasted period.	Vol. 1	Tab 21
Section 10(9)(a)	Prepared testimony of each witness supporting its application including testimony from chief officer in charge of Kentucky operations on the existing programs to achieve improvements in efficiency and productivity, including an explanation of the purpose of the program.	Vol. 2	Tab 23
Section 10(9)(v)	Cost of service study based on methodology generally accepted in the industry and based on current and reliable data from a single time period.	Vol. 5	Tab 44

Filing Requirement	Description	Volume	Tab #
Section 10(10)(a)	Jurisdictional financial summary for both base and forecasted periods detailing how utility derived amount of requested revenue increase.	Vol. 5	Tab 46
Section 10(10)(b)	Jurisdictional rate base summary for both base and forecasted periods with supporting schedules which include detailed analyses of each component of rate base.	Vol. 5	Tab 47
Section 10(10)(h)	Computation of revenue conversion factor for forecasted period	Vol. 5	Tab 53
Section 10(10)(l)	Narrative description and explanation of all proposed tariff changes	Vol. 5	Tab 57
Section 10(10)(m)	Revenue summary for both base and forecasted periods with supporting schedules which provide detailed billing analyses for all customer classes	Vol. 5	Tab 58
Section 10(10)(n)	Typical bill comparison under present and proposed rates for all customer classes	Vol. 5	Tab 59

Q. How is your testimony organized?

A. My testimony is divided into the following sections: (I) Introduction, (II) Qualifications, (III) Revenue Requirements, (IV) Cost of Service Study, and (V) Rate Design.

II. QUALIFICATIONS

Q. Please describe your educational background and prior work experience.

A. I received a Bachelor of Science degree in Mathematics from the University of Louisville in 1979. I have also completed 54 hours of graduate level course work in Industrial Engineering and Physics. From May 1979 until July 1996, I was employed by Louisville

Gas and Electric Company. From May 1979 until December 1990, I held various positions within the Rate Department of Louisville Gas and Electric Company. In December 1990, I became Manager of Rates and Regulatory Analysis. In May 1994, I was given additional responsibilities in the marketing area and was promoted to Manager of Market Management and Rates. I left Louisville Gas and Electric Company in July 1996 to form The Prime Group, LLC, with another former employee of the Company. Since then, we have performed cost of service studies, developed revenue requirements and designed rates for well over 130 investor-owned, cooperative and municipal utilities across North America. A more detailed description of my qualifications is included in Seelye Exhibit 1.

Q. Have you ever testified before any state or federal regulatory commissions?

A. Yes. I have testified in over 45 regulatory proceedings in 11 different jurisdictions regarding revenue requirements, cost of service and rate design. A listing of my testimony in other proceedings is included in Seelye Exhibit 1.

Q. Have you performed cost of service studies and developed rates for electric cooperatives?

A. Yes. I have performed cost of service studies and developed rates for a number of generation and transmission cooperatives ("G&T cooperatives"), including Hoosier Energy, South Mississippi Electric Power Association, Big Rivers Electric Corp, Southern Illinois Power Cooperative, Corn Belt Power Cooperative, and EKPC. I have also supervised the preparation of cost of service studies and the development of rates for over 130 electric distribution cooperatives.

III. REVENUE REQUIREMENTS

Q. Please describe how EKPC's proposed revenue increase was determined?

A. EKPC is proposing a general adjustment in rates supported by a fully forecasted test period. The proposed revenue increase is supported by an analysis of the revenue deficiency based on financial results for the forecasted test period. The revenue deficiency was determined as the difference between (i) EKPC's adjusted net margins for the forecasted test period without reflecting a general adjustment in rates, and (ii) EKPC's net margin requirement necessary to provide a 1.45 TIER. Based on the forecasted test year, the revenue deficiency is $70,041,960. EKPC's proposed wholesale rates to its members are projected to produce increased revenues of $67,858,922 based on estimated billing determinants for the forecasted test year.

Q. Why is the proposed revenue increase of $67,858,922 less than EKPC's revenue deficiency of $70,041,960?

A. The rates that EKPC is proposing in this proceeding were approved by EKPC's Board of Directors on September 9, 2008. However, the rates were developed using preliminary revenue requirement and billing determinant estimates which indicated that the revenue requirement was approximately $67.7 million based on a forecasted test period for the 12 months ended April 30, 2010, rather than the 12 months ended May 31, 2010, used in the rate case filing. Because EKPC was unable to file the rate case application until the end of October 2008, the forecasted test year utilized in the rate case filing had to be delayed by one month in order to meet the requirement set forth in KRS 278.192 that the forecasted test period must correspond to the first 12 consecutive calendar months the proposed increase would be in effect after the maximum suspension period for the proposed rates. When EKPC finalized the revenue requirement using costs for the fully forecasted test period that had to be utilized in this proceeding, the revenue requirement turned out to be $70.0 million rather than $67.7 million. Likewise, when the rates that were approved by the Board of Directors were applied to test-year billing determinants, the revenue increase turned out to be $67.9 million rather than the $67.7 million amount indicated in the Board resolution provided as an exhibit to Mr. Marshall's testimony. Because the proposed revenue increase is less than the revenue deficiency determined based on operating results for the fully forecasted test period, EKPC made the decision not to revisit the issue with its Board of Directors for the purpose of obtaining approval to propose a larger increase with the Commission. Particularly, EKPC decided to maintain its proposed rates in this proceeding at the level approved by its Board of Directors even though a higher revenue increase could be supported.

Q. Why did EKPC choose to support the proposed rate increase with a fully forecasted test period?

A. As the Commission is well aware, EKPC has been in financial distress since 2005. Its interest and debt coverage ratios are forecasted to be inadequate to meet the requirements set forth in the mortgage and credit facility agreements with its lenders. Without a rate increase, EKPC's financial condition will deteriorate even further once Spurlock 4 is placed into commercial operation. Considering its dangerously low level of equity capital, without increasing its rates it would be difficult for EKPC to withstand the stress of an unanticipated expense, such as expenditures that might result from an unanticipated equipment failure at one of its generating stations. Spurlock 4, a 278 MW coal-fired generating unit which will cost approximately $528 million, is scheduled to be placed into commercial operation on April 1, 2009. None of the cost of Spurlock 4 is currently in rate base. EKPC has not included the Construction Work In Progress ("CWIP") for Spurlock 4 in rate base. Because it has been accruing an Allowance for Funds Used During Construction ("AFUDC") on its construction expenditures, EKPC is currently not recovering interest expenses associated with Spurlock 4 through rates. Once Spurlock 4 is placed into commercial operation, EKPC will experience a significant increase in its non-fuel operation and maintenance expenses, depreciation expenses and current interest expenses. Although Spurlock 4 will result in fuel and purchased power cost savings, those savings will be automatically passed along to its members through the application of the monthly fuel adjustment clause. Therefore, the fuel cost savings will not off-set the impact on EKPC's net income from placing Spurlock 4 in service.

With that background, it is easier to understand why EKPC is supporting its rate increase with forecasted test period costs. If EKPC were to use a historical test year, the very earliest that any of the costs of Spurlock 4 would be reflected in historical test period costs would be in April 2009. EKPC simply could not wait until after April 2009 to file a rate case application, which would not provide additional revenues to cover the increased costs of Spurlock 4 until approximately nine months later. Even though EKPC has never filed a fully forecasted rate case, it was critical that the company move forward with a forecasted rate case considering the serious consequences of not being able to adjust its rates until after April 1, 2009. In its Order in Case No. 2006-00472 dated December 5, 2007, the Commission directed EKPC to file its next base rate case when conditions warrant. Given EKPC's precarious financial circumstances, conditions warrant filing a rate case utilizing a forecasted test year that provides increased revenues to cover the additional costs associated with Spurlock 4.

Q. What are the forecasted test period and the base period for the rate case application?

A. The *forecasted test period* for the filing is the 12 months ended May 31, 2010. Consistent with KRS 278.192, the forecasted test period used to determine revenue requirements in this proceeding corresponds to the first 12 consecutive calendar months the proposed increase would be in effect after the maximum suspension period for the proposed rates. According to KRS 278.190, the maximum suspension period is six months for a general adjustment in rates supported by a fully forecasted test period. Because the effective date of the EKPC's proposed rates is December 1, 2008, the first 12 consecutive calendar months after the 6 month suspension period corresponds to the 12 months beginning June 1, 2009, and ending on May 31, 2010.

The *base period* for the filing is the 12 months ended January 31, 2009. The base period consists of seven months of actual historical data and five months of estimated data. KRS 278.192(2)(a) requires that any rate case application utilizing a forecasted test period must include a base period which begins not more than nine months prior to the date of the filing, and consisting of not less than six months of actual historical data and not more than six months of estimated data. Because EKPC's proposed base period, which begins February 1, 2008, includes more than six months of actual historical data, includes less than six months of estimated data, and begins less than nine months prior to the October 31, 2008 filing date in this proceeding, its proposed base period is in compliance with the requirements for a forecasted test year set forth in KRS 278.192(2)(a).

Q. Why didn't EKPC file its rate case using a fully forecasted test period beginning April 1, 2009, rather than June 1, 2009?

A. Because EKPC is a member-owned G&T cooperative, preparing a rate case involves considerably more steps than for either an investor owned utility or a distribution cooperative. EKPC had to build in enough time to prepare its financial budget incorporating accurate and up-to-date construction cost estimates for Spurlock 4 and other projects, present the proposed financial budget and wholesale rates to its member systems, obtain EKPC Board approvals for its financial budget and proposed rates, develop pass-through rates for its member systems in accordance with the provisions of KRS 278.455, and then provide enough time for the boards of its member systems to approve their individual pass-through rates and publish their individual statutory notices in newspapers across the state. As it turned out, there was simply not enough time between preparing the financial budget incorporating updated construction cost estimates and publishing the member systems' statutory notices that would have allowed EKPC to file a rate case application with rates to be effective six months prior to the suspension period for a forecasted test year.

Q. Given that EKPC's proposed rates would not go into effect until June 1, 2009, won't there be two months when its rates will be unable to provide recovery of the increased costs associated with Spurlock 4?

A. Yes. The fact that EKPC will not be able to offset its increased non-fuel operation and maintenance expenses, depreciation expenses and current interest expenses associated with Spurlock 4 with additional revenues will cause its net margin for April and May, 2009, to deteriorate sharply. The inability to recover Spurlock 4 carrying charges for those two months would have a significant adverse effect on EKPC's fiscal 2009 financial results. Without some sort of rate recovery mechanism to deal with this short-fall, EKPC will never be able to recover these fixed charges, which represents a serious problem for a utility whose interest and debt coverage ratios are dangerously low and whose equity percentage is projected to be only 6.8 percent during April and May, 2009.

Q. How is EKPC proposing to address these uncollected costs associated with Spurlock 4?

A. As described in greater detail in the *Motion for the Creation of a Regulatory Asset Relating to Spurlock Unit 4 Expenses* that is being filed in this proceeding, EKPC is proposing to establish a regulatory asset that would allow it to record the additional revenue that it would have collected in April and May, 2009, if EKPC's new rates would have gone into effect on April 1, 2009, rather than on June 1, 2009. In other words, EKPC would record the additional revenues that would have been billed through the application of the new rates during April and May 2009 in a deferred debit (Account No. 182.4). The amount ultimately recorded as a regulatory asset in Account No. 182.4 would correspond to the billing difference in April and May 2009, (based on forecasted billing determinants) between the rates ultimately approved by the Commission (without the amortization of the regulatory asset) and EKPC's current rates. Therefore, the ultimate amount recorded as a regulatory asset would be based on the rates that the Commission ultimately authorizes in the rate case order, without considering the amortization of the regulatory asset. The regulatory asset – whatever the amount turns out to be – would be amortized over three years and reflected in the final rates approved by the Commission.

As an alternative to setting up a regulatory asset to provide recovery of the unbilled Spurlock 4 carrying charges, the Commission could waive its six-month *maximum* suspension period applicable to rate applications using a forecasted test period and allow EKPC to place its proposed rates into effect on April 1, 2009, subject to refund. Because this alternative could possibly require that EKPC's member systems make refunds to their retail members, allowing EKPC to establish a regulatory asset would represent a simpler approach.

Q. Have you prepared an exhibit that shows how EKPC's revenue deficiency is calculated?

A. Yes. Seelye Exhibit 2 shows the calculation of EKPC's revenue deficiency.

Q. Please walk us through Seelye Exhibit 2.

A. The purpose of Seelye Exhibit 2 is to calculate the difference between EKPC's adjusted net margin (deficit) for the forecasted test year and the margin necessary for EKPC to achieve a 1.45 TIER. The exhibit starts out with Operating Revenue and Patronage Capital from EKPC's budget for the 12 months ended May 31, 2010 (line 1). This amount is obtained from the 2009 and 2010 budgets that were approved by EKPC's Board of Directors. EKPC's Board is comprised of a board member from each of its 16 member systems. The monthly and 12-month total budget amounts for the forecasted test year are shown in Exhibit 1 to Mr. Eames's testimony. A number of pro-forma adjustments are applied to Operating Revenue. The pro-forma revenue adjustments are shown on lines 4 through 7 of the exhibit. EKPC's Adjusted Revenue, as adjusted to reflect the four pro-forma revenue adjustments, is shown on line 9.

The Total Cost of Service from EKPC's budget is shown on line 12. In the context of EKPC's budget and financial reports, Total Cost of Service includes operation expenses, maintenance expenses, depreciation and amortization expenses, taxes, interest expenses on long-term debt, other interest expenses, and other deductions. Total Cost of Service is then adjusted to reflect pro-forma adjustments shown on lines 15 through 31 of the exhibit. Adjusted Cost of Service, which reflects the pro-forma expense adjustments, is shown on line 34. Adjusted Operating Margins (line 36) is calculated by subtracting Adjusted Cost of Service (line 34) from Adjusted Revenue (line 9). Interest income (line 39), other non-operating income (line 40), and other capital credits/patronage dividends (line 41) are added to Adjusted Operating Margins (line 36) to determine EKPC's Adjusted Net Margin (Deficit). For the forecasted test-period, EKPC is projected to a have an Adjusted Net Deficit of -$25,603,606 (line 46).

The Revenue Deficiency is calculated on page 2 of Seelye Exhibit 2. To achieve a 1.45 TIER, EKPC needs a net margin requirement of $44,438,354. EKPC's $70,041,960 revenue deficiency corresponds to the difference between this net margin requirement of

$44,438,354 and EKPC's adjusted net deficit of -$25,603,606 (calculated as $44,438,354 - (-$25,603,606) = $70,041,960).

Q. Why was a 1.45 TIER used to determine EKPC's revenue requirement?

A. As explained in the prepared direct testimonies of David G. Eames, Jonathon Andrew Don, and Daniel M. Walker, a 1.45 TIER is in line with what other investment-grade G&T cooperatives are earning and is necessary to provide EKPC with an opportunity to maintain its financial integrity, to maintain adequate interest and debt service coverage ratios, and to rebuild its members' equity to a level that will allow EKPC to continue to attract capital on reasonable terms and to serve its members in a safe and reliable manner.

Q. Please explain why it is necessary to make pro-forma adjustments to financial results from EKPC's budget.

A. It was necessary to make a number of pro-forma adjustments to eliminate costs and associated revenues that are recovered through the fuel adjustment clause (FAC) and the environmental surcharge. A number of other adjustments were required to eliminate expenses that are generally not allowed to be recovered through service rates of utilities in Kentucky that are regulated by the Commission. Two other adjustments were required to amortize or re-amortize certain extraordinary expenses. One final adjustment was required to normalize generation overhaul expenses so that forecasted test-year expenses will be representative on a going forward basis. Support for each adjustment is contained in Schedules 1.01 through 1.18 of Seelye Exhibit 2. The pro-forma adjustments are identified as follows:

(a) Eliminate costs recoverable through the FAC and associated revenues (Schedules 1.01, 1.03).

(b) Remove the impact of revenues and expenses included in the environmental surcharge (Schedules 1.02, 1.04, 1.05, 1.06, 1.07, 1.08).

(c) Eliminate expenses normally excluded by the Commission (Schedules 1.09, 1.10, 1.11, 1.12, 1.13, 1.14, 1.15).

(d) Amortize extraordinary expenses (Schedules 1.16 and 1.17).

(e) Normalize overhaul expenses (Schedule 1.18)

Q. Please describe the adjustments necessary to eliminate expenses and associated revenues related to the fuel adjustment clause.

A. EKPC is proposing to eliminate all fuel and purchased power expenses that would be recoverable through the FAC, the fuel cost revenue associated with base fuel cost component of the FAC, and projected FAC billings. In other words, EKPC is proposing to remove all fuel cost and fuel cost revenues that would be considered in the application of the FAC, including fuel costs recovered through the base rate component which is collected through base rates. Specifically, adjustments were made to remove fuel cost revenue recovered through base rates (Schedule 1.01), to remove FAC revenue (Schedule 1.01), to remove fuel expenses recoverable through the FAC (Schedule 1.01), and to remove purchased power expenses recoverable through the FAC (Schedule 1.03).

Q. Please describe the adjustments to eliminate expenses and associated revenues related to the environmental surcharge.

A. EKPC is proposing to eliminate all environmental costs that would be recoverable through the environmental surcharge and associated environmental surcharge revenue. Specifically, adjustments were made to remove environmental surcharge revenue (Seelye Exhibit 2, Page 1 of 2, line 6), to adjust off-system sales environmental surcharge revenue (Schedule 1.02), to remove operation and maintenance expense recoverable through the environmental surcharge (Schedule 1.04), to remove emissions allowance expense recoverable through the environmental surcharge (Schedule 1.05), to remove property taxes and property insurance recoverable through the environmental surcharge (Schedule 1.06), to remove depreciation expense recoverable through the environmental surcharge (Schedule 1.07), and to remove interest expense recoverable through the environmental surcharge (Schedule 1.08). Because EKPC budgets these revenues and expenses individually they were readily identified from the budget for purposes of removing them from the calculation of the revenue deficiency. EKPC is not proposing any roll-in of environmental costs into base rates in this proceeding.

Q. Please explain the adjustment to off-system sales environmental surcharge revenue (Schedule 1.02) in greater detail.

A. In determining the environmental surcharge, a portion of EKPC's environmental compliance costs recovered through the surcharge are allocated to off-system sales. However, by including off-system revenues in test-year operating results, off-system revenues are credited to jurisdictional customers. This results in an overstatement of margins from off-system sales and a mismatch of the revenues and expenses related to the off-system sales portion of the allocated environmental surcharge monthly revenue requirement. Therefore, consistent with the Commission's orders in the most recent rate cases filed by Louisville Gas and Electric Company and Kentucky Utilities Company, an adjustment was made to reduce revenues to reflect the environmental surcharge methodology for allocating environmental costs to off-system sales. (Order in Case No. 2003-00433 , pp 24-25 and Appendix F and Order in Case No. 2003-00434, p. 24 and Appendix F.)

Q. Please explain the adjustment to remove promotional advertising shown in Schedule 1.09.

A. Pursuant to 807 KAR 5:016, this adjustment eliminates Touchstone Energy advertising and other promotional items included in EKPC's budget for the forecasted test year. These expenses are individually projected in developing the budget and are therefore readily identifiable.

Q. Please explain the adjustment to remove certain directors' expenses shown in Schedule 1.10.

A. Consistent with the Commission's Order in Case No. 2006-00472, EKPC is removing a portion of directors' expenses from the forecasted test-year revenue requirement. The items not removed include the following: fees for regular board meetings, chair and secretary fees, committee chair fees, audit committee chair fees, two special board meetings for each member, fees for training seminars, and expenses of $25,000 for the test year. A total of $93,300 of directors' expenses has been removed from test-year operating expenses.

Q. Please describe the adjustments to remove donations in Schedule 1.11, affiliate expenses in Schedule 1.12, lobbying expenses in Schedule 1.13, Touchstone Energy dues in Schedule 1.14, and Miscellaneous Expenses in Schedule 1.15.

A. Consistent with Commission practice, all donations, contributions, and sponsorships are removed from test-year expenses in Schedule 1.11. All affiliate expenses related to Alliance for Cooperative Energy Services (ACES) Power Marketing, Envision Energy Services, LLC, and the propane gas program for members are removed from test-year expenses in Schedule 1.12. It should be noted, however, that fees paid to ACES for their power marketing functions on behalf of EKPC have not been removed from revenue requirements in this proceeding. Consistent with the procedure followed in its last rate case application in Case No. 2006-00472, EKPC is removing lobbying expenses (Schedule 1.13), Touchstone Energy dues (Schedule 1.14), and certain employee-related expenses (Schedule 1.15). These expenses are individually projected in developing the budget and are therefore readily identifiable.

Q. Please describe the adjustment to reflect an amortization of rate case expenses in Schedule 1.16.

A. This adjustment is necessary to include amortization of the expense incurred in conjunction with this rate case. It is consistent with similar adjustments in revenue requirements found reasonable in numerous rate case orders issued by the Commission, including the Commission's Order approving the settlement agreement in Union Light, Heat and Power Company's recent rate case, which was supported by a fully forecasted test period. (In its Order in Case No. 2006-00172 dated December 21, 2006, the

Commission affirmed that the accounting and ratemaking treatments to which the parties stipulated in the settlement agreement, including the amortization of rate case expenses over 3 years, "generally reflect the approach the Commission has followed in previous rate cases", pp. 4 and 8.)

Q. Please explain the adjustment to reflect the amortization of the 2004 forced outage balance in Schedule 1.17.

A. In Case No. 2006-00472, the Commission determined that it was appropriate to amortize $20,514,346 of expenses related to a 2004 Spurlock 1 forced outage over a 3-year period. As of the beginning of the forecasted test period on June 1, 2009, EKPC will have amortized $10,257,173, or one half of the original amount, leaving a balance of $10,257,173. EKPC is proposing to amortize the remaining balance of $10,257,173 over three years, resulting in an increase in expenses of $3,419,058.

Q. Please explain the adjustment to normalize generation overhaul expenses in Schedule 1.18.

A. This adjustment is necessary to ensure that forecasted test-year expenses will be representative on a going forward basis. During the forecasted test period, EKPC's overhaul expenses are less than the normal level that would be incurred annually by the company. EKPC projects that it will incur $4.8 million in overhaul expenses during the forecasted test year ($2.1 million for Cooper Unit 1 and $2.7 million for Dale Units 1 and 2) compared to an average annual expense of $7.1 million. For the steam generating units, the boiler and generators are overhauled on a 10-year cycle, and the combustion turbines are overhauled on a six-year cycle. The $7.1 million average overhaul expense was calculated by dividing the estimated cost of a boiler/generator overhaul for each steam generating unit in 2009 dollars by 10 years to determine the average amount for the unit, and by dividing the estimated cost of a generator overhaul for each combustion turbine in 2009 dollars by 6 years to determine the average amount for the unit. Therefore, EKPC is proposing a normalization adjustment of $2.3 million, which represents the difference between $4.8 million amount budgeted for the test year and the $7.1 million average level.

Q. Have you prepared exhibits showing the development of the 13-month average rate base and capitalization for the forecasted test year.

A. Yes. Seelye Exhibit 3 shows the development of the 13-month average rate base for the test year, and Seelye Exhibit 4 shows the development of the 13-month average capitalization for the test year. In Seelye Exhibit 3, rate base is shown both with and without environmental assets for which costs are recovered through the environmental surcharge. These environmental assets have been removed from capitalization in Seelye Exhibit 4. It should be noted that EKPC's revenue requirement was determined using a 1.45 TIER, which is an approach that is often utilized by cooperative utilities, rather than a rate of return on rate base or a rate of return on total capitalization, which is used by investor-owned utilities in Kentucky.

Q. Have you prepared an exhibit that shows key financial performance measurements for EKPC with and without the proposed increase?

A. Yes. Seelye Exhibit 5 shows TIER, debt service coverage ratio (DSC), rate of return on net cost rate base, and rate of return on total capitalization for the forecasted test year with and without the proposed increase. The following table summarizes the financial measurements calculated in Seelye Exhibit 5:

FINANCIAL MEASUREMENT	WITHOUT RATE INCREASE	WITH PROPOSED INCREASE
Times Interest Earned Ratio (TIER)	0.74	1.43
Debt Service Coverage Ratio (DSC)	0.81	1.25
Rate of Return on Net Cost Rate Base (ROR)	3.17%	6.19%
Rate of Return on Total Capitalization (ROI)	3.16%	6.16%

It should be noted that the financial measurements shown in this table are calculated using EKPC's proposed revenue increase of $67,858,922 rather than the $70,041,960 revenue deficiency amount necessary to produce a TIER of 1.45. Because EKPCs Board approved increase is used instead of the revenue deficiency, the TIER shown above is slightly lower than the 1.45 TIER that is appropriate for EKPC. The DSC, ROR and ROI are correspondingly lower than what they would otherwise be if the $70,041,960 revenue deficiency were used to calculate these financial measurements.

Q. Based on your experience in developing rates for other G&T cooperatives, are these financial performance measurements that result from applying the proposed rates reasonable?

A. Yes. They are in line with what the G&T cooperatives I have worked with are using to develop rates. It should be noted, however, that none of the G&T cooperatives for which I have developed base rates are subject to regulation by a public service commission. More important, the proposed TIER will allow EKPC to gradually rebuild its equity over time; however, it is important to realize that even with the new rates which are designed to produce a TIER of 1.43, EKPC's equity as a percentage of total capitalization is projected to only be 9.67 percent in December 2011, which is still inadequate. (See Tab 30, page 10 of the filing requirements set forth in the Application.) One of the main reasons that its equity position will not improve more than this is because EKPC will continue to add assets to the balance sheet in support of its effort to install sufficient generation facilities (e.g., Smith Unit 1) to meet the needs of its members.

IV. CLASS COST OF SERVICE STUDY

Q. Did you prepare a cost of service study for EKPC's electric operations based on financial and operating results for the fully forecasted test period?

A. Yes. I supervised the preparation of a fully allocated, time-differentiated, embedded cost of service study. The cost of service study corresponds to the pro-forma financial exhibits included in Seelye Exhibit 2. The objective in performing the electric cost of service study is to determine the rate of return on rate base that EKPC is earning from each rate class, which provides an indication as to whether EKPC's service rates reflect the cost of providing service to each rate class.

Q. Did you develop the model used to perform the cost of service study?

A. Yes. I developed the spreadsheet model used to perform the cost of service study submitted in this proceeding.

Q. What procedure was used in performing the cost of service study?

A. The three traditional steps of an embedded cost of service study – functional assignment, classification, and allocation – were utilized. The cost of service study was therefore prepared using the following procedure: (1) costs were functionally assigned (*functionalized*) to the major functional groups; (2) costs were then *classified* as commodity-related, demand-related, or customer-related; and then (3) costs were allocated to the rate classes.

Q. Is this a standard approach used in the electric utility industry?

A. Yes.

Q. What functional groups were used in the cost of service study?

A. The following functional groups were identified in the cost of service study: (1) Production, (2) Production Steam – Direct, (3) Transmission, (3) Distribution Substation, and (4) Distribution Meters. Production Steam – Direct corresponds to production costs that are specifically assigned to provide steam service to a industrial customer.

Q. How were costs classified as energy related, demand related or customer related?

A. Classification provides a method of identifying the appropriate cost driver for each functionally assigned cost so that the service characteristics that give rise to the cost can serve as a basis for allocation. Costs classified as *energy related* tend to vary with the amount of kilowatt-hours consumed. Fuel and purchased power expenses are examples of costs typically classified as energy costs. Costs classified as *demand related* tend to vary with the capacity needs of customers, such as the amount of generation, transmission or distribution equipment necessary to meet a customer's needs. Production plant and the cost of transmission lines are examples of costs typically classified as demand costs. Costs classified as *customer related* include costs incurred to serve customers regardless of the quantity of electric energy purchased or the peak requirements of the customers and include the cost of the minimum system necessary to provide a customer with access to the electric grid. Distribution meters are the only costs classified as customer-related in the cost of service study.

Q. Have you prepared an exhibit showing the results of the functional assignment and classification steps of the electric cost of service study?

A. Yes. Seelye Exhibit 6 shows the results of the first two steps of the cost of service study – functional assignment and classification.

Q. In your cost of service model, once costs are functionally assigned and classified, how are these costs allocated to the customer classes?

A. In the cost of service model used in this study, EKPC's test-year costs are functionally assigned and classified using what are referred to in the model as "functional vectors". These vectors are multiplied (using *scalar multiplication*) by the various accounts in order to simultaneously assign costs to the functional groups and classify costs. Therefore, in the portion of the model included in Seelye Exhibit 6, EKPC's accounting costs are functionally assigned and classified using the explicitly determined functional vectors identified in the analysis and using internally generated functional vectors. The explicitly determined functional vectors, which are primarily used to direct where costs are functionally assigned and classified, are shown on pages 27 and 28. Internally generated functional vectors are utilized throughout the study to functionally assign costs either on the basis of similar costs or on the basis of internal cost drivers. The internally generated functional vectors are also shown on pages 27 and 28 of Seelye Exhibit 6. An example of this process is the use of total operation and maintenance expenses less purchased power ("OMLPP") to allocate cash working capital included in rate base. Because cash working capital is determined on the basis of 12.5% of operation and maintenance expenses, exclusive of purchased power expenses, it is appropriate to functionally assign and classify these costs on the same basis. (See Seelye Exhibit 6, pages 3 and 4 for the functional assignment of cash working capital on the basis of OMLPP shown on pages 13 and 14.) The functional vector used to allocate a specific cost is identified by the column in the model labeled "Vector" and refers to a vector identified elsewhere in the analysis by the column labeled "Name".

Once costs for all of the major accounts are functionally assigned and classified, the resultant cost matrix for the major cost groupings (e.g., Plant in Service, Rate Base, Operation and Maintenance Expenses) is then transposed and allocated to the customer classes using "allocation vectors" or "allocation factors".

The results of the class allocation step of the cost of service study are included in Seelye Exhibit 7. The costs shown in the column labeled "Total System" in Seelye

Exhibit 6 were carried forward *from* the functionally assigned and classified costs shown in Seelye Exhibit 7. The column labeled "Ref" in Seelye Exhibit 7 provides a reference to the results included in Seelye Exhibit 6.

Q. Please describe the allocation factors used in the electric cost of service study.

A. The following allocation factors were used in the electric cost of service study:

- **PENG** – Production energy-related costs are allocated to the rate classes on the basis of the amount of energy (kWh) delivered to each rate class.
- **6CP** – Production demand-related costs are allocated on the basis of the sum of the class coincident peak demands during the six peak months of June, July, August, December, January, and February.
- **STMD** – The fixed production costs directly assigned in the functional assignment section of the cost of service study are allocated to the industrial customer that receives steam service from EKPC.
- **12CP** – Transmission demand-related costs are allocated on the basis of the sum of the 12 monthly class coincident peak demands during the test year.
- **SUBA** – Distribution substations are allocated to the rate class on the basis of cost weighted number of substations for each rate class by substation capacity category.

- **CUST05** – Meter costs were specifically assigned by relating the costs associated with various types of meters to the class of customers for whom these meters were installed.

Q. How was the cost of providing interruptible service addressed in the cost of service study?

A. Customers taking service under the interruptible service rider are assigned a demand cost credit per kW based on the levelized carrying costs associated with the current cost of a combustion turbine generating unit. The cost credit is calculated in Seelye Exhibit 8. This calculation is based on an installed cost of $550/kW for a combustion turbine and a cost of capital (return) of 7 percent. Subsequent to developing this estimate, it was brought to my attention that this avoided cost credit may be somewhat overstated because the capital cost of financing a new combustion turbine would almost certainly be less than 7 percent. Although the credit shown in Seelye Exhibit 8 may be somewhat overstated, I believe that the avoided cost estimate is within a range that is reasonable, particularly given the volatility in the cost of purchasing new combustion turbines.

Q. Does the cost of service study consider load-following costs that EKPC will likely incur to provide service to non-conforming loads on the system?

A. No. It is my understanding that EKPC is currently having difficulty meeting certain North American Electric Reliability Corporation (NERC) control performance standards as a result of large fluctuations of a non-conforming load in EKPC's control area. EKPC is currently analyzing various options for addressing these load/resource balancing problems. The cost of service study submitted in this proceeding does not consider the load-following costs created by non-conforming loads, which are difficult to quantify. The Midwest Independent System Operator (MISO) and other regional transmission operators are currently developing markets for ancillary services, including markets for the types of regulation services that may possibly be used to follow large non-conforming loads. In the absence of an ancillary service market, EKPC may have to enter into a bilateral agreement to obtain regulation services from an organization that controls large amounts of generation capacity, which could prove to be more costly than services obtained from an ancillary service market. Because it is unclear at this time whether load-following services will be obtained from an ancillary service market, or by entering into a bilateral agreement with a regulation service provider, or in some other manner, EKPC is currently unable to develop a reasonable estimate of the load-following costs associated with serving non-conforming loads.

Q. Please summarize the results of the electric cost of service study.

A. The following table (Table 1) summarizes the rates of return for each customer class before and after reflecting the Phase 1 rate adjustments proposed by EKPC. The Actual Adjusted Rate of Return was calculated by dividing the adjusted net operating income by the adjusted net cost rate base for each customer class. The adjusted net operating income and rate base reflect the pro-forma adjustments discussed earlier in my testimony regarding the determination of EKPC's revenue requirements. The Proposed Rate of Return was calculated by dividing the net operating income adjusted for the proposed rate increase by the adjusted net cost rate base.

TABLE 2 Electric Class Rates of Return		
Customer Class	**Actual Adjusted Rate of Return**	**Proposed Rate of Return Phase I Rates**
Rate E	3.20%	6.12%
Rate B	2.53%	6.63%
Rate C	2.33%	6.02%
Rate G	0.50%	4.43%
Large Special Contract	2.86%	5.72%
Special Contract – Pumping Stations	29.52%	29.52%
Steam Service	4.74%	10.66%
Total System	3.17%	6.19%

Determination of the actual adjusted and proposed rates of return are detailed in Seelye Exhibit 7, pages 21-22 and pages 23-24, respectively.

V. RATE DESIGN

Q. Please describe how EKPC proposes to transition to a cost-based rate structure.

A. The unit charge components of EKPC's current rates do not accurately reflect the cost of providing service. From a cost of service perspective, too large of a portion of EKPC's fixed costs are recovered through the energy charge component of its rates. This is particularly true of EKPC's Rate E. The cost of service study indicates that a large portion of its fixed costs that are currently recovered through the energy charge should instead be recovered through the demand charge component of EKPC's rates. Rather than moving to a fully cost-based rate design in a single step, EKPC is proposing to move to a cost-based rate design in two phases. Under its rate design proposal in this proceeding, EKPC's is proposing that its Phase I rates would go into effect upon approval by the Commission, which presumably will be at the end of the 6-month suspension period, and would remain in effect for 12 months, at which time Phase II rates would go into effect and remain in effect as EKPC's on-going rates until superseded by a subsequent rate order. The Phase I rates are designed to serve as a *temporary* or *transitional* rate design until cost-based rates can be implemented in Phase II. A phased-in approach was developed because of concerns expressed by EKPC's member systems about implementing cost-based rates in a short period of time. Although there was a general recognition on the part of the member systems that EKPC's rates should reflect the cost of providing service, a number of member systems expressed a desire to transition to a cost-based rate structure in a more gradual, two-phased manner. This phase-in of cost-based rates would provide the member systems with more time to develop retail rates that reflect wholesale costs and to educate retail customers about how to take advantage of cost-based rate offerings.

Q. Is EKPC's phased-in approach consistent with the ratemaking principle of "gradualism"?

A. Yes.

Q. How were the Phase I rates developed?

A. EKPC's Phase I rates were developed by allocating the proposed revenue increase to each rate component of each rate schedule and special contract on a pro-rata basis, with the exception of the special contract for the pumping stations. In other words, in Phase I

EKPC is proposing to increase each rate component of each rate schedule by the same percentage.

Q. Have you prepared an exhibit detailing the revenue impact of the Phase I rates?

A. Yes. The revenue impact of EKPC's Phase I rates is detailed in Seelye Exhibit 9. This schedule shows the impact of the Phase I rates on the components of each rate schedule. The proposed revenue increase for each rate schedule, stated as a dollar amount and as a percentage, is shown on page 1 of this exhibit.

Q. How were the Phase II rate developed?

A. The Phase II rates were developed based on the results of the cost of service study. Specifically, the individual charges within each rate schedule were based on the unit costs determined from the cost of service study. Consequently, the demand charges, substation charges, and meter-point charges included in the Phase II rates are higher than those included in the Phase I rates. However, the energy charges in the Phase II rates are lower than those included in the Phase I rates.

Q. What is the proposed metering point charge for the Phase II rates?

A. For the Phase II rates, EKPC is proposing to increase the metering point charge from the current level of $125 per month to $230 per month. The $230 charge is supported by the cost of service study.

Q. Please describe the changes to the substation charges in the Phase II rates?

A. EKPC currently has substation categories: (i) 1,000 to 2,999 kVa, (ii) 3,000 to 7,499 kVa, (iii) 7,500 to 14,999 kVa, and (iv) greater than 15,000 kVa. For the Phase II rates, EKPC proposes to incorporate the following six substation categories: (i) 1,000 to 4,999 kVa, (ii) 5,000 to 9,999 kVa, (iii) 10,000 to 14,999 kVa substation, (iv) 15,000 to 29,999 kVa, (v) 30,000 to 50,999, and (iv) greater than 51,000 kVa. These six categories more accurately represent the capacity and cost relationships of the various types of substations that EKPC installs. The proposed unit costs reflect the carrying costs of six categories of substations based on average embedded installed costs.

Q. There are two rate alternatives available to members under EKPC's current Rate E. In the proposed Phase II, rates would this optional rate structure be available.

A. No. In the Phase II rates, the two rate options for Rate E would be eliminated, and the rate schedule would reflect cost-based demand and energy charges.

Q. Would the interruptible credit be modified under the Phase II rates?

A. The interruptible credit is updated for both the Phase I and Phase II rates. For the Phase I rates, the interruptible credit is increased by the same percentage as all other rate components. For the Phase II rates, the interruptible credit is increased to reflect the carrying costs associated with the current cost of installing a combustion turbine, as described earlier in my testimony.

Q. Are the proposed Phase II rates designed to produce the same overall revenue as the Phase I rates?

A. Yes. Although both Phase I and Phase II rates are designed to produce approximately the same overall revenues based on test-year billing determinants, the proposed Phase II rates include unit charges that more accurately track the results of the cost of service study. The two sets of rates result in slightly different overall revenues because of rounding.

Q. Have you prepared an exhibit detailing the revenue impact of the Phase II rates?

A. Yes. The revenue impact of EKPC's Phase II rates is detailed in Seelye Exhibit 10. This schedule shows the impact of the Phase I rates on the components of each rate schedule. The proposed revenue increase for each rate schedule, stated as a dollar amount and as a percentage, is shown on page 1 of this exhibit.

Q. Does this conclude your testimony?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In re the Matter of:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A GENERAL ADJUSTMENT OF ITS WHOLESALE ELECTRIC RATES	)	**CASE NO. 2008-00409**

AFFIDAVIT

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

William Steven Seelye, 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.

Subscribed and sworn before me on this 27th day of October, 2008.

Notary Public

My Commission expires: December 8, 2009

Seelye Exhibit 1

QUALIFICATIONS OF WILLIAM STEVEN SEELYE

Summary of Qualifications

Provides consulting services to numerous investor-owned utilities, rural electric cooperatives, and municipal utilities regarding utility rate and regulatory filings, cost of service and wholesale and retail rate designs; and develops revenue requirements for utilities in general rate cases, including the preparation of analyses supporting pro-forma adjustments and the development of rate base.

Employment

Senior Consultant and Principal
The Prime Group, LLC
(July 1996 to Present)

Provides consulting services in the areas of tariff development, regulatory analysis revenue requirements, cost of service, rate design, fuel and power procurement, depreciation studies, lead-lag studies, and mathematical modeling.

Assists utilities with developing strategic marketing plans and implementation of those plans. Provides utility clients assistance regarding regulatory policy and strategy; project management support for utilities involved in complex regulatory proceedings; process audits; state and federal regulatory filing development; cost of service development and support; the development of innovative rates to achieve strategic objectives; unbundling of rates and the development of menus of rate alternatives for use with customers; performance-based rate development.

Prepared retail and wholesale rate schedules and filings submitted to the Federal Energy Regulatory Commission (FERC) and state regulatory commissions for numerous of electric and gas utilities. Performed cost of service or rate studies for over 130 utilities throughout North America. Prepared market power analyses in support of market-based rate filings submitted to the FERC for utilities and their marketing affiliates. Performed business practice audits for electric utilities, gas utilities, and independent transmission organizations (ISOs), including audits of production cost modeling, retail utility tariffs, retail utility billing practices, and ISO billing processes and procedures.

Manager of Rates and Other Positions
Louisville Gas & Electric Co.
(May 1979 to July 1996)

Held various positions in the Rate Department of LG&E. In December 1990, promoted to Manager of Rates and Regulatory Analysis. In May 1994, given additional responsibilities in the marketing area and promoted to Manager of Market Management and Rates.

Education

Bachelor of Science Degree in Mathematics, University of Louisville, 1979
54 Hours of Graduate Level Course Work in Industrial Engineering and Physics.

Expert Witness Testimony

Alabama: Testified in Docket 28101 on behalf of Mobile Gas Service Corporation concerning rate design and pro-forma revenue adjustments.

Colorado: Testified in Consolidated Docket Nos. 01F-530E and 01A-531E on behalf of Intermountain Rural Electric Association in a territory dispute case.

FERC: Submitted direct and rebuttal testimony in Docket No. EL02-25-000 et al. concerning Public Service of Colorado's fuel cost adjustment.

Submitted direct and responsive testimony in Docket No. ER05-522-001 concerning a rate filing by Bluegrass Generation Company, LLC to charge reactive power service to LG&E Energy, LLC.

Submitted testimony in Docket Nos. ER07-1383-000 and ER08-05-000 concerning Duke Energy Shared Services, Inc.'s charges for reactive power service.

Submitted testimony in Docket No. ER08-1468-000 concerning changes to Vectren Energy's transmission formula rate.

Submitted testimony in Docket No. ER08-1588-000 concerning a generation formula rate for Kentucky Utilities Company.

Florida: Testified in Docket No. 981827 on behalf of Lee County Electric Cooperative, Inc. concerning Seminole Electric Cooperative Inc.'s wholesale rates and cost of service.

Illinois: Submitted direct, rebuttal, and surrebuttal testimony in Docket No. 01-0637 on behalf of Central Illinois Light Company ("CILCO") concerning the modification of interim supply service and the implementation of black start service in connection with providing unbundled electric service.

Indiana: Submitted direct testimony and testimony in support of a settlement agreement in Cause No. 42713 on behalf of Richmond Power & Light regarding revenue requirements, class cost of service studies, fuel adjustment clause and rate design.

Submitted direct and rebuttal testimony in Cause No. 43111 on behalf of Vectren Energy in support of a transmission cost recovery adjustment.

Kansas: Submitted direct and rebuttal testimony in Docket No. 05-WSEE-981-RTS on behalf of Westar Energy, Inc. and Kansas Gas and Electric Company regarding transmission delivery revenue requirements, energy cost adjustment clauses, fuel normalization, and class cost of service studies.

Kentucky: Testified in Administrative Case No. 244 regarding rates for cogenerators and small power producers, Case No. 8924 regarding marginal cost of service, and in numerous 6-month and 2-year fuel adjustment clause proceedings.

Submitted direct and rebuttal testimony in Case No. 96-161 and Case No. 96-362 regarding Prestonsburg Utilities' rates.

Submitted direct and rebuttal testimony in Case No. 99-046 on behalf of Delta Natural Gas Company, Inc. concerning its rate stabilization plan.

Submitted direct and rebuttal testimony in Case No. 99-176 on behalf of Delta Natural Gas Company, Inc. concerning cost of service, rate design and expense adjustments in connection with Delta's rate case.

Submitted direct and rebuttal testimony in Case No. 2000-080, testified on behalf of Louisville Gas and Electric Company concerning cost of service, rate design, and pro-forma adjustments to revenues and expenses.

Submitted rebuttal testimony in Case No. 2000-548 on behalf of Louisville Gas and Electric Company regarding the company's prepaid metering program.

Testified on behalf of Louisville Gas and Electric Company in Case No. 2002-00430 and on behalf of Kentucky Utilities Company in Case No. 2002-00429 regarding the calculation of merger savings.

Submitted direct and rebuttal testimony in Case No. 2003-00433 on behalf of Louisville Gas and Electric Company and in Case No. 2003-00434 on behalf of Kentucky Utilities Company regarding pro-forma revenue, expense and plant adjustments, class cost of service studies, and rate design.

Submitted direct and rebuttal testimony in Case No. 2004-00067 on behalf of Delta Natural Gas Company regarding pro-forma adjustments, depreciation rates, class cost of service studies, and rate design.

Testified on behalf of Kentucky Utilities Company in Case No. 2006-00129 and on behalf of Louisville Gas and electric Company in Case No. 2006-00130 concerning methodologies for recovering environmental costs through base electric rates.

Testified on behalf of Delta Natural Gas Company in Case No. 2007-00089 concerning cost of service, temperature normalization, year-end normalization, depreciation expenses, allocation of the rate increase, and rate design.

Submitted testimony on behalf of Big Rivers Electric Corporation and E.ON U.S. LLC in Case No 2007-00455 and Case No. 2007-00460 regarding the design and implementation of a Fuel Adjustment Clause, Environmental Surcharge, Unwind Surcredit, Rebate Adjustment, and Member Rate Stability Mechanism for Big Rivers Electric Corporation in connection with the unwind of a lease and purchase power transaction with E.ON U.S. LLC.

Submitted testimony in Case No. 2008-00251 on behalf of Kentucky Utilities Company and in Case No. 2008-00252 on behalf of Louisville Gas and Electric Company regarding pro-forma revenue and expense adjustments, electric temperature normalization, jurisdictional separation, class cost of service studies, and rate design.

Nevada: Submitted direct and rebuttal testimony in Case No. 03-10001 on behalf of Nevada Power Company regarding cash working capital and rate base adjustments.

Submitted direct and rebuttal testimony in Case No. 03-12002 on behalf of Sierra Pacific Power Company regarding cash working capital.

Submitted direct and rebuttal testimony in Case No. 05-10003 on behalf of Nevada Power Company regarding cash working capital for an electric general rate case.

Submitted direct and rebuttal testimony in Case No. 05-10005 on behalf of Sierra Pacific Power Company regarding cash working capital for a gas general rate case.

Submitted direct and rebuttal testimony in Case Nos. 06-11022 and 06-11023 on behalf of Nevada Power Company regarding cash working capital for a gas general rate case.

Submitted direct and rebuttal testimony in Case No. 07-12001 on behalf of Sierra Pacific Power Company regarding cash working capital for an electric general rate case.

Nova Scotia: Testified on behalf of Nova Scotia Power Company in NSUARB – NSPI – P-887 regarding the development and implementation of a fuel adjustment mechanism.

Submitted testimony in NSUARB – NSPI – P-884 regarding Nova Scotia Power Company's application to approve a demand-side management plan and cost recovery mechanism.

Submitted testimony in NSUARB – NSPI – P-888 regarding a general rate application filed by Nova Scotia Power Company.

Submitted testimony on behalf of Nova Scotia Power Company in the matter of the approval of backup, top-up and spill service for use in the Wholesale Open Access Market in Nova Scotia.

Virginia: Submitted testimony in Case No. PUE-2008-00076 on behalf of Northern Neck Electric Cooperative regarding revenue requirements, class cost of service, jurisdictional separation and an excess facilities charge rider.

Seelye Exhibit 2

EAST KENTUCKY POWER COOPERATIVE, INC.
Calculation of Revenue Requirement
Based on Forecasted Revenues and Expenses
For the 12 Month Period Ended May 31, 2010

Line	Description	Reference		Amount
1	**Total Operating Revenue & Patronage Capital Per Budget**	Eames Exhibit 1, Page 1, Line 8	$	886,273,772
2				
3	Adjustments to Revenue:			
4	To Remove Fuel In Base Rates	Schedule 1.01		(350,719,383)
5	To Remove Fuel Adjustment Clause Revenue	Schedule 1.01		(108,692,230)
6	To Remove Environmental Surcharge Revenue	Eames Exhibit 1, Page 1, Line 3		(104,725,169)
7	To Adjust Off-System Sales Environmental Surcharge Revenue	Schedule 1.02		(1,377,517)
8				
9	**Adjusted Revenue**	Lines 1 through 7	$	320,759,474
10				
11				
12	**Total Cost of Service**	Eames Exhibit 1, Page 2, Line 26	$	898,541,897
13				
14	Adjustments to Cost of Service:			
15	To Remove Fuel Expense Recoverable through the FAC	Schedule 1.01	$	(403,441,802)
16	To Remove Purchased Power Expense Recoverable through the FAC	Schedule 1.03		(51,684,614)
17	To Remove O&M Expenses Recoverable through the Environmental Surcharge	Schedule 1.04		(31,800,030)
18	To Remove Emissions Allowance Expense Recoverable through the Environmental Surcharge	Schedule 1.05		(6,615,208)
19	To Remove Property Taxes and Property Insurance Recoverable through the Environmental Surcharge	Schedule 1.06		(2,098,198)
20	To Remove Depreciation Expenses Recoverable through the Environmental Surcharge	Schedule 1.07		(19,564,992)
21	To Remove Interest Expenses Recoverable through the Environmental Surcharge	Schedule 1.08		(37,031,989)
22	To Remove Promotional Advertising Expense pursuant to Commission Rule KAR 5:016	Schedule 1.09		(658,906)
23	To Remove Certain Directors' Expenses	Schedule 1.10		(93,300)
24	To Remove Donations	Schedule 1.11		(95,485)
25	To Remove Affiliate Expenses	Schedule 1.12		(28,712)
26	To Remove Lobbying Expenses	Schedule 1.13		(85,422)
27	To Remove Touchstone Energy Dues	Schedule 1.14		(414,000)
28	To Remove Other Miscellaneous Expenses	Schedule 1.15		(155,940)
29	To Normalize Ratecase Expenses	Schedule 1.16		100,000
30	Amortize 2004 Force Outage Balance	Schedule 1.17		3,419,058
31	To Normalize Generation Overhaul Expenses	Schedule 1.18		2,300,000
32				
33				
34	**Adjusted Cost of Service**	Lines 12 through 31	$	350,592,357
35				
36	**Adjusted Operating Margins**	Line 9 less Line 34	$	(29,832,883)
37				
38	**Non-Operating Items**			
39	Interest Income	Eames Exhibit 1, Page 2, Line 32	$	4,007,189
40	Other Non-Operating Income	Eames Exhibit 1, Page 2, Line 34		(27,912)
41	Other Capital Credits/Patronage Dividends	Eames Exhibit 1, Page 2, Line 35		250,000
42				
43	**Total Non-Operating Items**	Lines 39 through 41	$	4,229,277
44				
45				
46	**Adjusted Net Margin (Deficit)**	Line 36 plus Line 43	$	(25,603,606)

EAST KENTUCKY POWER COOPERATIVE, INC.
Calculation of Revenue Requirement
Based on Forecasted Revenues and Expenses
For the 12 Month Period Ended May 31, 2010

Line	Description	Reference			Amount
1	**Calculation of Revenue Deficiency**				
2					
3	Adjusted Net Margin (Deficit)	Page 1, Line 46		$	(25,603,606)
4					
5	Interest on Long-Term Debt	Eames Exhibit 1, Page 2, Line 19 Less Line 21, Above	$98,751,898.00		
6					
7	Net Margin Requirement at 1.45 TIER (0.45 x Line 5)			$	44,438,354
8					
9	Revenue Deficiency (Line 7 - Line 3)			$	70,041,960

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove FAC Base Rate Revenue

		MWh Sales Subject to FAC	Fuel Cost in Base Rates*	FAC Base Rate Revenue	Member FAC Billings**	Steam FAC Billings	Pumping Station Fuel Cost Billings	Total Fuel Cost Billings
June	2009	1,034,405.00	26.38	27,287,604	4,839,308	94,804	801,201	5,735,313
July	2009	1,170,414.00	26.38	30,875,521	5,695,708	97,842	837,235	6,630,785
August	2009	1,158,883.00	26.38	30,571,334	9,418,926	165,036	691,092	10,275,054
September	2009	1,003,496.00	26.38	26,472,224	7,092,765	142,441	491,972	7,727,178
October	2009	942,223.00	26.38	24,855,843	4,579,464	112,807	431,549	5,123,820
November	2009	1,069,459.00	26.38	28,212,328	4,936,575	100,577	714,603	5,751,755
December	2009	1,301,930.00	26.38	34,344,913	12,775,630	243,670	783,520	13,802,820
January	2010	1,380,682.00	26.38	36,422,391	12,408,150	225,090	916,130	13,549,370
February	2010	1,176,215.00	26.38	31,028,552	12,056,270	235,177	859,292	13,150,739
March	2010	1,147,783.00	26.38	30,278,516	11,385,749	229,815	917,256	12,532,820
April	2010	952,326.00	26.38	25,122,360	6,637,509	152,575	827,377	7,617,461
May	2010	957,081.00	26.38	25,247,797	5,791,586	132,745	870,785	6,795,116
Total		13,294,897.00		350,719,383	97,617,640	1,932,579	9,142,011	108,692,230

* As approved in Case No. 2006-00508, dated July 25, 2007
** Eames Exhibit 1, Page 1, Line 2

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Fuel Costs Recoverable Through the FAC

Total Fuel Costs Excluding Handling -- Eames Exhibit 1, Page 1, Line 3	$412,609,991
Less: Fuel Costs Assigned to Off-System Sales	9,168,189
Fuel Costs Recoverable Through FAC	$403,441,802

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Off-System Sales Environmental Surcharge Revenue

		Off-System Sales Revenue	Monthly Environmental Surcharge Factor	Off-System Sales Environmental Cost
June	2009	1,332,340	13.85%	184,529
July	2009	1,119,946	14.21%	159,144
August	2009	1,159,704	14.22%	164,910
September	2009	1,311,731	13.88%	182,068
October	2009	1,001,815	13.54%	135,646
November	2009	253,615	13.82%	35,050
December	2009	272,436	14.02%	38,196
January	2010	398,354	13.30%	52,981
February	2010	439,280	13.40%	58,864
March	2010	1,096,284	13.54%	148,437
April	2010	866,814	13.46%	116,673
May	2010	734,687	13.75%	101,019
Total		9,987,006		1,377,517

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Purchased Power Expense Recoverable Through the Fuel Adjustment Clause

		Total Purchased Power	Purchased Power Assigned to Forced Outages	Purchased Power Recoverable Through the FAC
June	2009	3,871,392	833,300	3,038,092
July	2009	5,316,797	833,300	4,483,497
August	2009	5,207,600	833,300	4,374,300
September	2009	3,745,707	833,300	2,912,407
October	2009	3,611,051	833,300	2,777,751
November	2009	7,484,043	833,300	6,650,743
December	2009	7,533,457	833,700	6,699,757
January	2010	9,284,117	833,300	8,450,817
February	2010	7,024,925	833,300	6,191,625
March	2010	4,123,190	833,300	3,289,890
April	2010	3,649,035	833,300	2,815,735
May	2010	3,391,056	833,300	2,557,756
Total		$ 64,242,370	$ 10,000,000	$ **51,684,614**

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove O&M Expenses Recoverable Through the Environmental Surcharge

Descr	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	
Ash Storage	$ 553,633	$ 553,633	$ 553,633	$ 553,633	$ 407,573	$ 553,633	$ 553,633	$ 621,047	$ 621,047	$ 621,047	$ 621,047	$ 433,510	$ 6,647,069
Ammonia	325,000	335,000	335,000	304,000	256,000	325,000	333,000	381,654	344,719	381,654	326,426	338,825	$ 3,986,278
Limestone	981,019	1,013,719	1,013,719	829,578	748,707	981,019	1,013,719	1,122,668	1,014,024	1,122,668	1,042,123	822,606	$ 11,705,569
Magnesium	142,000	207,000	208,000	202,000	138,000	202,000	207,000	220,000	199,000	220,000	194,000	220,000	$ 2,359,000
Units 3 and 4 Boiler Controls Maint	110,464	110,435	60,750	60,464	62,346	310,477	63,624	81,110	81,110	121,110	81,110	581,110	$ 1,724,110
Unit 1 Precipitator Maint	500	500	500	500	500	500	500	500	500	500	125,500	500	$ 131,000
Units 3 and 4 BagHouse Maint	59,172	59,172	59,172	59,172	59,172	104,172	71,674	50,951	63,867	63,867	63,867	138,867	$ 853,125
Unit 1 SCR Maint	9,833	9,833	9,833	9,833	9,833	9,833	14,003	4,250	7,375	7,375	27,375	7,375	$ 126,751
Unit 2 SCR Maint	9,833	9,833	9,833	9,833	58,833	9,833	14,003	4,125	7,250	7,250	7,250	7,250	$ 155,126
Unit 1 Scrubber Maint	75,429	75,427	75,451	75,429	75,572	75,430	75,667	29,257	47,091	47,104	47,099	47,091	$ 746,047
Unit 2 Scrubber Maint	85,897	85,896	85,926	85,897	86,083	85,901	123,889	31,695	51,592	51,609	51,617	51,592	$ 877,594
Air Permit Fees	-	-	-	-	-	-	1,410,000	-	-	-	-	-	$ 1,410,000
Stack Monitoring Supplies	19,273	19,273	19,273	19,273	19,273	19,273	28,908	10,036	20,071	20,071	20,071	20,071	$ 234,866
Stack Monitoring Consulting	68,200	68,200	68,200	68,200	68,200	68,200	96,050	38,738	65,472	65,472	65,472	65,472	$ 805,876
Stack Monitoring Maintenance	2,917	2,917	2,917	2,917	2,917	2,917	4,371	1,750	3,499	3,499	3,499	3,499	$ 37,619
Totals by month	$ 2,443,170	$ 2,550,838	$ 2,502,207	$ 2,280,729	$ 1,993,009	$ 2,748,188	$ 4,010,041	$ 2,597,781	$ 2,526,617	$ 2,733,226	$ 2,676,456	$ 2,737,768	**$ 31,800,030**

Seelye Exhibit 2
Schedule 1.05

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Emissions Allowance Expense Recoverable Through the Environmental Surcharge

		Amount
June	2009	800,853
July	2009	982,179
August	2009	958,652
September	2009	722,765
October	2009	511,628
November	2009	768,152
December	2009	838,169
January	2010	230,884
February	2010	199,796
March	2010	185,781
April	2010	117,482
May	2010	298,867
Total		**$ 6,615,208**

Seelye Exhibit 2
Schedule 1.06

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Property Taxes and Insurance Expenses Recoverable Through the Environmental Surcharge

		Amount
June	2009	177,316
July	2009	176,867
August	2009	176,419
September	2009	175,971
October	2009	175,522
November	2009	175,074
December	2009	174,626
January	2010	174,177
February	2010	173,729
March	2010	173,281
April	2010	172,832
May	2010	172,384
Total		**$ 2,098,198**

Seelye Exhibit 2
Schedule 1.07

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Depreciation Expense Recoverable Through the Environmental Surcharge

		Amount
June	2009	1,630,416
July	2009	1,630,416
August	2009	1,630,416
September	2009	1,630,416
October	2009	1,630,416
November	2009	1,630,416
December	2009	1,630,416
January	2010	1,630,416
February	2010	1,630,416
March	2010	1,630,416
April	2010	1,630,416
May	2010	1,630,416
		$ 19,564,992

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Interest Expense Recoverable Through the Environmental Surcharge

		Amount
June	2009	3,140,884
July	2009	3,129,337
August	2009	3,117,876
September	2009	3,107,416
October	2009	3,097,328
November	2009	3,085,754
December	2009	3,075,310
January	2010	3,072,217
February	2010	3,063,967
March	2010	3,055,908
April	2010	3,047,553
May	2010	3,038,439
		$ 37,031,989

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Promotional Advertising

		Amount
June	2009	24,191
July	2009	19,701
August	2009	62,451
September	2009	65,951
October	2009	62,451
November	2009	59,451
December	2009	36,324
January	2010	149,782
February	2010	67,451
March	2010	72,251
April	2010	19,451
May	2010	19,451
		$ 658,906

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Directors' Expenses

		Amount
June	2009	7,775
July	2009	7,775
August	2009	7,775
September	2009	7,775
October	2009	7,775
November	2009	7,775
December	2009	7,775
January	2010	7,775
February	2010	7,775
March	2010	7,775
April	2010	7,775
May	2010	7,775
		$ 93,300

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Directors' Expenses

1	Test-Year Directors' Fees and Expenses	$	312,000
2			
3	Items not Removed from test year		
4			
5	Fees for Regular Board Meetings	$	163,200
6	Chair and Secretary Fees		9,600
7	Committee Chair Fees		7,200
8	Audit Committee Chair Fees		800
9	Two Special Board Meetings		13,600
10	Fees for Training Seminars for Each Board Member for Three Days		15,300
11	Normal Expenses		25,000
12			
13	Total Ordinary Expenses (lines 5 thru 11)	$	234,700
14			
15	Amounts Removed From Directors' Fees and Expenses (line 1 less 13)	$	77,300
16			
17	Monthly Amounts Removed From Directors' Fees and Expenses (line 15 / 12)	$	6,442
18			
19	Monthly Directors' Severence Fees Budgeted Separately	$	1,333
20			
21	Total Monthly Amount Removed from Test-Year Expenses (line 17 + line 19)	$	7,775

Seelye Exhibit 2
Schedule 1.11

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Donations

		Amount
June	2009	8,317
July	2009	8,327
August	2009	7,667
September	2009	7,667
October	2009	7,867
November	2009	7,667
December	2009	11,587
January	2010	5,418
February	2010	7,937
March	2010	7,667
April	2010	7,667
May	2010	7,697
		$ 95,485

Seelye Exhibit 2
Schedule 1.12

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Affiliate Transactions

		ACES Expenses	Propane Expenses	Envision Expenses	Total
June	2009	458	568	1,124	2,150
July	2009	458	567	1,075	2,100
August	2009	458	570	1,075	2,103
September	2009	458	649	1,112	2,219
October	2009	458	585	1,151	2,194
November	2009	458	567	1,091	2,116
December	2009	690	646	1,250	2,586
January	2010	250	565	2,041	2,856
February	2010	500	611	1,359	2,470
March	2010	1,300	612	1,514	3,426
April	2010	500	611	1,111	2,222
May	2010	500	611	1,159	2,270
		$ 6,488	$ 7,162	$ 15,062	**$ 28,712**

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Lobbying Expenses

		Amount
June	2009	$ 29,994
July	2009	4,992
August	2009	5,013
September	2009	4,994
October	2009	5,080
November	2009	4,882
December	2009	5,347
January	2010	4,922
February	2010	4,977
March	2010	5,143
April	2010	4,941
May	2010	5,137
Total		**$ 85,422**

Seelye Exhibit 2
Schedule 1.14

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Touchstone Energy Dues

		Amount
January	2010	**$ 414,000**

Seelye Exhibit 2
Schedule 1.15

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Miscellaneous Expenses

		Forecasted Expense June 2009-May 2010
Executive Retirement Plan	$	45,000
Employee Recognition Dinner		40,000
Employee Food Certificates		26,000
Vending Supplies		25,940
Employee Recreation		19,000
Total	**$**	**155,940**

Estimated Rate Case Expenses
Case No. 2008-00409

Rate Case Consultant	$	175,000
TIER and Equity Consultant		25,000
Decoupling Rate Expert		5,000
Rate Design Consultant		5,000
Advertising Member Cooperatives		50,000
Supplies, Expenses, Shipping		40,000
Total	$	300,000
Amortization Period		3 Years
Annual Amortized Amount	$	100,000

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Amortize 2004 Forced Outage Balance

2004 Spurlock 1 Forced Outage Costs-- Allowance for 3-Year Amortization per Order in Case No. 2006-00472, dated December 5, 2007			$ 20,514,346
Monthly Amortization	$ 569,842.94		
Amortization December 2007- May 2009			$ 10,257,173
Unamortized Balance--June 1, 2009			$ 10,257,173
Period for Amortizing Remaining Balance		3 Years	
Annual Amortization			**$ 3,419,058**

East Kentucky Power Cooperative, Inc.
Adjustment to Normalize Generating Unit Turbine/Boiler Overhaul

Unit	Turbine/Boiler Overhaul Costs 2009 Dollars	Scheduled *Overhaul* Period in Years	Annual *Normalization* Adjustment
Cooper 1	$ 3,100,000	10	$ 300,000
Cooper 2	4,400,000	10	400,000
Dale 1	1,500,000	10	200,000
Dale 2	1,500,000	10	200,000
Dale 3	2,500,000	10	300,000
Dale 4	4,000,000	10	400,000
Spurlock 1	8,000,000	10	800,000
Spurlock 2	8,000,000	10	800,000
Spurlock 3	8,000,000	10	800,000
Spurlock 4	8,000,000	10	800,000
Smith CT1	4,000,000	6	700,000
Smith CT2	4,000,000	6	700,000
Smith CT3	4,000,000	6	700,000
Total			$ 7,100,000
Less: Overhaul Expenses During Test Year (Cooper 1)			2,100,000
Less: Overhaul Expenses During Test Year (Dale 1&2)			2,700,000
Annual Normalization Adjustment for Turbine/Boiler Overhauls			**$ 2,300,000**

Seelye Exhibit 3

EAST KENTUCKY POWER COOPERATIVE, INC.
Forecasted Test Period 13-Month Average Net Cost Rate Base

Item	1 May 2009	2 June 2009	3 July 2009	4 August 2009	5 September 2009	6 October 2009	7 November 2009	8 December 2009	9 January 2010	10 February 2010	11 March 2010	12 April 2010	13 May 2010	13-Month Average
Net Cost Rate Base – Including Environmental														
Utility Plant in Service														
Generation	2,551,870,180	2,563,656,180	2,575,442,180	2,587,228,180	2,599,014,180	2,610,800,180	2,622,586,180	2,634,372,180	2,639,663,180	2,644,954,180	2,650,245,180	2,655,536,180	2,660,827,180	2,615,091,949
Transmission	459,617,373	464,793,173	469,968,973	475,144,773	480,320,573	485,496,373	490,672,173	495,847,973	497,393,573	498,939,173	500,484,773	502,030,373	503,575,973	486,483,481
Distribution	166,725,511	168,943,711	171,161,911	173,380,111	175,598,311	177,816,511	180,034,711	182,252,911	182,915,311	183,577,711	184,240,111	184,902,511	185,564,911	178,239,557
General	78,029,799	78,568,799	79,107,799	79,646,799	80,185,799	80,724,799	81,263,799	81,802,799	82,050,799	82,298,799	82,546,799	82,794,799	83,042,799	80,928,030
Total Utility Plant in Service	3,256,242,863	3,275,961,863	3,295,680,863	3,315,399,863	3,335,118,863	3,354,837,863	3,374,556,863	3,394,275,863	3,402,022,863	3,409,769,863	3,417,516,863	3,425,263,863	3,433,010,863	3,360,743,017
Construction Work in Progress (CWIP)														
Generation	189,194,310	191,258,310	193,322,310	195,386,310	197,450,310	199,514,310	201,578,310	203,642,310	226,540,310	249,438,310	272,336,310	295,234,310	318,132,310	225,617,541
Transmission	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134
Distribution	41	41	41	41	41	41	41	41	41	41	41	41	41	41
General	114	114	114	114	114	114	114	114	114	114	114	114	114	114
Total CWIP	190,597,600	192,661,600	194,725,600	196,789,600	198,853,600	200,917,600	202,981,600	205,045,600	227,943,600	250,841,600	273,739,600	296,637,600	319,535,600	227,020,830
Materials & Supplies	48,347,000	50,141,000	51,934,000	53,728,000	55,522,000	57,316,000	59,110,000	60,904,000	61,059,000	61,214,000	61,369,000	61,524,000	61,678,000	57,218,923
Fuel Stock	62,517,000	62,930,000	63,343,000	63,756,000	64,169,000	64,582,000	64,995,000	65,408,000	65,701,000	65,994,000	66,287,000	66,580,000	66,872,000	64,856,462
Cash Working Capital (1/8th of Adj. Annual O&M)	26,985,673	26,985,673	26,985,673	26,985,673	26,985,673	26,985,673	26,985,673	26,985,673	26,985,673	26,985,673	26,985,673	26,985,673	26,985,673	26,985,673
Total	3,584,690,135	3,608,680,135	3,632,669,135	3,656,659,135	3,680,649,135	3,704,639,135	3,728,629,135	3,752,619,135	3,783,712,135	3,814,805,135	3,845,898,135	3,876,991,135	3,908,082,135	3,736,824,904
Less: Accumulated Depreciation														
Generation	585,350,251	589,740,447	594,130,677	598,520,907	603,251,096	608,008,072	612,765,048	617,544,759	622,328,934	627,113,109	631,903,980	636,694,851	641,485,722	612,987,527
Transmission	132,961,962	133,591,648	134,221,334	134,851,020	135,480,706	136,129,210	136,777,714	137,454,202	138,130,693	138,807,184	139,483,675	140,160,166	140,840,135	136,837,665
Distribution	39,576,599	39,913,146	40,249,693	40,586,240	40,922,787	41,259,631	41,596,475	41,944,669	42,292,866	42,641,063	42,989,260	43,337,457	43,692,632	41,615,578
General	49,379,855	49,746,442	50,113,279	50,480,179	50,847,225	51,214,396	51,581,567	52,227,752	52,737,638	53,249,024	53,768,625	54,288,557	54,808,489	51,880,233
Total Accumulated Depreciation	807,268,667	812,991,683	818,714,983	824,438,346	830,501,814	836,611,309	842,720,804	849,171,382	855,490,131	861,810,380	868,145,540	874,481,031	880,826,978	843,321,004
Net Investment Rate Base	2,777,421,468	2,795,688,452	2,813,954,152	2,832,220,789	2,850,147,321	2,868,027,826	2,885,908,331	2,903,447,753	2,928,222,004	2,952,994,755	2,977,752,595	3,002,510,104	3,027,255,157	2,893,503,901

EAST KENTUCKY POWER COOPERATIVE, INC.
Forecasted Test Period 13-Month Average Net Cost Rate Base

Item	1 May 2009	2 June 2009	3 July 2009	4 August 2009	5 September 2009	6 October 2009	7 November 2009	8 December 2009	9 January 2010	10 February 2010	11 March 2010	12 April 2010	13 May 2010	13-Month Average
Net Cost Rate Base Items -- Environmental Plant														
Plant in Service	700,309,943	700,309,943	700,309,943	700,309,943	700,309,943	700,309,943	700,309,943	700,309,943	700,309,943	700,309,943	700,309,943	700,309,943	700,309,943	700,309,943
Accumulated Depreciation	53,894,690	55,525,106	57,155,222	58,785,937	60,416,353	62,046,769	63,677,184	65,307,600	66,938,016	68,568,431	70,198,847	71,829,263	73,459,678	63,677,161
Allowance Inventory	8,317,890	7,516,228	6,531,823	5,571,555	4,847,780	4,336,152	3,568,000	2,729,832	3,597,547	3,397,752	3,211,970	3,094,488	2,795,622	4,576,203
Cash Working Capital	2,496,344	2,687,838	2,892,790	3,091,664	3,262,853	3,299,600	3,282,709	3,571,585	3,688,928	3,797,374	3,931,648	3,935,936	3,963,052	3,377,102
Net Cost Rate Base -- Excluding Environmental														
Utility Plant in Service														
Generation	1,851,560,237	1,863,346,237	1,875,132,237	1,886,918,237	1,898,704,237	1,910,490,237	1,922,276,237	1,934,062,237	1,939,353,237	1,944,644,237	1,949,935,237	1,955,226,237	1,960,517,237	1,914,782,006
Transmission	459,617,373	464,793,173	469,968,973	475,144,773	480,320,573	485,496,373	490,672,173	495,847,973	497,393,573	498,939,173	500,484,773	502,030,373	503,575,973	486,483,481
Distribution	166,725,511	168,943,711	171,161,911	173,380,111	175,598,311	177,816,511	180,034,711	182,252,911	182,915,311	183,577,711	184,240,111	184,902,511	185,564,911	178,239,557
General	78,029,799	78,568,799	79,107,799	79,646,799	80,185,799	80,724,799	81,263,799	81,802,799	82,050,799	82,298,799	82,546,799	82,794,799	83,042,799	80,928,030
Total Utility Plant in Service	2,555,932,920	2,575,651,920	2,595,370,920	2,615,089,920	2,634,808,920	2,654,527,920	2,674,246,920	2,693,965,920	2,701,712,920	2,709,459,920	2,717,206,920	2,724,953,920	2,732,700,920	2,660,433,074
Construction Work in Progress (CWIP)														
Generation	189,194,310	191,258,310	193,322,310	195,386,310	197,450,310	199,514,310	201,578,310	203,642,310	226,540,310	249,438,310	272,336,310	295,234,310	318,132,310	225,617,541
Transmission	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134
Distribution	41	41	41	41	41	41	41	41	41	41	41	41	41	41
General	114	114	114	114	114	114	114	114	114	114	114	114	114	114
Total CWIP	190,597,600	192,661,600	194,725,600	196,789,600	198,853,600	200,917,600	202,981,600	205,045,600	227,943,600	250,841,600	273,739,600	296,637,600	319,535,600	227,020,830
Materials & Supplies	48,347,000	50,141,000	51,934,000	53,728,000	55,522,000	57,316,000	59,110,000	60,904,000	61,059,000	61,214,000	61,369,000	61,524,000	61,678,000	57,218,923
Fuel Stock	54,199,110	55,413,772	56,811,177	58,184,445	59,321,220	60,245,848	61,427,000	62,678,168	62,103,453	62,596,248	63,075,030	63,485,512	64,076,378	60,278,259
Cash Working Capital (1/8th of Adj. Annual O&M)	24,489,329	24,297,835	24,092,883	23,894,009	23,722,820	23,686,073	23,702,964	23,414,088	23,296,745	23,188,299	23,054,025	23,049,737	23,022,621	23,608,571
Total	2,873,565,958	2,898,166,126	2,922,934,579	2,947,685,973	2,972,228,559	2,996,693,440	3,021,468,483	3,046,007,775	3,076,115,717	3,107,300,066	3,138,444,574	3,169,650,768	3,201,013,518	3,028,559,657
Less: Accumulated Depreciation														
Generation	531,455,561	534,215,341	536,975,455	539,734,970	542,834,743	545,961,303	549,087,864	552,237,159	555,390,918	558,544,678	561,705,133	564,865,588	568,026,044	549,310,366
Transmission	132,961,962	133,591,648	134,221,334	134,851,020	135,480,706	136,129,210	136,777,714	137,454,202	138,130,693	138,807,184	139,483,675	140,160,166	140,840,135	136,837,665
Distribution	39,576,599	39,913,146	40,249,693	40,586,240	40,922,787	41,259,631	41,596,475	41,944,669	42,292,866	42,641,063	42,989,260	43,337,457	43,692,632	41,615,578
General	49,379,855	49,746,442	50,113,279	50,480,179	50,847,225	51,214,396	51,581,567	52,227,752	52,737,638	53,249,024	53,768,625	54,288,557	54,808,489	51,880,233
Total Accumulated Depreciation	753,373,977	757,466,577	761,559,761	765,652,409	770,085,461	774,564,540	779,043,620	783,863,782	788,552,115	793,241,949	797,946,693	802,651,768	807,367,300	779,643,842
Net Investment Rate Base	2,120,191,981	2,140,699,549	2,161,374,818	2,182,033,564	2,202,143,098	2,222,128,900	2,242,424,863	2,262,143,993	2,287,563,602	2,314,058,117	2,340,497,881	2,366,999,000	2,393,646,218	2,248,915,815

Seelye Exhibit 4

EAST KENTUCKY POWER COOPERATIVE, INC.
13-Month Average Capitalization

Item	1 May 2009	2 June 2009	3 July 2009	4 August 2009	5 September 2009	6 October 2009	7 November 2009	8 December 2009	9 January 2010	10 February 2010	11 March 2010	12 April 2010	13 May 2010	13-Month Average
Capitalization														
Members' Equity	186,645,000	189,290,000	192,747,000	203,104,000	208,837,000	205,568,000	202,821,000	214,570,000	227,679,000	237,682,000	247,682,000	247,216,000	246,465,000	216,177,385
Long-Term Debt	2,570,995,000	2,648,125,000	2,666,867,000	2,660,609,000	2,654,351,000	2,678,092,000	2,671,834,000	2,715,576,000	2,708,726,000	2,701,877,000	2,735,027,000	2,778,178,000	2,771,328,000	2,689,352,692
Total	2,757,640,000	2,837,415,000	2,859,614,000	2,863,713,000	2,863,188,000	2,883,660,000	2,874,655,000	2,930,146,000	2,936,405,000	2,939,559,000	2,982,709,000	3,025,394,000	3,017,793,000	2,905,530,077
Capital Structure (Percentage of Total)														
Members' Equity	6.77%	6.67%	6.74%	7.09%	7.29%	7.13%	7.06%	7.32%	7.75%	8.09%	8.30%	8.17%	8.17%	7.44%
Long-Term Debt	93.23%	93.33%	93.26%	92.91%	92.71%	92.87%	92.94%	92.68%	92.25%	91.91%	91.70%	91.83%	91.83%	92.56%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Total Capitalization -- 13-Month Average	$2,905,530,077
Less: Impact on Equity from Rate Increase	(5,219,927)
Less: Environmental Plant	(641,210,985)
	$2,259,099,165

Seelye Exhibit 5

EAST KENTUCKY POWER COOPERATIVE, INC.
Summary of Coverage Ratios and Rates of Return

		Forecast Net of Adjustments Before Revenue Increase		*Forecast* Net of Adjustments After Revenue Increase*
Adjusted Net Margins	$	(25,603,606)	$	42,255,316
Interest		98,751,898		98,751,898
Times Interest Earned (TIER)		**0.74**		**1.43**
Adjusted Net Margins	$	(25,603,606)	$	42,255,316
Interest		98,751,898		98,751,898
Depreciation		53,993,319		53,993,319
Total	$	127,141,611	$	195,000,533
Normalized Principal and Interest (Excluding Environment P&I)	$	156,157,108	$	156,157,108
Debt Service Coverage Ratio (DSC)		**0.81**		**1.25**
Adjusted Net Margins Before Interest		71,322,720.37		139,181,642.37
Net Cost Rate Base		2,248,915,815		2,248,915,815
Rate of Return on Net Cost Rate Base		**3.17%**		**6.19%**
Capitalization		2,259,099,165		2,259,099,165
Rate of Return on Total Capitalization		**3.16%**		**6.16%**

**The Board-approved rate increase is used, which produces a lower TIER than shown in the revenue requirement.*

Seelye Exhibit 6

EAST KENTUCI. ,WER COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Plant in Service							
Intangible Plant	INTPLT	PT&D	$ -	-	-	-	-
Production Plant	PPROD	F001	1,914,782,006	1,895,587,544	-	19,194,462	-
Transmission Plant	PTRAN	F002	486,483,481	-	-	-	486,483,481
Distribution Plant	PDIST	F003	178,239,557	2,752,427	-	-	618,605
Total Production & Transmission Plant	PT&D		2,579,505,044	1,898,339,971	-	19,194,462	487,102,086
General Plant	PGP	PT&D	$ 80,928,030	59,557,516	-	602,197	15,282,084
Total Plant in Service	TPIS		$ 2,660,433,074	$ 1,957,897,487	$ -	$ 19,796,659	$ 502,384,170
Construction Work in Progress (CWIP)							
CWIP Production	CWIP1	PPROD	$ 225,617,541	223,355,870	-	2,261,671	-
CWIP Transmission	CWIP2	PTRAN	1,403,134	-	-	-	1,403,134
CWIP Distribution Plant	CWIP3	PDIST	41	1	-	-	0
CWIP General Plant	CWIP4	PT&D	114	84	-	1	22
Total Construction Work in Progress	TCWIP		$ 227,020,830	$ 223,355,954	$ -	$ 2,261,672	$ 1,403,156
Total Utility Plant			$ 2,887,453,904	$ 2,181,253,442	$ -	$ 22,058,331	$ 503,787,326

EAST KENTUC. ,WER COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector		Distribution Substations		Distribution Meters
Plant in Service						
Intangible Plant	INTPLT	PT&D		-		-
Production Plant	PPROD	F001		-		-
Transmission Plant	PTRAN	F002		-		-
Distribution Plant	PDIST	F003		167,119,502		7,749,023
Total Production & Transmission Plant	PT&D			167,119,502		7,749,023
General Plant	PGP	PT&D		5,243,119		243,114
Total Plant in Service	TPIS		$	172,362,621	$	7,992,137
Construction Work in Progress (CWIP)						
CWIP Production	CWIP1	PPROD		-		-
CWIP Transmission	CWIP2	PTRAN		-		-
CWIP Distribution Plant	CWIP3	PDIST		38		2
CWIP General Plant	CWIP4	PT&D		7		0
Total Construction Work in Progress	TCWIP		$	46	$	2
Total Utility Plant			$	172,362,667	$	7,992,139

EAST KENTUCK /ER COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Rate Base							
Total Utility Plant	TUP		$ 2,887,453,904	$ 2,181,253,442	$ -	$ 22,058,331	$ 503,787,326
Less: Acummulated Provision for Depreciation							
Production	ADEPREPA	PPROD	$ 549,310,366	543,803,882	-	5,506,484	-
Transmission	ADEPRTP	PTRAN	136,837,665	-	-	-	136,837,665
Distribution	ADEPRD11	PDIST	41,615,578	642,640	-	-	144,433
General & Common Plant	ADEPRD12	PT&D	51,880,233	38,180,317	-	386,048	9,796,829
Intangible, Misc, and Other Plant	ADEPRGP	PT&D	-	-	-	-	-
Retirement Work In Progress	ADEPRRT	PT&D	-	-	-	-	-
Total Accumulated Depreciation	TADEPR		$ 779,643,842	$ 582,626,838	$ -	$ 5,892,532	$ 146,778,927
Net Utility Plant	NTPLANT		$ 2,107,810,062	$ 1,598,626,603	$ -	$ 16,165,799	$ 357,008,399
Working Capital							
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	$ 23,608,571	12,519,953	6,071,375	4,348	4,676,152
Materials and Supplies	M&S	TPIS	57,218,923	42,109,229	-	425,774	10,804,963
Fuel Stock	PREPAY	TPIS	60,278,259	44,360,692	-	448,539	11,382,674
Total Working Capital	TWC		$ 141,105,753	$ 98,989,874	$ 6,071,375	$ 878,662	$ 26,863,789
Net Rate Base	RB		$ 2,248,915,815	$ 1,697,616,477	$ 6,071,375	$ 17,044,460	$ 383,872,188

EAST KENTUC   OWER COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector		Distribution Substations		Distribution Meters
Rate Base						
Total Utility Plant	TUP		$	172,362,667	$	7,992,139
Less: Acummulated Provision for Depreciation						
Production	ADEPREPA	PPROD		-		-
Transmission	ADEPRTP	PTRAN		-		-
Distribution	ADEPRD11	PDIST		39,019,255		1,809,251
General & Common Plant	ADEPRD12	PT&D		3,361,187		155,852
Intangible, Misc, and Other Plant	ADEPRGP	PT&D		-		-
Retirement Work In Progress	ADEPRRT	PT&D		-		-
Total Accumulated Depreciation	TADEPR		$	42,380,442	$	1,965,103
Net Utility Plant	NTPLANT		$	129,982,225	$	6,027,036
Working Capital						
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP		321,820		14,922
Materials and Supplies	M&S	TPIS		3,707,067		171,890
Fuel Stock	PREPAY	TPIS		3,905,273		181,080
Total Working Capital	TWC		$	7,934,161	$	367,892
Net Rate Base	RB		$	137,916,386	$	6,394,928

EAST KENTUC. ,WER COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Operation and Maintenance Expenses							
Steam Power Generation Operation Expenses							
500 OPERATION SUPERVISION & ENGINEERING	OM500	PROFIX	$ 7,885,308	7,885,308	-	-	-
501 FUEL	OM501	Energy	$ 386,058,927	-	386,058,927	-	-
502 STEAM EXPENSES	OM502	PROFIX	$ 11,355,691	11,355,691	-	-	-
505 ELECTRIC EXPENSES	OM505	PROFIX	$ 5,274,586	5,274,586	-	-	-
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	$ 33,482,685	33,482,685	-	-	-
507 RENTS	OM507	PROFIX	$ -	-	-	-	-
509 ALLOWANCES	OM509	Energy	$ 6,620,870	-	6,620,870	-	-
Total Steam Power Operation Expenses			$ 450,678,067	$ 57,998,270	$ 392,679,797	$ -	$ -
Steam Power Generation Maintenance Expenses							
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	Energy	$ 2,604,989	-	2,604,989	-	-
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	$ 3,713,719	3,713,719	-	-	-
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	$ 28,840,241	-	28,840,241	-	-
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	$ 9,015,056	-	9,015,056	-	-
514 MAINTENANCE OF MISC STEAM PLANT	OM514	PROFIX	$ 117,139	117,139	-	-	-
Total Steam Power Generation Maintenance Expense			$ 44,291,144	$ 3,830,858	$ 40,460,286	$ -	$ -
Total Steam Power Generation Expense			$ 494,969,211	$ 61,829,128	$ 433,140,083	$ -	$ -

Description	Name	Functional Vector		Distribution Substations		Distribution Meters
Operation and Maintenance Expenses						
Steam Power Generation Operation Expenses						
500 OPERATION SUPERVISION & ENGINEERING	OM500	PROFIX		-		-
501 FUEL	OM501	Energy		-		-
502 STEAM EXPENSES	OM502	PROFIX		-		-
505 ELECTRIC EXPENSES	OM505	PROFIX		-		-
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX		-		-
507 RENTS	OM507	PROFIX		-		-
509 ALLOWANCES	OM509	Energy		-		-
Total Steam Power Operation Expenses			$	-	$	-
Steam Power Generation Maintenance Expenses						
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	Energy		-		-
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX		-		-
512 MAINTENANCE OF BOILER PLANT	OM512	Energy		-		-
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy		-		-
514 MAINTENANCE OF MISC STEAM PLANT	OM514	PROFIX		-		-
Total Steam Power Generation Maintenance Expense			$	-	$	-
Total Steam Power Generation Expense			$	-	$	-

EAST KENTUCK. ... WER COOPERATIVE, INC.
Cost of Service Study
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12 Months Ended
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Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Steam Direct		Transmission Demand
Operation and Maintenance Expenses (Continued)												
Other Power Generation Operation Expense												
546 OPERATION SUPERVISION & ENGINEERING	OM546	PROFIX	$	278,826		278,826		-		-		-
547 FUEL	OM547	Energy	$	40,878,558		-		40,878,558		-		-
548 GENERATION EXPENSE	OM548	PROFIX	$	3,513,607		3,513,607		-		-		-
549 MISC OTHER POWER GENERATION	OM549	PROFIX	$	1,055,967		1,055,967		-		-		-
550 RENTS	OM550	PROFIX	$	-		-		-		-		-
Total Other Power Generation Expenses			$	45,726,958	$	4,848,400	$	40,878,558	$	-	$	-
Other Power Generation Maintenance Expense												
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	$	170,556		170,556		-		-		-
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	$	186,558		186,558		-		-		-
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	$	3,955,857		3,955,857		-		-		-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	$	70,216		70,216		-		-		-
Total Other Power Generation Maintenance Expense			$	4,383,187	$	4,383,187	$	-	$	-	$	-
Total Other Power Generation Expense			$	50,110,145	$	9,231,587	$	40,878,558	$	-	$	-
Total Station Expense			$	545,079,356	$	71,060,715	$	474,018,641	$	-	$	-

EAST KENTUCK /VER COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector	Distribution Substations	Distribution Meters
Operation and Maintenance Expenses (Continued)				
Other Power Generation Operation Expense				
546 OPERATION SUPERVISION & ENGINEERING	OM546	PROFIX	-	-
547 FUEL	OM547	Energy	-	-
548 GENERATION EXPENSE	OM548	PROFIX	-	-
549 MISC OTHER POWER GENERATION	OM549	PROFIX	-	-
550 RENTS	OM550	PROFIX	-	-
Total Other Power Generation Expenses			$ -	$ -
Other Power Generation Maintenance Expense				
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	-	-
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	-	-
Total Other Power Generation Maintenance Expense			$ -	$ -
Total Other Power Generation Expense			$ -	$ -
Total Station Expense			$ -	$ -

EAST KENTUC WER COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Operation and Maintenance Expenses (Continued)							
Other Power Supply Expenses							
555 PURCHASED POWER	OM555	OMPP	$ 64,242,370	-	64,242,370	-	-
555 PURCHASED POWER OPTIONS	OMO555	OMPP	-	-	-	-	-
555 BROKERAGE FEES	OMB555	OMPP	-	-	-	-	-
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	3,993,169	3,993,169	-	-	-
557 OTHER EXPENSES	OM557	PROFIX	8,951,678	8,951,678	-	-	-
558 DUPLICATE CHARGES	OM558	Energy	-	-	-	-	-
Total Other Power Supply Expenses	TPP		$ 77,187,217	$ 12,944,847	$ 64,242,370	$ -	$ -
Total Electric Power Generation Expenses			$ 622,266,573	$ 84,005,562	$ 538,261,011	$ -	$ -
Transmission Expenses							
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	$ 3,904,970	-	-	-	3,904,970
561 LOAD DISPATCHING	OM561	LBTRAN	2,555,050	-	-	-	2,555,050
562 STATION EXPENSES	OM562	PTRAN	2,192,606	-	-	-	2,192,606
563 OVERHEAD LINE EXPENSES	OM563	PTRAN	2,307,161	-	-	-	2,307,161
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	PTRAN	15,632,950	-	-	-	15,632,950
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	945,367	-	-	-	945,367
567 RENTS	OM567	PTRAN	446,300	-	-	-	446,300
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	-	-	-	-	-
569 STRUCTURES	OM569	PTRAN	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	OM570	PTRAN	1,920,486	-	-	-	1,920,486
571 MAINT OF OVERHEAD LINES	OM571	PTRAN	2,774,520	-	-	-	2,774,520
572 UNDERGROUND LINES	OM572	PTRAN	-	-	-	-	-
573 MISC PLANT	OM573	PTRAN	144,039	-	-	-	144,039
Total Transmission Expenses			$ 32,823,449	$ -	$ -	$ -	$ 32,823,449
Distribution Operation Expense							
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	$ -	-	-	-	-
581 LOAD DISPATCHING	OM581	PDIST	213,127	3,291	-	-	740
582 STATION EXPENSES	OM582	PDIST	808,499	12,485	-	-	2,806
583 OVERHEAD LINE EXPENSES	OM583	PDIST	-	-	-	-	-
584 UNDERGROUND LINE EXPENSES	OM584	PDIST	-	-	-	-	-
585 STREET LIGHTING EXPENSE	OM585	PDIST	-	-	-	-	-
586 METER EXPENSES	OM586	PDIST	-	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	PDIST	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	PDIST	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	-	-	-	-	-
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	-	-	-	-	-
589 RENTS	OM589	PDIST	-	-	-	-	-
Total Distribution Operation Expense	OMDO		$ 1,021,626	$ 15,776	$ -	$ -	$ 3,546

Description	Name	Functional Vector	Distribution Substations	Distribution Meters
Operation and Maintenance Expenses (Continued)				
Other Power Supply Expenses				
555 PURCHASED POWER	OM555	OMPP	-	-
555 PURCHASED POWER OPTIONS	OMO555	OMPP	-	-
555 BROKERAGE FEES	OMB555	OMPP	-	-
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	-	-
557 OTHER EXPENSES	OM557	PROFIX	-	-
558 DUPLICATE CHARGES	OM558	Energy	-	-
Total Other Power Supply Expenses	TPP		$ -	$ -
Total Electric Power Generation Expenses			$ -	$ -
Transmission Expenses				
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	-	-
561 LOAD DISPATCHING	OM561	LBTRAN	-	-
562 STATION EXPENSES	OM562	PTRAN	-	-
563 OVERHEAD LINE EXPENSES	OM563	PTRAN	-	-
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	PTRAN	-	-
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	-	-
567 RENTS	OM567	PTRAN	-	-
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	-	-
569 STRUCTURES	OM569	PTRAN	-	-
570 MAINT OF STATION EQUIPMENT	OM570	PTRAN	-	-
571 MAINT OF OVERHEAD LINES	OM571	PTRAN	-	-
572 UNDERGROUND LINES	OM572	PTRAN	-	-
573 MISC PLANT	OM573	PTRAN	-	-
Total Transmission Expenses			$ -	$ -
Distribution Operation Expense				
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	-	-
581 LOAD DISPATCHING	OM581	PDIST	199,830	9,266
582 STATION EXPENSES	OM582	PDIST	758,058	35,150
583 OVERHEAD LINE EXPENSES	OM583	PDIST	-	-
584 UNDERGROUND LINE EXPENSES	OM584	PDIST	-	-
585 STREET LIGHTING EXPENSE	OM585	PDIST	-	-
586 METER EXPENSES	OM586	PDIST	-	-
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	PDIST	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	PDIST	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	-	-
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	-	-
589 RENTS	OM589	PDIST	-	-
Total Distribution Operation Expense	OMDO		$ 957,889	$ 44,416

EAST KENTUC WER COOPERATIVE, INC.
Cost of Service Study
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12 Months Ended
May 31, 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Operation and Maintenance Expenses (Continued)							
Distribution Maintenance Expense							
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	$ -	-	-	-	-
591 STRUCTURES	OM591	PDIST	$ -	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	OM592	PDIST	987,836	15,254	-	-	3,428
593 MAINTENANCE OF OVERHEAD LINES	OM593	PDIST	-	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	OM594	PDIST	-	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	OM595	PDIST	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	PDIST	-	-	-	-	-
597 MAINTENANCE OF METERS	OM597	PDIST	-	-	-	-	-
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	-	-	-	-	-
Total Distribution Maintenance Expense	OMDM		$ 987,836	$ 15,254	$ -	$ -	$ 3,428
Total Distribution Operation and Maintenance Expenses			2,009,462	31,031	-	-	6,974
Transmission and Distribution Expenses			34,832,911	31,031	-	-	32,830,423
Production, Transmission and Distribution Expenses	OMSUB		$ 657,099,484	$ 84,036,593	$ 538,261,011	$ -	$ 32,830,423
Customer Accounts Expense							
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	$ -	-	-	-	-
902 METER READING EXPENSES	OM902	F025	-	-	-	-	-
903 RECORDS AND COLLECTION	OM903	F025	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	-	-	-	-	-
905 MISC CUST ACCOUNTS	OM903	F025	-	-	-	-	-
Total Customer Accounts Expense	OMCA		$ -	$ -	$ -	$ -	$ -
Customer Service Expense							
907 SUPERVISION	OM907	TUP	$ -	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	TUP	1,742,340	1,316,206	-	13,310	303,994
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	TUP	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	TUP	500	378	-	4	87
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	TUP	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	TUP	21,750	16,430	-	166	3,795
911 DEMONSTRATION AND SELLING EXP	OM911	TUP	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	OM912	TUP	-	-	-	-	-
913 ADVERTISING EXPENSES	OM913	TUP	10,000	7,554	-	76	1,745
915 MDSE-JOBBING-CONTRACT	OM915	TUP	-	-	-	-	-
916 MISC SALES EXPENSE	OM916	TUP	-	-	-	-	-
Total Customer Service Expense	OMCS		$ 1,774,590	$ 1,340,569	$ -	$ 13,557	$ 309,621
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		658,874,074	85,377,161	538,261,011	13,557	33,140,044

EAST KENTUC[illegible]WER COOPERATIVE, INC.
Cost of Service Study
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12 Months Ended
May 31, 2010

Description	Name	Functional Vector	Distribution Substations	Distribution Meters
Operation and Maintenance Expenses (Continued)				
Distribution Maintenance Expense				
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	-	-
591 STRUCTURES	OM591	PDIST	-	-
592 MAINTENANCE OF STATION EQUIPME	OM592	PDIST	926,207	42,946
593 MAINTENANCE OF OVERHEAD LINES	OM593	PDIST	-	-
594 MAINTENANCE OF UNDERGROUND LIN	OM594	PDIST	-	-
595 MAINTENANCE OF LINE TRANSFORME	OM595	PDIST	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	PDIST	-	-
597 MAINTENANCE OF METERS	OM597	PDIST	-	-
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	-	-
Total Distribution Maintenance Expense	OMDM		$ 926,207	$ 42,946
Total Distribution Operation and Maintenance Expenses			1,884,095	87,362
Transmission and Distribution Expenses			1,884,095	87,362
Production, Transmission and Distribution Expenses	OMSUB		$ 1,884,095	$ 87,362
Customer Accounts Expense				
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	-	-
902 METER READING EXPENSES	OM902	F025	-	-
903 RECORDS AND COLLECTION	OM903	F025	-	-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	-	-
905 MISC CUST ACCOUNTS	OM903	F025	-	-
Total Customer Accounts Expense	OMCA		$ -	$ -
Customer Service Expense				
907 SUPERVISION	OM907	TUP	-	-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	TUP	104,007	4,823
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	TUP	-	-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	TUP	30	1
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	TUP	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	TUP	1,298	60
911 DEMONSTRATION AND SELLING EXP	OM911	TUP	-	-
912 DEMONSTRATION AND SELLING EXP	OM912	TUP	-	-
913 ADVERTISING EXPENSES	OM913	TUP	597	28
915 MDSE-JOBBING-CONTRACT	OM915	TUP	-	-
916 MISC SALES EXPENSE	OM916	TUP	-	-
Total Customer Service Expense	OMCS		$ 105,932	$ 4,912
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		1,990,027	92,274

EAST KENTUCK. .VER COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Steam Direct		Transmission Demand
Operation and Maintenance Expenses (Continued)												
Administrative and General Expense												
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB9	$	11,309,693		5,778,671		3,620,520		1,123		1,708,572
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB9		5,606,260		2,864,510		1,794,706		557		846,946
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB9		-		-		-		-		-
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB9		2,046,640		1,045,728		655,181		203		309,189
924 PROPERTY INSURANCE	OM924	TUP		-		-		-		-		-
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB9		905,423		462,625		289,849		90		136,784
926 EMPLOYEE BENEFITS	OM926	LBSUB9		787,580		402,413		252,124		78		118,981
927 FRANCHISE REQUIREMENTS	OM927	TUP		-		-		-		-		-
928 REGULATORY COMMISSION FEES	OM928	TUP		1,238,124		935,309		-		9,458		216,021
929 DUPLICATE CHARGES-CR	OM929	LBSUB9		(478,800)		(244,642)		(153,276)		(48)		(72,333)
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB9		5,260,409		2,687,798		1,683,991		522		794,698
931 RENTS AND LEASES	OM931	PGP		-		-		-		-		-
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP		1,245,791		916,817		-		9,270		235,250
Total Administrative and General Expense	OMAG		$	27,921,120	$	14,849,230	$	8,143,096	$	21,254	$	4,294,106
Total Operation and Maintenance Expenses	TOM		$	686,795,194	$	100,226,391	$	546,404,107	$	34,811	$	37,434,150
Operation and Maintenance Expenses Less Purchase Power & Fuel	OMLPP		$	188,994,469	$	100,226,391	$	48,603,382	$	34,811	$	37,434,150

EAST KENTUC,   ,WER COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector		Distribution Substations		Distribution Meters
Operation and Maintenance Expenses (Continued)						
Administrative and General Expense						
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB9		191,909		8,898
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB9		95,130		4,411
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB9		-		-
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB9		34,728		1,610
924 PROPERTY INSURANCE	OM924	TUP		-		-
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB9		15,364		712
926 EMPLOYEE BENEFITS	OM926	LBSUB9		13,364		620
927 FRANCHISE REQUIREMENTS	OM927	TUP		-		-
928 REGULATORY COMMISSION FEES	OM928	TUP		73,908		3,427
929 DUPLICATE CHARGES-CR	OM929	LBSUB9		(8,125)		(377)
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB9		89,261		4,139
931 RENTS AND LEASES	OM931	PGP		-		-
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP		80,712		3,742
Total Administrative and General Expense	OMAG		$	586,252	$	27,183
Total Operation and Maintenance Expenses	TOM		$	2,576,279	$	119,457
Operation and Maintenance Expenses Less Purchase Power & Fuel	OMLPP		$	2,576,279	$	119,457

EAST KENTUCI WER COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Steam Direct		Transmission Demand
Labor Expenses												
Steam Power Generation Operation Expenses												
500 OPERATION SUPERVISION & ENGINEERING	LB500	PROFIX	$	2,252,669		2,252,669		-		-		-
501 FUEL	LB501	Energy	$	1,477,744		-		1,477,744		-		-
502 STEAM EXPENSES	LB502	PROFIX	$	1,770,487		1,770,487		-		-		-
505 ELECTRIC EXPENSES	LB505	PROFIX	$	1,368,779		1,368,779		-		-		-
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	$	958,705		958,705		-		-		-
507 RENTS	LB507	PROFIX	$	-		-		-		-		-
509 ALLOWANCES	LB509	Energy	$	-		-		-		-		-
Total Steam Power Operation Expenses	LBSUB1		$	7,828,384	$	6,350,640	$	1,477,744	$	-	$	-
Steam Power Generation Maintenance Expenses												
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	Energy	$	729,965		-		729,965		-		-
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	$	306,869		306,869		-		-		-
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	$	2,668,789		-		2,668,789		-		-
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	$	645,029		-		645,029		-		-
514 MAINTENANCE OF MISC STEAM PLANT	LB514	PROFIX	$	15,125		15,125		-		-		-
Total Steam Power Generation Maintenance Expense	LBSUB2		$	4,365,777	$	321,994	$	4,043,783	$	-	$	-
Total Steam Power Generation Expense			$	12,194,161	$	6,672,634	$	5,521,527	$	-	$	-

EAST KENTUC WER COOPERATIVE, INC.
Cost of Service Study
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12 Months Ended
May 31, 2010

Description	Name	Functional Vector		Distribution Substations		Distribution Meters
Labor Expenses						
Steam Power Generation Operation Expenses						
500 OPERATION SUPERVISION & ENGINEERING	LB500	PROFIX		-		-
501 FUEL	LB501	Energy		-		-
502 STEAM EXPENSES	LB502	PROFIX		-		-
505 ELECTRIC EXPENSES	LB505	PROFIX		-		-
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX		-		-
507 RENTS	LB507	PROFIX		-		-
509 ALLOWANCES	LB509	Energy		-		-
Total Steam Power Operation Expenses	LBSUB1		$	-	$	-
Steam Power Generation Maintenance Expenses						
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	Energy		-		-
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX		-		-
512 MAINTENANCE OF BOILER PLANT	LB512	Energy		-		-
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy		-		-
514 MAINTENANCE OF MISC STEAM PLANT	LB514	PROFIX		-		-
Total Steam Power Generation Maintenance Expense	LBSUB2		$	-	$	-
Total Steam Power Generation Expense			$	-	$	-

Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Steam Direct		Transmission Demand
Labor Expenses (Continued)												
Other Power Generation Operation Expense												
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	$	79,755		79,755		-		-		-
547 FUEL	LB547	Energy	$	7,355		-		7,355		-		-
548 GENERATION EXPENSE	LB548	PROFIX	$	327,970		327,970		-		-		-
549 MISC OTHER POWER GENERATION	LB549	PROFIX	$	34,616		34,616		-		-		-
550 RENTS	LB550	PROFIX	$	-		-		-		-		-
Total Other Power Generation Expenses	LBSUB7		$	449,696	$	442,341	$	7,355	$	-	$	-
Other Power Generation Maintenance Expense												
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	$	47,915		47,915		-		-		-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	$	1,695		1,695		-		-		-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	$	145,449		145,449		-		-		-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	$	5,195		5,195		-		-		-
Total Other Power Generation Maintenance Expense	LBSUB8		$	200,254	$	200,254	$	-	$	-	$	-
Total Other Power Generation Expense			$	649,950	$	642,595	$	7,355	$	-	$	-
Total Production Expense	LPREX		$	12,844,111	$	7,315,229	$	5,528,882	$	-	$	-

EAST KENTUCKY ...ER COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
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Description	Name	Functional Vector	Distribution Substations	Distribution Meters
Labor Expenses (Continued)				
Other Power Generation Operation Expense				
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	-	-
547 FUEL	LB547	Energy	-	-
548 GENERATION EXPENSE	LB548	PROFIX	-	-
549 MISC OTHER POWER GENERATION	LB549	PROFIX	-	-
550 RENTS	LB550	PROFIX	-	-
Total Other Power Generation Expenses	LBSUB7		$ -	$ -
Other Power Generation Maintenance Expense				
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	-	-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	-	-
Total Other Power Generation Maintenance Expense	LBSUB8		$ -	$ -
Total Other Power Generation Expense			$ -	$ -
Total Production Expense	LPREX		$ -	$ -

EAST KENTUCKY ER COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Steam Direct		Transmission Demand
Labor Expenses (Continued)												
Purchased Power												
555 PURCHASED POWER	LB555	OMPP	$	-		-		-		-		-
555 PURCHASED POWER OPTIONS	LBO555	OMPP	$	-		-		-		-		-
555 BROKERAGE FEES	LBB555	OMPP	$	-		-		-		-		-
555 MISO TRANSMISSION EXPENSES	LBM555	OMPP	$	-		-		-		-		-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	$	969,165		969,165		-		-		-
557 OTHER EXPENSES	LB557	PROFIX		366,045		366,045		-		-		-
558 DUPLICATE CHARGES	LB558	Energy		-		-		-		-		-
Total Purchased Power Labor	LBPP		$	1,335,210	$	1,335,210	$	-	$	-	$	-
Transmission Labor Expenses												
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	$	844,080		-		-		-		844,080
561 LOAD DISPATCHING	LB561	PTRAN		511,215		-		-		-		511,215
562 STATION EXPENSES	LB562	PTRAN		225,550		-		-		-		225,550
563 OVERHEAD LINE EXPENSES	LB563	PTRAN		264,500		-		-		-		264,500
565 TRANSMISSION OF ELECTRICITY BY OTHERS	LB565	PTRAN		-		-		-		-		-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN		275,005		-		-		-		275,005
567 RENTS	LB567	PTRAN		-		-		-		-		-
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN		-		-		-		-		-
569 MAINTENACE OF STRUCTURES	LB569	PTRAN		-		-		-		-		-
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN		255,005		-		-		-		255,005
571 MAINT OF OVERHEAD LINES	LB571	PTRAN		193,605		-		-		-		193,605
573 MAINT OF MISC. TRANSMISSION PLANT	LB573	PTRAN		-		-		-		-		-
Total Transmission Labor Expenses	LBTRAN		$	2,568,960	$	-	$	-	$	-	$	2,568,960
Distribution Operation Labor Expense												
580 OPERATION SUPERVISION AND ENGI	LB580	F023	$	-		-		-		-		-
581 LOAD DISPATCHING	LB581	PDIST		21,440		331		-		-		74
582 STATION EXPENSES	LB582	PDIST		136,630		2,110		-		-		474
583 OVERHEAD LINE EXPENSES	LB583	PDIST		-		-		-		-		-
584 UNDERGROUND LINE EXPENSES	LB584	PDIST		-		-		-		-		-
585 STREET LIGHTING EXPENSE	LB585	PDIST		-		-		-		-		-
586 METER EXPENSES	LB586	PDIST		-		-		-		-		-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	PDIST		-		-		-		-		-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	PDIST		-		-		-		-		-
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST		-		-		-		-		-
589 RENTS	LB589	PDIST		-		-		-		-		-
Total Distribution Operation Labor Expense	LBDO		$	158,070	$	2,441	$	-	$	-	$	549

Description	Name	Functional Vector		Distribution Substations		Distribution Meters
Labor Expenses (Continued)						
Purchased Power						
555 PURCHASED POWER	LB555	OMPP		-		-
555 PURCHASED POWER OPTIONS	LBO555	OMPP		-		-
555 BROKERAGE FEES	LBB555	OMPP		-		-
555 MISO TRANSMISSION EXPENSES	LBM555	OMPP		-		-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX		-		-
557 OTHER EXPENSES	LB557	PROFIX		-		-
558 DUPLICATE CHARGES	LB558	Energy		-		-
Total Purchased Power Labor	LBPP		$	-	$	-
Transmission Labor Expenses						
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN		-		-
561 LOAD DISPATCHING	LB561	PTRAN		-		-
562 STATION EXPENSES	LB562	PTRAN		-		-
563 OVERHEAD LINE EXPENSES	LB563	PTRAN		-		-
565 TRANSMISSION OF ELECTRICITY BY OTHERS	LB565	PTRAN		-		-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN		-		-
567 RENTS	LB567	PTRAN		-		-
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN		-		-
569 MAINTENACE OF STRUCTURES	LB569	PTRAN		-		-
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN		-		-
571 MAINT OF OVERHEAD LINES	LB571	PTRAN		-		-
573 MAINT OF MISC. TRANSMISSION PLANT	LB573	PTRAN		-		-
Total Transmission Labor Expenses	LBTRAN		$	-	$	-
Distribution Operation Labor Expense						
580 OPERATION SUPERVISION AND ENGI	LB580	F023		-		-
581 LOAD DISPATCHING	LB581	PDIST		20,102		932
582 STATION EXPENSES	LB582	PDIST		128,106		5,940
583 OVERHEAD LINE EXPENSES	LB583	PDIST		-		-
584 UNDERGROUND LINE EXPENSES	LB584	PDIST		-		-
585 STREET LIGHTING EXPENSE	LB585	PDIST		-		-
586 METER EXPENSES	LB586	PDIST		-		-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	PDIST		-		-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	PDIST		-		-
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST		-		-
589 RENTS	LB589	PDIST		-		-
Total Distribution Operation Labor Expense	LBDO		$	148,208	$	6,872

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Labor Expenses (Continued)							
Distribution Maintenance Labor Expense							
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	$ -	-	-	-	-
591 MAINTENANCE OF STRUCTURES	LB591	PDIST	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	LB592	PDIST	140,205	2,165	-	-	487
593 MAINTENANCE OF OVERHEAD LINES	LB593	PDIST	-	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	LB594	PDIST	-	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	LB595	PDIST	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	PDIST	-	-	-	-	-
597 MAINTENANCE OF METERS	LB597	PDIST	-	-	-	-	-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	-	-	-	-	-
Total Distribution Maintenance Labor Expense	LBDM		$ 140,205	$ 2,165	$ -	$ -	$ 487
Total Distribution Operation and Maintenance Labor Expenses		PDIST	298,275	4,606	-	-	1,035
Transmission and Distribution Labor Expenses			2,867,235	4,606	-	-	2,569,995
Production, Transmission and Distribution Labor Expenses	LBSUB		$ 17,046,556	$ 8,655,045	$ 5,528,882	$ -	$ 2,569,995
Customer Accounts Expense							
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	$ -	-	-	-	-
902 METER READING EXPENSES	LB902	F025	-	-	-	-	-
903 RECORDS AND COLLECTION	LB903	F025	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	-	-	-	-	-
905 MISC CUST ACCOUNTS	LB903	F025	-	-	-	-	-
Total Customer Accounts Labor Expense	LBCA		$ -	$ -	$ -	$ -	$ -
Customer Service Expense							
907 SUPERVISION	LB907	TUP	$ -	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	TUP	224,432	169,541	-	1,715	39,158
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	TUP	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	TUP	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	TUP	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	TUP	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	LB911	TUP	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	LB912	TUP	-	-	-	-	-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	TUP	-	-	-	-	-
915 MDSE-JOBBING-CONTRACT	LB915	TUP	-	-	-	-	-
916 MISC SALES EXPENSE	LB916	TUP	-	-	-	-	-
Total Customer Service Labor Expense	LBCS		$ 224,432	$ 169,541	$ -	$ 1,715	$ 39,158
Sub-Total Labor Exp	LBSUB9		17,270,988	8,824,586	5,528,882	1,715	2,609,153

Description	Name	Functional Vector		Distribution Substations		Distribution Meters
Labor Expenses (Continued)						
Distribution Maintenance Labor Expense						
590 MAINTENANCE SUPERVISION AND EN	LB590	F024		-		-
591 MAINTENANCE OF STRUCTURES	LB591	PDIST		-		-
592 MAINTENANCE OF STATION EQUIPME	LB592	PDIST		131,458		6,095
593 MAINTENANCE OF OVERHEAD LINES	LB593	PDIST		-		-
594 MAINTENANCE OF UNDERGROUND LIN	LB594	PDIST		-		-
595 MAINTENANCE OF LINE TRANSFORME	LB595	PDIST		-		-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	PDIST		-		-
597 MAINTENANCE OF METERS	LB597	PDIST		-		-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST		-		-
Total Distribution Maintenance Labor Expense	LBDM		$	131,458	$	6,095
Total Distribution Operation and Maintenance Labor Expenses		PDIST		279,666		12,968
Transmission and Distribution Labor Expenses				279,666		12,968
Production, Transmission and Distribution Labor Expenses	LBSUB		$	279,666	$	12,968
Customer Accounts Expense						
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025		-		-
902 METER READING EXPENSES	LB902	F025		-		-
903 RECORDS AND COLLECTION	LB903	F025		-		-
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025		-		-
905 MISC CUST ACCOUNTS	LB903	F025		-		-
Total Customer Accounts Labor Expense	LBCA		$	-	$	-
Customer Service Expense						
907 SUPERVISION	LB907	TUP		-		-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	TUP		13,397		621
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	TUP		-		-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	TUP		-		-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	TUP		-		-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	TUP		-		-
911 DEMONSTRATION AND SELLING EXP	LB911	TUP		-		-
912 DEMONSTRATION AND SELLING EXP	LB912	TUP		-		-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	TUP		-		-
915 MDSE-JOBBING-CONTRACT	LB915	TUP		-		-
916 MISC SALES EXPENSE	LB916	TUP		-		-
Total Customer Service Labor Expense	LBCS		$	13,397	$	621
Sub-Total Labor Exp	LBSUB9			293,063		13,589

EAST KENTUCKY POWER COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
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Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Labor Expenses (Continued)							
Administrative and General Expense							
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB9	$ 3,220,000	1,645,254	1,030,804	320	486,450
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB9		-	-	-	-
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB9	-	-	-	-	-
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB9	-	-	-	-	-
924 PROPERTY INSURANCE	LB924	TUP	-	-	-	-	-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB9	-	-	-	-	-
926 EMPLOYEE BENEFITS	LB926	LBSUB9	-	-	-	-	-
928 REGULATORY COMMISSION FEES	LB928	TUP	-	-	-	-	-
929 DUPLICATE CHARGES-CR	LB929	LBSUB9	-	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB9	322,128	164,591	103,121	32	48,664
931 RENTS AND LEASES	LB931	PGP	-	-	-	-	-
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	84,265	62,013	-	627	15,912
Total Administrative and General Expense	LBAG		$ 3,626,393	$ 1,871,859	$ 1,133,925	$ 979	$ 551,027
Total Operation and Maintenance Expenses	TLB		$ 20,897,381	$ 10,696,445	$ 6,662,807	$ 2,693	$ 3,160,179
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$ 20,897,381	$ 10,696,445	$ 6,662,807	$ 2,693	$ 3,160,179

12 Months Ended
May 31, 2010

Description	Name	Functional Vector		Distribution Substations		Distribution Meters
Labor Expenses (Continued)						
Administrative and General Expense						
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB9		54,639		2,533
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB9		-		-
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB9		-		-
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB9		-		-
924 PROPERTY INSURANCE	LB924	TUP		-		-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB9		-		-
926 EMPLOYEE BENEFITS	LB926	LBSUB9		-		-
928 REGULATORY COMMISSION FEES	LB928	TUP		-		-
929 DUPLICATE CHARGES-CR	LB929	LBSUB9		-		-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB9		5,466		253
931 RENTS AND LEASES	LB931	PGP		-		-
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP		5,459		253
Total Administrative and General Expense	LBAG		$	65,564	$	3,040
Total Operation and Maintenance Expenses	TLB		$	358,627	$	16,629
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$	358,627	$	16,629

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Other Expenses							
Depreciation Expenses							
Production	DEPRDP2	PPROD	56,135,471	55,572,749	-	562,722	-
Transmission	DEPRDP3	PTRAN	-	-	-	-	-
Transmission	DEPRDP4	PTRAN	7,878,173	-	-	-	7,878,173
Distribution	DEPRDP5	PDIST	4,116,033	63,561	-	-	14,285
General & Common Plant	DEPRDP6	PGP	5,428,634	3,995,105	-	40,395	1,025,119
Other Plant	DEPROTH	TPIS	-	-	-	-	-
Total Depreciation Expense	TDEPR		$ 73,558,311	59,631,415	-	603,117	8,917,577
Accretion Expense							
Production	ACRTNP	F017	$ -	-	-	-	-
Transmission	ACRTNT	PTRAN	$ -	-	-	-	-
Distribution	ACRTND	PDIST	$ -	-	-	-	-
Total Accretion Expense	TACRTN		$ -	$ -	$ -	$ -	$ -
Property Taxes & Other	PTAX	TUP	$ 800	604	-	6	140
Amortization of Investment Tax Credit	OTAX	TUP	$ -	-	-	-	-
Other Expenses	OT	TUP	$ -	-	-	-	-
Interest	INTLTD	TUP	$ 135,823,886	102,604,692	-	1,037,609	23,697,816
Other Deductions	DEDUCT	TUP	$ 2,363,706	1,785,601	-	18,057	412,407
Total Other Expenses	TOE		$ 211,746,703	$ 164,022,313	$ -	$ 1,658,790	$ 33,027,940
Total Cost of Service (O&M + Other Expenses)			$ 898,541,897	$ 264,248,704	$ 546,404,107	$ 1,693,600	$ 70,462,089

EAST KENTUCKY ER COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector		Distribution Substations		Distribution Meters
Other Expenses						
Depreciation Expenses						
Production	DEPRDP2	PPROD		-		-
Transmission	DEPRDP3	PTRAN		-		-
Transmission	DEPRDP4	PTRAN		-		-
Distribution	DEPRDP5	PDIST		3,859,241		178,946
General & Common Plant	DEPRDP6	PGP		351,707		16,308
Other Plant	DEPROTH	TPIS		-		-
Total Depreciation Expense	TDEPR			4,210,948		195,254
Accretion Expense						
Production	ACRTNP	F017		-		-
Transmission	ACRTNT	PTRAN		-		-
Distribution	ACRTND	PDIST		-		-
Total Accretion Expense	TACRTN		$	-	$	-
Property Taxes & Other	PTAX	TUP		48		2
Amortization of Investment Tax Credit	OTAX	TUP		-		-
Other Expenses	OT	TUP		-		-
Interest	INTLTD	TUP		8,107,824		375,945
Other Deductions	DEDUCT	TUP		141,098		6,542
Total Other Expenses	TOE		$	12,459,918	$	577,743
Total Cost of Service (O&M + Other Expenses)			$	15,036,197	$	697,201

EAST KENTUCKY :R COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Functional Vectors							
Production Plant	F001		1,733,178,865	1,715,804,858	0.000000	17,374,007	0.000000
Transmission Plant	F002		1.000000	0.000000	0.000000	0.000000	1.000000
Distribution Plant	F003		1.000000	0.015442	0.000000	0.000000	0.003471
Production Plant	F017		1.000000	0.000000	1.000000	0.000000	0.000000
Provar	PROVAR		1.000000	0.000000	0.000000	0.000000	0.500000
PROFIX	PROFIX		1.000000	1.000000	0.000000	0.000000	0.000000
Distribution Operation Labor	F023		158,070.00	2,440.96	-	-	548.60
Distribution Maintenance Labor	F024		140,205.00	2,165.09	-	-	486.60
Customer Accounts Expense	F025		1.000000	0.000000	0.000000	0.000000	0.000000
Customer Service Expense	F026		1.000000	0.000000	0.000000	0.000000	0.000000
Purchased Power Expenses	OMPP		1.000000	-	1	-	$ -
Production Energy	Energy		1.000000	0.000000	1.000000	0.000000	0.000000
Internally Generated Functional Vectors							
Total Prod, Trans, and Dist Plant		PT&D	1.000000	0.735932	-	0.007441	0.188835
Total Transmission Plant		PTRAN	1.000000	-	-	-	1.000000
Operation and Maintenance Expenses Less Purchase Power		OMLPP	1.000000	0.530314	0.257168	0.000184	0.198070
Total Plant in Service		TPIS	1.000000	0.735932	-	0.007441	0.188835
Total Operation and Maintenance Expenses (Labor)		TLB	1.000000	0.511856	0.318835	0.000129	0.151224
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	1.000000	0.129580	0.816941	0.000021	0.050298
Total Steam Power Operation Expenses (Labor)		LBSUB1	1.000000	0.811233	0.188767	-	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	1.000000	0.073754	0.926246	-	-
Total Other Power Generation Expenses (Labor)		LBSUB5	1.000000	0.983645	0.016355	-	-
Total Transmission Labor Expenses		LBTRAN	1.000000	-	-	-	1.0000000
Sub-Total Labor Exp		LBSUB7	1.000000	0.510949	0.320125	0.000099	0.151071
Total General Plant		PGP	1.000000	0.735932	-	0.007441	0.188835
Total Production Plant		PPROD	1.000000	0.989976	-	0.010024	-
Total Intangible Plant		INTPLT	1.000000	-	-	-	-

Description	Name	Functional Vector	Distribution Substations	Distribution Meters
Functional Vectors				
Production Plant	F001		0.000000	0.000000
Transmission Plant	F002		0.000000	0.000000
Distribution Plant	F003		0.937612	0.043475
Production Plant	F017		0.000000	0.000000
Provar	PROVAR		0.000000	0.500000
PROFIX	PROFIX		0.000000	0.000000
Distribution Operation Labor	F023		148,208.29	6,872.14
Distribution Maintenance Labor	F024		131,457.85	6,095.46
Customer Accounts Expense	F025		0.000000	0.000000
Customer Service Expense	F026		0.000000	0.000000
Purchased Power Expenses	OMPP		$ -	$ -
Production Energy	Energy		0.000000	0.00%
Internally Generated Functional Vectors				
Total Prod, Trans, and Dist Plant		PT&D	0.064787	0.003004
Total Transmission Plant		PTRAN	-	-
Operation and Maintenance Expenses Less Purchase Power		OMLPP	0.013632	0.000632
Total Plant in Service		TPIS	0.064787	0.003004
Total Operation and Maintenance Expenses (Labor)		TLB	0.017161	0.000796
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	0.003020	0.000140
Total Steam Power Operation Expenses (Labor)		LBSUB1	-	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	-	-
Total Other Power Generation Expenses (Labor)		LBSUB5	-	-
Total Transmission Labor Expenses		LBTRAN	-	-
Sub-Total Labor Exp		LBSUB7	0.016969	0.000787
Total General Plant		PGP	0.064787	0.003004
Total Production Plant		PPROD	-	-
Total Intangible Plant		INTPLT	-	-

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EAST KENTUCK WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Total System		Rate E		Rate B		Rate C
Plant in Service											
Power Production Plant											
Production Demand	TPIS	PLPDMD	6CP	$	1,957,897,487	$	1,657,339,742	$	100,395,334	$	45,383,089
Production Energy	TPIS	PLPENG	PENG	$	-	$	-	$	-	$	-
Production - Steam Direct	TPIS	PLPSTM	STMD	$	19,796,659	$	-	$	-	$	-
Total Power Production Plant		PLPT		$	1,977,694,146	$	1,657,339,742	$	100,395,334	$	45,383,089
Transmission Plant	TPIS	PLTRN	12CP	$	502,384,170	$	411,511,104	$	27,740,381	$	12,524,298
Distribution Substation	TPIS	PLDST	SUBA	$	172,362,621	$	170,619,193	$	-	$	-
Distribution Meters	TPIS	PLDMC	Cust05	$	7,992,137	$	7,966,535	$	-	$	-
Total		PLT		$	2,660,433,074	$	2,247,436,574	$	128,135,715	$	57,907,387

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Rate G		Large Special Contract		Special Contract Pumping Stations		Steam Service
Plant in Service											
Power Production Plant											
Production Demand	TPIS	PLPDMD	6CP	$	34,154,141	$	120,625,182	$	-	$	-
Production Energy	TPIS	PLPENG	PENG	$	-	$	-	$	-	$	-
Production - Steam Direct	TPIS	PLPSTM	STMD	$	-	$	-	$	-	$	19,796,659
Total Power Production Plant		PLPT		$	34,154,141	$	120,625,182	$	-	$	19,796,659
Transmission Plant	TPIS	PLTRN	12CP	$	9,377,821	$	33,164,092	$	8,066,474	$	-
Distribution Substation	TPIS	PLDST	SUBA	$	1,743,428	$	-	$	-	$	-
Distribution Meters	TPIS	PLDMC	Cust05	$	25,602	$	-	$	-	$	-
Total		PLT		$	45,300,991	$	153,789,274	$	8,066,474	$	19,796,659

EAST KENTUC. .WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Total System		Rate E		Rate B		Rate C
Net Utility Plant											
Power Production Plant											
Production Demand	NTPLANT	NTPDMD	6CP	$	1,598,626,603	$	1,353,220,697	$	81,972,960	$	37,055,369
Production Energy	NTPLANT	NTPENG	PENG	$	-	$	-	$	-	$	-
Production - Steam Direct	NTPLANT	NTPSTM	STMD	$	16,165,799	$	-	$	-	$	-
Total Power Production Plant		NTPT		$	1,614,792,402	$	1,353,220,697	$	81,972,960	$	37,055,369
Transmission Plant	NTPLANT	NTTRN	12CP	$	357,008,399	$	292,431,429	$	19,713,099	$	8,900,121
Distribution Substation	NTPLANT	NTDST	SUBA	$	129,982,225	$	128,667,470	$	-	$	-
Distribution Meters	NTPLANT	NTDMC	Cust05	$	6,027,036	$	6,007,729	$	-	$	-
Total		NTPLT		$	2,107,810,062	$	1,780,327,324	$	101,686,059	$	45,955,489

EAST KENTUC. ,WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Rate G		Large Special Contract		Special Contract Pumping Stations		Steam Service
Net Utility Plant											
Power Production Plant											
Production Demand	NTPLANT	NTPDMD	6CP	$	27,886,914	$	98,490,665	$	-	$	-
Production Energy	NTPLANT	NTPENG	PENG	$	-	$	-	$	-	$	-
Production - Steam Direct	NTPLANT	NTPSTM	STMD	$	-	$	-	$	-	$	16,165,799
Total Power Production Plant		NTPT		$	27,886,914	$	98,490,665	$	-	$	16,165,799
Transmission Plant	NTPLANT	NTTRN	12CP	$	6,664,145	$	23,567,341	$	5,732,265	$	-
Distribution Substation	NTPLANT	NTDST	SUBA	$	1,314,755	$	-	$	-	$	-
Distribution Meters	NTPLANT	NTDMC	Cust05	$	19,307	$	-	$	-	$	-
Total		NTPLT		$	35,885,120	$	122,058,006	$	5,732,265	$	16,165,799

EAST KENTUC. JWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Total System	Rate E	Rate B	Rate C
Net Cost Rate Base							
Power Production Plant							
Production Demand	RB	RBPDMD	6CP	$ 1,697,616,477	$ 1,437,014,589	$ 87,048,875	$ 39,349,905
Production Energy	RB	RBPENG	PENG	$ 6,071,375	$ 4,632,980	$ 445,944	$ 175,434
Production - Steam Direct	RB	RBPSTM	STMD	$ 17,044,460	$ -	$ -	$ -
Total Power Production Plant		RBPT		$ 1,720,732,313	$ 1,441,647,569	$ 87,494,819	$ 39,525,338
Transmission Plant	RB	RBTRN	12CP	$ 383,872,188	$ 314,435,998	$ 21,196,450	$ 9,569,827
Distribution Substation	RB	RBDST	SUBA	$ 137,916,386	$ 136,521,378	$ -	$ -
Distribution Meters	RB	RBDMC	Cust05	$ 6,394,928	$ 6,374,443	$ -	$ -
Total		RBPLT		$ 2,248,915,815	$ 1,898,979,388	$ 108,691,268	$ 49,095,166

EAST KENTUC. ,WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Rate G		Large Special Contract		Special Contract Pumping Stations		Steam Service
Net Cost Rate Base											
Power Production Plant											
Production Demand	RB	RBPDMD	6CP	$	29,613,722	$	104,589,386	$	-	$	-
Production Energy	RB	RBPENG	PENG	$	160,098	$	434,722	$	105,352	$	116,846
Production - Steam Direct	RB	RBPSTM	STMD	$	-	$	-	$	-	$	17,044,460
Total Power Production Plant		RBPT		$	29,773,820	$	105,024,108	$	105,352	$	17,161,306
Transmission Plant	RB	RBTRN	12CP	$	7,165,601	$	25,340,712	$	6,163,600	$	-
Distribution Substation	RB	RBDST	SUBA	$	1,395,008	$	-	$	-	$	-
Distribution Meters	RB	RBDMC	Cust05	$	20,486	$	-	$	-	$	-
Total		RBPLT		$	38,354,915	$	130,364,820	$	6,268,952	$	17,161,306

EAST KENTUC‹ ›WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Total System		Rate E		Rate B		Rate C
Operation and Maintenance Expenses											
Power Production Plant											
Production Demand	TOM	OMPDMD	6CP	$	100,226,391	$	84,840,592	$	5,139,320	$	2,323,198
Production Energy	TOM	OMPENG	PENG	$	546,404,107	$	416,953,137	$	40,133,541	$	15,788,463
Production - Steam Direct	TOM	OMPSTM	STMD	$	34,811	$	-	$	-	$	-
Total Power Production Plant		OMPT		$	646,665,308	$	501,793,729	$	45,272,861	$	18,111,661
Transmission Plant	TOM	OMTRN	12CP	$	37,434,150	$	30,662,925	$	2,067,019	$	933,223
Distribution Substation	TOM	OMDST	SUBA	$	2,576,279	$	2,550,220	$	-	$	-
Distribution Meters	TOM	OMDMC	Cust05	$	119,457	$	119,075	$	-	$	-
Total		OMPLT		$	686,795,194	$	535,125,949	$	47,339,880	$	19,044,884

EAST KENTUC JWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Rate G	Large Special Contract	Special Contract Pumping Stations	Steam Service
Operation and Maintenance Expenses							
Power Production Plant							
Production Demand	TOM	OMPDMD	6CP	$ 1,748,379	$ 6,174,903	$ -	$ -
Production Energy	TOM	OMPENG	PENG	$ 14,408,275	$ 39,123,577	$ 9,481,342	$ 10,515,771
Production - Steam Direct	TOM	OMPSTM	STMD	$ -	$ -	$ -	$ 34,811
Total Power Production Plant		OMPT		$ 16,156,654	$ 45,298,480	$ 9,481,342	$ 10,550,582
Transmission Plant	TOM	OMTRN	12CP	$ 698,770	$ 2,471,156	$ 601,057	$ -
Distribution Substation	TOM	OMDST	SUBA	$ 26,059	$ -	$ -	$ -
Distribution Meters	TOM	OMDMC	Cust05	$ 383	$ -	$ -	$ -
Total		OMPLT		$ 16,881,864	$ 47,769,636	$ 10,082,399	$ 10,550,582

EAST KENTUCI WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Total System	Rate E	Rate B	Rate C
Labor Expenses							
Power Production Plant							
Production Demand	TLB	LBPDMD	6CP	$ 10,696,445	$ 9,054,429	$ 548,483	$ 247,938
Production Energy	TLB	LBPENG	PENG	$ 6,662,807	$ 5,084,293	$ 489,385	$ 192,523
Production - Steam Direct	TLB	LBPSTM	STMD	$ 2,693	$ -	$ -	$ -
Total Power Production Plant		LBPT		$ 17,361,945	$ 14,138,721	$ 1,037,868	$ 440,462
Transmission Plant	TLB	LBTRN	12CP	$ 3,160,179	$ 2,588,555	$ 174,497	$ 78,782
Distribution Substation	TLB	LBDST	SUBA	$ 358,627	$ 355,000	$ -	$ -
Distribution Meters	TLB	LBDMC	Cust05	$ 16,629	$ 16,576	$ -	$ -
Total		LBPLT		$ 20,897,381	$ 17,098,852	$ 1,212,365	$ 519,244

EAST KENTUCK[illegible]WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Rate G	Large Special Contract	Special Contract Pumping Stations	Steam Service
Labor Expenses							
Power Production Plant							
Production Demand	TLB	LBPDMD	6CP	$ 186,592	$ 659,003	$ -	$ -
Production Energy	TLB	LBPENG	PENG	$ 175,693	$ 477,070	$ 115,615	$ 128,228
Production - Steam Direct	TLB	LBPSTM	STMD	$ -	$ -	$ -	$ 2,693
Total Power Production Plant		LBPT		$ 362,285	$ 1,136,073	$ 115,615	$ 130,922
Transmission Plant	TLB	LBTRN	12CP	$ 58,990	$ 208,614	$ 50,741	$ -
Distribution Substation	TLB	LBDST	SUBA	$ 3,627	$ -	$ -	$ -
Distribution Meters	TLB	LBDMC	Cust05	$ 53	$ -	$ -	$ -
Total		LBPLT		$ 424,956	$ 1,344,687	$ 166,356	$ 130,922

EAST KENTUC. .WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Total System		Rate E		Rate B		Rate C
Depreciation Expenses											
Power Production Plant											
Production Demand	TDEPR	DPPDMD	6CP	$	59,631,415	$	50,477,369	$	3,057,727	$	1,382,226
Production Energy	TDEPR	DPPENG	PENG	$	-	$	-	$	-	$	-
Production - Steam Direct	TDEPR	DPPSTM	STMD	$	603,117	$	-	$	-	$	-
Total Power Production Plant		DPPT		$	60,234,532	$	50,477,369	$	3,057,727	$	1,382,226
Transmission Plant	TDEPR	DPTRN	12CP	$	8,917,577	$	7,304,533	$	492,406	$	222,313
Distribution Substation	TDEPR	DPDST	SUBA	$	4,210,948	$	4,168,355	$	-	$	-
Distribution Meters	TDEPR	DPDMC	Cust05	$	195,254	$	194,628	$	-	$	-
Total		DPPLT		$	73,558,311	$	62,144,885	$	3,550,133	$	1,604,539

EAST KENTUC OWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Rate G		Large Special Contract		Special Contract Pumping Stations		Steam Service
Depreciation Expenses											
Power Production Plant											
Production Demand	TDEPR	DPPDMD	6CP	$	1,040,228	$	3,673,865	$	-	$	-
Production Energy	TDEPR	DPPENG	PENG	$	-	$	-	$	-	$	-
Production - Steam Direct	TDEPR	DPPSTM	STMD	$	-	$	-	$	-	$	603,117
Total Power Production Plant		DPPT		$	1,040,228	$	3,673,865	$	-	$	603,117
Transmission Plant	TDEPR	DPTRN	12CP	$	166,461	$	588,680	$	143,184	$	-
Distribution Substation	TDEPR	DPDST	SUBA	$	42,593	$	-	$	-	$	-
Distribution Meters	TDEPR	DPDMC	Cust05	$	625	$	-	$	-	$	-
Total		DPPLT		$	1,249,908	$	4,262,544	$	143,184	$	603,117

EAST KENTUC. JWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Total System		Rate E		Rate B		Rate C
<u>Property and Other Taxes</u>											
Power Production Plant											
Production Demand	PTAX	PRPDMD	6CP	$	604	$	512	$	31	$	14
Production Energy	PTAX	PRPENG	PENG	$	-	$	-	$	-	$	-
Production - Steam Direct	PTAX	PRPSTM	STMD	$	6	$	-	$	-	$	-
Total Power Production Plant		PRPT		$	610	$	512	$	31	$	14
Transmission Plant	PTAX	PRTRN	12CP	$	140	$	114	$	8	$	3
Distribution Substation	PTAX	PRDST	SUBA	$	48	$	47	$	-	$	-
Distribution Meters	PTAX	PRDMC	Cust05	$	2	$	2	$	-	$	-
Total		PRPLT		$	800	$	675	$	39	$	17

EAST KENTUC[illegible]WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Rate G	Large Special Contract	Special Contract Pumping Stations	Steam Service
Property and Other Taxes								
Power Production Plant								
Production Demand	PTAX	PRPDMD	6CP	$	11 $	37 $	- $	-
Production Energy	PTAX	PRPENG	PENG	$	- $	- $	- $	-
Production - Steam Direct	PTAX	PRPSTM	STMD	$	- $	- $	- $	6
Total Power Production Plant		PRPT		$	11 $	37 $	- $	6
Transmission Plant	PTAX	PRTRN	12CP	$	3 $	9 $	2 $	-
Distribution Substation	PTAX	PRDST	SUBA	$	0 $	- $	- $	-
Distribution Meters	PTAX	PRDMC	Cust05	$	0 $	- $	- $	-
Total		PRPLT		$	14 $	46 $	2 $	6

EAST KENTUC. ✓WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Total System		Rate E		Rate B		Rate C
Interest Expenses											
Power Production Plant											
Production Demand	INTLTD	INPDMD	6CP	$	102,604,692	$	86,853,799	$	5,261,273	$	2,378,326
Production Energy	INTLTD	INPENG	PENG	$	-	$	-	$	-	$	-
Production - Steam Direct	INTLTD	INPSTM	STMD	$	1,037,609	$	-	$	-	$	-
Total Power Production Plant		INPT		$	103,642,301	$	86,853,799	$	5,261,273	$	2,378,326
Transmission Plant	INTLTD	INTRN	12CP	$	23,697,816	$	19,411,270	$	1,308,533	$	590,780
Distribution Substation	INTLTD	INDST	SUBA	$	8,107,824	$	8,025,814	$	-	$	-
Distribution Meters	INTLTD	INDMC	Cust05	$	375,945	$	374,741	$	-	$	-
Total		INPLT		$	135,823,886	$	114,665,623	$	6,569,806	$	2,969,106

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Rate G		Large Special Contract		Special Contract Pumping Stations		Steam Service
Interest Expenses											
Power Production Plant											
Production Demand	INTLTD	INPDMD	6CP	$	1,789,866	$	6,321,429	$	-	$	-
Production Energy	INTLTD	INPENG	PENG	$	-	$	-	$	-	$	-
Production - Steam Direct	INTLTD	INPSTM	STMD	$	-	$	-	$	-	$	1,037,609
Total Power Production Plant		INPT		$	1,789,866	$	6,321,429	$	-	$	1,037,609
Transmission Plant	INTLTD	INTRN	12CP	$	442,358	$	1,564,374	$	380,501	$	-
Distribution Substation	INTLTD	INDST	SUBA	$	82,010	$	-	$	-	$	-
Distribution Meters	INTLTD	INDMC	Cust05	$	1,204	$	-	$	-	$	-
Total		INPLT		$	2,315,439	$	7,885,802	$	380,501	$	1,037,609

EAST KENTUC[illegible] [illegible]WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Total System		Rate E		Rate B		Rate C
Cost of Service Summary -- Unadjusted											
Operating Revenues											
Sales to Members		REVUC	R01	$	873,498,600	$	698,429,398	$	57,697,996	$	23,333,746
Off System Sales Revenue			Energy	$	9,987,006	$	7,655,465	$	736,872	$	289,884
Wheeling Revenue		LSDPR	RBTRN	$	2,389,123	$	1,956,970	$	131,921	$	59,560
Other Operating Revenue		OTHREV	RBPLT	$	399,043	$	336,951	$	19,286	$	8,711
Total Operating Revenues		TOR		$	886,273,772	$	708,378,784	$	58,586,075	$	23,691,901
Operating Expenses											
Operation and Maintenance Expenses				$	686,795,194	$	535,125,949	$	47,339,880	$	19,044,884
Depreciation and Amortization Expenses					73,558,311		62,144,885		3,550,133		1,604,539
Property and Other Taxes			NPT		800		675		39		17
Total Operating Expenses		TOE		$	760,354,305	$	597,271,510	$	50,890,052	$	20,649,441
Utility Operating Margin				$	125,919,467	$	111,107,274	$	7,696,023	$	3,042,461
Non-Operating Items											
Interest Income			RBPLT	$	4,007,189	$	3,383,661	$	193,670	$	87,479
Other Non-Operating Income			RBPLT	$	(27,912)	$	(23,569)	$	(1,349)	$	(609)
Other Credits			RBPLT	$	250,000	$	211,099	$	12,083	$	5,458
Interest on Long Term Debt				$	(135,823,886)	$	(114,665,623)	$	(6,569,806)	$	(2,969,106)
Other Interest Expense			RBPLT	$	-	$	-	$	-	$	-
Other Deductions			RBPLT	$	(2,363,706)	$	(1,995,908)	$	(114,239)	$	(51,601)
Total Non-Operating Items				$	(133,958,315)	$	(113,090,339)	$	(6,479,642)	$	(2,928,379)
Net Utility Operating Margin		TOM		$	(8,038,848)	$	(1,983,065)	$	1,216,381	$	114,082
Net Cost Rate Base				$	2,248,915,815	$	1,898,979,388	$	108,691,268	$	49,095,166

EAST KENTUCK WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Rate G	Large Special Contract	Special Contract Pumping Stations	Steam Service
Cost of Service Summary -- Unadjusted							
Operating Revenues							
Sales to Members		REVUC	R01	$ 19,703,308	$ 49,563,171	$ 11,330,994	$ 13,439,988
Off System Sales Revenue			Energy	$ 264,543	$ 718,328	$ 128,839	$ 193,075
Wheeling Revenue		LSDPR	RBTRN	$ 44,597	$ 157,714	$ 38,361	$ -
Other Operating Revenue		OTHREV	RBPLT	$ 6,806	$ 23,132	$ 1,112	$ 3,045
Total Operating Revenues		TOR		$ 20,019,253	$ 50,462,345	$ 11,499,306	$ 13,636,108
Operating Expenses							
Operation and Maintenance Expenses				$ 16,881,864	$ 47,769,636	$ 10,082,399	$ 10,550,582
Depreciation and Amortization Expenses				1,249,908	4,262,544	143,184	603,117
Property and Other Taxes			NPT	14	46	2	6
Total Operating Expenses		TOE		$ 18,131,786	$ 52,032,226	$ 10,225,585	$ 11,153,705
Utility Operating Margin				$ 1,887,468	$ (1,569,882)	$ 1,273,721	$ 2,482,402
Non-Operating Items							
Interest Income			RBPLT	$ 68,342	$ 232,288	$ 11,170	$ 30,579
Other Non-Operating Income			RBPLT	$ (476)	$ (1,618)	$ (78)	$ (213)
Other Credits			RBPLT	$ 4,264	$ 14,492	$ 697	$ 1,908
Interest on Long Term Debt				$ (2,315,439)	$ (7,885,802)	$ (380,501)	$ (1,037,609)
Other Interest Expense			RBPLT	$ -	$ -	$ -	$ -
Other Deductions			RBPLT	$ (40,313)	$ (137,019)	$ (6,589)	$ (18,037)
Total Non-Operating Items				$ (2,283,622)	$ (7,777,659)	$ (375,301)	$ (1,023,373)
Net Utility Operating Margin		TOM		$ (396,154)	$ (9,347,541)	$ 898,420	$ 1,459,029
Net Cost Rate Base				$ 38,354,915	$ 130,364,820	$ 6,268,952	$ 17,161,306

EAST KENTUCK OWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Total System		Rate E		Rate B		Rate C
Cost of Service Summary -- Pro-Forma											
Operating Revenues											
Total Operating Revenue				$	886,273,772	$	708,378,784	$	58,586,075	$	23,691,901
Pro-Forma Adjustments:											
To Remove Base Fuel Revenue				$	350,719,383	$	272,354,902	$	26,215,336	$	10,313,066
To Remove FAC Revenue			FACA		108,692,230		77,066,195		7,417,955		2,918,210
To Remove Environmental Surcharge Revenue		ESR			104,725,170		84,331,966		6,966,754		2,817,437
To Adjust Off-System Sales Environmental Sur. Rev.			RBPLT		1,377,517		1,163,172		66,576		30,072
Total Pro-Forma Operating Revenue				$	320,759,472	$	273,462,548	$	17,919,454	$	7,613,117

EAST KENTUCK /VER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Rate G		Large Special Contract		Special Contract Pumping Stations		Steam Service
Cost of Service Summary -- Pro-Forma											
Operating Revenues											
Total Operating Revenue				$	20,019,253	$	50,462,345	$	11,499,306	$	13,636,108
Pro-Forma Adjustments:											
To Remove Base Fuel Revenue				$	9,411,524	$	25,555,625	$	-	$	6,868,930
To Remove FAC Revenue			FACA		2,663,107		7,231,280		9,451,834		1,943,649
To Remove Environmental Surcharge Revenue		ESR			2,379,079		5,984,513		622,608		1,622,813
To Adjust Off-System Sales Environmental Sur. Rev.			RBPLT		23,493		79,852		3,840		10,512
Total Pro-Forma Operating Revenue				$	5,542,051	$	11,611,075	$	1,421,024	$	3,190,204

EAST KENTUCI ,WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Total System	Rate E	Rate B	Rate C
Cost of Service Summary -- Pro-Forma							
Operating Expenses							
Operation and Maintenance Expenses				$ 686,795,194	$ 535,125,949	$ 47,339,880	$ 19,044,884
Depreciation and Amortization Expenses				73,558,311	62,144,885	3,550,133	1,604,539
Property and Other Taxes			NPT	800	675	39	17
Adjustments to Operating Expenses:							
To Remove Fuel Expense Recoverable Through FAC			FACAL	$ (403,441,802)	$ (305,889,756)	$ (29,443,211)	$ (11,582,906)
To Remove Purchased Power Expense Recoverable Through FAC			FACEX	(51,684,614)	$ (39,310,488)	$ (3,783,804)	$ (1,488,542)
To Remove O&M Expenses Recoverable Through Env. Surcharge			6CP	(31,800,030)	$ (26,918,393)	$ (1,630,614)	$ (737,109)
To Remove Emissions Allowance Expense Recoverable Through ESR			Energy	(6,615,208)	$ (5,070,838)	$ (488,090)	$ (192,014)
To Remove Property Tax & Insurance Recoverable Through ESR			6CP	(2,098,198)	$ (1,776,103)	$ (107,590)	$ (48,635)
To Remove Depreciation Expense Recoverable Through ESR			6CP	(19,564,992)	$ (16,561,561)	$ (1,003,236)	$ (453,507)
To Remove Promotional Advertising Expense			LBPLT	(658,906)	$ (539,136)	$ (38,227)	$ (16,372)
To Remove Certain Director's Expenses			LBPLT	(93,300)	$ (76,341)	$ (5,413)	$ (2,318)
To Remove Donations			LBPLT	(95,485)	$ (78,129)	$ (5,540)	$ (2,373)
To Remove Affiliate Expenses			LBPLT	(28,712)	$ (23,493)	$ (1,666)	$ (713)
To Remove Lobbying Expenses			LBPLT	(85,422)	$ (69,895)	$ (4,956)	$ (2,123)
To Remove Touchstone Energy Dues			LBPLT	(414,000)	$ (338,747)	$ (24,018)	$ (10,287)
To Remove Other Misc. Expenses			LBPLT	(155,940)	$ (127,595)	$ (9,047)	$ (3,875)
To Normalize Rate Case Expenses			RBPLT	100,000	$ 84,440	$ 4,833	$ 2,183
To Amortize 2004 Forced Outage Balance			Energy	3,419,058	$ 2,620,853	$ 252,268	$ 99,242
To Normalize Generation Overhaul Expenses			OMPDMD	$ 2,300,000	$ 1,946,926	$ 117,937	$ 53,313
To Reflect Avoided Costs of Interruptible Service				$ (8,824,500)			
Reallocation of Avoided Cost Savings			6CP	$ 8,824,500	$ 7,469,847	$ 452,495	$ 204,548
Total Expense Adjustments				(510,917,551)	(384,658,408)	(35,717,877)	(14,181,487)
Total Operating Expenses		TOE		$ 249,436,754	$ 212,613,102	$ 15,172,175	$ 6,467,953
Utility Operating Margins -- Pro-Forma				$ 71,322,718	$ 60,849,446	$ 2,747,279	$ 1,145,163
Non-Operating Items							
Sum of Non-Operating Items				$ (133,958,315)	$ (113,090,339)	$ (6,479,642)	$ (2,928,379)
Adjustment To Remove Interest Exp. Recoverable Through ESR			6CP	$ 37,031,989	$ 31,347,191	$ 1,898,894	$ 858,383
Total Non-Operating Items				$ (96,926,326)	$ (81,743,147)	$ (4,580,748)	$ (2,069,996)
Net Utility Operating Margin				$ (25,603,608)	$ (20,893,701)	$ (1,833,469)	$ (924,833)
Net Cost Rate Base				$ 2,248,915,815	$ 1,898,979,388	$ 108,691,268	$ 49,095,166
Return on Rate Base -- Utility Operating Margin Divided by Rate Base				3.17%	3.20%	2.53%	2.33%

EAST KENTUC. WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Rate G		Large Special Contract		Special Contract Pumping Stations		Steam Service
Cost of Service Summary -- Pro-Forma											
Operating Expenses											
Operation and Maintenance Expenses				$	16,881,864	$	47,769,636	$	10,082,399	$	10,550,582
Depreciation and Amortization Expenses					1,249,908		4,262,544		143,184		603,117
Property and Other Taxes			NPT		14		46		2		6
Adjustments to Operating Expenses:											
To Remove Fuel Expense Recoverable Through FAC			FACAL	$	(10,570,357)	$	(28,702,269)	$	(9,538,606)	$	(7,714,696)
To Remove Purchased Power Expense Recoverable Through FAC			FACEX	$	(1,358,417)	$	(3,688,584)	$	(1,063,348)	$	(991,431)
To Remove O&M Expenses Recoverable Through Env. Surcharge			6CP	$	(554,729)	$	(1,959,186)	$	-	$	-
To Remove Emissions Allowance Expense Recoverable Through ESR			Energy	$	(175,228)	$	(475,807)	$	(85,341)	$	(127,889)
To Remove Property Tax & Insurance Recoverable Through ESR			6CP	$	(36,602)	$	(129,269)	$	-	$	-
To Remove Depreciation Expense Recoverable Through ESR			6CP	$	(341,297)	$	(1,205,390)	$	-	$	-
To Remove Promotional Advertising Expense			LBPLT	$	(13,399)	$	(42,399)	$	(5,245)	$	(4,128)
To Remove Certain Director's Expenses			LBPLT	$	(1,897)	$	(6,004)	$	(743)	$	(585)
To Remove Donations			LBPLT	$	(1,942)	$	(6,144)	$	(760)	$	(598)
To Remove Affiliate Expenses			LBPLT	$	(584)	$	(1,848)	$	(229)	$	(180)
To Remove Lobbying Expenses			LBPLT	$	(1,737)	$	(5,497)	$	(680)	$	(535)
To Remove Touchstone Energy Dues			LBPLT	$	(8,419)	$	(26,640)	$	(3,296)	$	(2,594)
To Remove Other Misc. Expenses			LBPLT	$	(3,171)	$	(10,034)	$	(1,241)	$	(977)
To Normalize Rate Case Expenses			RBPLT	$	1,705	$	5,797	$	279	$	763
To Amortize 2004 Forced Outage Balance			Energy	$	90,566	$	245,920	$	44,108	$	66,099
To Normalize Generation Overhaul Expenses			OMPDMD	$	40,122	$	141,702	$	-	$	-
To Reflect Avoided Costs of Interruptible Service						$	(8,824,500)				
Reallocation of Avoided Cost Savings			6CP	$	153,937	$	543,673	$	-	$	-
Total Expense Adjustments					(12,781,449)		(44,146,479)		(10,655,102)		(8,776,750)
Total Operating Expenses		TOE		$	5,350,337	$	7,885,748	$	(429,516)	$	2,376,955
Utility Operating Margins -- Pro-Forma				$	191,714	$	3,725,327	$	1,850,540	$	813,249
Non-Operating Items											
Sum of Non-Operating Items				$	(2,283,622)	$	(7,777,659)	$	(375,301)	$	(1,023,373)
Adjustment To Remove Interest Exp. Recoverable Through ESR			6CP	$	645,997	$	2,281,524	$	-	$	-
Total Non-Operating Items				$	(1,637,625)	$	(5,496,135)	$	(375,301)	$	(1,023,373)
Net Utility Operating Margin				$	(1,445,911)	$	(1,770,808)	$	1,475,240	$	(210,124)
Net Cost Rate Base				$	38,354,915	$	130,364,820	$	6,268,952	$	17,161,306
Return on Rate Base -- Utility Operating Margin Divided by Rate Base					**0.50%**		**2.86%**		**29.52%**		**4.74%**

EAST KENTUC. ,WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Total System		Rate E		Rate B		Rate C
Cost of Service Summary -- Pro-Forma (Proposed Phase I Increase)											
Operating Revenues											
Total Operating Revenue				$	320,759,472	$	273,462,548	$	17,919,454	$	7,613,117
Pro-Forma Adjustments: To Reflect Proposed Increase				$	67,858,922	$	55,330,720	$	4,457,951	$	1,811,240
Total Pro-Forma Operating Revenue				$	388,618,394	$	328,793,268	$	22,377,405	$	9,424,357
Operating Expenses											
Total Operating Expenses				$	249,436,754	$	212,613,102	$	15,172,175	$	6,467,953
Utility Operating Margins -- Pro-Formed for Phase I Increase				$	139,181,640	$	116,180,166	$	7,205,230	$	2,956,403
Net Cost Rate Base				$	2,248,915,815	$	1,898,979,388	$	108,691,268	$	49,095,166
Rate of Return					6.19%		6.12%		6.63%		6.02%
Cost of Service Summary -- Pro-Forma (Proposed Phase II Increase)											
Operating Revenues											
Total Operating Revenue				$	320,759,472	$	273,462,548	$	17,919,454	$	7,613,117
Pro-Forma Adjustments: To Reflect Proposed Increase				$	67,699,051	$	55,345,926	$	4,635,408	$	2,168,710
Total Pro-Forma Operating Revenue				$	388,458,523	$	328,808,474	$	22,554,862	$	9,781,827
Operating Expenses											
Total Operating Expenses				$	249,436,754	$	212,613,102	$	15,172,175	$	6,467,953
Utility Operating Margins -- Pro-Formed for Phase II Increase				$	139,021,769	$	116,195,372	$	7,382,687	$	3,313,873
Net Cost Rate Base				$	2,248,915,815	$	1,898,979,388	$	108,691,268	$	49,095,166
Rate of Return					6.18%		6.12%		6.79%		6.75%

EAST KENTUC   JWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Rate G	Large Special Contract	Special Contract Pumping Stations	Steam Service
Cost of Service Summary -- Pro-Forma (Proposed Phase I Increase)							
Operating Revenues							
Total Operating Revenue				$ 5,542,051	$ 11,611,075	$ 1,421,024	$ 3,190,204
Pro-Forma Adjustments: To Reflect Proposed Increase				$ 1,506,943	$ 3,736,682	$ -	$ 1,015,386
Total Pro-Forma Operating Revenue				$ 7,048,994	$ 15,347,757	$ 1,421,024	$ 4,205,590
Operating Expenses							
Total Operating Expenses				$ 5,350,337	$ 7,885,748	$ (429,516)	$ 2,376,955
Utility Operating Margins -- Pro-Formed for Phase I Increase				$ 1,698,657	$ 7,462,009	$ 1,850,540	$ 1,828,635
Net Cost Rate Base				$ 38,354,915	$ 130,364,820	$ 6,268,952	$ 17,161,306
Rate of Return				**4.43%**	**5.72%**	**29.52%**	**10.66%**
Cost of Service Summary -- Pro-Forma (Proposed Phase II Increase)							
Operating Revenues							
Total Operating Revenue				$ 5,542,051	$ 11,611,075	$ 1,421,024	$ 3,190,204
Pro-Forma Adjustments: To Reflect Proposed Increase				$ 1,858,583	$ 3,017,371	$ -	$ 673,053
Total Pro-Forma Operating Revenue				$ 7,400,634	$ 14,628,446	$ 1,421,024	$ 3,863,257
Operating Expenses							
Total Operating Expenses				$ 5,350,337	$ 7,885,748	$ (429,516)	$ 2,376,955
Utility Operating Margins -- Pro-Formed for Phase II Increase				$ 2,050,297	$ 6,742,698	$ 1,850,540	$ 1,486,302
Net Cost Rate Base				$ 38,354,915	$ 130,364,820	$ 6,268,952	$ 17,161,306
Rate of Return				**5.35%**	**5.17%**	**29.52%**	**8.66%**

EAST KENTUC. ɔWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Total System		Rate E		Rate B		Rate C
Allocation Factors										
Energy Allocation Factors										
Energy Usage by Class		E01	Energy	1.000000		0.766543		0.073783		0.029026
Customer Allocation Factors										
Rev		R01		873,498,603		698,429,400		57,697,996		23,333,746
Energy		Energy		13,468,652,000		10,324,295,000		993,758,000		390,942,617
FAC Revenue Allocator		FACA		109,031,560	$	77,306,791	$	7,441,113	$	2,927,320
Base Fuel Revenue Allocator		BSFL		13,294,897,000		10,324,295,000		993,758,000		390,942,617
Fuel Expense Applicable to FAC Allocator		FACEX		459,411,613		349,421,098		33,633,291		13,231,276
										407,101,213
Customer Allocators										
Customers (Metering Points)		Cust05		3,746		3,734		-		-
Demand Allocators										
Steam - Direct Assignment		STMD		1		-		-		-
Substation Allocator		SUBA		86,668,910		85,792,264		-		-
Production 6 CP Demands		6CP		15,582,000		13,190,000		799,000		361,183
						0.8465		0.0513		0.0232
Production 12 CP Demands		12CP		29,085,000		23,824,000		1,606,000		725,081
						0.8191		0.0552		0.0249

EAST KENTUC. .WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Rate G	Large Special Contract	Special Contract Pumping Stations	Steam Service
Allocation Factors							
Energy Allocation Factors							
Energy Usage by Class		E01	Energy	0.026489	0.071926	0.012901	0.019333
Customer Allocation Factors							
Rev		R01		19,703,308	49,563,171	11,330,994	13,439,988
Energy		Energy		356,767,383	968,750,000	173,755,000	260,384,000
FAC Revenue Allocator		FACA		$ 2,671,421	$ 7,253,856	$ 9,481,342	$ 1,949,717
Base Fuel Revenue Allocator		BSFL		356,767,383	968,750,000	-	260,384,000
Fuel Expense Applicable to FAC Allocator		FACEX		12,074,631	32,786,905	9,451,834	8,812,579
				371,513,435	1,008,790,761	18,933,176	-
Customer Allocators							
Customers (Metering Points)		Cust05		12	-	-	-
Demand Allocators							
Steam - Direct Assignment		STMD		-	-	-	1
Substation Allocator		SUBA		876,646	-	-	-
Production 6 CP Demands		6CP		271,817	960,000	-	-
				0.0174	0.0616	-	-
Production 12 CP Demands		12CP		542,919	1,920,000	467,000	-
				0.0187	0.0660	0.0161	-

EAST KENTUC. JWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Total System		Rate E		Rate B		Rate C
					-						
Production Energy Allocation											
Production Energy Residual Allocator		PENGA			13,294,897,000		10,324,295,000		993,758,000		390,942,617
Production Energy Costs				$	546,404,107						
Member Specific Assignment				$	9,481,342		-		-		-
Production Energy Residual			PENGA	$	536,922,765	$	416,953,137	$	40,133,541	$	15,788,463
Production Energy Total		PENGT		$	546,404,107	$	416,953,137	$	40,133,541	$	15,788,463
Production Energy Total Allocator		PENG	PENGT		1.000000		0.76309		0.07345		0.02890
FAC Expense Residual Allocator		FACALL			449,959,779		349,421,098		33,633,291		13,231,276
FAC Expense Cost				$	(403,441,802)						
Member Specific Assignment				$	(9,538,606)		-		-		-
FAC Expense Residual			FACALL	$	(393,903,196)	$	(305,889,756)	$	(29,443,211)	$	(11,582,906)
FAC Expense Total		FACT		$	(403,441,802)	$	(305,889,756)	$	(29,443,211)	$	(11,582,906)
FAC Expense Allocator		FACAL	FACT		1.000000		0.75820		0.07298		0.02871

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Rate G	Large Special Contract	Special Contract Pumping Stations	Steam Service
Production Energy Allocation							
Production Energy Residual Allocator		PENGA		356,767,383	968,750,000	-	260,384,000
Production Energy Costs							
Member Specific Assignment				$ -	-	$ 9,481,342	-
Production Energy Residual			PENGA	$ 14,408,275	$ 39,123,577	$ -	$ 10,515,771
Production Energy Total		PENGT		$ 14,408,275	$ 39,123,577	$ 9,481,342	$ 10,515,771
Production Energy Total Allocator		PENG	PENGT	0.02637	0.07160	0.01735	0.01925
FAC Expense Residual Allocator		FACALL		12,074,631	32,786,905	-	8,812,579
FAC Expense Cost							
Member Specific Assignment				$ -	-	(9,538,606)	-
FAC Expense Residual			FACALL	$ (10,570,357)	$ (28,702,269)	$ -	$ (7,714,696)
FAC Expense Total		FACT		$ (10,570,357)	$ (28,702,269)	$ (9,538,606)	$ (7,714,696)
FAC Expense Allocator		FACAL	FACT	0.02620	0.07114	0.02364	0.01912

Seelye Exhibit 8

East Kentucky Power Cooperative, Inc.
Avoided Cost Estimate of Interruptible Power

Estimated Installed Cost of a CT	$ 550	per kW
Estimated Cost of Capital	7.00%	
Depreciation	4.00%	
ASL for CT	25	Years
Annual Capacity Cost	$47.20	per kW
Annual Fixed O&M Expenses	16.5	per kW
Total Annual Cost	$63.70	per kW
Monthly Cost	$5.30	per kW

Seelye Exhibit 9

Forecasted Period Phase 1
Summary
Rate Impact Test Year Ended May 31, 2010

	Current	Proposed	$ Incr	% Incr
Rate E	698,429,400	753,760,120	55,330,720	7.92%
Rate B	57,697,996	62,155,947	4,457,951	7.73%
Rate C	23,333,746	25,144,986	1,811,240	7.76%
Rate G	19,703,308	21,210,250	1,506,943	7.65%
Large Special Contract	49,563,171	53,299,853	3,736,682	7.54%
Steam Service	13,439,988	14,455,374	1,015,386	7.55%
Pumping Stations	11,330,994	11,330,994	-	0.00%
Total	873,498,604	941,357,525	67,858,922	7.77%

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase 1
Billing Analysis - 12-Mo Ended May 31, 2010

Description	Current Billing Units		Current Rate	Current $	Proposed Billing Units	Proposed Rate	Proposed $
RATE E - 16 Customers							
Metering Point Charge							
All Customers	3,734	$	125.00	466,750	3,734	138.00	515,292
Substation charges							
Substation 1,000 - 2,999 kVa	36	$	944	33,984	36	1,041.00	37,476
Substation 3,000 - 7,499 kVa	504		2,373	1,195,992	504	2,617.00	1,318,968
Substation 7,500 - 14,999 kVa	2,544		2,855	7,263,120	2,544	3,149.00	8,011,056
Substation > 15,000 kVa	578		4,605	2,661,690	578	5,079.00	2,935,662
	3,662			11,154,786			12,303,162
Demand Charge							
Option 1 (Owen)	2,343,000	$	6.92	16,213,560	2,343,000	7.63	17,877,090
Option 2	21,481,000	$	5.22	112,130,820	21,481,000	5.76	123,730,560
	23,824,000			128,344,380			141,607,650
Energy Charge	kWh						
On-Peak (Option 1)	564,787,000	$	0.035406	19,996,849	564,787,000	0.039053	22,056,627
Off-Peak (Option 1)	526,652,000	$	0.034904	18,382,261	526,652,000	0.038499	20,275,575
On-Peak (Option 2)	4,782,184,968	$	0.042470	203,099,396	4,782,184,968	0.046844	224,016,673
Off-Peak (Option 2)	4,450,671,032	$	0.034904	155,346,222	4,450,671,032	0.038499	171,346,384
	10,324,295,000			396,824,727			437,695,259
Sub-Total -- Base Rates				536,790,643			592,121,363
FAC	10,324,295,000		0.00749	77,306,791			77,306,791
Environmental Surcharge	$ 614,097,434		13.73%	84,331,966			84,331,966
Total Billings				698,429,400			753,760,120

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase 1
Billing Analysis - 12-Mo Ended May 31, 2010

Description		Current			Proposed		
		Billing Units	Rate	Current $	Billing Units	Rate	Proposed $
RATE B - 9 Customers							
Demand Charge							
Minimum Demand		1,583,516	$ 6.22	9,849,470	1,583,516	6.86	10,862,920
Excess Demand		22,484	$ 8.65	194,487	22,484	9.54	214,497
		1,606,000					
Energy Charge	kWh						
All kWh		993,758,000	$ 0.033455	33,246,174	993,758,000	0.036901	36,670,664
Sub-Total -- Base Rates				43,290,130			47,748,081
FAC		993,758,000	0.00749	7,441,113			7,441,113
Environmental Surcharge	$	50,731,243	13.73%	6,966,754			6,966,754
Total Billings				$ 57,697,996			$ 62,155,947
RATE C - 6 Customers							
Demand Charge							
All Kw		725,081	$ 6.22	4,510,004	725,081	6.86	4,974,056
Energy Charge	kWh						
All kWh		390,942,617	$ 0.033455	13,078,985	390,942,617	0.036901	14,426,174
Sub-Total -- Base Rates				17,588,989			19,400,229
FAC		390,942,617	0.00749	2,927,320			2,927,320
Environmental Surcharge	$	20,516,309	13.73%	2,817,437			2,817,437
Total Billings				$ 23,333,746			$ 25,144,986

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase 1
Billing Analysis - 12-Mo Ended May 31, 2010

Description		Current			Proposed		
		Billing Units	Rate	Current $	Billing Units	Rate	Proposed $
RATE G - 2 Customers							
Meter Pt Charge		12	125	1,500	12	138.00	1,656
Substation charges							
Substation 1,000 - 2,999 kVa		-	$ 944				
Substation 3,000 - 7,499 kVa		-	2,373				
Substation 7,500 - 14,999 kVa		-	2,855				
Substation > 15,000 kVa		12	4,605	55,260	12	5,079.00	60,948
Demand Charge							
All Kw		542,919	$ 6.06	3,290,089	542,919	6.68	3,626,699
Energy Charge	kWh						
All kWh		356,767,383	$ 0.031690	11,305,958	356,767,383	0.034954	12,470,447
Sub-Total -- Base Rates				14,652,808			16,159,750
FAC		356,767,383	0.00749	2,671,421			2,671,421
Environmental Surcharge	$	17,324,229	13.73%	2,379,079			2,379,079
Total Billings				19,703,308			21,210,250

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase 1
Billing Analysis - 12-Mo Ended May 31, 2010

Description	Current Billing Units		Current Rate	Current $	Proposed Billing Units	Proposed Rate	Proposed $
Large Special Contract							
Demand Charge							
Firm Demand	180,000	$	6.06	1,090,800	180,000	6.68	1,202,400
10-Min Inturruptible Demand	1,440,000	$	2.46	3,542,400	1,440,000	2.71	3,902,400
90-Min Inturruptible Demand	300,000	$	3.36	1,008,000	300,000	3.71	1,113,000
	1,920,000						
Energy Charge	kWh						
On-Peak	288,492,371	$	0.033780	9,745,272	288,492,371	0.037259	10,748,937
Off-Peak	680,257,629	$	0.030780	20,938,330	680,257,629	0.033950	23,094,747
	968,750,000						
Sub-Total -- Base Rates				36,324,802			40,061,484
FAC	968,750,000		0.00749	7,253,856			7,253,856
Environmental Surcharge	$ 43,578,659		13.73%	5,984,513			5,984,513
				49,563,171			53,299,853
Total Billings							3,736,682

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase 1
Billing Analysis - 12-Mo Ended May 31, 2010

Description	Current Billing Units	Current Rate	Current $	Proposed Billing Units	Proposed Rate	Proposed $
Special Contract - Pumping Stations - 2 Customers						
Demand Charge						
All Kw	467,000	$ 1.75	817,250	467,000	$ 1.75	817,250
Energy Charge	kWh					
Off-Pk Jun-Dec	46,363,340	$ 0.004440	205,853	46,363,340	$ 0.004440	205,853
Off-Peak Jan-May	45,726,810	$ 0.004460	203,942	45,726,810	$ 0.004460	203,942
	92,090,150		409,795			409,795
Monthly Revenue						
Off Peak Fuel/Purchased Power Cost Recovery			3,306,725			3,306,725
Sub-Total -- Base Rates			4,533,770			4,533,770
Environmental Surcharge	4,533,770	13.73%	622,608			622,608
On Peak Fuel/Purchased Power Cost Recovery			6,174,617			6,174,617
Total Billings			11,330,994			11,330,994

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase 1
Billing Analysis - 12-Mo Ended May 31, 2010

Description	Current				Proposed		
	Billing Units		Rate	Current $	Billing Units	Rate	Proposed $
Steam Service							
Demand Charge							
Per MMBTU	3,790	$	500.49	1,897,068	3,790	552.040	2,092,464
Energy Charge	MMBTU						
Per MMBTU	2,228,233	$	3.577	7,970,390	2,228,233	3.945	8,790,380
Sub-Total -- Base Rates				9,867,458			10,882,844
FAC	260,384,000		0.00749	1,949,717			1,949,717
Environmental Surcharge	$ 11,817,175		13.73%	1,622,813			1,622,813
Total Billings				13,439,988			14,455,374
Total Base Rate Revenue EKPC Members				669,223,217			737,082,138
Total FAC				99,550,218			99,550,218
Total ES				104,725,170			104,725,170
Total EKPC Member Revenue				**873,498,604**			**941,357,525**

Seelye Exhibit 10

Forecasted Period Phase II
Summary
Rate Impact Test Year Ended May 31, 2010

	Current	Proposed	$ Incr	% Incr
Rate E	698,429,400	753,775,327	55,345,926	7.92%
Rate B	57,697,996	62,333,404	4,635,408	8.03%
Rate C	23,333,746	25,502,456	2,168,710	9.29%
Rate G	19,703,308	21,561,891	1,858,583	9.43%
Large Special Contract	49,563,171	52,580,542	3,017,371	6.09%
Steam Service	13,439,988	14,113,041	673,053	5.01%
Pumping Stations	11,330,994	11,330,994	-	0.00%
Total	873,498,604	941,197,656	67,699,051	7.75%

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase II
Billing Analysis - 12-Mo Ended May 31, 2010

Description	Current Billing Units	Current Rate	Current $		Proposed Billing Units	Proposed Rate	Proposed $
RATE E							
Metering Point Charge				Metering Point Charge			
All Customers	3,734	$ 125.00	466,750	All Customers	3,734	230.00	858,820
Substation charges				Substation charges			
				Substation 1,000-4,999 kVa	48	1,168.00	56,064
				Substation 5,000-9,999 kVa	396	3,087.00	1,222,452
Substation 1,000 - 2,999 kVa	36	$ 944	33,984	Substation 10,000-14,999 kVa	2,513	4,265.00	10,717,945
Substation 3,000 - 7,499 kVa	504	2,373	1,195,992	Substation 15,000-29,999 kVa	645	9,220.00	5,946,900
Substation 7,500 - 14,999 kVa	2,544	2,855	7,263,120	Substation 30,000-50,999 kVa	48	14,488.00	695,424
Substation > 15,000 kVa	578	4,605	2,661,690	Substation > 51,000 kVa	12	16,155.00	193,860
	3,662		11,154,786		3,662		18,832,645
Demand Charge				Demand Charge Rate E			
Option 1 (Owen)	2,343,000	$ 6.92	16,213,560	All kW	23,824,000	10.10	240,622,400
Option 2	21,481,000	$ 5.22	112,130,820				-
	23,824,000		128,344,380				240,622,400
Energy Charge	kWh			Energy Charge			
On-Peak (Option 1)	564,787,000	$ 0.035406	19,996,849	On-Peak kWh	5,346,971,968	0.032382	173,145,646
Off-Peak (Option 1)	526,652,000	$ 0.034904	18,382,261	Off-Peak kWh	4,977,323,032	0.031880	158,677,058
On-Peak (Option 2)	4,782,184,968	$ 0.042470	203,099,396				-
Off-Peak (Option 2)	4,450,671,032	$ 0.034904	155,346,222				-
	10,324,295,000		396,824,727				331,822,705
Sub-Total -- Base Rates			536,790,643	Sub-Total -- Base Rates			592,136,570
FAC	10,324,295,000	0.00749	77,306,791	FAC			77,306,791
Environmental Surcharge	$ 614,097,434	13.73%	84,331,966	Environmental Surcharge			84,331,966
Total Billings			698,429,400	Total Billings			753,775,327

Annual Increase Rate E

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase II
Billing Analysis - 12-Mo Ended May 31, 2010

Description	Current Billing Units		Current Rate	Current $		Proposed Billing Units	Proposed Rate	Proposed $
RATE B								
Demand Charge					**Demand Charge**			
Minimum Demand	1,583,516	$	6.22	9,849,470	Minimum Demand	1,583,516	9.92	15,708,479
Excess Demand	22,484	$	8.65	194,487	Excess Demand	22,484	12.35	277,677
	1,606,000							
Energy Charge	kWh				**Energy Charge**			
All kWh	993,758,000	$	0.033455	33,246,174	All kWh	993,758,000	0.032140	31,939,382
Sub-Total -- Base Rates				43,290,130	Sub-Total -- Base Rates			47,925,538
FAC	993,758,000		0.00749	7,441,113	FAC			7,441,113
Environmental Surcharge	$ 50,731,243		13.73%	6,966,754	Environmental Surcharge			6,966,754
Total Billings				$ 57,697,996	**Total Billings**			$ 62,333,404

RATE C	Billing Units		Rate	Existing $		Billing Units	Rate	Proposed $
Demand Charge					**Demand Charge**			
All kW	725,081	$	6.22	4,510,004	All kW	725,081	9.92	7,192,804
Energy Charge	kWh				**Energy Charge**			
All kWh	390,942,617	$	0.033455	13,078,985	All kWh	390,942,617	0.032140	12,564,896
Sub-Total -- Base Rates				17,588,989	Sub-Total -- Base Rates			19,757,699
FAC	390,942,617		0.00749	2,927,320	FAC			2,927,320
Environmental Surcharge	$ 20,516,309		13.73%	2,817,437	Environmental Surcharge			2,817,437
Total Billings				$ 23,333,746	**Total Billings**			$ 25,502,456

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase II
Billing Analysis - 12-Mo Ended May 31, 2010

Description	Current Billing Units		Current Rate	Current $		Proposed Billing Units	Proposed Rate	Proposed $
RATE G								
Meter Pt Charge	12		125	1,500	**Meter Pt Charge**	12	230.00	2,760
Substation Charges					**Substation Charges**			
Substation 1,000 - 2,999 kVa	-	$	944					
Substation 3,000 - 7,499 kVa	-		2,373					
Substation 7,500 - 14,999 kVa	-		2,855					
Substation > 15,000 kVa	12		4,605	55,260	Substation > 51,000 kVa	12	16,155.00	193,860
Demand Charge					**Demand Charge**			
All Kw	542,919	$	6.06	3,290,089	All Kw	542,919	8.93	4,848,267
Energy Charge	kWh				**Energy Charge**			
All kWh	356,767,383	$	0.031690	11,305,958	All kWh	356,767,383	0.032140	11,466,504
Sub-Total -- Base Rates				14,652,808	Sub-Total -- Base Rates			16,511,390
FAC	356,767,383		0.00749	2,671,421	FAC			2,671,421
Environmental Surcharge	$ 17,324,229		13.73%	2,379,079	Environmental Surcharge			2,379,079
Total Billings				19,703,308	**Total Billings**			21,561,891

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase II
Billing Analysis - 12-Mo Ended May 31, 2010

Description	Current Billing Units		Current Rate	Current $		Proposed Billing Units	Proposed Rate	Proposed $
Large Special Contract								
Demand Charge					**Demand Charge**			
Firm Demand	180,000	$	6.06	1,090,800	Firm Demand	180,000	8.93	1,607,400
10-Min Inturruptible Demand	1,440,000	$	2.46	3,542,400	10-Min Inturruptible Demand	1,440,000	3.63	5,227,200
90-Min Inturruptible Demand	300,000	$	3.36	1,008,000	90-Min Inturruptible Demand	300,000	4.93	1,479,000
	1,920,000							
Energy Charge	kWh				**Energy Charge**			
On-Peak	288,492,371	$	0.033780	9,745,272	On-Peak	288,492,371	0.032382	9,341,960
Off-Peak	680,257,629	$	0.030780	20,938,330	Off-Peak	680,257,629	0.031880	21,686,613
	968,750,000							
Sub-Total -- Base Rates				36,324,802	Sub-Total -- Base Rates			39,342,173
FAC	968,750,000		0.00749	7,253,856	FAC			7,253,856
Environmental Surcharge	$ 43,578,659		13.73%	5,984,513	Environmental Surcharge			5,984,513
Total Billings				49,563,171	**Total Billings**			52,580,542

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase II
Billing Analysis - 12-Mo Ended May 31, 2010

Description	Current Billing Units		Current Rate	Current $		Proposed Billing Units		Proposed Rate	Proposed $
Special Contract - Pumping Stations									
Demand Charge					**Demand Charge**				
All Kw	467,000	$	1.75	817,250	All Kw	467,000	$	1.75	817,250
Energy Charge	kWh				**Energy Charge**				
Off-Pk Jun-Dec	46,363,340	$	0.004440	205,853	Off-Pk Jun-Dec	46,363,340	$	0.004440	205,853
Off-Peak Jan-May	45,726,810	$	0.004460	203,942	Off-Peak Jan-May	45,726,810	$	0.004460	203,942
				409,795					409,795
Monthly Revenue									
Off Peak Fuel/Purchased Power Cost Recovery				3,306,725	Off Peak Fuel/Purchased Power Cost Recovery				3,306,725
Sub-Total -- Base Rates				4,533,770	Sub-Total -- Base Rates				4,533,770
Environmental Surcharge	4,533,770		13.73%	622,608	Environmental Surcharge				622,608
On Peak Fuel/Purchased Power Cost Recovery				6,174,617	On Peak Fuel/Purchased Power Cost Recovery				6,174,617
Total Billings				11,330,994	**Total Billings**				11,330,994

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase II
Billing Analysis - 12-Mo Ended May 31, 2010

Description	Current Billing Units	Current Rate	Current $	Description	Proposed Billing Units	Proposed Rate	Proposed $
Steam Service							
Demand Charge				Demand Charge			
Per MMBTU	3,790	$ 500.49	1,897,068	Per MMBTU	3,790	572.830	2,171,267
Energy Charge				Energy Charge			
Per MMBTU	2,228,233	$ 3.577	7,970,390	Per MMBTU	2,228,233	3.756	8,369,244
Sub-Total -- Base Rates			9,867,458	Sub-Total -- Base Rates			10,540,511
FAC	260,384,000	0.00749	1,949,717	FAC			1,949,717
Environmental Surcharge	$ 11,817,175	13.73%	1,622,813	Environmental Surcharge			1,622,813
Total Billings			13,439,988	**Total Billings**			14,113,041
Total Base Rate Revenue EKPC Members			669,223,217				736,922,268
Total FAC			99,550,218				99,550,218
Total ES			104,725,170				104,725,170
Total Member Revenue			873,498,604				941,197,656