East Kentucky Power Cooperative, Inc.

Case No. 2010-00167
Fully Forecasted Test Period Filing Requirements
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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.	Anthony S. Campbell Frank J. Oliva
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.	Isaac S. Scott
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.	Isaac S. Scott
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

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 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	Ann F. Wood

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			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.	
1	14	807 KAR 5:001 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.	Ann F. Wood
1	15	807 KAR 5:001 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.	Ann F. Wood
1	16	807 KAR 5:001 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.	Ann F. Wood
1	17	807 KAR 5:001 Section 10(4)(g)	Compliance with this subsection shall constitute compliance with 807 KAR 5:051, Section 2.	Ann F. Wood
1	18	807 KAR 5:001 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	Ann F. Wood
1	19	807 KAR 5:001 Section 10 (8)(a)	Financial data for forecasted period presented as pro forma adjustments to base period.	Frank J. Oliva Ann F. Wood
1	20	807 KAR 5:001 Section 10 (8)(b)	Forecasted adjustments shall be limited to the 12 months immediately following the suspension period.	Ann F. Wood
1	21	807 KAR 5:001 Section 10 (8)(c)	Capitalization and net investment rate base shall be based on a 13 month average for the forecasted period.	Ann F. Wood
1	22	807 KAR 5:001 Section 10 (8)(f)	The utility shall provide a reconciliation of the rate base and capital used to determine its revenue requirements.	Ann F. Wood
2	23	807 KAR 5:001 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.	Ann F. Wood
3	24	807 KAR 5:001 Section 10(9)(b)	Most recent capital construction budget containing at minimum 3 year forecast of construction expenditures.	John R. Twitchell Craig A. Johnson

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Volume	Tab	Filing Requirement	Description	Sponsoring Witness(es)
				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;	Anthony S. Campbell
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;	John R. Twitchell
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;	John R. Twitchell 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); 2. Balance sheet;	John R. Twitchell Frank J. Oliva Ann F. Wood

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Volume	Tab	Filing Requirement	Description	Sponsoring Witness(es)
			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 month of base period, and subsequent months, as available;	Frank J. Oliva

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Volume	Tab	Filing Requirement	Description	Sponsoring Witness(es)
5	38	807 KAR 5:001 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;	Ann F. Wood
5	39	807 KAR 5:001 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;	Ann F. Wood
5	40	807 KAR 5:001 Section 10(9)(r)	Quarterly reports to the stockholders for the most recent 5 quarters;	Ann F. Wood
5	41	807 KAR 5:001 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.	Ann F. Wood
5	42	807 KAR 5:001 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.	Ann F. Wood
5	43	807 KAR 5:001 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 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.	Ann F. Wood
5	44	807 KAR 5:001 Section 10(9)(v)	If gas, electric or water utility with annual gross revenues greater than $5,000,000, cost of service study based on methodology generally accepted in industry and based on current and reliable data from single time period.	Dennis Eicher

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Volume	Tab	Filing Requirement	Description	Sponsoring Witness(es)
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;	Frank J. Oliva Ann F. Wood
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;	Ann F. Wood
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
5	53	807 KAR 5:001 Section 10(10)(h)	Computation of gross revenue conversion factor for forecasted period;	Ann F. Wood

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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.

Anthony S. Campbell
Frank J. Oliva
Daniel M. Walker
John R. Twitchell
Craig A. Johnson
Ricky L. Drury
Dennis R. Eicher
Isaac S. Scott
Ann F. Wood

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

GENERAL ADJUSTMENT OF ELECTRIC RATES	)	PSC CASE NO.
OF EAST KENTUCKY POWER	)	2010-00167
COOPERATIVE, INC.	)	

TESTIMONY OF
ANTHONY S. CAMPBELL
PRESIDENT AND CHIEF EXECUTIVE OFFICER
EAST KENTUCKY POWER COOPERATIVE, INC.

Filed: May 27, 2010

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

A. My name is Anthony S. Campbell and my business address is East Kentucky Power Cooperative, Inc. (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 June 2009.

Q. Please state your education and professional experience.

A. I received a Bachelor of Science degree in electrical engineering from the University of Southern Illinois at Carbondale and a Masters of Business Administration from the University of Illinois at Champaign. Prior to joining EKPC, I served as CEO of Citizens Electric Corporation, a transmission and distribution company located in southeast Missouri.

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, and an introduction of the witnesses.

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(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 Campbell Exhibit 1, which is the resolution from the EKPC Board of Directors ("Board") 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 $49.4 million in additional annual revenues, which is an increase to base rates of 5.27%. The background information contained in the management audit action plan prepared by the Liberty Consulting Group ("Liberty") states: "EKPC management should immediately evaluate and establish optimal equity level target and credit rating goals. Equity levels should be increased to 20 percent or more to establish the more adequate equity levels maintained by most other G&T companies that provide increased protection and attractiveness to capital markets and meet its loan covenants." Absent this requested rate increase, EKPC's interest and debt coverage ratios will be inadequate to meet the requirements needed to attract private lenders in the capital markets and meet its loan covenants. In addition, EKPC's equity is far below the level needed to attract such capital funding. The direct testimony of Mr. Eames will address these items in greater detail. EKPC is in the process of developing a long-term equity management plan. This rate increase request is a necessary step toward EKPC building equity, which will improve EKPC's ability to attract capital in the future.

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

A. EKPC's proposed effective date is July 1, 2010.

Q. What was EKPC's process in developing the revenue and expenses used in the forecasted test year?

A. EKPC carefully scrutinized the revenue and expense levels contained in this 2011 forecasted test year. The CEO and the Vice President, Finance reviewed and implemented several budget cuts before arriving at the forecasted test year income statement presented to the EKPC Board for their review in approving this rate increase.

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

A. The Commission approved EKPC's last base rate increase, which was a result of a settlement agreement, on March 31, 2009. The Order allowed EKPC an annual revenue increase of $59.5 million effective April 1, 2009 (Case No. 2008-00409.)

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

A. (1) Mr. Frank Oliva, Manager of Finance and Risk at EKPC, will describe the overall financial condition of EKPC, the need for additional equity, and the basis of the requested increase in base rates. He will also provide an overview of EKPC's budgeting process and 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.

(2) Mr. Dan Walker, President of Walker and Associates, will recommend TIER and equity levels that will enable EKPC to maintain its financial integrity.

(3) Mr. John Twitchell, Senior Vice-President, Power Delivery and Construction, at EKPC, will describe EKPC's budgeting process for major construction and will

explain the methodology and assumptions used to prepare the load forecast.

(4) Mr. Craig Johnson, Senior 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.

(5) Mr. Ricky 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.

(6) Mr. Dennis Eicher, President of D.R. Eicher Consulting, Inc., will discuss the cost-of-service study and the methodology used to develop this study.

(7) Mr. Isaac Scott, Manager of Pricing at EKPC, will discuss EKPC's current rate design and its impact on the wholesale tariff in this Application, address how the base rate increase will be passed through to EKPC's Member Systems, and will explain planned rate design changes.

(8) Ms. Ann Wood, Manager of Regulatory Services at EKPC, will explain the revenue requirement calculation and will sponsor a number of regulatory filing requirements for this Application.

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

A. As discussed by Mr. Scott in his testimony, the increase will be passed through to EKPC's sixteen Member Systems pursuant to KRS 278.455(2) when the rates go into effect.

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. 2010-00167**

AFFIDAVIT

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Anthony S. Campbell, 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.

Anthony S Campbell

Subscribed and sworn before me on this 27th day of May, 2010.

Notary Public

MY COMMISSION EXPIRES NOVEMBER 30, 2013
NOTARY ID #409352

**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, April 13, 2010, at 10:45a.m., EDT, the following business was transacted:

Approval to File a Rate Application

After review of the applicable information, a motion was made by Mike Adams and, there being no further discussion, passed to approve the following:

Whereas, East Kentucky Power Cooperative, Inc. ("EKPC") continues to closely monitor its financial condition; and

Whereas, The Rural Utilities Service ("RUS") has placed a moratorium on lending for fossil fuel generation projects, causing EKPC to pursue other financing alternatives; and

Whereas, Other financing alternatives contain more stringent debt covenant requirements; and

Whereas, the Kentucky Public Service Commission ("Commission") has urged EKPC to request rate increases in a more timely basis; and

Whereas, EKPC intends to file the rate adjustment application with the Commission using a fully forecasted test period of calendar year 2011 and seeks to increase annual revenues by no more than $50 million, or a 5.33 percent wholesale increase (approximately 3.95% increase at retail); and

Whereas, EKPC plans to file notice with the Commission on April 26, 2010, then file its application on May 27, 2010, and will seek actual implementation of the proposed rates, subject to refund, for service rendered on or after January 1, 2011; 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 not to exceed $50 million, or 5.33 percent, to be effective for service rendered on or after July 1, 2010, which would support an actual implementation date, subject to refund, of January 1, 2011, after the statutory suspension period; and that the Board authorizes EKPC to seek RUS and National Rural Utilities Cooperative Finance Corporation 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 13th day of April 2010.

A. L. Rosenberger

A. L. Rosenberger, Secretary

Corporate Seal

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

GENERAL ADJUSTMENT OF ELECTRIC RATES	) PSC CASE NO.
OF EAST KENTUCKY POWER	) 2010-00167
COOPERATIVE, INC.	)

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

Filed: May 27, 2010

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 and Risk.

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 31 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 Vice President, Finance.

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. In addition, my testimony provides 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 sponsoring any exhibits?

A. Yes. I am sponsoring Oliva Exhibit 1 and Oliva Exhibit 2. Oliva Exhibit 1 summarizes EKPC's income statement for the fully-forecasted test year which was used to support EKPC's proposed revenue increase. It is utilized by Ms. Wood in her direct testimony in this proceeding to determine EKPC's revenue requirements. Oliva Exhibit 2 provides the forecasted Times Interest Earned Ratio ("TIER") and Debt Service Reserve ("DSR") calculations without this rate increase.

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(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)(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)(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)(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

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 the basis for the requested $49.4 million increase in base rates?

A. During the 2010-2011 budgeting process, it became evident that EKPC's revenue in 2011 would not be sufficient for EKPC to meet its equity goal of 15% by 2016. EKPC sees this rate increase as a key step in meeting its equity goal in a timely fashion. As indicated in the action plan prepared by the Liberty Consulting Group, EKPC's equity ratio should be increased to 20 percent or more in order to provide protection against contingencies and to attract capital.

Q. What TIER is EKPC seeking in this proceeding?

A. EKPC is seeking a TIER of 1.50, which is supported by the testimony of Mr. Daniel Walker, President of Walker and Associates.

Q. What are the forecasted TIER and DSC ratios for the test year (calendar year 2011) without the increase in base rates?

A. As reflected on Oliva Exhibit 2, test year 2011 TIER and DSCR without rate relief are forecasted to be 1.076 and .972, respectively.

Q. Is a TIER level of 1.50 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. The "calculated" TIER from the settlement agreement in Case No. 2008-00409 yielded a 1.38 TIER. However, EKPC has been unable to significantly improve its equity level. 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 1.50, and a corresponding annual rate increase of $49.4 million are needed, based on those risks, to allow EKPC to start rebuilding its equity level, to meet its financial obligations pursuant to the RUS/CFC Mortgage Agreement and the Credit Facility Agreement, and to comply with the management audit recommendation of increasing EKPC's equity.

Q. Did EKPC meet its loan covenants in 2009?

A. Yes. EKPC's TIER and DSCR in 2009 were 1.27 and 1.11, respectively. However, EKPC's equity ratio and total equity were 7.3% and $219.1 million, respectively.

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 private financing in the future, in order to fund 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 April 2010 was 8.1%, below the level EKPC needs to be considered to be in a strong credit position by the investment community.

Q. What is considered to be a "strong credit position" by the investment community and rating agencies?

A. The investment community and rating agencies consider companies with an equity ratio of 15-20%, along with having other strong financial ratios, to be a strong credit.

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. 2008-00409, 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. The RUS is still not lending for baseload generation projects. It appears doubtful that this suspension of baseload generation loans will be lifted at any point in the near future. In addition, the U.S. President's federal 2011 budget proposes to prohibit the Rural Utilities Service from financing any fossil fueled generation projects, including pollution control equipment. EKPC continues to pursue private financing alternatives for the Smith Unit 1 CFB project. Such private financing will be more expensive than the loans guaranteed by the RUS in the past.

Q. What level of interest expense relating to the Smith 1 CFB is included in the forecasted test year?

A. EKPC has included $13 million of interest expense, exclusive of the TIER impacts, in the forecasted test year. This interest expense is related to a $175 million private placement financing expected to be consummated in late 2010.

Q. Do you anticipate any difficulty in renewing the Credit Facility Agreement in 2010?

A. During early 2010, in discussing the Credit Facility renewal with numerous banks, EKPC did not expect to encounter any difficulty in renewing the unsecured credit facility. However, the issuance of the management audit report in April has negatively impacted the renewal of this credit facility, as some banks became very concerned about the unfavorable implications contained in the consultant's report.

Q. How did the management audit report negatively impact EKPC's ability to renew the Credit Facility Agreement?

A. The Bank of Tokyo Mitsubishi and the Bank of Nova Scotia, two of the proposed lead arrangers in the renewal of the credit facility syndication, withdrew from participation in the EKPC credit facility renewal, citing primarily the tone of the management audit versus the substance of the recommendations. EKPC hosted a meeting for the parties in the existing credit facility syndication on May 13, 2010. Subsequently, EKPC has received comments from several banks indicating potential interest in participating in the credit facility renewal, pending approval by their credit analysts. The National Rural Utilities Cooperative Finance Corporation ("CFC") continues to be the lead lender in this renewal.

Q. How do these turn of events impact EKPC's unsecured credit facility financing application pending at the Commission (Case No. 2010-00166)?

A. The main impacts on the renewal are on: 1) the amount of the credit facility and 2) the increased associated interest cost and upfront fees.

Q. What is meant by the amount of the credit facility?

A. In EKPC's application in Case No. 2010-00166, EKPC requested an amount up to $500 million. This amount may need to be reduced if an insufficient amount is bid by banks still willing to participate in EKPC's credit facility renewal.

Q. Have the impacts of these increased fees and interest rate adjustments been reflected in this Application?

A. Yes. EKPC has assumed a certain level, approximately $1,500,000, in increased annual interest expense and financing fees. However, the higher interest cost (50 basis points) and increased upfront fees could potentially increase the annual cost of the credit facility by as much as $2,400,000 per year.

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

A. I am responsible for overall coordination of the corporate 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. Twitchell, Mr. Johnson, and Mr. Drury 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 associated contracts, 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 continuously, 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, EKPC's plan administrator.
- Sick Leave Liability—The Accounting area provides this information based on historical charges incurred.
- 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 $.64 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 expenses incurred.
- 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 $.205 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 estimated 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. 2010-00167**

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 27th day of May, 2010.

Gwyn M. Willoughby
Notary Public

MY COMMISSION EXPIRES NOVEMBER 30, 2013
NOTARY ID #409352

EAST KENTUCKY POWER COOPERATIVE

Budgeted Statement of Operations

Forecasted Test Year January - December 2011

	STATEMENT OF OPERATIONS	January 2011	February 2011	March 2011	April 2011	May 2011	June 2011	July 2011	August 2011	September 2011	October 2011	November 2011	December 2011	Totals
	Electric Energy Revenues													
1	Power Sales-Member Coops - Basic Rate	$88,687,550	$76,634,756	$73,648,862	$61,959,292	$61,734,385	$69,236,192	$77,051,881	$76,468,468	$66,024,425	$61,926,122	$71,424,843	$85,792,858	870,589,634
2	Power Sales-Member Coops - Fuel Clause	(204,796)	(1,235,982)	(4,600,290)	(4,512,416)	(5,645,341)	(5,580,566)	(4,984,708)	(5,167,257)	(6,472,098)	(3,468,166)	(5,245,783)	(801,842)	(47,919,245)
3	Power Sales-Member Coops - Environmental Surc	12,213,842	9,210,753	6,395,209	4,440,740	6,031,756	7,719,892	9,835,006	10,404,574	8,105,082	7,125,043	8,166,889	12,682,378	102,331,164
4	Power Sales-Member Coops - Steam	1,238,878	1,123,553	1,075,592	1,004,570	995,951	937,307	954,764	962,333	910,983	1,077,254	1,007,032	1,227,252	12,515,469
5	Power Sales - Off System	416,573	713,812	173,138	351,732	203,748	104,176	209,328	752,295	331,111	237,331	252,316	332,313	4,077,873
6	Wheeling Revenue	229,432	217,535	215,797	151,686	164,408	184,064	195,678	195,942	227,786	306,525	315,710	134,230	2,538,793
7	Other Operating Revenue - Income	183,930	183,930	183,930	183,930	183,930	183,930	183,930	183,930	183,930	183,930	183,930	183,939	2,207,169
8	Total Operating Revenue & Patronage Capital	102,765,409	86,848,357	77,092,238	63,579,534	63,668,837	72,784,995	83,445,879	83,800,285	69,311,219	67,388,039	76,104,937	99,551,128	946,340,857
9														
10	Operation Expenses													
11	Production Costs Excluding Fuel - Dale	536,584	562,735	511,788	542,322	530,889	625,170	543,926	566,614	505,848	567,487	553,996	773,954	6,821,313
12	Production Costs Excluding Fuel - Cooper	599,356	573,137	610,625	609,997	586,663	752,300	637,927	672,237	627,579	643,778	641,128	1,023,971	7,978,698
13	Production Costs Excluding Fuel - Spurlock	2,129,172	2,262,661	2,395,426	2,194,829	2,265,954	2,561,528	2,364,635	2,427,337	2,357,796	2,330,991	2,399,078	3,447,378	29,136,785
14	Production Costs Excluding Fuel - Gilbert & Unit #4	1,430,066	1,342,877	1,304,897	1,244,710	1,415,577	1,433,086	1,430,215	1,435,562	1,345,576	1,213,488	1,400,762	1,905,194	16,902,010
15	Production Costs Excluding Fuel - Smith	327,851	325,090	339,072	387,932	324,544	338,541	363,711	333,760	336,592	363,618	328,457	431,655	4,200,823
16	Production Costs Excluding Fuel - Dist. Generatior	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Production Costs Excluding Fuel - Landfill Gases	62,161	65,249	67,367	66,625	63,011	83,758	66,237	66,949	65,445	68,391	66,526	106,724	848,443
18	Production Costs Excluding Fuel - Allowances	463,061	388,224	419,941	388,183	337,519	361,631	485,723	493,792	377,945	388,628	348,727	440,988	4,894,362
19	Fuel-Dale	3,139,379	2,539,035	2,216,457	2,285,529	2,139,214	2,795,600	2,992,559	3,029,669	2,001,501	2,470,178	2,058,839	2,891,309	30,559,269
20	Fuel-Cooper	6,315,601	5,191,612	6,049,533	5,565,725	3,552,032	3,210,322	5,677,243	5,856,973	4,520,198	5,413,617	4,146,876	5,923,528	61,423,260
21	Fuel-Spurlock	17,090,730	15,173,643	16,988,481	13,914,850	13,201,103	15,637,095	16,048,234	16,352,891	15,465,370	14,539,410	16,174,282	16,885,706	187,471,795
22	Fuel - Gilbert & Unit #4	8,481,071	7,668,148	6,949,462	5,781,517	8,373,799	8,169,894	8,422,215	8,470,158	7,419,853	5,263,530	8,379,574	8,634,017	92,013,238
23	Fuel-Smith	7,456,019	5,040,165	5,560,519	3,682,926	3,272,033	4,163,692	5,851,068	5,520,141	2,236,504	5,218,796	4,837,396	6,530,675	59,369,934
24	Fuel-Distributive Generation	266	534	534	534	534	534	534	534	534	534	534	794	6,400
25	Fuel-Landfill Gas	44,057	39,610	43,950	42,716	43,812	44,575	48,104	47,852	46,380	48,122	46,388	47,771	543,337
26	Fuel Handling	1,148,957	1,190,612	1,195,654	1,197,907	1,197,188	1,242,018	1,226,907	1,235,657	1,211,815	1,232,855	1,217,597	1,268,876	14,566,043
27														
28														
29	Other Power Supply	13,071,101	9,638,834	2,616,735	2,660,149	2,200,474	2,316,131	2,724,665	2,407,955	2,213,022	2,392,640	2,409,742	10,748,543	55,399,991
30	Other Power Supply-ACES Fees	158,333	158,333	158,333	158,333	158,333	158,333	158,333	158,333	158,333	158,333	158,333	158,337	1,900,000
31	Transmission Wheeling	2,171,837	2,133,325	1,633,082	1,622,911	1,697,338	1,494,608	1,661,801	1,517,920	1,439,400	1,273,974	1,260,782	1,444,851	19,351,829
32	Transmission Expense	1,494,560	1,195,162	1,227,062	1,212,795	1,223,793	1,231,506	1,216,849	1,208,941	1,189,344	1,595,489	1,181,934	1,258,933	15,236,368
33	Distribution Expense	125,022	123,204	120,228	125,846	132,970	118,516	118,680	118,166	117,603	118,291	118,024	131,319	1,467,869
34	Customer Accounts	0	0	0	0	0	0	0	0	0	0	0	0	0
35	Customer Service and Information	265,442	274,218	290,918	271,653	278,421	274,789	270,566	271,558	275,459	274,550	269,210	343,406	3,360,190
36	Sales	1,997	1,652	1,800	1,715	1,703	1,679	1,690	1,755	1,679	1,715	1,679	1,938	21,002
37	Administrative and General	4,380,174	2,527,783	2,865,427	2,167,405	2,421,285	2,347,871	3,462,750	2,155,724	2,323,496	2,086,527	2,471,978	2,218,773	31,429,193
38	Total Operation Expenses	70,892,797	58,415,843	53,567,291	46,127,109	45,418,189	49,363,177	55,774,572	54,350,478	46,237,272	47,664,942	50,471,842	66,618,640	644,902,152

EAST KENTUCKY POWER COOPERATIVE

Budgeted Statement of Operations

Forecasted Test Year January - December 2011

	STATEMENT OF OPERATIONS	January 2011	February 2011	March 2011	April 2011	May 2011	June 2011	July 2011	August 2011	September 2011	October 2011	November 2011	December 2011	Totals
	Maintenance Expenses													
1	Production - Dale	287,808	348,557	520,419	685,011	822,355	594,379	573,659	837,609	442,318	339,011	322,573	365,714	6,139,413
2	Production - Cooper	553,186	710,684	724,054	902,712	1,077,184	1,016,522	719,412	717,473	1,025,022	718,167	711,062	878,058	9,753,536
3	Production - Spurlock	1,255,577	1,746,030	1,682,112	2,017,813	2,644,697	2,488,397	3,776,313	2,049,264	1,933,530	1,784,107	2,582,116	2,146,248	26,106,204
4	Production - Gilbert & Unit #4	320,298	547,583	503,911	683,950	986,139	1,419,841	923,950	852,660	585,341	1,058,071	1,840,862	608,939	10,331,545
5	Production - Smith	82,710	115,034	365,852	365,110	240,034	240,083	150,110	116,023	165,083	116,122	115,088	147,926	2,219,175
6	Production - Dist. Generation	4,151	4,122	4,165	4,126	4,122	4,124	4,126	4,174	4,124	4,179	4,125	4,138	49,676
7	Production - Landfill Gases	102,839	119,611	152,442	263,740	282,026	297,837	120,205	211,281	142,177	254,191	265,526	104,585	2,316,460
8	Transmission Expense	310,478	445,715	460,038	445,502	446,765	578,417	528,502	532,313	448,417	448,625	458,355	583,689	5,686,816
9	Distribution Expense	64,898	84,505	85,883	84,064	84,505	84,043	84,064	84,764	84,043	84,842	84,047	104,684	1,014,342
10	General Plant	97,983	248,382	103,710	153,663	208,382	687,149	90,460	89,087	90,449	89,129	88,701	102,047	2,049,142
11	Total Maintenance Expenses	3,079,928	4,370,223	4,602,586	5,605,691	6,796,209	7,410,792	6,970,801	5,494,648	4,920,504	4,896,444	6,472,455	5,046,028	65,666,309
12														
16	Fixed Costs													
17	Depreciation/Amortization	6,493,971	6,511,576	6,525,626	6,536,851	6,547,198	6,576,124	6,585,392	6,587,928	6,596,462	6,602,254	6,602,495	6,732,945	78,898,822
18	Taxes	0	0	800	0	0	0	0	0	0	0	0	0	800
19	Interest on Long-Term Debt	11,648,897	11,500,424	11,661,264	12,432,998	12,482,789	12,432,111	12,432,272	12,431,053	12,379,847	12,665,117	12,603,007	12,647,018	147,316,797
20	Interest During Construction	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Other Interest Expense	3,397	3,068	3,397	3,288	3,397	3,288	3,397	3,397	3,288	3,397	3,288	3,397	39,999
22	Other Deductions	154,977	156,924	156,605	156,523	56,569	157,260	157,271	156,651	156,770	156,745	156,560	159,730	1,782,585
23	Total Fixed Costs	18,301,242	18,171,992	18,347,692	19,129,660	19,089,953	19,168,783	19,178,332	19,179,029	19,136,367	19,427,513	19,365,350	19,543,090	228,039,003
24														
25														
26	Total Cost of Electric Service	92,273,967	80,958,058	76,517,569	70,862,460	71,304,351	75,942,752	81,923,705	79,024,155	70,294,143	71,988,899	76,309,647	91,207,758	938,607,464
27														
28	Operating Margins	10,491,442	5,890,299	574,669	(7,282,926)	(7,635,514)	(3,157,757)	1,522,174	4,776,130	(982,924)	(4,600,860)	(204,710)	8,343,370	7,733,393
29														
30														
31	Non-Operating Items													
32	Interest Income	267,160	251,406	266,989	261,679	266,817	261,506	309,046	308,946	303,621	308,740	303,414	308,555	3,417,879
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	(7,690)	(6,074)	(6,443)	(5,242)	(5,374)	(5,468)	(5,395)	(5,389)	(5,569)	(5,602)	(5,403)	(5,839)	(69,488)
35	Other Capital Credits/Patronage Dividends	4,166	4,166	4,166	4,166	4,166	4,166	4,166	104,166	4,166	4,166	4,166	4,174	150,000
36	Total Non-Operating Items	263,636	249,498	264,712	260,603	265,609	260,204	307,817	407,723	302,218	307,304	302,177	306,890	3,498,391
37														
38														
39	Net Patronage Capital & Margins(Deficits)	10,755,078	6,139,797	839,381	(7,022,323)	(7,369,905)	(2,897,553)	1,829,991	5,183,853	(680,706)	(4,293,556)	97,467	8,650,260	11,231,784

For 2011: Mortgage Agreement and Credit Agreement (Without Requested Rate Increase)

TIER	(a) Net Margins	11,232,000					
	(b) Interest on Long Term Debt	147,316,797					
	TIER = (a) + (b) / (b) =	158,548,797	/	147,316,797	=	**1.076**

DSC	(a) Depreciation	78,898,822
	(b) Interest on L-T Debt	147,316,797
	(c) Margins	11,232,000
	(d) Interest + Principal	244,219,797
	DSC = (a) + (b) + (c) / (d) =	**0.972**

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

GENERAL ADJUSTMENT OF ELECTRIC RATES	)	PSC CASE NO.
OF EAST KENTUCKY POWER	)	2010-00167
COOPERATIVE, INC.	)	

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

Filed: May 27, 2010

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 on regulation in the College of William & Mary Business Review, EPRI Research Journal, and Public Utilities Fortnightly. I 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 served as the Chief Financial Officer for Old Dominion Electric Cooperative for 21 years. In that capacity, I was directly responsible for the issuance of approximately $3 billion of cooperative financings. Also, in that capacity I 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 $3 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, DSC, 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 it has 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 rated cooperatives that are comparable to East Kentucky. 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 TIERs 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+ from at least one of the three major rating agencies. I call these G&Ts the "Reference Group." In addition I also analyzed a collection of data prepared by National Rural Utilities Cooperative Finance Corporation (CFC). This data compared East Kentucky with 21 G&Ts that generate the majority of their power requirements from their own resources. This data also compared East Kentucky with over 60 G&Ts that are members of CFC.

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 or TIERs are directly related to the perceived risk of an investment. It follows that if a particular cooperative has a risk profile similar to other rated cooperatives, its cost of capital will also be similar to that of the rated cooperatives. In most cases, to determine the cost of capital for a cooperative, one would

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

compare its 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 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 its credit position must improve in order 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 to attract capital.

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 managed 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 ratio 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 subject only 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, 2009:

Cooperatives with Investment-Grade Ratings

G&T Cooperatives	Moody's	S&P	Fitch
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	A3	A-	A-
Dairyland Power Cooperative	A3	A	
Georgia Transmission Cooperative	A3	AA-	AA-
Golden Spread	A3	A	A-
Great River Energy	A3	A-	A-
Hoosier Energy Rural	Baa2	BBB-	---
Oglethorpe Power	A3 (Neg.)	A	A
Old Dominion Electric	A3	A	A
Power South	Baa1	A-	A-
Seminole Electric Cooperative	---	A-	---
Square Butte Electric Cooperative	A1	A-	---
Tri-State G&T Association	Baa1	A	A- (Neg.)
Wabash Valley	---	A-	---
Western Farmers	---	BBB+	A-

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 more 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 experiences events beyond its control which may create a credit negative. Weather and unexpected economic conditions that impact demand are good examples of such events.

Within a rating category, each cooperative has different credit negatives and positives. For example, consider two cooperatives, Cooperative (A) and Cooperative (B), with the exact same letter credit rating. Cooperative (A) may build into rates a higher TIER that could be a credit positive; however, it may also have a credit negative that limits rate flexibility, such as that which occurs 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. But, 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 rate regulated by the 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. Five years ago when East Kentucky solicited bank commitments for a five year credit revolver, the responding banks judged East Kentucky to have a credit profile in the BBB range. This assessment placed East Kentucky at the lower end of G&T credit ratings. It was critical for East Kentucky to improve its credit profile as it approached the renewal of its $650 million credit facility in 2010. In the view of some bankers responding to the 2010 solicitation, East Kentucky's credit assessment did not improve but actually deteriorated. Two of the primary banks involved in the previous syndication have currently downgraded East Kentucky to the BB+ credit level, subsequent to the release of Liberty Consulting's management audit report of East Kentucky. As a result of this assessment, these two banks have withdrawn their participation in the credit facility renewal. This is a step backwards in East Kentucky's ability to build a credit profile to attract capital.

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

A. No, not consistently. Even though East Kentucky's financial performance improved in 2007 with a TIER of 1.43x, it declined from this level in 2008 and 2009 with TIERs of 1.25x and 1.27x, respectively. This raises the issue of East Kentucky's ability to consistently sustain margins and debt coverage at a level that would support a stronger credit profile. In East Kentucky's previous rate case, the Commission took a positive step towards improving East Kentucky's reception in the capital markets by addressing the quality of earnings issue and allowing construction interest to be recovered in rates on a current basis.

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 made it difficult for even "A" rated credits to borrow. While most analysts believe this condition will improve in the future, it has resulted in a 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 long-term capital on reasonable terms in the future, which will be necessary to finance future capital additions. Thus, it is critical that earnings improve in order for East Kentucky to have an opportunity to arrange capital for its generation facilities, in order to meet the power requirements of its members.

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 2006 to 2008 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 <u>not</u> 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 2006, 2007, and 2008 TIER data. In column (H) I have included only those G&Ts 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&Ts" in column (H), they would likely also have similar ratings.

The average of the earned TIERs in the reference group is 1.49x. Given East Kentucky's risk profile, it is clear to me that they should earn TIERs above the average level for these G&Ts.

Q. Would you explain why East Kentucky should earn a TIER greater than the average of this group of G&Ts?

A. 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 at the bottom of Exhibit 1 have a tendency to earn relatively low TIERs. In evaluating their credit, their financial performance is actually a credit negative; however, 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 ensure 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 members' 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 consistent TIER above the midpoint and average of the TIER earned by the BBB+ to A+ G&T cooperatives. To be more specific, before its next financing, East Kentucky should post annual financial performance above the average of these G&Ts 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 two last rate cases?

A. The methodology I used in the last two cases and this case is essentially the same. In the first 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 and 2005, 2006, and 2007 in the last case. In this case I updated the data and used a three-year average of TIERs for essentially the same G&Ts for the years 2006, 2007, and 2008. As discussed below, I also expanded my testimony to show the average TIERs, DSCs, and equity ratios for cooperatives that have operating characteristics similar to East Kentucky as defined by CFC.

Q. Would you explain the additional data points for the Commission to consider in this case?

A. Yes. In addition to looking at "rated" G&Ts, the Commission may also want to consider the TIERs of both rated and unrated G&Ts with operating characteristics similar to East Kentucky. In addition, I also included average financial ratios of all G&Ts. CFC is the largest supplemental lender in the country to both distribution and G&T cooperatives.

Each year they provide East Kentucky with a comparison of East Kentucky's financial performance to that of comparable G&Ts and to the G&T population as a whole. To be consistent with my first analysis of "rated" G&Ts, I averaged the TIERs, DSCs, and equity ratios for 2006, 2007, and 2008. The results are shown on Exhibit DMW 3.

Q. Why did you include DSC ratios on Exhibit DMW-3?

A. I am not aware of any state regulatory agency that uses DSC ratios to set rates. However, it is a very important financial indicator to the banks and rating agencies in that it describes the ability, from a cash perspective, to cover both interest and principal. In dealing with banks and future bondholders, East Kentucky must achieve sufficient coverage based on both TIER and DSC.

Q. Would you explain how CFC develops its "comparison group" of G&Ts?

A. For its analysis, CFC separates the G&Ts into four groups: Generation, Purchase, Transmission, and Participation Group. East Kentucky falls in the Generation group because they generate more than 50% of their member power requirements from their owned assets. This group is made up of 21 G&Ts.

Q. How does East Kentucky's financial performance compare with the Generation group?

A. As shown on Exhibit DMW-3 the TIER for the Generation group of 1.51x, DSC of 1.21x and equity ratio of 14.57% far exceed East Kentucky's financial performance. For the same time period East Kentucky posted a TIER of 1.27x, DSC of 1.06x, and an equity ratio of 6.77%.

Q. What are the results when you compare East Kentucky to the entire population of G&Ts?

A. A comparison of East Kentucky to the group of all G&Ts is consistent with the Generation group comparison. The group making up all of the G&Ts exhibit far stronger financial performance than East Kentucky with an average TIER of 1.55x, DSC of 1.21x, and an equity ratio of over 15%.

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

A. It is exigent that East Kentucky improve its credit profile before it has to raise hundreds of millions of dollars for its next capacity addition. As was demonstrated in East Kentucky's last solicitation for its short term bank facility, a weaken credit position can be painful and expensive. From this point forward, East Kentucky must prove it can increase its equity and earn margins on a level that, at the very minimum, is equal to the average of G&Ts. My analysis has demonstrated that the average TIER for "rated" G&Ts is 1.49x while the average TIER of CFC's G&T Generation group is 1.51x and for all G&Ts is 1.55x. I could easily recommend that East Kentucky's comparatively weak equity position calls into question its ability to raise necessary capital, necessitating special consideration to allow East Kentucky to earn margins above the 1.55x level. I also understand that ratemaking is a balancing act, and that smaller steps often need to be taken which would suggest something less than a TIER of 1.55x. For setting rates, I recommend the Commission use a TIER no less than 1.50x.

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

A. The equity ratio is a key component of a utility's 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 of "rated" G&Ts is 17.6% compared to East Kentucky's current level of 6.8%. East Kentucky's extremely low equity level is and will continue to be a major concern to credit analysts as they advise potential bondholders. Allowing my suggested improvement in East Kentucky's earned TIER will go a long way towards improving the cooperative's equity level.

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	)	**CASE NO. 2010-00167**
GENERAL ADJUSTMENT OF ITS	)	
WHOLESALE ELECTRIC RATES	)	

<u>A F F I D A V I T</u>

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.

Daniel M. Walker

Subscribed and sworn before me on this 20th day of May, 2010.

Notary Public

My Commission expires: August 31, 2010

LI MIE WOO WARREN
NOTARY PUBLIC
COMMONWEALTH OF VIRGINIA

East Kentucky Power Cooperative
Rated G&T Cooperatives
TIER Analysis

	Moody's (A)	S&P (B)	Fitch (C)	2006 (D)	2007 (E)	2008 (F)	Average (G)	Reference Group of BBB+ to A+ G&Ts (H)
Golden Spread	A3	A	A-	3.55x	6.01x	6.09x	5.22x	
Buckeye	**A1**	**A+**	**A+**	**2.67**	**2.40**	**1.42**	**2.16**	**2.16**
Basin	**A1**	**A+**	**AA-**	**2.04**	**1.13**	**2.59**	**1.92**	**1.92**
Tri-State	**Baa1**	**A**	**A-**	**1.11**	**1.23**	**2.09**	**1.84**	**1.84**
Brazos	**---**	**A-**	**A**	**2.07**	**1.76**	**1.36**	**1.73**	**1.73**
Great River	**A3**	**A-**	**A-**	**1.83**	**1.91**	**1.29**	**1.68**	**1.68**
Central Iowa	**A2**	**A**	**---**	**1.61**	**1.89**	**1.34**	**1.61**	**1.61**
Western Farmers	**---**	**BBB+**	**A-**	**1.33**	**1.58**	**1.63**	**1.51**	**1.51**
Wabash Valley	**---**	**A-**	**---**	**1.23**	**1.31**	**1.65**	**1.40**	**1.40**
Dairyland	**A3**	**A**	**A-**	**1.51**	**1.41**	**1.29**	**1.40**	**1.40**
Arkansas	**A2**	**AA-**	**---**	**1.53**	**1.29**	**1.34**	**1.39**	**1.39**
South Mississippi	**A3**	**BBB+**	**A-**	**1.25**	**1.42**	**1.48**	**1.38**	**1.38**
Power South	**Baa1**	**BBB+**	**---**	**1.29**	**1.25**	**1.42**	**1.32**	**1.32**
San Miguel	**---**	**A-**	**---**	**1.35**	**1.37**	**1.20**	**1.31**	**1.31**
Old Dominion	**A3**	**A**	**A**	**1.39**	**1.27**	**1.20**	**1.29**	**1.29**
South Texas	**A1**	**A-**	**A-**	**1.24**	**1.37**	**1.22**	**1.28**	**1.28**
Chugach Electric	**A3**	**A-**	**A-**	**1.41**	**1.12**	**1.30**	**1.28**	**1.28**
GTC	A3	AA-	AA-	1.18	1.21	1.22	1.20	
Seminole	**---**	**A-**	**---**	**1.24**	**1.18**	**1.18**	**1.20**	**1.20**
Oglethorpe	**A3(Neg.)**	**A**	**A**	**1.10**	**1.10**	**1.10**	**1.10**	**1.10**
Square Butte	---	A-	---	1.06	1.08	1.08	1.07	
Average								**1.49x**
Median								**1.40x**
East Kentucky (3 year average)								**1.27x**

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

Exhibit DMW-1

East Kentucky Power Cooperative
Equity Ratios of Reference Group

Arkansas	41.1%
Chugach	30.3%
Buckeye	27.0%
Basin	23.8%
Tri-State	21.4%
Old Dominion	21.4%
Central Iowa	15.0%
Western Famers	14.5%
Oglethorpe	12.6%
Hoosier	12.3%
Wabash Valley	11.6%
Brazos	11.2%
Dairyland	11.1%
Great River	11.0%
Alabama	10.7%
Seminole	6.4%
Average	17.6%
Median	13.6%
East Kentucky	**6.8%**

Source:
- 2009 National G&T Accounting and Finance Association Handbook

East Kentucky Power Cooperative
CFC Financial Analysis
3 Year Average (2006 – 2008)

	TIER	DSC	Equity
Generation Cooperatives*	1.51x	1.21x	14.57%
All G&Ts**	1.55x	1.21x	15.21%
East Kentucky	1.27x	1.06x	6.77%

* This group consists of 21 G&Ts that generated more than half of their power requirements

** This group consists of 60 G&Ts that are members of CFC.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

GENERAL ADJUSTMENT OF ELECTRIC RATES	)	**PSC CASE NO.**
OF EAST KENTUCKY POWER	)	**2010-00167**
COOPERATIVE, INC.	)	

TESTIMONY OF
JOHN R. TWITCHELL
SENIOR VICE PRESIDENT OF POWER DELIVERY AND CONSTRUCTION
EAST KENTUCKY POWER COOPERATIVE, INC.

Filed: May 27, 2010

I. INTRODUCTION AND PURPOSE

Q. Please state your name and business address.

A. My name is John R. Twitchell and my business address is East Kentucky Power Cooperative, Inc., 4775 Lexington Road, Winchester, Kentucky 40391.

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 Delivery and Construction.

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

A. My undergraduate degree is a Bachelor of Science in Electrical Engineering with an emphasis in electric energy systems from the University of Florida. My graduate degree is a Master of Business Administration from the University of North Florida. I am a licensed professional engineer. I have over thirty five years of experience in management, and the planning, permitting, design, construction, operation, and maintenance of electrical utility transmission and generation systems.

Q. How long have you been employed by EKPC?

A. I have been employed by EKPC since April 2006.

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

A. I am responsible for the permitting, design, construction, and environmental compliance of EKPC's generation fleet. I am responsible for the planning, design, construction, operation, and maintenance of EKPC's transmission system. I am also responsible for resource planning, power purchase and sales, load forecasting, and the purchase of fuels and emission credits.

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

A. The purpose of my testimony is to: 1) provide a general description of EKPC's construction process with regard to generation and 2) 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 JRT-1 and JRT-2.

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 #
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
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

Q. Please describe the process that was used to develop the costs that were included in the *construction capital* budget used in the forecasted test year.

A. Annual expenditures for major construction capital projects were developed from estimates provided by either consulting engineering firms retained to design and manage a specific project, or from EKPC's internal engineering staff.

Q. What assumptions were made in preparing your construction budget relating to major projects?

A. The Smith 1 project cost estimate is based on a construction start in early 2011. The Cooper Retrofit Air Pollution Project is mandated by EKPC's Consent Decree with the EPA. The Cooper Retrofit Project is included in EKPC's proposed environmental surcharge compliance plan amendment (Case No. 2010-00083, pending before the Commission).

Q. Please provide a description of EKPC's load forecasting process.

A. A detailed description of EKPC's load forecasting process is contained in the work plan and attached as Exhibit JRT-1.

Q. How often is the load forecast prepared?

A. A load forecast is prepared every other year.

Q. Is this load forecast work plan approved by any regulatory agency?

A. Yes. EKPC submits the load forecast work plan to the Rural Utilities Service for approval. Attached as Exhibit JRT-2 is a letter from RUS approving EKPC's 2009 load forecast work plan.

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. 2010-00167**

AFFIDAVIT

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

John R. Twitchell, 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 May, 2010.

Notary Public

MY COMMISSION EXPIRES NOVEMBER 30, 2013
NOTARY ID #409352

2009 Load Forecast Work Plan

Prepared by:
East Kentucky Power Cooperative
Resource Planning Department

November 2009

EAST KENTUCKY
POWER COOPERATIVE

TABLE OF CONTENTS

Summary

East Kentucky Power Cooperative Inc. (EKPC) is a generation and transmission electric cooperative headquartered in Winchester, Kentucky. It serves 16 member distribution cooperatives, who in 2008 served approximately 518,000 retail customers in 87 of the state's 120 counties. EKPC's all time peak demand of 3,152 MW occurred on Janurary 16, 2009. Member distribution cooperatives currently served by EKPC are listed below:

Big Sandy RECC	Jackson Energy Cooperative
Blue Grass Energy Coop. Corp.	Licking Valley RECC
Clark Energy Cooperative, Inc.	Nolin RECC
Cumberland Valley Electric	Owen Electric Cooperative, Inc.
Farmers RECC	Salt River Electric Cooperative
Fleming-Mason Energy Cooperative, Inc.	Shelby Energy Cooperative, Inc.
Grayson RECC	South Kentucky RECC
Inter-County Energy Coop. Corp.	Taylor County RECC

This report contains a description of the load forecast process that is currently followed by EKPC and its member systems. The major steps, in general, in developing the load forecasts are:

- EKPC prepares a preliminary load forecast for each member that is based on retail sales forecasts for four classes - residential, small commercial, large commercial, and other. The classifications are taken from the Rural Utilities Service (RUS) Form 7, which contains retail sales data for member systems. In instances where seasonal and public authority classes are reported, these are forecasted separately. Table 1 summarizes the forecast methodology. EKPC's sales to member systems are then determined by adding distribution losses to total retail sales and EKPC's total requirements are estimated by adding transmission losses to sales to members. Seasonal peak demands are determined by summing individual appliance and class loadshapes based on normal EKPC peak day weather.
- EKPC meets with each member to discuss their preliminary forecast. Member system personnel present at the meetings include the Manager and other key

staff members. During the meeting, preliminary projections are reviewed and, if necessary, revised as mutually agreed upon. Member systems often have access to information not available to EKPC, or member systems may elect to use assumptions different from preliminary forecast assumptions.

- EKPC then compiles its forecast, which is the summation of the 16 member system forecasts.

There is close collaboration between EKPC and its members. This working relationship is vital since both EKPC and member systems have significant input into the load forecast process. Input from member systems includes industrial development, subdivision growth, and other specific service area information. The meeting also provides an opportunity for the member system to critique assumptions used and overall results of the preliminary forecast. The resulting forecasts reflect a combination of EKPC's structured forecast methodology tempered by the judgment and experience of member system staff.

Table 1
East Kentucky Power Cooperative
Forecast Model Summary

	Methodology
Residential Sales	Sales for this class are projected as the product of residential customers and residential use per customer. Residential customers are projected by means of regression analysis. Residential use per customer is projected with a statistically-adjusted end-use model.
Small Commercial Sales	Small commercial sales are analyzed and projected with regression analysis. Independent variables include real electric price, economic activity, weather, and residential customer growth. The models vary by member system.
Large Commercial Sales	Sales for this class are projected by both the member systems and EKPC. Member systems project existing large loads. EKPC projects new large loads using a probabilistic approach that is based on historical development, the presence of industrial sites, and the economy of the service territory.
Other Sales	Other sales are projected as a function of residential customers.
Peak Demand	Seasonal peak demands are projected using peak day load factors. Residential load factors are appliance specific. Small and large commercial factors are an aggregate for the class.

Load Forecast Coordination and Communication

Coordination with Member Systems

The 17 load forecasts that are produced within the EKPC system reflect a group effort. EKPC's philosophy of developing load forecasts is that all 17 systems are interrelated. EKPC cannot make accurate energy and peak demand projections for itself without studying the 16 member systems. As a result of this interrelation, EKPC works jointly with members to prepare load forecasts.

Communication with Member Systems

EKPC personnel are in constant contact with member system personnel relating to the load forecast. There is a meeting between EKPC and member systems to discuss the load forecast in order to arrive at a final set of projections. EKPC communicates with members regarding end-use surveys, substation information, billing information, demand-side management programs, marketing programs, and other miscellaneous data. Member systems communicate with EKPC regarding sensitivity analyses, substation load projections, potential industrial loads, end-use survey reports, and other miscellaneous topics.

Dates

EKPC generally begins work on the load forecasts in December of the previous year with planning stages occurring prior to that as early as October. Normally by the end of January, year-end retail sales data on customers, sales, and revenue have been collected to allow for retail sales analysis. By the middle of April, EKPC will have prepared a preliminary load forecast for each member system. Individual member system visits occur in May through July. By the end of August, an official EKPC load forecast has been prepared, and is presented to EKPC's Board of Directors, usually in September. Table 2 lists important milestones in the process. Table 3 shows the schedule. A detailed timeline is included in the appendix.

Table 2
Load Forecast Milestones

Regional Economic Modeling Completed	January
December Form 7 Reports Collected	January
Customer Forecast by Class	February
Preliminary Forecast Completed	April
Member System Visits	May – July
Board Approval	September
Final Report	September

Table 3
Load Forecast Schedule

December
Regional Economy Analyses

January
Regional Economy Forecasts Complete
Appliance Saturation Projections Complete

February
Customer Forecast by Class

March
Finalize Year-End Form 7 Data • Finalize Winter Season Peak

April
Sales Forecast by Class • Peak Demand Forecast
Preliminary Load Forecasts Completed • EKPC Review

May / June
Member System Visits • Member System Reports

July / August
Model EKPC System Hourly Load • Prepare Draft EKPC Report

September
Board Approval • Final EKPC Report Complete

Start of Process

EKPC's communication and coordination with member systems starts with a letter from EKPC to member systems. The letter serves to make member systems aware of the process, and also to request pertinent information and input into the load forecast. Specifically, member systems are asked to provide EKPC with individual large commercial customers', both existing and planned, monthly sales and monthly peak demand projections for three years. Information concerning demand-side management programs is collected, analyzed and used as inputs to the load forecast, specifically, expected participation. EKPC also provides an estimate of a rates forecast for small commercial and residential customers. Member systems review and comment. Finally, members are asked to update their narratives for the load forecast report.

Meeting with Member Systems

Once a preliminary forecast is complete, EKPC visits each member system to discuss the results. The meetings take place at each member system's headquarters. Meeting attendees vary by member system and typically include the following:

Table 4

Load Forecast Meeting Attendees

Member System	Manager Key Staff from the following departments: Finance Engineering / Operations Member Services Administrative
EKPC	Vice President or Director, Power Supply Resource Planning Manager and Team Members

RUS's General Field Representative (GFR)

EKPC meets with the GFR to review the member system forecasts. After questions and comments are addressed, the GFR signs the RUS Form 341. The GFR's knowledge of RUS rules and regulations is useful to EKPC and member systems.

Interaction with RUS's Energy Forecasting Branch

EKPC strives to maintain regular contact with the Energy Forecasting Branch (EFB), mainly the Senior Load Forecast Officer who has been assigned to EKPC. The EFB has served as a resource for the latest information regarding energy efficiency standards and alternative fuels prices.

<u>EKPC Personnel</u>

The load forecasting function is in EKPC's Resource Planning Department in the Power Supply Business Unit. Key contributors include:

- James Lamb is the Senior Vice President of Power Supply and has over 20 years of experience in forecasting. He has an MBA from the University of Kentucky.
- Sally Witt, Manager of Resource Planning, will provide overall support for the 2010 Load Forecast. She has been with EKPC for 20 years and has been an analyst or project manager for the load forecast for 10 years.
- Mark Mefford, Analyst in the Resource Planning Department, will serve as the project manager for the 2010 Load Forecast. He has been with EKPC since 1999 and part of Resource Planning since 2007.
- Wanda Kirby, the staff secretary, will assist in scheduling the member system meetings.
- Sandy Mollenkopf, Analyst in the Resource Planning Department, will provide support for the load forecast process in areas of data collection, specifically, saturation survey data, load research data, and RUS Form 7 data. The load forecast requires input from many individuals.

<u>Resources and Data Management</u>

Computer Resources

EKPC currently uses personal computers for analyses and presentation of the load forecast. The following software packages are used in the process:

Microsoft EXCEL – used for spreadsheet analysis
Microsoft WORD and PowerPoint – used for preparing reports
@RISK – used for risk analysis
SAS – a statistical package used for regressions and data manipulation
MetrixLT – a program used to calibrate the monthly forecasts to hourly forecasts
MetrixND – a forecasting modeling program

Purchased Data Resources

Economic

EKPC uses services from Global Insight, Inc., to analyze regional economic performance. The regions are based on EKPC member systems' service territories. Variables forecasted include:

- EMPLOYMENT [NAICS] by sector
  - Total Non-farm
  - Non-Manufacturing
  - Service Providing Private
  - Construction, Natural Resources, and Mining
  - Manufacturing
  - Transportation, Trade, & Utilities
  - Information
  - Financial Activities
  - Professional & Business Services
  - Educational & Health Services
  - Leisure & Hospitality
  - Other Services
  - Government
  - Federal Government
  - State & Local Government
  - Military

- NOMINAL INCOME
  - Personal Income
  - Wage & Salary Disbursements
  - Non-wage Income
  - Average Annual Wage, Non-farm Employment
  - Per Capita Personal Income
  - Average Household Income

- REAL INCOME
  - Real Personal Income
  - Real Wage & Salary Disbursements
  - Real Non-wage Income
  - Real Per Capita Personal Income

- POPULATION
  Total Resident Population and by Age group

- HOUSEHOLDS
  Heads of Household, Total and by Age group.

In addition, EKPC purchases forecasted information about the U.S. economy including:

1. A long-term economic forecast of the U.S. economy including output, price level, and interest rate projections.

2. Cost and price projections of generation and transmission capital equipment price escalation rates and fuel price forecasts.

3. Miscellaneous data searches and special requests.

The cost of the above services and data is approximately $30,000 annually.

The extensive amount of economic data available relating to load forecasting at EKPC is a valuable resource to other departments at EKPC, as well as member systems, who often make requests for various economic data.

Demographic

EKPC uses forecasts prepared by the Urban Studies Institute, a University of Louisville organization that is the state's official demographer. They prepare forecasts of population and households and disseminate Census Bureau data. EKPC uses these to maintain a Kentucky perspective on how Kentucky is expected to grow.

Weather

EKPC subscribes to a service provided by DTN Meteorlogix (formerly WeatherBank), which provides actual weather data including monthly high and low temperatures, hourly temperatures, humidity, sunshine minutes, wind chill and other variables. EKPC currently maintains seven 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. This service costs $1,500 annually.

Loadshapes

Specific hourly load research data is used when available. EKPC's load research to date includes a sample in the small commercial sector (0-50 kW), a sample of the medium commercial sector (51-350 kW) and a census for the large power sector (>350 kW). The load forecast also uses residential load research data for appliance usage estimation.

Data Management

EKPC deals with a tremendous amount of economic, weather, demographic, retail sales, and end-use data. Maintaining all of this information is challenging. The data is stored on EKPC's network in numerous datasets. Housing the data on a network allows multiple users to be working on this project simultaneously. Most regression analyses are performed in SAS or MetrixND. The resulting regression coefficients are used in developing the load forecasts.

Report Writing

Member System Reports

Once final projections have been calculated following the load forecast meeting at the member system, EKPC prepares a report for each of its member systems. Just as member systems work jointly with EKPC on the preparation of the load forecast, they also contribute to the report's development by providing the narrative for the report.

EKPC Report

EKPC's report consists of a summary report and supporting appendices. The summary report essentially finalizes the load forecast process by combining the 16 individual member system forecasts. Key assumptions and member system growth rates are presented. The forecast methodology is described briefly with energy projections provided for the individual classes of consumers. Seasonal peak demands, load factors, and high and low forecasts are presented. Table 6 summarizes the table of contents from EKPC's Load Forecast report.

Table 6

Load Forecast Report Table of Contents

Section 1.0	Executive Summary
Section 2.0	Load Forecast Methodology
Section 3.0	Load Forecast Discussion
Section 4.0	Regional Economic Model
Section 5.0	Residential Customer Forecast
Section 6.0	Residential Sales Forecast
Section 7.0	Commercial and Other Sales Forecast
Section 8.0	Peak Demand Forecast and High and Low Case Scenarios

Report Appendices

A description of data included in the appendices is in Table 7.

Table 7

Load Forecast Report Appendices

Appendix	Number of Volumes	Contents
A	1	Signed RUS Form 341s Member System Load Forecast Reports
B	1	Regional Model Code and Results Sales Forecast Definitions, Assumptions, and Results Class Model Statistics for each Member System

Model Description

Regional Economic Forecasts

An important part of the load forecast is the regional economic outlook. EKPC has divided its members' service area into seven economic regions based on the member system service territorial boundaries. As stated above, Global Insight collects the historical data, models the data, and provides forecast data to EKPC. Variables include: population, income, employment levels, wages, labor force, and unemployment rate. Consistent regional forecasts for population, income, and employment are developed. Population forecasts are used to project residential class customers; regional household income is used to project residential sales; and regional economic activity is used to project small commercial sales.

Projections of regional economic activity can greatly impact the sales forecasting and strategic planning of EKPC. Changes in regional employment and income are important determinants of customer and sales growth.

Regions are based on natural regions that exist within the EKPC territory. For example, the Central region defined by EKPC fits closely within the Lexington Metropolitan Statistical Area (MSA). The BEA defines MSA's as areas of interrelated economic activity that go beyond a single county's boundaries. The coal mining industry dominates EKPC's eastern region. The Northern region includes Kentucky counties that border Cincinnati. The Southern region is influenced by tourism. The Louisville metropolitan area influences the West Central region. Finally, services and retail trade dominate the northeastern region.

A list of regions and counties is provided in Table 8. Models for these regions provide EKPC with a way of linking the electricity needs of a service area to the rest of the economy in a consistent and reasonable manner.

Table 8

East Kentucky Power Cooperative Regional Definitions
Counties by Region

Central South	Central North	South	Central	North	North East	East
Allen	Bullitt	Adair	Anderson	Boone	Bath	Bell
Barren	Hardin	Boyle	Bourbon	Bracken	Boyd	Breathitt
Butler	Henry	Casey	Clark	Campbell	Carter	Clay
Cumberland	Jefferson	Garrard	Fayette	Carroll	Elliott	Estill
Edmonson	Larue	Green	Franklin	Gallatin	Fleming	Floyd
Grayson	Meade	Lincoln	Harrison	Grant	Greenup	Harlan
Hart	Nelson	Marion	Jessamine	Kenton	Lawrence	Jackson
Metcalfe	Oldham	McCreary	Madison	Owen	Lewis	Johnson
Monroe	Shelby	Pulaski	Mercer	Pendleton	Mason	Knott
Simpson	Spencer	Russell	Scott		Menifee	Knox
Warren	Trimble	Taylor	Woodford		Montgomery	Laurel
	Washington	Wayne			Nicholas	Lee
					Powell	Leslie
					Robertson	Letcher
					Rowan	Magoffin
						Martin
						Morgan
						Owsley
						Perry
						Pike
						Rockcastle
						Whitley
						Wolfe

Customer Model

Residential customers are analyzed by means of regression analysis with resulting coefficients used to prepare customer projections. Regressions for residential customers are typically a function of regional economic and demographic variables. Different explanatory variables are used for member systems in order to account for regional differences in local economies.

Two variables that are very significant for these regressions are the numbers of households by county in each member system's economic region and the percent of total households served by the member system. The number of households by county is determined through EKPC's household model, which was developed in 1994 by the University of Louisville's Center for Urban and Economic Research. This model is a cohort survival model that uses regional model population forecasts to determine regional households. The percent of total households served by the member system is based on RUS Form 7 data and projected by trend growth.

Table 9 provides details of regressions for residential customers.

Table 9

Residential Customer Forecast

Model Inputs	**Source**	
	Historical Source	**Forecast Source**
Population	Global Insight database	Global Insight model results
Households - The number of households by county	Global Insight database	Global Insight model results
Share – The percent of the region's households served by member system	RUS Form 7	Trend Growth
Employment - Regional employment levels by SIC Code	Global Insight database	Global Insight model results
Income – Regional income levels	Global Insight database	Global Insight model results
Model Outputs	**Use of**	
Residential Customers	Residential customers are input into the residential sales model. They are also used to complete RUS Form 341.	

Note: Model inputs vary by member system. Member system equations do not contain every model input listed above.

Residential Sales Model

EKPC uses statistically adjusted end-use (SAE) models to forecast residential sales. This method of modeling incorporates end-use forecasts in the background and can be used to decompose the monthly and annual forecasts into end-use components. SAE models offer the structure of end-use models while also utilizing the strength of time-series analysis.

This method, like end-use modeling, requires detailed information about appliance saturation, appliance use, appliance efficiencies, household characteristics, weather characteristics, and demographic and economic information. The SAE approach segments the average household use into end-use components as follows:

$$\text{Use}_{y,m} = \text{Heat}_{y,m} + \text{Cool}_{y,m} + \text{Water Heat}_{y,m} + \text{Other}_{y,m}$$

Where, y=year
m=month

Each component is defined in terms of its end-use structure. For example, the cool index 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 usages.

$$\text{CoolIndex}_y = \sum_{\text{Type}} \text{Wgt}^{\text{Type}} * \frac{\left(\text{CoolShare}_y^{\text{Type}} \big/ \text{Eff}_y^{\text{Type}}\right)}{\left(\text{CoolShare}_{98}^{\text{Type}} \big/ \text{Eff}_{98}^{\text{Type}}\right)}$$

$$\text{CoolUse}_{y,m} = \left(\left(\frac{\text{CDD}_{y,m}}{\text{NormCDD}}\right) * \left(\frac{\text{HHSize}_y}{\text{HHSize}_{by}}\right) * \left(\frac{\text{Income}_y}{\text{Income}_{by}}\right) * \left(\frac{\text{Price}_{y,m}}{\text{Price}_{by}}\right)^{-.30}\right)$$

Where, by=base year

$$\text{Cool}_{y,m} = \text{CoolIndex}_y * \text{CoolUse}_{y,m}$$

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.

Features of EKPC's SAE model are as follows:

1. Over 20 years of End-use Survey historical data are used to forecast saturation of appliances.

2. Appliance efficiencies due to government regulation have been accounted for in the model using a standard roll-in method, where new households and existing households in the market for new appliances encounter more efficient units. Indices pertaining to appliance efficiency trends and usage are used to construct energy models based on heating, cooling, water heating and other energy for the residential class. Source: Energy Information Administration Annual Energy Outlook, East South Central region representing Kentucky.

3. Various demographic and socioeconomic factors that affect appliance choice and appliance use are present in the methodology. 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.

Every two years since 1981, EKPC has surveyed the member systems' residential customers. The most recent survey was conducted in September and October 2009. EKPC gathers appliance, heating and cooling, economic, and demographic data. Appliance holdings of survey respondents are analyzed in order to project future appliance saturations and to better understand their electricity consumption.

EKPC's analysis and forecast of appliance saturations and appliance usage is econometric in nature. The decision made by customers to purchase an appliance can often be understood by examining customer income levels, fuel price, and household characteristics. The choice to purchase an appliance is modeled separately from the decision to use the appliance. This is because these actions are separate and subject to different driving forces.

Tables 10 and 11 provide modeling details of residential sales.

Table 10
Residential Sales Forecast - Appliance Usage Projections

Dependent Variable: Appliance Saturation	
Model Inputs	**Source**
Residential Customers	Historical number of customers is taken from Form 7 data. Future number of customers is projected by EKPC and member systems.
Average Real Price of Electricity	Historical price is taken from Form 7. Future prices are projected by EKPC's Rates Department and member systems.
Cooling Degree Days & Heating Degree Days	Historical data come from DTN Meteorlogix. Regional weather stations are used to account for the geographical diversity of member systems. Future values are historical averages.
Household Size (People Per Household)	Census Bureau, Trend Growth
Percent of Customers Who Live In Rural, Urban, And Farm Areas	End-Use Surveys, Trend Growth
Real Household Income	Global Insight model results
Model Outputs	**Use of**
Appliance Saturations	The forecast of appliance saturations is combined with the forecast of appliance usages in order to forecast total residential sales.

Table 11

Residential Sales Forecast - Appliance Usage Projections

Dependent Variable: Appliance Usage	
Model Inputs	***Source***
Residential Customers	Historical customers are taken from Form 7. Future customers are projected by EKPC and member systems.
Average Real Price of Electricity	Historical price is taken from Form 7. Future prices are projected by EKPC's Rates Department and member systems.
Appliance Lifetimes	Association Of Home Appliance Manufacturers, EIA Data, U.S. Department of Energy
Appliance Efficiency Improvements	U.S. Department Of Energy, Energy Forecasters Group
Size of Water Heater	End-Use Survey, Trend Growth
Percent of Customers With A Cistern or Well	End-Use Survey, Trend Growth
Household Size (People Per Household)	Census Bureau, Trend Growth
Percent of Customers Who Live In Rural, Urban, And Farm Areas	End-Use Surveys, Trend Growth
Real Household Income	Global Insight model results
Model Outputs	**Use of**
Appliance Usage Levels	The forecast of appliance usages is combined with the forecast of appliance saturations in order to forecast total residential sales.

Small Commercial Sales Model

In 2008, there were over 32,000 total small commercial customers in the EKPC system, with an average annual use per customer of approximately 60 MWh. This class is analyzed by means of regression analysis, and the resulting coefficients are used to prepare sales and customer forecasts. Each member system has two regression equations which requires 32 regression equations in order to analyze and forecast preliminary small commercial sales. The first regression consists of total small commercial sales as a function of price, weather, and some measure of the local or national economy. The second regression consists of small commercial customers as a function of residential customers, the unemployment rate, or time. Different explanatory variables are used for member systems in order to account for regional differences in local area economies. For example, small commercial sales in some territories are heavily influenced by the oil and gas industry, while other areas are more affected by retail stores.

This class has experienced a fair amount of reclassification over the years. Reclassifications can certainly be accounted for in the regression analysis, but the breaks in the data tend to lower the overall robustness of the regressions. Small commercial analysis and forecasting represent a challenge due to reclassifications and the relative heterogeneity of the data. Customers in this class include small mines, quarries, churches, schools, retail stores, large farm operations, and others, who each respond in different ways to different factors. The tables below provides regression modeling details of the small commercial class.

Table 12

Small Commercial Customer Forecast

Dependent Variable: Small Commercial Customers	
Model Inputs	**Source**
Residential Customers	Historical customers are taken from Form 7. Future customers are projected by EKPC and member systems.
Unemployment Rate	Global Insight model results
Time	
Model Outputs	**Use of**
Total Small Commercial Customers	Used to determine average use per customer. This forecasted variable is used to complete RUS Form 341.

Note: Model inputs vary by member system. Member system equations do not contain every model input listed above.

Table 13
Small Commercial Sales Forecast

Dependent Variable: Small Commercial Sales	
Model Inputs	**Source**
Residential Customers	Historical customers are taken from Form 7. Future customers are projected by EKPC and member systems.
Average Real Price of Electricity	Historical price is taken from Form 7. Future prices are projected by EKPC's Rates Department and member systems.
Cooling Degree Days & Heating Degree Days	Historical data come from NOAA. Regional weather stations are used to account for the geographical diversity of member systems. Future values are historical averages.
Regional Employment Levels by SIC Code	Global Insight model results
Total Regional Income	Global Insight model results
Model Outputs	**Use of**
Total Small Commercial Sales	This retail class is combined with other retail class forecasts in order to project member system purchases and EKPC total requirements.

Note: Model inputs vary by member system. Member system equations do not contain every model input listed above.

Large Commercial Sales Model

In 2008, there was an average of 132 customers in this class with an annual average use per customer of over 20,000 MWh. Unlike the small commercial class, no member system regression equations are used in the analysis and forecast of large commercial sales. Since there are so few large commercial customers, use of regression to study the past history would reflect individual plant production decisions and not necessarily responses to economic conditions. EKPC and its members have a two-part method for making projections in this class. First, existing customer forecasts are made, and second, forecasts of new customers are prepared.

Forecasts of Existing Customers

These projections are made directly by member systems since they are in regular contact with the customers. Each member system prepares a three-year projection of each one of their customers whose monthly demand exceeds 1 MW. Load forecasts beyond the three-year horizon for existing large commercial customers are either fixed at the third year level or are adjusted based on information shared at the load forecast meeting.

Forecasts of New Customers

In the short-term, usually for a two or three-year period, both EKPC and member systems are aware of planned large load additions. 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.

Over the long-term, a regression technique is used to forecast new large commercial 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 to the member systems using a probabilistic model which provides an analytical basis for locating large loads on the EKPC system. The model is spreadsheet based using @RISK. The model probabilistically distributes the new large commercial 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 commercial customers is determined, energy projections are based on the assumption that all new unknown large commercial customers have the same characteristics as the average of all existing large commercial customers, for example, a peak load of 1.8 MW with a 70 percent load factor. This methodology for forecasting new large commercial customers and energy provides a robust and defensible projection at the member system level.

Table 14

Existing Large Commercial Customer Sales Forecast

Model Inputs	Source
Use per Customer	Historical data are taken from Form 7. Projections are made by member systems based on current trends, and based on knowledge of customer's intentions.
Model Outputs	**Use of**
Large Commercial Sales – Existing Customers	This segment of large commercial sales is combined with new customer sales. The large commercial retail class is combined with other retail class forecasts in order to project member system purchases and EKPC total requirements.

Table 15

New Customer Large Commercial Sales Forecast, Short-Term

Model Inputs	Source
Number of Customers	Number of Service Area Industrial Sites, Chamber of Commerce Efforts, Industrial Recruiting Efforts, EKPC Industrial Development Efforts.
Use per Customer	Type of Customer and Process, NAICS Characteristics, Characteristics of Similar Customers
Model Outputs	**Use of**
Large Commercial Sales - New Customers, Short-Term	This segment of large commercial sales is combined with new customer sales. The large commercial retail class is combined with other retail class forecasts in order to project member system purchases and EKPC total requirements.

Table 16

New Large Commercial Customer Sales Forecast, Long-Term

Model Inputs	Source
Number of Customers	Short-term forecast, trend growth, regional employment trends
Regional Income	Global Insight model results
Regional Employment	Global Insight model results
U.S. GNP	Global Insight
Share of County Served	RUS Form 7 and trend growth
Model Outputs	**Use of**
Large Commercial Sales - New Customers, Long-Term	This segment of large commercial sales is combined with new customer sales. The large commercial retail class is combined with other retail class forecasts in order to project member system purchases and EKPC total requirements.

Other Sales

Other retail sales vary by member system. Some members do not report consumers in this category. Some members report seasonal sales, street light sales and sales to public authorities. EKPC's approach to this class is the same for each member system. Member system regression equations are developed with resulting coefficients used to forecast the class.

Table 17

Other Sales Forecast

Model Inputs	**Source**
Residential Customers	Historical customers are taken from Form 7. Future customers are projected by EKPC and member systems.
Model Outputs	**Use of**
Other Sales	This retail class is combined with other retail class forecasts in order to project member system purchases and EKPC total requirements.

Peak Model

EKPC's peak demand forecast is a bottom-up approach, meaning the member system peaks are summed to determine the EKPC peak. Model inputs include annual energy by end-use for the residential class and total energy use for small and large commercial. Model outputs are hourly demand for winter peak day and hourly demand for summer peak day. Weather sensitive appliance demands reflect typical peak day temperature profiles for winter and summer. The resulting peaks are explicitly linked to energy projections. Load factor is an input to the forecast. The load factors used are derived from data collected in the EKPC Load Research Program. The table below lists model inputs and model outputs.

Table 18

Peak Demand Forecast

Model Inputs	**Source**
January Electric Heat Sales	Residential Forecast Model
January and July Electric Water Heater Sales	Residential Forecast Model
July Air Conditioning Sales	Residential Forecast Model
January and July Residential Residual Sales	Residential Forecast Model
January and July Small Commercial Sales	Small Commercial Model
January and July Large Commercial Sales	Large Commercial Model
January Electric Heat Peak Day Load Factors	Load Research
January and July Electric Water Heater Load Factors	Load Research
July Air Conditioning Load Factor	Load Research
January and July Residential Residual Load Factor	Load Research
January and July Small Commercial Load Factor	Load Research
January and July Large Commercial Load Factor	Load Research
Model Outputs	**Use of**
Winter Peak Day Load Profile Summer Peak Day Load Profile	These represent EKPC and member system peak demand forecasts.

Loss Calculations

Transmission and distribution losses make up approximately eight percent of total energy requirements on the EKPC system. For this reason, EKPC analyzes distribution and transmission losses carefully in order to accurately project future values. While there is no formal modeling process in loss analysis, member systems provide excellent input into future distribution loss determination using several decision rules including:

1. Comprehensive right-of-way programs tend to reduce losses.

2. Direct-served large commercial customers, customers with no distribution line, reduce overall distribution losses.

In addition to energy losses, demand losses are also developed. Winter peak day losses are assumed to be one percent greater than average energy losses and summer peak day losses are two percent higher than average energy losses.

Hourly Load Model

EKPC develops a 20 year hourly load forecast using ITRON's MetrixLT program. This program is PC based and runs in a Windows environment. It calculates hourly demands given input load shapes, energies and peak demands. In addition, the model accounts for transmission and distribution losses and allows for reconciliation to an external forecast.

EKPC generates 8,760 hourly demands from annual energy for each year of the 20 year load forecast for the EKPC system. Hourly forecasts for member systems are developed as requested.

Uncertainty Analysis

Probabilistic Forecasting

EKPC brackets its base load forecast with high and low projections by analyzing probability distributions of significant variables that impact the forecast allowing the capture and study of a model's inherent uncertainty. The software @RISK is used for this. For example, price, income, number of customers are all variables that impact residential sales. Each of these can be expressed as a probability distribution. A probabilistic forecast of residential sales for each year in the forecast involves many passes through the residential sales forecasting model with different values of the above variables randomly selected from their corresponding probability distributions. The net result is a distribution of possible outcomes for residential sales for each year. EKPC uses the 50/50 value of the probability distribution as the base case whereas the high and low case represent the 90 percent bounds.

Scenario Forecasting

Scenario forecasts are different from the probabilistic forecasts described above. In scenario forecasting, certain events are modeled in order to examine the effect on the forecast. Consider, for example, the occurrence of an economic depression. Because the chances of such an event are remote, a probabilistic load forecast will not contain the results of such a catastrophe. In scenario forecasting, however, one can assume that an economic depression occurs, without explicit regard to the probability of such an occurrence, in order to study the effects of such an event on the load forecast. Both scenario forecasting and probabilistic forecasting are common techniques in uncertainty analysis.

High and low scenarios are developed using the same methodology as with the base case, however, the starting summary file is different. Instead of using the sum of the member system files, two new models are built: one reflecting assumptions that result in high usage and one with assumptions that result in low usage. A summary of the assumptions for each case is listed below:

Case 1 - Pessimistic economic assumptions with mild weather causing lower loads
Case 2 - Most probable economic assumptions with mild weather causing lower loads
Case 3 (Base) - Most probable economics assumptions with normal weather (Base Case)
Case 4 - Most probable economic assumptions with severe weather causing higher loads
Case 5 - Optimistic economic assumptions with severe weather causing higher loads.

The assumptions that are varied include:

1. Weather: based on historical heating and cooling degree day data, alternate weather projections are developed based upon the 90th and 10th percentile to reflect extreme and mild weather, respectively.

2. Electric price: The general approach is to use price forecasts that are available and use the growth rates from those forecasts to prepare the high and low growth rates around the growth patterns for the base case residential price forecast. The manner in which the price of electricity will change in the future is primarily a function of how prices change for the underlying fixed and variable components of electricity rates.

3. Residential customers: The basic approach to preparing high and low case scenarios for the future number of residential customers is to determine the magnitude of variation in the past between long term average growth rates and higher or lower growth rates during shorter periods of time.

   First, the data on the historic monthly household counts for the previous 20 year period is prepared. Next, the compound annual growth rate in households is calculated for each rolling ten year. This produced a set of twelve compound annual growth rate values each representing a unique ten year span. Maximum and minimum values are determined. The highest growth is used to prepare the high case scenario, while the 10 year period that experienced the lowest growth is used to prepare the low case scenario.

   These resulting adjustments are applied to the 20 year compound annual growth rate in the base case customer count forecast to produce the high case and low case compound annual growth rate forecast scenarios. This relationship is preserved when preparing the monthly customer counts for the high and low case scenarios.

Adjusting these assumptions leads to different customer forecasts which in turn results in different energy forecasts.

Interaction with Other Areas of EKPC

Load Research

Due of the end-use nature of EKPC's residential sales and peak demand forecast methodology, the load forecast relies on data collected by traditional load research techniques. The information used includes:

1. Winter and summer load factors for the large and small commercial classes.

2. Load factors for winter and summer for the residential class for heating, cooling, water heating, and residual load.

Marketing

More and more, EKPC's load forecasting analysis is becoming a study of why customers choose electricity and in what amounts. Load forecasts are the result of econometric models that attempt to simulate customer behavior regarding energy consumption. Traditional marketing efforts are likewise concerned with understanding customer wants and needs and then responding to unmet conditions. Since both groups at EKPC are interested in similar customer characteristics, there are frequent exchanges of customer data and ideas. Additionally, the Marketing Department is the home of the demand-side management participation data which is needed to account for usage impacts in the forecast. Over the past year, EKPC and the state of Kentucky has become more interested and active in DSM.

Transmission Planning

EKPC provides Transmission Planning with aggregate load forecasts and peak demand forecasts at the substation level.

Resource Planning

An important use of the load forecast is as input into Integrated Resource Planning (IRP). Every three years, EKPC must file an IRP with the Kentucky Public Service Commission. EKPC's load forecast becomes more detailed as needed to support the IRP. The Commission's order requires a detailed reporting of the load forecast used in developing the IRP. For the sake of consistency, EKPC's load forecast report also doubles as its load forecast contribution to the IRP report.

Rates

EKPC's resource planning cycle functions in the following manner: (1) after a new load forecast is completed, integrated resource planning provides updated information on future capacity needs as well as production cost forecasts, (2) the Rates Department then uses the load forecast to calculate revenue and prepares wholesale power cost forecasts, (3) the resulting rates forecast then becomes an input to the next load forecast, and (4) the cycle repeats.

Finance

The load forecast is provided to the Finance Department to be used in the budget process.

Surveys

EKPC has conducted a residential end-use mail survey every two years since 1981. Questions asked in the survey relate to heating and cooling methods, appliance holdings, and farm equipment. In addition to end-use questions, data on lifestyle, age, demographics, and income are collected. In 2009, 800 surveys per member system were mailed for a total of 12,800. Another 200 surveys were mailed to capture the demographics of a recent municipal addition. EKPC measures sampled customer kWh usage with population customer kWh usage to determine whether the sample has been a true representation of the population. In general, the sample has been very close to the population.

The end-use survey is the cornerstone of EKPC's residential sales forecasting. The survey provides historical appliance saturation levels and is also used to forecast future appliance saturation levels.

In addition, the end-use survey provides a picture of the retail customer's electricity use, which is extremely important in marketing, DSM, and other applications at EKPC and at the member system.

APPENDIX

EKPC Load Forecast 2010
Tasks and Time Line

Task	Projected Completion Date	Sally Witt	Sandy Mollenkopf	Wanda Kirby	Mark Mefford
Industrial Customer Worksheet - existing customers > 1MW - provide Mark with 2 years history, KW and kWh, in spreadsheet	11/30/2009		x		
Rate Worksheet - set up - provide to Mark	12/15/2009				x
Member Appliance Survey Results - by member system, EKPC system - spreadsheet	12/15/2009		x		
Review NCP winter and summer factors - evaluate by member system	12/15/2009				x
Rate Worksheet - send initial set up to member systems - receive and enter data from member systems	1/15/2010				x
Industrial Customer Worksheet - prepare data from Sandy for existing customers - send to member systems requesting forecast of existing customers and knowledge of new loads coming in next couple of years - receive and enter data	1/15/2010		x		x
Load Factors - annual, winter, summer - by class - by member system	11/30/2009				x
Economic Model results	12/31/2009	x			x
Actual and Forecasted Price - by class - by member system	1/31/2010				x
Form 7 data - use and customers	3/31/2010		x		x

Task	Projected Completion Date	Sally Witt	Sandy Mollenkopf	Wanda Kirby	Mark Mefford
Member System Narratives - prepare for visits	2/28/2010				x
Board Resolutions - Prepare draft to be taken to meetings	2/28/2010				x
Presentation Materials - economic model results - RUS Form 5, RUS Form 736 data - rate forecast sheet - customer and sales forecast results - comparisons of current and past forecasts - appliance saturation projections - seasonal peak demand forec	4/30/2010	x			x
Schedule meetings - with member systems - coordinate with RUS	5/31/2010			x	
Member System Visits	6/30/2010	x			x
Reports - Member System and EKPC System - copy and bind - distribute to appropriate parties	9/30/2010				x
Prepare Board Agenda item	8/31/2010				x
Weather - update database - update models - update normals	2/28/2010				x
Economic data - update database - update models	12/31/2009				x
Prices - update database - update models	2/28/2010				x
Parameters - analyze current values and update - update models	12/2/2009				x
Demand Factors - evaluate existing DF - update models as necessary	12/31/2009				x

Task	Projected Completion Date	Sally Witt	Sandy Mollenkopf	Wanda Kirby	Mark Mefford
Member Appliance Saturation Survey - forecast saturations - by member system - EKPC system - heating, cooling, water heating, and other	12/31/2009				x
Appliance Efficiency data - evaluate and update data from EFG CD	11/30/2009				x
Form 7 Data - update ForecastManager - update models	3/31/2010				x
Large Commercial - add new loads to spreadsheet - System run to determine # of new >1 MW loads - @RISK model to allocate new large loads among member systems	2/28/2010				x
Usage Models - by member system - by class	4/30/2010	x			x
Peak Models - by member system - monthly and hourly forecasts	4/30/2010	x			x
Make necessary adjustments to models based on member system input	7/31/2010				x
EKPC System Forecast - Energy - Peak	8/31/2010	x			x
Reports - member system specific - EKPC total	9/30/2010				x
					x
Substation Forecasts - analyze results - prepare preliminary reports for meetings - make changes per member system - send 'final' reports to member systems and internal customers	9/30/2010				x

USDA
Rural Development

United States Department of Agriculture
Rural Development

T - Please have changed. T.C.

JAN 27 2010

Mr. Robert M. Marshall
President & CEO
East Kentucky Power Cooperative, Inc.
P.O. Box 707
Winchester, Kentucky 40392-0707

Dear Mr. Marshall:

We have reviewed the 2009 Load Forecast Work Plan for East Kentucky Power Cooperative, Inc. (East Kentucky), and its members. This work plan was approved by the East Kentucky Board of Directors on November 10, 2009. It was submitted to the Rural Utilities Service on November 23, 2009.

The work plan establishes the resources, methods, schedules, and milestones to be used in the preparation and maintenance of the load forecast for East Kentucky and its members. East Kentucky and its member systems are required to follow the work plan in preparing their respective load forecasts. According to the regulation (7 CFR 1710), a work plan may cover a period for up to 3 years. The work plan submitted covers the load forecast currently prepared and submitted in 2010.

This letter documents approval of the 2009 Load Forecast Work Plan for East Kentucky Power Cooperative, Inc. A copy of this letter is being sent to each of East Kentucky's members.

Sincerely,

GEORG A. SHULTZ
Director
Electric Staff Division

FEB 0 2010

cc:
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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

GENERAL ADJUSTMENT OF ELECTRIC RATES	)	PSC CASE NO.
OF EAST KENTUCKY POWER	)	2010-00167
COOPERATIVE, INC.	)	

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

Filed: May 27, 2010

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 Senior Vice President of Power Production 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 January 2010.

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 plants. I report to the CEO.

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)(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. Has EKPC added any new pollution control equipment since case no. 2008-00409?

A. Yes, EKPC constructed wet flue gas desulfurization equipment (scrubbers) on Spurlock Station Unit 1 and Unit 2.

Q. Has EKPC added any new generation since the filing in Case No. 2008-00409?

A. Yes, EKPC has added Spurlock Station Unit 4 and Smith Combustion Turbine Units 9 and 10.

Q. Has the addition of the new generation or pollution control equipment changed the way that Power Production budgets for operations and maintenance?

A. No.

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

A. The operation and maintenance expenses that are included in the forecasted test year are based on 2011 budget for EKPC. The budget is divided into budget categories for each generating facility. Each electric generating plant has its own responsibility center. The responsibility centers are then divided into individual budget categories for operational items, maintenance items and capital items. The budget categories are standardized among the facilities to the maximum extent possible. There are budget categories 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 categories and the methodology used to develop the expenses that are included in Plant Operations.

A. The budget categories 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 categories 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 categories and the methodology used to develop the expenses that are included in Distributive Generator (Cagles).

A. The budget categories 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 categories 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 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 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 and Unit No. 4 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 and Unit No. 4 is also taken into consideration. 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 methodology used to develop the expenses that are included in Ash Storage – Operations.

A. The estimated quantity of ash produced by the units and gypsum produced by Spurlock Units 1 and 2 are based upon the amount of ash in the fuel and the amount of generation estimated from the Planning Department's Generation Model. This is compared with the historical amounts as a check.

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

A. The budget categories 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 categories 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 Vehicles 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 $26.72 per megawatt hour in 2004 to $36.34 per megawatt hour in 2009. The national average during the same time period ranged from $19.96 per megawatt hour in 2004 to $31.07 per megawatt hour in 2009. EKPC's stated O&M costs have all allocations accounted for in the rate. EKPC's O&M costs are approximately ten percent lower than the rates stated if the allocated costs are not included. Allocated items include support staff not located at the plants, employee benefits, insurance and taxes. It is not known if the O&M costs shown for the national averages are fully burdened with allocated costs.

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 2004 -

2008 Generating Availability Report (GADS) published in August of 2009. This report 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 2004-2008	National Average FOR 2004-2008
Dale 1	2.8%	6.5%
Dale 2	2.0%	6.5%
Dale 3	2.6%	6.5%
Dale 4	2.8%	6.5%
Cooper 1	2.5%	4.7%
Cooper 2	2.2%	4.4%
Spurlock 1	0.3% (avg. yrs 05, 06, 07 & 08)	4.2%
Spurlock 2	1.1%	5.4%
Gilbert	6.4%	4.4%

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. Note that the average FOR for the Gilbert Unit is for the period March 2005 through the end of the year 2008. Spurlock Unit 4 went into commercial operation in April 2009. This unit had a 2009 FOR of 6.2% during its first nine months of operation. The generating data collected by NERC does not distinguish between the different types of coal boilers and groups

Gilbert and Spurlock 4, both CFB's, 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	)	**CASE NO. 2010-00167**
GENERAL ADJUSTMENT OF ITS	)	
WHOLESALE ELECTRIC RATES	)	

A F F I D A V I T

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 May, 2010.

Gwyn M. Willoughby
Notary Public

MY COMMISSION EXPIRES NOVEMBER 30, 2013
NOTARY ID #409352

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

GENERAL ADJUSTMENT OF ELECTRIC RATES	**)**	**PSC CASE NO.**
OF EAST KENTUCKY POWER	**)**	**2010-00167**
COOPERATIVE, INC.	**)**	

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

Filed: May 27, 2010

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 Power Delivery & Construction.

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)(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 are used to identify system problems and to evaluate 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 Engineering, Maintenance or System Operations 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 of 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 and maintenance budget for System Operations.

A. In addition to the above transmission capital and maintenance budgets for inspection and maintenance, the transmission System Operations Business Unit also has an operating and maintenance budget associated with daily operations of the Energy Control Center, telecommunications, metering, control and monitoring of the transmission system, and support of the Energy Control Center applications and technology. 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. 2010-00167**

AFFIDAVIT

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 27th day of May, 2010.

Gwyn M. Willoughby
Notary Public

MY COMMISSION EXPIRES NOVEMBER 30, 2013
NOTARY ID #409352

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
GENERAL ADJUSTMENT OF THE ELECTRIC RATES OF EAST KENTUCKY POWER COOPERATIVE, INC.	)))	CASE NO.: 2010-00167

PREFILED DIRECT TESTIMONY AND EXHIBITS OF
DENNIS R. EICHER
PRESIDENT
D. R. EICHER CONSULTING, INC.

ON BEHALF OF
EAST KENTUCKY POWER COOPERATIVE, INC.

May 27, 2010

PREFILED DIRECT TESTIMONY AND EXHIBITS OF
DENNIS R. EICHER
PRESIDENT
D. R. EICHER CONSULTING, INC.

ON BEHALF OF
EAST KENTUCKY POWER COOPERATIVE, INC.

PART I - QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Dennis R. Eicher. My business address is 28947 River Ridge Rd. NW, Isanti, MN 55040.

Q. What is your profession?

A. I am a Professional Engineer ("P.E.") and the President/Owner of D.R. Eicher Consulting, Inc. ("DREC").

Q. Please summarize your educational and work experience.

A. A copy of my curriculum vitae is provided as Exhibit __(DRE-1).

Q. Have you ever testified before the Public Service Commission of the State of Kentucky ("PSC" or "Commission")?

A. No.

Q. Have you ever testified before other regulatory bodies relative to electric utility issues?

A. Yes. A list of the cases where I have provided written and/or oral testimony regarding electric utility issues is attached to my curriculum vitae attached hereto as Exhibit ___(DRE-1).

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

A. I have been retained by East Kentucky Power Cooperative, Inc. ("EKPC") to prepare a Cost of Service Analysis ("COS") in conjunction with its instant rate filing.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

- Exhibit __(DRE-1) Curriculum Vitae – Dennis R. Eicher
- Exhibit __(DRE-2) Cost of Service Analysis

Q. Were these exhibit prepared by you or under your direct supervision?

A. Yes.

PART II – DIRECT TESTIMONY

A. Overview

Q. Please provide a brief overview of the cost of service analysis you prepared.

A. I followed the traditional approach for preparing a fully allocated, average embedded cost of service ("COS") analysis for an electric utility, which may be described as consisting of the following steps:

Step 1 - Functionalize the utility's Rate Base and Revenue Requirements into four basic functional categories:

- Production;
- Transmission;
- Distribution; and
- General and/or Common.

Step 2 - Classify the utility's Rate Base and Revenue Requirements into the following categories:

- Direct -- Costs which are directly attributed to one specific classification (i.e., in this case, a single Member-System or contract customer). Expense associated with Steam Service is an example of the Direct Expense;
- Customer -- Costs which are a function of the number of customers served or delivery points (i.e., in this case, the Member-Systems) that do not vary significantly with the demand imposed on the system or the amount of energy consumed. Expense associated with metering at the delivery points is an example of a customer related cost;

- Capacity -- Costs resulting from providing and maintaining in readiness for operation facilities required to meet the peak demand imposed on the system; and
- Energy -- Costs related to the amount of energy used.

Step 3 - Allocate the classified costs to the various rate classes.

In the case of a generation and transmission ("G&T") cooperative, such as EKPC, which basically has only a single class of service, namely its Member Systems, the three steps are often merged into a consolidated process for simplicity.

Q. Please describe the COS analysis that you prepared on behalf of EKPC.

A. The cost of service analysis I prepared in conjunction with this case is presented in Exhibit __(DRE-2), and consists of the following schedules:

- Schedule A--Classification of Revenue Requirements;
- Schedule B—Classification of Plant-in-Service;
- Schedule C—Classification of Accumulated Reserves for Depreciation;
- Schedule D—Classification of Rate Base; and
- Schedule E—Classification of Labor Expense.

The analysis, however, may be more easily explained starting with Schedule B, where Plant-in-Service is functionalized/classified.

Q. Please describe how you classified Plant-in Service.

A. I first defined the relevant functional/classification categories as follows:

- Production--Capacity related;
- Production--Energy related;

- Production—Steam Service;
- Transmission;
- Distribution substations; and
- Distribution metering.

I then walked through each of the plant accounts, defined on the basis of the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts ("USA"), and assessed what function and/or classification was most appropriate for each account. In the case of production, I first needed to allocate a portion of the Steam Plant investment associated with Spurlock Units 1 and 2 to the Steam Service category. (Steam Service is provided to Inland Steam out of Spurlock Units 1 and 2.) This was done on the basis of ratios of the equivalent capacity and energy requirements of Inland Steam to the total capacity and energy output of Spurlock Units 1 and 2. The remainder of the investment in production facilities was assigned to the Production-Capacity category.

Q. Please explain why you classified production plant-in-service, after netting out the allocated portion of Spurlock Units 1 and 2 for service to Steam Service, as 100 percent capacity related.

A. This is the method that was used by EKPC in its last rate filing; and while I am assisting EKPC and its Member-Systems in considering alternate methods that would recognize the dual role that capacity and energy play in driving production plant investment, that project is still in process; and no decision on methodology or approach has yet been made. Therefore, it seemed prudent, particularly since EKPC is proposing to implement the requested rate increase on a pro rata basis, to follow the general approach used in preparing the COS analysis filed with EKPC's last rate case.

Q. Please explain how you functionalized/classified investment in transmission facilities.

A. In functionalizing and classifying transmission investment, I first identified the investment in generator step-up ("GSU") transformers, and assigned this investment to the Production-Capacity component. I then identified the portion of transmission substation investment that was related to distribution metering and assigned that to the Distribution Metering category. I should note that it is somewhat unusual for distribution metering investment to be recorded in a transmission account. In this case, it is due to the fact that at one time the Member Systems owned the distribution substations, but EKPC owned the meters; and a decision was made to record EKPC's metering investment in Account 353, Transmission Stations. When EKPC acquired ownership of the distribution substations from its Members, that investment was recorded in the distribution accounts (Accounts 360 to 373), but the investment in the metering was left in Account 353.

Q. Please explain how you functionalized/classified the investment in the distribution accounts, Accounts 360 to 373.

A. All of the investment in Accounts 360 to 373 is associated with distribution substations, and so was assigned to that category.

Q. Please explain how you functionalized/classified investment in General Plant facilities.

A. General Plant serves an overhead function, for which there exists no direct correlation with the functional/classification categories. Therefore, it is customary to functionalize/classify this investment based on a labor expense allocator. The rationale for this approach is that General Plant is related to administration and equipping employees to perform the job functions.

Q. Please explain how you functionalized/classified labor expense.

A. The functionalization/classification of labor expense is provided in Schedule E. As shown, I chose to functionalize/classify labor expense in the same manner that the corresponding operation and maintenance ("O&M") expense was functionalized/classified. I will describe in more detail the methodology used to classify O&M expense later in my testimony.

Q. Please explained how you functionalized/classified Accumulated Reserves for Depreciation, as shown in Schedule C.

A. EKPC, like most G&T cooperatives, does not maintain Accumulated Reserves for Depreciation records by individual accounts corresponding to FERC defined plant accounts, but instead by functional category. Therefore, the first step was to allocate the amount recorded for each functional category to subaccounts corresponding to the plant accounts within that functional category. The allocated Accumulated Reserves for Depreciation for each plant account were than allocated to each functional/ classification category on the same basis as the corresponding investment.

Q. Please explained how you functionalized/classified Rate Base shown in Schedule D.

A. The functionalization/classification of Plant-in-Service and Accumulated Reserves for Depreciation, presented in Exhibit___(DRE-2) Schedules B and C, was described previously. Construction Work in Progress ("CWIP") was first broken down into appropriate categories, with the amounts in each category functionalized/classified in the same manner as the corresponding plant accounts. Similarly, Materials and Supplies ("M&S") were first broken down into relevant categories, and then functionalized/classified in the same manner as the corresponding plant accounts. Finally, working capital was determined using the customary 45 days (1/8) rule, and functionalized/classified in the same manner as the corresponding expense.

Q. Please explain how you functionalized/classified Revenue Requirements, as shown in Schedule A.

A. The first category of expenses to be functionalized/classified is Production Operations and Maintenance ("O&M") expense. After direct assigning Production O&M expenses related to providing steam service to the steam category, the remaining expenses were assigned based on FERC's predominance method, which assigns an expense account to either Production-Capacity or Production-Energy in a FERC prescribed manner. This approach is intended to reflect the cost driver for the majority of the expense recorded in each account. Purchased Power expense was found to be entirely related to energy purchases, and, thus, was assigned to the Production-Energy category. Account 556, System Control and Dispatch, was evaluated by experienced EKPC staff to identify the relevant cost drivers, and was functionalized/classified accordingly. Finally, Account 557, Other Expenses was determined to be roughly 50 percent capacity and 50 percent energy related, and was functionalized/classified accordingly.

Transmission and distribution O&M expense was functionalized/classified, primarily on the basis of the corresponding plant accounts. Customer Service and Information and

Sales expense was deemed to be primarily associated with energy sales, and, thus, was assigned to the Production-Energy category. Administrative and General ("A&G") expense was generally functionalized/classified based on the labor ratios developed in Schedule E. The one exception was Account 924, Outage Insurance, which was assigned to the Production-Capacity category.

Depreciation expense was functionalized/classified in accordance with the corresponding plant accounts. Amortization of Debt Expense and Discounts, Account 428, was functionalized/classified on the basis of Net Plant.

Interest and Margin Requirements were functionalized/classified according to Rate Base, as shown in Schedule D.

Other Revenue and Non Operating Income Credits were assigned based on an analysis of their respective sources. For example, revenue from off system sales (i.e., non-Member Sales) was determined to be energy sales and were assigned to the Production-Energy component. Wheeling (i.e., transmission service) revenue was assigned to the Transmission category. Other Operating Revenue was direct assigned based on the source of the revenue, while Interest Income and Patronage Capital Allocations from Associated Organizations were assigned on the basis of Rate Base.

Q. Please summarize the results of your analysis.

A. The results of my COS analysis may be found on page 5 of Schedule A of Exhibit___(DRE-2), and are summarized below:

Function/Classification		Amount	% of Total
Production-Capacity	$	249,338,468	57.4%
Production-Energy		92,338,635	21.3%
Steam Service		3,180,994	0.7%
Transmission		74,145,497	17.1%
Distribution Substations		13,765,993	3.2%
Distribution Metering		1,353,286	0.3%
Total	$	434,122,872	100.0%

Q. Does that conclude your prefiled Direct 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. 2010-00167**

AFFIDAVIT

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Dennis R. Eicher, 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.

Dennis R. Eicher

Subscribed and sworn before me on this 7th day of May, 2010.

Gwyn M. Willoughby
Notary Public

MY COMMISSION EXPIRES NOVEMBER 30, 2013
NOTARY ID #409352

Dennis R. Eicher, P.E.

SUMMARY OF EXPERIENCE & EXPERTISE

- Over 40 years in the electric utility industry and consulting.
- Experienced in all aspects of electric utility system planning and financial operation.
- Specialized expertise in the areas of economic and financial analysis, integrated resource planning, demand response and energy efficiency evaluations, wholesale and retail rate design, litigation support, merger and acquisition evaluation and strategic planning.
- Registered professional engineer in the states listed below.

PROFESSIONAL EXPERIENCE

D.R. Eicher Consulting, Inc. – Isanti, Minnesota (2009 – Present)

President
Independent consultant to small electric utilities and industrial customers specializing in economic and financial analysis, integrated resource planning, demand response and energy efficiency evaluations, wholesale and retail rate design, litigation support, merger and acquisition evaluation and strategic planning.

Power System Engineering – Blaine, Minnesota (1976 – 2008)

Various Responsibilities Including President and Executive Vice president
Supervisory, client liaison and project responsibility for analytical projects involving rate and cost of service applications, expert testimony, merger and acquisition analysis, contract negotiations, distribution, transmission, and power supply, demand response, strategic planning, implementation of legislative directives.

Daverman Associates, Inc. – Grand Rapids, Michigan (1974 – 1976)

Administrator of Power Division
Supervisory and technical responsibilities for Power Division, responsible for all utility related work of the firm.

Stanley Consultants, Inc. – Muscatine, Iowa (1969 - 1974)

Head of Power Systems Department
Supervisory and technical responsibilities in power system analysis disciplines including power supply and feasibility analysis, interconnection and power supply contract negotiations, financial forecasting, rate applications, distribution and transmission studies, load projections, and control center planning and implementation.

Detroit Edison Company – Detroit, Michigan (1965 – 1969)

Engineer
Engineer in Electric Systems Operations Department with increasing levels of responsibilities in various aspects of electric utility operations.

EDUCATION

Wayne State University – Detroit, Michigan, 1965

Bachelor of Science Degree in Electrical Engineering
Postgraduate work in:

- Power System Analysis
- Engineering Mathematics
- Energy Resources
- Valuation
- Accounting

REGISTRATIONS

- Colorado
- Indiana
- Iowa
- Michigan
- Minnesota
- Nebraska
- New Hampshire
- North Dakota
- Wisconsin

PROFESSIONAL MEMBERSHIPS

- Institute of Electrical and Electronics Engineers – Life Member
- Rural Electric Power Committee (IEEE) – Past Chairman
- Minnesota Society of Professional Engineers
- National Society of Professional Engineers

ADDENDUM REFERENCES

- Expert Testimony

EXPERT TESTIMONY

- Provided testimony before 8 state and/or federal regulatory bodies
- Approximately 85 cases on a wide variety of issues

REGULATORY EXPERIENCE (TESTIMONY FILED)[1/]

Case or Jurisdiction	Docket No.	Description
Alaska	U-01-108	Chugach Electric Association, application to increase rates. Testimony provided on behalf of Alaska Electric Generation and Transmission Cooperative and Homer Electric Association.
Alaska	U-94-2	Tlingit-Haida Regional Electrical Authority. Consideration of the provision of electrical service to the Klawock Area currently certificated to Tlingit-Haida Regional Electrical Authority and Alaska Power and Telephone Company. Testimony filed on behalf of Tlingit-Haida Regional Electrical Authority.
Alaska	U-87-35	Chugach Electric Association, application to increase rates. Testimony provided on behalf of Alaska Electric Generation and Transmission Cooperative and Homer Electric Association.
Colorado	I&S 1640	Public Service Company of Colorado, Phase II (cost of service and rate design) application to increase rates. Testimony filed on behalf of AMAX, Inc.
Colorado	89I-4986	Colorado-Ute Electric Cooperative application to increase rates. Testimony filed on behalf of municipal customers of Colorado-Ute.
Colorado	I&S 941-430E	Public Service Company of Colorado, Phase II (cost of service and rate design) application to increase rates. Testimony filed on behalf of Climax Metals and Golden Technologies.
Indiana	37205	Wabash Valley Power Association, application to modify rate design. Testimony provided on behalf of five distribution cooperative members of WVPA.
Kansas	02 SEPE-247 -RTS	Sunflower Electric Power Corporation, application to modify rates. Testimony filed on behalf of Sunflower.
Kansas	09-MKEE-969 -RTS	Mid-Kansas Electric Company, LLC, application for approval to make certain changes in the charges for electric services. Filed on behalf of Mid-Kansas and its member-owners: Lane-Scott Electric Cooperative, Inc., Prairie Land Electric Cooperative, Inc., Southern Pioneer Electric Company, Inc., Victory Electric Cooperative Association, Inc., Western Cooperative Electric Association, Inc., and Wheatland Electric Cooperative, Inc.
Michigan	U-13716	Cherryland Rural Electric Cooperative Association, application to implement a large resort service rate. Rebuttal Testimony provided on behalf of Cherryland.
Michigan	U-5093	Cherryland Rural Electric Cooperative Association, application to increase rates. Testimony filed on behalf of Cherryland.

1/ Does not include over 200 rate studies for rural electric cooperatives and municipal electric systems who are not regulated.

Case or Jurisdiction	Docket No.	Description
Michigan	U-6089	Thumb Electric Cooperative, application to increase rates. Testimony filed on behalf of Thumb.
Michigan	U-6655	Cherryland Rural Electric Cooperative Association, application to increase rates. Testimony filed on behalf of Cherryland.
Michigan	U-7830	Consumers Power Company, application to increase rates. Testimony provided on behalf of Dow Corning Corporation.
Michigan	U-7909	Wolverine Power Supply Cooperative, Inc., application to revise rates. Testimony filed on behalf of Wolverine.
Michigan	U-7963	Wabash Valley Power Association, Inc., petition to Michigan PSC to assert jurisdiction over WVPA wholesale rate. Testimony filed on behalf of Fruit Belt Electric Cooperative.
Michigan	U-8115	Wolverine Power Supply Cooperative, Inc., application to revise rates. Testimony filed on behalf of Wolverine.
Michigan	U-8297	Upper Peninsula Power Company, application to implement a PSCR Clause (1986 Plan). Testimony provided on behalf of Michigan Technological University.
Michigan	U-8478	Cherryland Rural Electric Cooperative Association, application to increase rates. Testimony filed on behalf of Cherryland.
Michigan	U-8534	Wolverine Power Supply Cooperative. Complaint filed by Grand River Power Company to compel Wolverine to enter into PURPA type contract. Testimony filed on behalf of Wolverine.
Michigan	U-8617	Western Michigan Electric Cooperative, application to increase rates. Testimony filed on behalf of Western.
Michigan	U-8636	The Michigan Cogeneration and Renewable Resource Plan proposed by the MPSC Staff. Testimony provided on behalf of the Michigan Electric Cooperative Association.
Michigan	U-8667	Top O'Michigan Rural Electric Company application to revise rates. Testimony filed on behalf of Top O'Michigan.
Michigan	U-8670	Presque Isle application to revise rates. Testimony filed on behalf of Presque Isle.
Michigan	U-8783-R	Wabash Valley Power Association, Inc., reconciliation of Power Supply Cost Recovery for 1987. Testimony filed on behalf of Fruit Belt Electric Cooperative.
Michigan	U-8871	Midland Cogeneration Venture Limited Partnership Petition for approval of Purchased Power Agreement with Consumers Power Company. Testimony provided on behalf of the Michigan Rural Electric Cooperative.

Case or Jurisdiction	Docket No.	Description
Michigan	U-8906-R	Wabash Valley Power Association, Inc., reconciliation of Power Supply Cost Recovery for 1988. Testimony filed on behalf of Fruit Belt Electric Cooperative.
Michigan	U-9519	Tri-County Electric Cooperative, application to increase rates. Testimony filed on behalf of Tri-County.
Michigan	U-9375	Complaint filed by Consumers Power Company against Tri-County Electric Cooperative regarding service extension. Testimony filed on behalf of Tri-County.
Michigan	U-9517	Complaint filed by Top O'Michigan Electric Company against Consumers Power Company regarding service extension. Testimony filed on behalf of Top O'Michigan.
Michigan	U-9712	Fruit Belt Electric Cooperative, application to increase rates. Testimony filed on behalf of Fruit Belt.
Michigan	U-9750-R	Wabash Valley Power Association, Inc., power supply cost reconciliation. Testimony filed on behalf of Fruit Belt.
Michigan	U-9765	Wabash Valley Power Association, Inc., application to modify rate structure. Testimony filed on behalf of Fruit Belt.
Michigan	U-10056	Top O'Michigan Rural Electric Company, application to increase rates. Testimony filed on behalf of Top O'Michigan.
Michigan	U-10060	Tri-County Electric Cooperative, application to increase rates. Testimony filed on behalf of Tri-County.
Michigan	U-10066 U-10067 U-10068 U-10069 & U-10070	The Detroit Edison Company for approval of purchase of capacity and energy from resource recovery facilities. Testimony filed on behalf of Central Wayne Energy Recovery Limited.
Michigan	U-10080	Wabash Valley Power Association, Inc., 1991 PSCR reconciliation and parallel proceeding. Testimony filed on behalf of Fruit Belt.
Michigan	U-10093	Oceana Electric Cooperative, application to increase rates. Testimony filed on behalf of Oceana.
Michigan	U-10094	Upper Peninsula Power Company, application to increase rates. Testimony filed on behalf of Michigan Technological University and ME International.
Michigan	U-10115	Western Michigan Electric Cooperative, complaint against Consumers Power Company regarding service extension. Testimony filed on behalf of Western.

Case or Jurisdiction	Docket No.	Description
Michigan	U-10143 & U-10176	Detroit Edison Company and Consumers Power Company. Petition by ABATE to implement an experimental retail-wheeling program. Testimony provided on behalf of the Michigan Electric Cooperative Association.
Michigan	U-10785	Fruit Belt Electric Cooperative, application to increase rates. Testimony filed on behalf of Fruit Belt.
Michigan	U-11016	Fruit Belt Electric Cooperative, application to increase rates. Testimony filed on behalf of Fruit Belt.
Michigan	U-12604	Upper Peninsula Power Company, application to implement PSCR factors for 2001. Testimony filed on behalf of Michigan Technological University.
Michigan	U-12675	Upper Peninsula Power Company, application to increase base rates. Testimony filed on behalf of Michigan Technological University.
Michigan	U-12533	Upper Peninsula market power case. Testimony provided on behalf of the Upper Peninsula municipals and cooperatives and the Michigan Electric Cooperative Association and the Michigan Municipal Utilities Association.
Michigan		Upper Peninsula Power Company, application to increase rates. Testimony filed on behalf of Michigan Technological University.
Minnesota	00-90-281	Acquisition of a portion of the service territory of People's Cooperative Power Association by the City of Rochester. Testimony filed on behalf of People's.
Minnesota	24073 (circa 1982)	Acquisition of a portion of the service territory of Minnesota Valley Electric Cooperative by the City of Shakopee.
Minnesota	E-145/ GR-77-645	North Star Electric Cooperative, Inc., application to increase rates. Testimony filed on behalf of North Star.
Minnesota		Tri-County Electric Cooperative, application to increase rates. Testimony filed on behalf of Tri-County.
Minnesota	E-132,299/ SA-95-1030	Acquisition of a portion of the service territory of People's Cooperative Power Association by the City of Rochester. Testimony filed on behalf of People's.
Minnesota	E-126/ GR-77-751	Nobles Cooperative Electric, application to increase rates. Testimony filed on behalf of Nobles.
Minnesota	E-130/ 77-1233	Northern Electric Cooperative Association, application to increase GR-rates. Testimony filed on behalf of Northern.
Minnesota	E-111/ GR-81-120	Dakota Electric Association, application to increase rates. Testimony filed on behalf of Dakota.

Case or Jurisdiction	Docket No.	Description
Minnesota	E-104/ GR-81-608	FROST-BENCO Electric Association, application to increase rates. Testimony filed on behalf of FROST-BENCO.
Minnesota	E-111/ GR-82-228	Dakota Electric Association, application to increase rates. Testimony filed on behalf of Dakota.
Minnesota	E-999-R-80-560	PURPA Rules and Regulations. Testimony filed on behalf of the Minnesota Rural Electric Association.
Minnesota	E228 136/SA-85-93	Proposed acquisition of a portion of the service area and facilities of the Renville-Sibley Cooperative Power Association by the City of Olivia. Testimony filed on behalf of Renville-Sibley.
Minnesota	E-221,E-148/ SA-87-661 (E86-01)	Proposed acquisition of a portion of the service area and facilities of the Wright-Hennepin Cooperative Electric Association by the City of Buffalo. Testimony filed on behalf of Wright-Hennepin.
Minnesota	E-221, 148/ SA-989	Proposed acquisition of a portion of the service area and facilities of the Wright-Hennepin Cooperative Electric Association by the City of Buffalo. Testimony filed on behalf of Wright-Hennepin.
Minnesota	E-132/ SA-88-270	Proposed annexation of a portion of the service territory of People's Cooperative Power Association North Park I & II by the City of Rochester. Testimony filed on behalf of the Minnesota Rural Electric Association.
Minnesota	E-309,124/ SA-89-778	Proposed acquisition of a portion of the service area of the Minnesota Valley Electric Cooperative by the City of Shakopee. Testimony filed on behalf of Minnesota Valley.
Minnesota	E132,299/ SA-88-996	Proposed acquisition of a portion of the service territory of People's Cooperative Power Association by the City of Rochester. Testimony filed on behalf of People's.
Minnesota	E132,299/ SA-93-498	Proposed acquisition of a portion of the service territory of People's Cooperative Power Association by the City of Rochester. Testimony filed on behalf of People's.
Minnesota	132,299/ SA-95-140	Proposed acquisition of a portion of the service territory of People's Cooperative Power Association by the City of Rochester. Testimony filed on behalf of People's.
Minnesota	E132,299/ SA-02-496	Proposed acquisition of a portion of the service territory of People's Cooperative Services by the City of Rochester. Testimony filed on behalf of People's.
Minnesota	E-111/ GR-91-74	Dakota Electric Association, application to increase rates. Testimony filed on behalf of Dakota.

Case or Jurisdiction	Docket No.	Description
Minnesota	E-243,106/ SA-03-896	Proposed acquisition of a portion of the service territory of Lake Country by the Grand Rapids Public Utilities Commission. Testimony filed on behalf of Lake Country.
Minnesota	E-135,298/ SA-05-1274	Proposed acquisition of a portion of the service territory and facilities of Redwood Electric Cooperative by the City of Redwood Falls. Testimony provided on behalf of Redwood Electric Cooperative.
Minnesota	CX-05-1032	Proposed acquisition of a portion of the service territory and facilities of Red River Valley Cooperative Power Association by the City of Moorhead. Testimony provided on behalf of Red River Valley.
Minnesota	38-CV-05-495	Proposed acquisition of a portion of the service territory and facilities of Cooperative Light & Power by the City of Two Harbors. Testimony provided on behalf of CLP.
Minnesota	14-CX-06-002515	Proposed acquisition of a portion of the service territory and facilities (Americana Estates) of Red River Valley Cooperative Power Association by the City of Moorhead. Testimony provided on behalf of Red River Valley.
New Hampshire	DR88-141	New Hampshire Electric Cooperative, Inc., application to increase rates. Testimony filed on behalf of NHEC.
New Hampshire	DR90-078	New Hampshire Electric Cooperative, Inc., application to increase rates. Testimony provided on behalf of NHEC.
New Hampshire	DR90-078	Application by New Hampshire Electric Cooperative, Inc. to approve Seabrook Sell-back Agreement. Testimony provided on behalf of NHEC.
New Hampshire	DR92-009	Application by New Hampshire Electric Cooperative, Inc. to increase rates. Testimony filed on behalf of NHEC.
New Hampshire	DR92-187	Application by New Hampshire Electric Cooperative, Inc. to implement an interruptible rate. Testimony filed on behalf of NHEC.
New Hampshire	DR92-244	Application by New Hampshire Electric Cooperative, Inc. to implement a standby rate. Testimony provided on behalf of NHEC.
New Hampshire	DR93-124	Application by New Hampshire Electric Cooperative, Inc. to increase rates. Testimony filed on behalf of NHEC.
New Hampshire	DR93-145	Application by New Hampshire Electric Cooperative, Inc. to implement Interruptible Load Program for the 1993-94 winter season. Testimony filed on behalf of NHEC.
New Hampshire	DR-94-00	Application by New Hampshire Electric Cooperative, Inc. to implement long range avoided cost rates. Testimony filed on behalf of NHEC.

Case or Jurisdiction	Docket No.	Description
New Hampshire	DR-94-160	Application by New Hampshire Electric Cooperative, Inc. to implement competitive bidding procedure to establish long term avoided cost rates. Testimony filed on behalf of NHEC.
New Hampshire	DE-03-155	Application of the Town of Ashland to acquire a portion of the service territory of New Hampshire Electric Cooperative, Inc. Testimony filed on behalf of NHEC.
FERC	ER83-429-000	Wisconsin Power & Light, application to increase rates. Testimony filed on behalf of W-2 Customers (rural electric cooperatives).
FERC	ER84-576-000	Wisconsin Power & Light, application to increase rates. Testimony filed on behalf of W-2 Customers (rural electric cooperatives).
FERC	ER00-3316-000	American Transmission Company LLC. Affidavit filed on behalf of the Upper Peninsula of Michigan Transmission Dependent Utilities.

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(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Pro Forma Test Year ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
1											
2		**Power Production**									
3		**Steam**									
4	500	Oper. Super. & Eng.	PROD_CAP	9,772,919	9,696,294		76,625				1
5	501	Fuel	PROD_ENG	17,623,007		17,256,135	366,871				1
6	502	Steam	PROD_CAP	13,419,389	13,347,069		72,320				1
7	503	Steam-Other Sources	PROD_CAP	-		-					1
8	504	Steam Transferred	PROD_CAP	-		-					1
9	505	Electric	PROD_CAP	5,368,977	5,318,167		50,810				1
10	506	Misc. Steam Power	PROD_CAP	11,714,610	11,501,253		213,357				1
11	507	Rents	PROD_CAP	-	-						1
12	509	Allowances	PROD_ENG	48,502		(55,918)	104,420				1
13	510	Main. Super. & Eng.	PROD_ENG	3,200,097		3,158,689	41,408				1
14	511	Main. Struct.	PROD_CAP	5,805,259	5,763,403		41,856				1
15	512	Main. Boiler Plant	PROD_ENG	28,640,569		28,075,339	565,230				1
16	513	Main. Electric Plant	PROD_ENG	5,075,932		5,019,793	56,139				1
17	514	Main. Misc. Plant	PROD_CAP	73,695	73,197		498				1
18											
19		**Nuclear**									
20	517	Oper. Super. & Eng.		-							
21	518	Nuclear Fuel		-							
22	519	Coolants & Water		-							
23	520	Steam Exp.		-							
24	521	Steam - Other Sources		-							
25	522	Steam Transferred		-							
26	523	Electric		-							
27	524	Misc. Nuclear Power		-							
28	525	Rents		-							
29	528	Main. Super. & Eng.		-							
30	529	Main. Struct.		-							
31	530	Main. Reactor Plant		-							
32	531	Main. Electric Plant		-							
33	532	Main. Misc. Plant		-							
34											
35		**Hydraulic**									
36	535	Oper. Super. & Eng.		-							
37	536	Water for Power		-							
38	537	Hydraulic		-							
39	538	Electric		-							
40	539	Misc. Hydr. Power		-							
41	540	Rents		-							
42	541	Main. Super. & Eng.		-							
43	542	Main. Struct.		-							
44	543	Main. Waterways		-							
45	544	Main. Electric Plant		-							
46	545	Main. Misc. Hydr. Plant		-							

1 Allocate O&M expense for the steam production related expense to Steam Service, using 2009 as a proxy for the Test Year. Assign the remainder in accordance with FERC standard methodology.

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(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Pro Forma Test Year ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
47											
48		**Power Production (Con't.)**									
49		**Other**									
50	546	Oper. Super. & Eng.	PROD_CAP	248,768	248,768						1
51	547	Fuel	PROD_ENG	296,206		296,206					1
52	548	Generation	PROD_CAP	3,368,497	3,368,497						1
53	549	Misc. Other Power	PROD_CAP	1,382,281	1,382,281						1
54	550	Rents	PROD_CAP	-	-						1
55	551	Main. Super. & Eng.	PROD_CAP	178,342	178,342						1
56	552	Main. Struct.	PROD_CAP	350,978	350,978						1
57	553	Main. Gen. & Elec. Plant	PROD_CAP	3,946,593	3,946,593						1
58	554	Main. Misc. Other Power		79,024	79,024						1
59											
60		**Other Power Supply**									
61	555	Purchased Power	PROD_ENG	11,327,272		11,327,272					
62	556	System Control & Dispatch		4,699,374	234,969	1,644,781		2,721,013		98,612	2
63	557	Other Expenses	DIRECT	9,366,089	4,683,045	4,683,045					3
64	557	Other Expenses	PTD_PLNT	-	-	-	-	-	-	-	
65											
66		Subtotal - Production		135,986,380	60,171,879	71,405,342	1,589,534	2,721,013	-	98,612	Sum(L4 . L64)
67											
68		**Transmission**									
69	560	Oper. Super. & Eng.	TRANS_OM	4,917,091	78,117	-	-	4,708,011	-	130,963	
70	561	Load Dispatching		3,004,349				2,680,543		323,806	4
71	562	Oper. Station	TRANS_STA	2,255,947	127,961	-	-	2,085,934	-	42,052	
72	563	Oper. OH Line	TRANS_LINES	3,675,355	-	-	-	3,675,355	-	-	
73	564	Oper. UG Line	TRANS_LINES	-	-	-	-	-	-	-	
74	565	Trans of Electricity - Others	TRANS	19,351,829				19,351,829			
75	566	Misc. Transmission Oper.	TRANS	556,673				556,673			
76	567	Rents	TRANS	446,300				446,300			
77	568	Main. Super. & Eng.	TRANS_OM	-	-	-	-	-	-	-	
78	569	Main. Structures	TRANS	-				-			
79	570	Main. Station Equipment	TRANS_STA	1,979,381	112,274	-	-	1,830,211	-	36,896	
80	571	Main. OH Lines	TRANS_LINES	3,270,524	-	-	-	3,270,524	-	-	
81	572	Main. UG Lines	TRANS_LINES	-	-	-	-	-	-	-	
82	573	Main. Misc. Trans. Plant	TRANS	379,460				379,460			
83											
84		Subtotal - Transmission		39,836,909	318,352	-	-	38,984,840	-	533,716	Sum(L69 : L82)

[2] Breakdown provided by EKPC.
[3] Assign DLC expenses to PROD_CAP, and expenses related to power supply and ACES brokerage fees to PROD_ENG. Assign the remainder of Acct. 557 based on PTD_PLNT.
[4] Direct assign metering expense. Assign the remainder to Transmission.

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85											
86		**Distribution**									
87	580	Oper. Super. & Eng.	DIST_SUB	-					-		
88	581	Load Dispatching		186,095					59,761	126,334	5
89	582	Station	DIST_SUB	1,255,540					1,255,540		
90	583	OH Line	DIST_SUB	-					-		
91	584	UG Line	DIST_SUB	-					-		
92	585	Street Light & Signal System	DIST_SUB	-					-		
93	586	Meters	DIST_SUB	-					-		
94	587	Customer Installation	DIST_SUB	-					-		
95	588	Misc. Operations	DIST_SUB	-					-		
96	589	Rents	DIST_SUB	-					-		
97	590	Main. Super. & Eng.	DIST_SUB	-					-		
98	591	Main. Struct.	DIST_SUB	-					-		
99	592	Main. Station Equipment	DIST_SUB	998,880					998,880		
100	593	Main. OH Lines	DIST_SUB	-					-		
101	594	Main. UG Lines	DIST_SUB	-					-		
102	595	Main. Line Transf.	DIST_SUB	-					-		
103	596	Main. Street Light & Signal	DIST_SUB	-					-		
104	597	Main. Meters	DIST_SUB	-					-		
105	598	Misc. Maintenance	DIST_SUB	-					-		
106											
107		Subtotal - Distribution		2,440,515	-	-	-	-	2,314,181	126,334	Sum(L87 . L105)
108											
109		**Customer Accounts**									
110	901	Supervision	PROD_ENG	-		-					
111	902	Meter Reading	PROD_ENG	-		-					
112	903	Cust. Rec. & Coll.	PROD_ENG	-		-					
113	904	Uncollectible Accts.	PROD_ENG	-		-					
114	905	Misc. Cust. Accts.	PROD_ENG	-		-					
115											
116		Subtotal - Cust. Accts.		-	-	-	-	-	-	-	Sum(L110 . L114)
117											
118		**Customer Service & Info.**									
119	907	Supervision	PROD_ENG	-		-					
120	908	Cust. Assistance	PROD_ENG	3,233,134		3,233,134					
121	909	Advertising	PROD_ENG	55,049		55,049					
122	910	Misc. Serv. & Info.	PROD_ENG	18,000		18,000					
123											
124		Subtotal - Cust. Serv. & Info.		3,306,183	-	3,306,183	-	-	-	-	Sum(L109 : L123)
125											
126		**Sales**									
127	911	Supervision	PROD_ENG	-		-					
128	912	Demo. & Selling	PROD_ENG	-		-					
129	913	Advertising	PROD_ENG	20,452		20,452					
130	916	Misc. Sales	PROD_ENG	-		-					
131											
132		Subtotal - Sales		20,452	-	20,452	-	-	-	-	Sum(L127 . L130)

5 Direct assign metering expense. Assign the remainder to Distribution Substations.

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133											
134		**Administrative & General**									
135	920	Salaries	LABOR	13,186,865	5,525,019	4,923,925	122,091	2,289,914	227,741	98,174	
136	921	Off. Supplies & Exp.	LABOR	5,710,537	2,392,595	2,132,293	52,871	991,641	98,623	42,514	
137	922	Admin. Transferred	LABOR	-	-	-	-	-	-	-	
138	923	Outside Services	LABOR	4,325,666	1,812,363	1,615,187	40,049	751,157	74,706	32,204	
139	924	Outage Insurance	PROD_ENG	900,000		900,000					
140	925	Injuries & Damages	LABOR	951,416	398,623	355,255	8,809	165,214	16,431	7,083	
141	926	Pensions & Benefits	LABOR	816,500	342,096	304,878	7,560	141,786	14,101	6,079	
142	927	Franchise Req.	LABOR	-	-	-	-	-	-	-	
143	928	Reg. Commission	LABOR	1,405,520	588,883	524,816	13,013	244,070	24,274	10,464	
144	929	Duplicate Charges	LABOR	(519,905)	(217,829)	(194,131)	(4,814)	(90,282)	(8,979)	(3,871)	
145	930	Misc. General Expense	LABOR	4,702,738	1,970,348	1,755,984	43,540	816,636	81,218	35,011	
146	931	Rents	LABOR	-	-	-	-	-	-	-	
147	935	Main. Gen. Plant	LABOR	2,040,825	855,063	762,036	18,895	354,391	35,246	15,194	
148											
149		Subtotal - Administration & General		33,520,161	13,667,163	13,080,244	302,014	5,664,527	563,360	242,853	Sum(L135 . L147)
150											
151		Subtotal - Operating Expense		215,110,599	74,157,394	87,812,221	1,891,549	47,370,380	2,877,541	1,001,515	L66+L84 + L107
152											+ L116 + L124
153		**Depreciation**									+ L132 + L149
154	405	Intangible	INTG_PLNT	51,882	60	54	1	51,763	2	1	
155	403	Production-Steam	PROD_STM_PLNT	28,029,144	27,804,591	-	224,553	-	-	-	
156	403	Production-Other	PROD_OTH_PLNT	11,038,604	11,038,604	-	-	-	-	-	
157	403	Transmission	TRANS_PLNT	5,980,006	178,471	-	-	5,742,884	-	58,650	
158	403	Distribution	DIST_PLNT	5,796,754	-	-	-	-	5,796,754	-	
159	403	General	PTD_PLNT	9,727,380	4,075,568	3,632,167	90,061	1,689,170	167,995	72,419	
160											
161		Subtotal - Depreciation		60,623,770	43,097,294	3,632,220	314,615	7,483,818	5,964,751	131,071	Sum(L154 . L159)
162											
163		**Taxes**									
164	408	Property--Production		-							[6]
165	408	Property--Transmission		-							[6]
166	408	Property--Distribution		-							[6]
167	408	Property--General Plant		-							[6]
168	408	Taxes Other States	LABOR	800	335	299	7	139	14	6	
169											
170		Subtotal - Taxes		800	335	299	7	139	14	6	Sum(L164 . L168)
171											
172	431	**Interest - Other**	NET_PLNT	39,999	32,716	133	220	5,715	1,162	52	
173											
174		**Other Deductions**									
175	426	EPA Penalties	FUEL_EXP	(100,000)	-	(97,953)	(2,047)	-	-	-	
176	428	Amort. Debt Exp. & Disc.	RATE_BASE	1,782,792	1,413,194	49,385	10,440	254,796	52,619	2,359	
177	426	Other	LABOR	(879)	(368)	(328)	(8)	(153)	(15)	(7)	
178											
179		**Total Expenses**		277,457,081	118,700,565	91,395,978	2,214,776	55,114,695	8,896,072	1,134,995	L151+L161 + L170
180											+ L172 + L174

[6] Property tax is allocated back to the functional areas in Accounts 500 to 935.

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East Kentucky Power Cooperative, Inc.
Classification of Revenue Requirements
Forecast 2011 as Adjusted
(continued)

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Pro Forma Test Year ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
181											
182		**Return Requirements**									
183		Rate Base		2,465,534,881	1,954,394,443	68,297,155	14,438,049	352,372,856	72,770,489	3,261,889	Exhibit D, L41
184		Rate of Return		6.8346%	6.8346%	6.8346%	6.8346%	6.8346%	6.8346%	6.8346%	L188 / L187
185		Return Requirements		168,509,889	133,575,393	4,667,850	986,785	24,083,338	4,973,585	222,938	L183 * L184
186		Interest Expense	RATE_BASE	112,339,926	89,050,262	3,111,900	657,857	16,055,559	3,315,723	148,625	
187		Margin Requirements	RATE_BASE	56,169,963	44,525,131	1,555,950	328,928	8,027,779	1,657,862	74,313	
188		Total Return Requirements		168,509,889	133,575,393	4,667,850	986,785	24,083,338	4,973,585	222,938	L186 + L187
189											
190		**Total Gross Revenue Requirements**		445,966,970	252,275,958	96,063,827	3,201,562	79,198,033	13,869,657	1,357,933	L179 + L185
191											
192		**Other Revenue/Non-Operating Income Credits**									
193		Sales for Resale--Non-Mem.	As Billed	3,585,901		3,585,901					
194		Other Operating Income-Wheeling	TRANS	2,538,793				2,538,793			
195		Other Operating Income	DIRECT	2,207,169	153,392	42,000		2,011,777			Workpaper WP-2
196		Interest Income	RATE_BASE	3,360,147	2,663,541	93,079	19,677	480,230	99,175	4,445	
197		AFUDC	RATE_BASE	-	-	-	-	-	-	-	
198		Cap. Credits & Pat.Dividend	RATE_BASE	150,000	118,903	4,155	878	21,438	4,427	198	
199		Other Non Operating Inc.	RATE_BASE	2,088	1,655	58	12	298	62	3	
200											
201		Subtotal - Rev. Credits		11,844,098	2,937,491	3,725,193	20,567	5,052,537	103,664	4,647	Sum(L192 . L199)
202											
203		**Net Member Revenue Requirements**		**434,122,872**	**249,338,468**	**92,338,635**	**3,180,994**	**74,145,497**	**13,765,993**	**1,353,286**	L190 - L201
204											
205		**Allocation Factors Based on Revenue requirements**									
206		Fuel Expense		17,919,213	-	17,552,341	366,871	-	-	-	
207			FUEL_EXP	1.000000	0.000000	0.979526	0.020474	0.000000	0.000000	0.000000	
208											
209		Transmission O&M		15,121,689	240,235	-	-	14,478,700	-	402,754	Sum(L70:L73) + L75 +
210			TRANS_OM	1.000000	0.015887	0.000000	0.000000	0.957479	0.000000	0.026634	Sum(L78:L82)

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East Kentucky Power Cooperative, Inc.
Classification of Plant in Service
Forecast 2011 as Adjusted

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Pro Forma Test Year ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
1											
2		**Intangible Plant**									
3	301	Organization	LABOR	5,040	2,112	1,882	47	875	87	38	
4	302	Franchises	LABOR		-	-	-	-	-	-	
5	303	Misc. Intang. Plant	TRANS	1,815,946				1,815,946			[1]
6		Subtotal - Intangible Plant		1,820,986.67	2,112	1,882	47	1,816,822	87	38	Sum(L3 : L5)
7											
8		**Production Plant**									
9		**Steam**									
10	310	Land & Land Rights	[2]	14,012,725	13,767,695	-	245,030				
11	311	Struct. & Improve.	[2]	241,320,145	238,213,072	-	3,107,073				
12	312	Boiler Plant Equip.	[2]	1,542,219,195	1,528,378,456	-	13,840,739				
13	313	Engines & Gen.	[2]	-	-	-	-				
14	314	Turbogenerator Units	[2]	268,719,253	268,719,253	-	-				
15	315	Access. Elec. Equip.	[2]	90,649,111	90,649,111	-					
16	316	Misc. Plant Equipment	[2]	8,132,140	7,979,864	-	152,276				
17		Subtotal		2,165,052,569	2,147,707,451	-	17,345,118	-	-	-	Sum(L10 : L16)
18		**Nuclear**									
19	320	Land & Land Rights									
20	321	Struct. & Improve.									
21	322	Reactor Plant Equip.									
22	323	Turbogenerator Units									
23	324	Access. Elec. Equip.									
24	325	Misc. Plant Equipment									
25		Subtotal		-	-	-	-	-	-	-	Sum(L19 : L24)
26		**Hydraulic**									
27	330	Land & Land Rights									
28	331	Struct. & Improve.									
29	332	Rsrvr Dams & Strwys									
30	333	Wheels Turb. & Gen.									
31	334	Accessory Electrical Equip.									
32	335	Misc. Plant Equipment									
33	336	Rds RR & Bridges									
34		Subtotal		-	-	-	-	-	-	-	Sum(L27 : L33)
35		**Other**									
36	340	Land & Land Rights	PROD_OTH_PLNT	4,759,583	4,759,583	-	-	-	-	-	
37	341	Struct. & Improve.	PROD_OTH_PLNT	41,057,771	41,057,771	-	-	-	-	-	
38	342	Prod. & Access.	PROD_OTH_PLNT	14,370,188	14,370,188	-	-	-	-	-	
39	343	Prime Movers	PROD_OTH_PLNT	296,488,506	296,488,506	-	-	-	-	-	
40	344	Generators	PROD_OTH_PLNT	58,396,437	58,396,437	-	-	-	-	-	
41	345	Access. Elec. Equip.	PROD_OTH_PLNT	18,773,076	18,773,076	-	-	-	-	-	
42	346	Misc. Plant Equip.	PROD_OTH_PLNT	5,910,707	5,910,707	-	-	-	-	-	
43		Subtotal		439,756,268	439,756,268	-	-	-	-	-	Sum(L36 : L42)
44		Subtotal--Production		2,604,808,837	2,587,463,719	-	17,345,118	-	-	-	L17 + L43

[1] Intangible plant related to transmission interconnections with other utilities.
[2] Investment in Steam Plant facilities has been assigned first directly to Inland Steam, using 2009 as a proxy for the Test Year, with the remainder allocated using PROD_CAP

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East Kentucky Power Cooperative, Inc.
Classification of Plant in Service
Forecast 2011 as Adjusted
(continued)

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Pro Forma Test Year ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
45											
46		**Transmission**									
47	350	Land & Land Rights	TRANS_PLNT	46,957,717				46,957,717			
48	352	Struct. & Improve.	TRANS_PLNT					-			
49	353	Station Equip.	[3,4]	207,436,188	14,429,684			188,264,524		4,741,980	
50	354	Towers & Fixtures	TRANS_PLNT	3,905,020				3,905,020			
51	355	Poles & Fixtures	TRANS_PLNT	132,271,752				132,271,752			
52	356	OH Cond. & Devices	TRANS_PLNT	92,899,082				92,899,082			
53	357	UG Conduit	TRANS_PLNT					-			
54	358	UG Cond. & Devices	TRANS_PLNT					-			
55	359	Roads & Trails	TRANS_PLNT	23,288				23,288			
56		Subtotal - Transmission		483,493,047	14,429,684	-	-	464,321,383	-	4,741,980	Sum(L47 : L55)
57											
58		**Distribution**									
59	360	Land & Land Rights	DISTSUB_PLANT	7,937,306					7,937,306		
60	361	Struct. & Improve.							-		
61	362	Station Equip.	DISTSUB_PLANT	163,833,848					163,833,848		
62	363	Stor. Battery Equip.							-		
63	364	Poles Tower & Fix.							-		
64	365	OH Cond. & Devices							-		
65	366	UG Conduit							-		
66	367	UG Cond. & Devices							-		
67	368	Line Transformers	DISTSUB_PLANT	1,333,351					1,333,351		
68	369	Services							-		
69	370	Meters							-		
70	371	Install on Cust. Ld							-		
71	372	Leased Ld from Cust.							-		
72	373	Street Light & Signal							-		
73		Subtotal - Distribution		173,104,505	-	-	-	-	173,104,505	-	Sum(L59 : L72)
74											
75		Subtotal - Prod, Trans, Dist Plant		3,088,301,884	2,601,893,403	-	17,345,118	464,321,383	-	4,741,980	L44 + L56 + L73
76											
77		**General**									
78	389	Land & Land Rights	LABOR	870,936	364,904	325,204	8,064	151,239	15,041	6,484	
79	390	Struct. & Improve.	LABOR	14,850,522	6,222,057	5,545,128	137,494	2,578,810	256,473	110,560	
80	391	Off. Furn. & Equip.	LABOR	13,191,160	5,526,819	4,925,529	122,131	2,290,660	227,815	98,206	
81	392	Transp. Equip.	LABOR	8,149,616	3,414,518	3,043,036	75,453	1,415,190	140,746	60,673	
82	393	Stores Equip.	LABOR	152,406	63,855	56,908	1,411	26,465	2,632	1,135	
83	394	Shop & Garage Equip.	LABOR	1,607,022	673,309	600,056	14,879	279,061	27,754	11,964	
84	395	Lab Equip.	LABOR	3,424,496	1,434,792	1,278,694	31,706	594,667	59,142	25,495	
85	396	Power Op. Equip.	LABOR	8,506,155	3,563,900	3,176,166	78,754	1,477,103	146,904	63,327	
86	397	Communication Equip.	LABOR	31,511,940	13,202,841	11,766,439	291,754	5,472,083	544,221	234,602	
87	398	Misc. Equip.	LABOR	1,215,623	509,321	453,909	11,255	211,094	20,994	9,050	
88	399	Other Tangible Prop.	LABOR		-	-	-	-	-	-	
89		Subtotal-General Plant		83,479,876	34,976,315	31,171,068	772,900	14,496,373	1,441,723	621,497	Sum(L78 : L88)
90											
91		Grand Total		3,346,707,252	2,636,871,830	31,172,950	18,118,065	480,634,578	174,546,315	5,363,514	L44 + L56 + L89
92											

[3] Distribution meters and Generator Step Up Transformers are direct assigned, with the remainder assigned to Transmission.

[4] Distribution meter investment does not include meters installed in portable substations.

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East Kentucky Power Cooperative, Inc.
Classification of Plant in Service
Forecast 2011 as Adjusted
(continued)

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Pro Forma Test Year	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
93											
94		**Allocation Factors Based on Plant**									
95	301-303	Intangible Plant		1,820,987	2,112	1,882	47	1,816,822	87	38	L6
96			INTG_PLNT	1.000000	0.001160	0.001034	0.000026	0.997713	0.000048	0.000021	
97											
98	310-316	Production Plant--Steam		2,165,052,569	2,147,707,451	-	17,345,118	-	-	-	L17
99			PROD_STM_PLNT	1.000000	0.991989	-	0.008011	-	-	-	
100											
101			PROD_CAP	1.000000	1.000000	0.000000					
102											
103	340-346	Production Plant--Other		439,756,268	439,756,268	-	-	-	-	-	L43
104			PROD_OTH_PLNT	1.000000	1.000000	0.000000					
105											
106	301-346	Total Production Plant		2,604,808,837	2,587,463,719	-	17,345,118	-	-	-	L44
107			PROD_PLNT	1.000000	0.993341	0.000000	0.006659	0.000000	0.000000	0.000000	
108											
109	353	Transmission Stations		254,393,905	14,429,684	-	-	235,222,241	-	4,741,980	Sum(L47:L49)
110			TRANS_STA	1.000000	0.056722	0.000000	0.000000	0.924638	0.000000	0.018640	
111											
112	354-358	Transmission Lines		229,075,854	-	-	-	229,075,854	-	-	Sum(L50:L55)
113			TRANS_LINES	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	
114											
115	350-359	Total Transmission Plant		483,493,047	14,429,684	-	-	464,321,383	-	4,741,980	L56
116			TRANS_PLNT	1.000000	0.029845	0.000000	0.000000	0.960348	0.000000	0.009808	
117											
118	360-373	Distribution Plant		173,104,505	-	-	-	-	173,104,505	-	L73
119			DISTSUB_PLNT	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	
120											
121	301-373	Prod, Trans, Dist Plant		3,088,301,884	2,601,893,403	-	17,345,118	464,321,383	-	4,741,980	L75
122			PTD_PLNT	1.000000	0.842500	0.000000	0.005616	0.150348	0.000000	0.001535	
123											
124	301-399	Total Gross Plant		3,346,707,252	2,636,871,830	31,172,950	18,118,065	480,634,578	174,546,315	5,363,514	L91
125			GROSS_PLNT	1.000000	0.78790035	0.00931451	0.00541370	0.14361417	0.05215464	0.00160262	
126											

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East Kentucky Power Cooperative, Inc.
Classification of Accumulated Reserves for Depreciation
Forecast 2011 as Adjusted

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Pro Forma Test Year ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
1											
2		**Intangible Plant**									
3		Organization	2	-	-	-	-	-	-	-	
4		Franchises	2	-							
5		Misc. Intang. Plant	2	(665,981)	-	-	-	(665,981)	-	-	1
6		Subtotal - Intangible Plant		(665,981)	-	-	-	(665,981)	-	-	Sum(L3 : L5)
7											
8		**Production Plant**									
9		**Steam**									
10	108	Land & Land Rights	2	(3,744,527)	(3,679,049)	-	(65,478)	-	-	-	
11	108	Struct. & Improve.	2	(64,486,377)	(63,656,095)	-	(830,282)	-	-	-	
12	108	Boiler Plant Equip.	2	(412,116,978)	(408,418,409)	-	(3,698,569)	-	-	-	
13	108	Engines & Gen.	2	-							
14	108	Turbogenerator Units	2	(71,808,059)	(71,808,059)	-	-	-	-	-	
15	108	Access. Elec. Equip.	2	(24,223,559)	(24,223,559)	-	-	-	-	-	
16	108	Misc. Plant Equipment	2	(2,173,098)	(2,132,406)	-	(40,692)	-	-	-	
17		Subtotal		(578,552,598)	(573,917,577)	-	(4,635,021)	-	-	-	Sum(L10 : L16)
18		**Nuclear**									
19	108	Land & Land Rights		-							
20	108	Struct. & Improve.		-							
21	108	Reactor Plant Equip.		-							
22	108	Turbogenerator Units		-							
23	108	Access. Elec. Equip.		-							
24	108	Misc. Plant Equipment		-							
25		Subtotal		-	-	-	-	-	-	-	Sum(L19 : L24)
26		**Hydraulic**									
27	108	Land & Land Rights		-							
28	108	Struct. & Improve.		-							
29	108	Rsrvr Dams & Strwys		-							
30	108	Wheels Turb. & Gen.		-							
31	108	Accessory Electrical Equip.		-							
32	108	Misc. Plant Equipment		-							
33	108	Rds RR & Bridges		-							
34		Subtotal		-	-	-	-	-	-	-	Sum(L27 : L33)
35		**Other**									
36	108	Land & Land Rights	2	(1,271,872)	(1,271,872)	-	-	-	-	-	
37	108	Struct. & Improve.	2	(10,971,595)	(10,971,595)	-	-	-	-	-	
38	108	Prod. & Access.	2	(3,840,050)	(3,840,050)	-	-	-	-	-	
39	108	Prime Movers	2	(79,228,651)	(79,228,651)	-	-	-	-	-	
40	108	Generators	2	(15,604,891)	(15,604,891)	-	-	-	-	-	
41	108	Access. Elec. Equip.	2	(5,016,604)	(5,016,604)	-	-	-	-	-	
42	108	Misc. Plant Equip.	2	(1,579,479)	(1,579,479)	-	-	-	-	-	
43		Subtotal		(117,513,142)	(117,513,142)	-		-			Sum(L36 : L42)
44		Subtotal--Production		(696,065,740)	(691,430,719)	-	(4,635,021)	-	-	-	L17 + L43

[1] Accumulated reserves for depreciation associated with interconnections with other utilities.

[2] Prorate based on plant investment in each account.

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East Kentucky Power Cooperative, Inc.
Classification of Accumulated Reserves for Depreciation
Forecast 2011 as Adjusted
(Continued)

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Pro Forma Test Year ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
45											
46		**Transmission**									
47	108	Land & Land Rights	2	(13,655,227.73)	-	-	-	(13,655,228)	-	-	
48	108	Struct. & Improve.	2	-							
49	108	Station Equip.	2, 3	(60,322,106)	(4,160,275)	-	-	(54,279,231)	-	(1,882,601)	
50	108	Towers & Fixtures	2	(1,135,573.48)	-	-	-	(1,135,573)	-	-	
51	108	Poles & Fixtures	2	(38,464,410.45)	-	-	-	(38,464,410)	-	-	
52	108	OH Cond. & Devices	2	(27,014,902.04)	-	-	-	(27,014,902)	-	-	
53	108	UG Conduit	2	-							
54	108	UG Cond. & Devices	2	-							
55	108	Roads & Trails	2	(6,772.01)	-	-	-	(6,772)	-	-	
56		Subtotal - Transmission		(140,598,992)	(4,160,275)	-	-	(134,556,116)	-	(1,882,601)	Sum(L47 : L55)
57											
58		**Distribution**									
59	108	Land & Land Rights	2	(4,835,071.29)	-	-	-	-	(4,835,071)	-	
60	108	Struct. & Improve.	2	-							
61	108	Station Equip.	2	(99,800,654.02)	-	-	-	-	(99,800,654)	-	
62	108	Stor. Battery Equip.	2	-							
63	108	Poles Tower & Fix.	2	-							
64	108	OH Cond. & Devices	2	-							
65	108	UG Conduit	2	-							
66	108	UG Cond. & Devices	2	-							
67	108	Line Transformers	2	(812,221.07)	-	-	-	-	(812,221)	-	
68	108	Services	2	-							
69	108	Meters	2	-							
70	108	Install on Cust. Ld	2	-							
71	108	Leased Ld from Cust.	2	-							
72	108	Street Light & Signal	2	-							
73		Subtotal - Distribution		(105,447,946)	-	-	-	-	(105,447,946)	-	Sum(L59 : L72)
74											
75		Subtotal - Prod, Trans, Dist Plant		(836,664,732)	(695,590,994)	-	(4,635,021)	(134,556,116)	-	(1,882,601)	L44 + L56 + L73
76											
77		**General**									
78	108	Land & Land Rights	2	(652,733.42)	(273,482)	(243,728)	(6,043)	(113,348)	(11,273)	(4,860)	
79	108	Struct. & Improve.	2	(11,129,907.66)	(4,663,198)	(4,155,865)	(103,046)	(1,932,721)	(192,217)	(82,861)	
80	108	Off. Furn. & Equip.	2	(9,886,278.54)	(4,142,143)	(3,691,499)	(91,532)	(1,716,763)	(170,739)	(73,602)	
81	108	Transp. Equip.	2	(6,107,830.86)	(2,559,053)	(2,280,641)	(56,549)	(1,060,632)	(105,484)	(45,472)	
82	108	Stores Equip.	2	(114,222.50)	(47,857)	(42,650)	(1,058)	(19,835)	(1,973)	(850)	
83	108	Shop & Garage Equip.	2	(1,204,402.85)	(504,620)	(449,719)	(11,151)	(209,146)	(20,800)	(8,967)	
84	108	Lab Equip.	2	(2,566,530.68)	(1,075,322)	(958,333)	(23,762)	(445,681)	(44,325)	(19,107)	
85	108	Power Op. Equip.	2	(6,375,043.09)	(2,671,009)	(2,380,417)	(59,023)	(1,107,033)	(110,099)	(47,461)	
86	108	Communication Equip.	2	(23,617,013.58)	(9,895,033)	(8,818,503)	(218,658)	(4,101,121)	(407,873)	(175,826)	
87	108	Misc. Equip.	2	(911,063.81)	(381,717)	(340,188)	(8,435)	(158,207)	(15,734)	(6,783)	
88	108	Other Tangible Prop.	2	-							
89	108	Subtotal-General Plant		(62,565,027)	(26,213,433)	(23,361,543)	(579,259)	(10,864,487)	(1,080,517)	(465,788)	Sum(L78 : L88)
90											
91		Grand Total		(1,005,343,686)	(721,804,427)	(23,361,543)	(5,214,280)	(146,086,584)	(106,528,463)	(2,348,389)	L75 + L89

3 Depreciation Reserves associated with distribution meters are direct assigned, with the remainder assigned based on plant investment in that account.

Exhibit_(DRE-2)
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Schedule C
Page 2 of 2

East Kentucky Power Cooperative, Inc.
Classification of Rate Base
Forecast 2011 as Adjusted

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Pro Forma Test Year ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
1											
2		Plant in Service		3,346,707,252	2,636,871,830	31,172,950	18,118,065	480,634,578	174,546,315	5,363,514	Ex. B, pg. 2
3		Accum. Depr. Reserves		(1,005,343,686)	(721,804,427)	(23,361,543)	(5,214,280)	(146,086,584)	(106,528,463)	(2,348,389)	Ex. C, pg. 2
4		Net Plant		2,341,363,565	1,915,067,403	7,811,407	12,903,785	334,547,994	68,017,852	3,015,125	L2 - L3
5	107	Construction Work in Progress									
6	107	Production Non-Steam Related	PROD_CAP	385,153,978	385,153,978	-	-	-	-	-	
7	107	Production-Steam Service Related	STEAM_SERV	32,856,726	31,292,122	-	1,564,604	-	-	-	
8	107	Transmission	TRANS	31,788,314				31,788,314			
9	107	Distribution Substations	DIST_SUB	5,760,548					5,760,548		
10	107	Ditstribution Meters	DIST_METER							-	
11	107	General Plant	LABOR	3,723,628	1,560,122	1,390,389	34,475	646,612	64,308	27,722	
12	107	Total CWIP		459,283,194	418,006,222	1,390,389	1,599,080	32,434,926	5,824,856	27,722	Sum(L6:L11)
13	108	Retirement Work in Progress	DIRECT	-							
14	108	Retirement Work in Progress	LABOR		-	-		-	-	-	
15		Adjusted Net Plant		2,800,646,759	2,333,073,624	9,201,796	14,502,864	366,982,920	73,842,708	3,042,847	L4+L12+L13-L14
16	165	Prepayments	NET_PLNT		-	-	-	-	-	-	
17	151	Fuel Stocks	FUEL_EXP	54,228,980	-	53,118,716	1,110,264	-	-	-	
18		Materials and Supplies									1
19	154	Production-Steam	PROD_STM_PLNT	29,133,997	28,900,593	-	233,404	-	-	-	1
20	154	Production-Other	PROD_OTH_PLNT	717,830	717,830	-	-	-	-	-	1
21	154	ETS	PROD_CAP	68,512	68,512						1
22	154	Transmission	TRANS_PLNT	12,394,838	369,920	-	-	11,903,353	-	121,565	1
23	154	Distribution Subtation	DIST_SUB	4,392,924	-	-	-	-	4,392,924	-	1
24	154	Distribution Meters	DIST_METER	-							1
25	154	General Plant	LABOR	1,220	511	455	11	212	21	9	
26		Subtotal--M&S		46,709,321	30,057,366	455	233,416	11,903,565	4,392,945	121,575	Sum(L19 : L25)
27		Cash Working Capital (1/8)									
28		Production Expense									
29		Total		16,998,297	7,521,485	8,925,668	198,692	340,127	-	12,327	Exhibit A, pg. 2
30		Less: Fuel		2,239,902	-	2,194,043	45,859	-	-	-	Ex. A, pg. 1&2
31		Less: Purch. Power		1,415,909	-	1,415,909	-	-	-	-	Ex. A, pg. 2
32		Net Production		13,342,487	7,521,485	5,315,716	152,833	340,127	-	12,327	L29 - L30 - L31
33		Transmission O&M		4,979,614	39,794	-	-	4,873,105	-	66,715	Ex. A, pg. 2
34		Distribution O&M		305,064	-	-	-	-	289,273	15,792	Ex. A, pg. 2
35		Customer Accounts		-	-	-	-	-	-	-	Ex. A, pg. 2
36		Customer Service & Info.		413,273	-	413,273	-	-	-	-	Ex. A, pg. 3
37		Sales		2,557	-	2,557	-	-	-	-	Ex. A, pg. 3
38		Administrative & General		4,190,020	1,708,395	1,635,031	37,752	708,066	70,420	30,357	Ex. A, pg. 3
39		Subtotal--CWC		23,233,014	9,269,674	7,366,576	190,585	5,921,297	359,693	125,189	Sum(L32 : L38)
40											
41		Total Rate Base		2,465,534,881	1,954,394,443	68,297,155	14,438,049	352,372,856	72,770,489	3,261,889	L4 + L13 + L16+L17+ L26+L39
42											
43				2,341,363,565	1,915,067,403	7,811,407	12,903,785	334,547,994	68,017,852	3,015,125	L4
44			NET_PLNT	1.000000	0.817928	0.003336	0.005511	0.142886	0.029051	0.001288	
45											
46				2,465,534,881	1,954,394,443	68,297,155	14,438,049	352,372,856	72,770,489	3,261,889	L41
47			RATE BASE	1.000000	0.792686	0.027701	0.005856	0.142919	0.029515	0.001323	
48											
49			STEAM_SERV	1.000000	0.952381	0.000000	0.047619				Workpaper WP-4

1 Prorate total Materials and Supplies to the various categories based on the 2010 Rate Study analysis.

Exhibit_(DRE-2)
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Schedule D
Page 1 of 1

East Kentucky Power Cooperative, Inc.
Classification of Payroll Expense
Forecast 2011 as Adjusted

Note: Labor expense is functionalized/classified on the same basis as the corresponding expense.

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Pro Forma Test Year	(f) Production Capacity	(g) Production Energy	(h) Production Steam Direct	(i) Transm.	(j) Distribution Substations	(k) Distribution Meters	(l) Notes
1				($)	($)	($)	($)	($)	($)	($)	
2		**Power Production**									
3		**Steam**									
4	500	Oper. Super. & Eng.		5,604,365	5,560,424	-	43,941	-	-	-	
5	501	Fuel		3,959,278	-	3,876,855	82,423	-	-	-	
6	502	Steam		3,983,734	3,962,265	-	21,469	-	-	-	
7	503	Steam-Other Sources									
8	504	Steam Transferred									
9	505	Electric		3,140,187	3,110,469	-	29,718	-	-	-	
10	506	Misc. Steam Power		2,454,551	2,409,847	-	44,704	-	-	-	
11	507	Rents									
12	510	Main. Super. & Eng.		2,065,492	-	2,038,765	26,727	-	-	-	
13	511	Main. Struct.		728,029	722,780	-	5,249	-	-	-	
14	512	Main. Boiler Plant		6,387,956	-	6,261,888	126,068	-	-	-	
15	513	Main. Electric Plant		1,559,918	-	1,542,666	17,252	-	-	-	
16	514	Main. Misc. Plant		38,031	37,774	-	257	-	-	-	
17											
18		**Nuclear**									
19	517	Oper. Super. & Eng.									
20	518	Nuclear Fuel									
21	519	Coolants & Water									
22	520	Steam Exp.									
23	521	Steam - Other Sources									
24	522	Steam Transferred									
25	523	Electric									
26	524	Misc. Nuclear Power									
27	525	Rents									
28	528	Main. Super. & Eng.									
29	529	Main. Struct.									
30	530	Main. Reactor Plant									
31	531	Main. Electric Plant									
32	532	Main. Misc. Plant									
33											
34		**Hydraulic**									
35	535	Oper. Super. & Eng.									
36	536	Water for Power									
37	537	Hydraulic									
38	538	Electric									
39	539	Misc. Hydr. Power									
40	540	Rents									
41	541	Main. Super. & Eng.									
42	542	Main. Struct.									
43	543	Main. Waterways									
44	544	Main. Electric Plant									
45	545	Main. Misc. Hydr. Plant									

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Schedule E
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East Kentucky Power Cooperative, Inc.
Classification of Payroll Expense
Forecast 2011 as Adjusted

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Pro Forma Test Year	(f) Production Capacity	(g) Production Energy	(h) Production Steam Direct	(i) Transm.	(j) Distribution Substations	(k) Distribution Meters	(l) Notes
46				($)	($)	($)	($)	($)	($)	($)	
47		**Power Production (Con't.)**									
48		**Other**									
49	546	Oper. Super. & Eng.		154,950	154,950	-	-	-	-	-	
50	547	Fuel		21,602	-	21,602	-	-	-	-	
51	548	Generation		637,838	637,838	-	-	-	-	-	
52	549	Misc. Other Power		128,279	128,279	-	-	-	-	-	
53	550	Rents									
54	551	Main. Super. & Eng.		115,000	115,000	-	-	-	-	-	
55	552	Main. Struct.		4,060	4,060	-	-	-	-	-	
56	553	Main. Gen. & Elec. Plant		377,423	377,423	-	-	-	-	-	
57	554	Main. Misc. Other Power		12,470	12,470	-	-	-	-	-	
58											
59		**Other Power Supply**									
60	555	Purchased Power (Net)			-	-	-	-	-	-	
61	556	System Control & Dispatch		2,622,689	131,134	917,941	-	1,518,579	-	55,035	
62	557	Other Expenses		1,064,184	532,092	532,092	-	-	-	-	
63											
64		Subtotal - Production		35,060,036	17,896,805	15,191,809	397,809	1,518,579	-	55,035	Sum(L4 : L62)
65											
66		<u>Transmission</u>									
67	560	Oper. Super. & Eng.		2,072,717	32,929	-	-	1,984,583	-	55,205	
68	561	Load Dispatching		1,400,082	-	-	-	1,249,182	-	150,900	
69	562	Oper. Station		716,513	40,642	-	-	662,515	-	13,356	
70	563	Oper. OH Line		706,509	-	-	-	706,509	-	-	
71	564	Oper. UG Line									
72	565	Trans of Electricity - Others			-	-	-	-	-	-	
73	566	Misc. Transmission Oper.		334,111	-	-	-	334,111	-	-	
74	567	Rents			-	-	-	-	-	-	
75	568	Main. Super. & Eng.									
76	569	Main. Struct.									
77	570	Main. Station Equip.		561,106	31,827	-	-	518,820	-	10,459	
78	571	Main. OH Lines		486,940	-	-	-	486,940	-	-	
79	572	Main. UG Lines									
80	573	Main. Misc. Trans. Plant			-	-	-	-	-	-	
81											
82		Subtotal - Transmission		6,277,978	105,398	-	-	5,942,660	-	229,920	Sum(L67 : L80)

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Schedule E
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East Kentucky Power Cooperative, Inc.
Classification of Payroll Expense
Forecast 2011 as Adjusted

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Pro Forma Test Year ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Notes
83											
84		**Distribution**									
85	580	Oper. Super. & Eng.									
86	581	Load Dispatching		51,450	-	-	-	-	16,522	34,928	
87	582	Station		416,283	-	-	-	-	416,283	-	
88	583	OH Line									
89	584	UG Line									
90	585	Street Light & Signal Sys.									
91	586	Meters									
92	587	Customer Installation									
93	588	Misc. Distribution									
94	589	Rents									
95	590	Main. Super. & Eng.									
96	591	Main. Struct.									
97	592	Main. Station Equipment		309,245	-	-	-	-	309,245	-	
98	593	Main. OH Lines									
99	594	Main. UG Lines									
100	595	Main. Line Transf.									
101	596	Main. Street Light & Sig.									
102	597	Main. Meters									
103	598	Main. Misc.									
104											
105		Subtotal - Distribution		776,978	-	-	-	-	742,050	34,928	
106											
107		**Customer Accounts**									
108	901	Supervision									
109	902	Meter Reading									
110	903	Cust. Rec. & Coll.									
111	904	Uncollectible Accts.									
112	905	Misc. Cust. Accts.									
113											
114		Subtotal - Cust. Accts.		-	-	-	-	-	-	-	Sum(L108 : L112)
115											
116		**Customer Service & Info.**									
117	907	Supervision									
118	908	Cust. Assistance		816,477	-	816,477		-			
119	909	Advertising		26,553	-	26,553		-			
120	910	Misc. Serv. & Info.			-	-		-			
121											
122		Subtotal - Cust. Service		843,030	-	843,030	-	-	-	-	Sum(L107 : L121)

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East Kentucky Power Cooperative, Inc.
Classification of Payroll Expense
Forecast 2011 as Adjusted

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Pro Forma Test Year	(f) Production: Capacity	(g) Production: Energy	(h) Production: Steam Direct	(i) Transm.	(j) Distribution Substations	(k) Distribution Meters	(l) Notes
123				($)	($)	($)	($)	($)	($)	($)	
124		Sales									
125	911	Supervision									
126	912	Demo. & Selling									
127	913	Advertising		8,815	-	8,815		-			
128	916	Misc. Sales									
129											
130		Subtotal - Sales		8,815	-	8,815	-	-	-	-	Sum(L125 : L128)
131											
132		Summary									
133		Total Labor (Excluding A&G)		42,966,837	18,002,203	16,043,654	397,809	7,461,239	742,050	319,882	L48+L66 + L89
134											+ L98+L106+L130
135		Labor Allocator	LABOR	1.000000	0.418979	0.373396	0.009259	0.173651	0.017270	0.007445	
136											

Exhibit_(DRE-2)
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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

GENERAL ADJUSTMENT OF ELECTRIC RATES	**)**	**PSC CASE NO.**
OF EAST KENTUCKY POWER	**)**	**2010-00167**
COOPERATIVE, INC.	**)**	

TESTIMONY OF
ISAAC S. SCOTT
MANAGER OF PRICING
EAST KENTUCKY POWER COOPERATIVE, INC.

Filed: May 27, 2010

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

A. My name is Isaac S. Scott and my business address is East Kentucky Power Cooperative ("EKPC"), 4775 Lexington Road, Winchester, Kentucky 40391. I am the Manager of Pricing for EKPC.

Q. Please state your education and professional experience.

A. I received a B.S. degree in Accounting, with distinction, from the University of Kentucky in 1979. After graduation I was employed by the Kentucky Auditor of Public Accounts. While at the Auditor's Office, I performed audits of numerous state agencies and was responsible for the payroll portion of centralized audits, the results of which formed the basis of the State Auditor's opinion letter on Kentucky's Annual Financial Statements. In December 1985, I transferred to the Kentucky Public Service Commission ("Commission") as a public utilities financial analyst, concentrating on the electric and natural gas industries. In August 2001, I became manager of the Electric and Gas Revenue Requirements Branch in the Division of Financial Analysis at the Commission. In this position I supervised staff in the preparation of revenue requirement determinations for electric and natural gas utilities as well as prepared the revenue requirement determinations for the major electric and natural gas utilities in Kentucky. I retired from the Commission effective August 1, 2008. In November 2008, I became the Manager of Pricing at EKPC.

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

A. As Manager of Pricing, I am responsible for rate-making activities which include designing and developing wholesale and retail electric rates and developing pricing concepts and methodologies. I report directly to the Vice President, Finance.

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

A. The purpose of my testimony is to sponsor certain exhibits in the application and discuss rate design issues related to the rate case. I will also discuss the Rate Design Feasibility Study EKPC and its Member Cooperatives are currently undertaking.

Q. What exhibits are you sponsoring in the application?

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

Filing Requirement	Description	Volume	Tab #
Section 10(1)(b)(7)	The proposed tariff in form complying with 807 KAR 5:011 with an effective date not less that 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(10)(1)	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. Please describe the proposed tariff changes and rate design proposals EKPC is including with the application.

A. The only tariff changes EKPC is proposing in the application are to reflect the increases in the various rate schedules necessary to produce the total increase in revenues requested. The requested increase in revenues has been allocated 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 and the interruptible service credit. EKPC is proposing to increase each rate component of each rate schedule by the same percentage. EKPC is proposing no changes to its current rate design in conjunction with the application.

Q. Would you explain why the special contract for the pumping stations and the interruptible service credit were not included in the pro-rata allocation of the proposed revenue increase?

A. The unique pricing provisions of the special contract for the pumping stations define the charges and rates utilizing a formula tied to market prices and do not recognize any adjustments due to a general rate case revenue increase by EKPC. Concerning the interruptible service credit, EKPC has calculated an avoided cost estimate of interruptible power. The result of that calculation is shown in Scott Exhibit 1. After considering the results of this calculation, EKPC concluded that the current level of the interruptible credit is reasonable and no changes would be proposed for the interruptible service credits.

Q. You have stated that EKPC is proposing no rate design changes in the application. Didn't the Commission's Order in EKPC's last rate case indicate that rate design issues were to be addressed in this application?

A. Yes. On page 6 of the March 31, 2009 Order in Case No. 2008-00409 the Commission stated:

> EKPC's proposed Phase II rates were intended as a means of implementing a revenue neutral rate adjustment that would better align its rates with its cost-of-service. The Phase II rates would have shifted more fixed cost recovery from the energy charge component to the demand charge component of EKPC's rate schedules. While there will be no Phase II rate adjustment under the terms of the Settlement, the Commission is very much interested in cost-of-service-based rates and demand-side management programs that incentivize both the utility and customers to practice energy efficiency in a cost-effective manner. Given the expectation that it will file a new rate application within the next few years, the Commission anticipates that EKPC will address these issues at that time.

Q. Would you explain why EKPC did not propose any changes in its rate design?

A. EKPC has not proposed any changes in its rate design in this application due to the fact it is currently conducting a Rate Design Feasibility Study along with its Member Cooperatives. This study is a coordinated examination of both the EKPC wholesale and the Member Cooperative retail rate designs. EKPC believes that the results of this study will provide a foundation that can be utilized to better respond to the rate design issues identified by the Commission in the March 31, 2009 Order.

Q. Would you explain why EKPC and its Member Cooperatives are performing this rate design study at this time?

A. After Case No. 2008-00409 was completed, EKPC began to evaluate how it had approached its rate design proposal in that case. EKPC understood that due to the diversity among its Member Cooperatives that the retail rate effects resulting from changes in the wholesale rates could vary from cooperative to cooperative. However, EKPC realized that it did not fully understand how changes in its wholesale rates could affect the retail rates of the Member Cooperatives.

EKPC further realized any coordination that had existed between East Kentucky's rates and those of the Member Cooperatives had been diminished due to the flow-through mechanism provided by KRS 278.455. Instead of a distribution cooperative having to file a general rate case to flow-through a rate increase from the wholesale power supplier, KRS 278.455 provides for an abbreviated procedure. The distribution cooperatives using this option must allocate the increase on a proportional basis that results in no change in the retail rate design currently in effect. EKPC's last two wholesale revenue increases had been flow-throughs by the Member Cooperatives utilizing KRS 278.455.

Finally, in addition to the Commission's comments in the March 31, 2009 Order in Case No. 2008-00409, the Commission had opened an administrative proceeding to consider provisions of the Energy Independence and Security Act of 2007 ("EISA 2007") that address aligning utility incentives with the delivery of cost-effective energy efficiency and promote energy efficiency investments. In recent decisions in several Member Cooperative general rate cases, the Commission had repeated its interest in cost-of-service based rates and demand side management programs that incentivize both the utility and the customers to practice energy efficiency in a cost-effective manner. EKPC realized that the Commission's stated interest in promoting energy efficiency and demand side management could require changes in the wholesale and retail rate designs. After considering and evaluating all of these factors, EKPC concluded that it should undertake a Rate Design Feasibility Study, a coordinated and integrated examination of the wholesale and retail rate designs of EKPC and its Member Cooperatives. EKPC then presented the idea to its Member Cooperatives, with a focus on the benefit of gaining an understanding of the interrelationship between the rate designs. EKPC stressed to the Member Cooperatives that conducting this study was a first step and that implementation of any study recommendations would be considered and discussed after the study was completed. After presenting the idea and meeting with the Member Cooperatives, EKPC decided to proceed with the study.

EKPC knew that a study of this size and scope would require the use of a consultant. In November 2009 EKPC issued a request for proposals for the Rate Design Feasibility Study. Respondents were expected to conduct wholesale and retail cost-of-service studies, perform load research, and develop proposed wholesale and retail rate designs, taking into consideration the standards included in the EISA 2007. The respondents were also requested to describe their work experience with cooperatives and state regulation. In December 2009, EKPC received six proposals from regional and national consulting firms. In January 2010, EKPC signed a consulting agreement with Power System Engineering, Inc. of Minneapolis, Minnesota. The final reports and study recommendations to

EKPC and the Member Cooperatives are scheduled to be delivered by July 31, 2010.

Q. But could EKPC, using the results from the cost-of-service study in this application, have developed and proposed a set of rate design changes that would begin to move the wholesale rates to something more consistent with cost-of-service-based rates?

A. Yes, EKPC could have utilized the cost-of-service study prepared for this application to propose a rate design that more closely matched the cost-of-service study results. However, EKPC believes that would not have been reasonable to do so at this time.

Q. Would you explain why this would not have been reasonable?

A. First, the Rate Design Feasibility Study will not be completed until July 31, 2010. After the study results are provided to EKPC and the Member Cooperatives there will be a period of review and evaluation to determine what rate design is the most appropriate for EKPC's wholesale rates and the Member Cooperatives' retail rates. At this point in time, it is not known what the new rate designs could look like or what components these could contain. To implement a change in wholesale rate design as part of this case, based on the cost-of-service study, without having a clear understanding of the potential impact on retail rates would be contrary to the main purpose of the Rate Design Feasibility Study.

Second, there are differences between the cost-of-service studies used in this application and the Rate Design Feasibility Study. The cost-of-service study in this application and the wholesale cost-of-service study developed in the Rate

Design Feasibility Study have both been prepared by Mr. Eicher. The cost-of-service study in this application reflects a forecasted 2011 calendar year and production costs have been allocated using the 100 percent capacity method. The cost-of-service study in the Rate Design Feasibility Study reflects a historic 2009 calendar year and EKPC requested Mr. Eicher to review and consider various accepted methods to allocate production costs. Thus, a rate design based on the cost-of-service study in this application would not necessarily be consistent or comparable with a rate design based on the cost-of-service study utilized in the Rate Design Feasibility Study.

Third, the Member Cooperatives' flow-throughs of EKPC's proposed revenue increase are being submitted under the provisions of KRS 278.455. As discussed previously, the Member Cooperatives must allocate the revenue increase on a proportional basis that results in no change in the retail rate design currently in effect. If EKPC were to propose wholesale rate design changes in this application, the Member Cooperatives would not be able to propose corresponding changes in the retail rate design when their flow-through applications are being filed pursuant to KRS 278.455. Such an action would not be reasonable at this time, given that EKPC and its Member Cooperatives are undertaking the Rate Design Feasibility Study.

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. 2010-00167**

AFFIDAVIT

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Isaac S. Scott, 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.

Isaac S. Scott

Subscribed and sworn before me on this 27th day of May, 2010.

Notary Public

MY COMMISSION EXPIRES NOVEMBER 30, 2013
NOTARY ID #409352

Avoided Cost Estimate of Interruptible Power

Estimated Installed Cost of a Combustion Turbine	$ 550	per kW
Estimated Cost of Capital	7.52%	
Depreciation	2.50%	
Average Term of Financing for Combustion Turbine	30	years
Annual Capacity Cost	$46.66	per kW
Annual Fixed O&M Expenses	6.25	per kW
Annual Depreciation	13.75	per kW
Total Annual Cost	$66.66	per kW
Monthly Cost	$5.56	per kW

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

GENERAL ADJUSTMENT OF ELECTRIC RATES	)	PSC CASE NO.
OF EAST KENTUCKY POWER	)	2010-00167
COOPERATIVE, INC.	)	

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

Filed: May 27, 2010

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 Vice President, Finance.

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

A. The purpose of my testimony is to present the financial summary and supporting exhibits detailing how EKPC derived the amount of the requested revenue increase, to describe EKPC's proposed pro-forma revenue, expense, and rate base adjustments, to describe the calculation of EKPC's adjusted net margin and revenue deficiency for the fully forecasted test year ended December 31, 2011, and to sponsor a number of regulatory filing requirements.

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)(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	Vol. 1	Tab 10

	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.		
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)(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(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)(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 A detailed explanation of any other information provided.	Vol. 3	Tab 30
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	Vol. 5	Tab 38

	during past 6 quarters;		
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 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.	Vol. 5	Tab 43
Section 10(9)(w)	Local exchange carriers with fewer than 50,000	Vol. 5	Tab 45

	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.		
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 the rate base;	Vol. 5	Tab 47
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 club; charitable contributions; marketing, sales, and advertising; professional services; civic and political activities; employee parties and outings; employee gifts; and rate cases;	Vol. 5	Tab 51

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)(h)	Computation of gross revenue conversion factor for forecasted period;	Vol. 5	Tab 53
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. 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 EKPC's adjusted net margins for the forecasted test period without reflecting a general adjustment in rates and EKPC's net margin requirement necessary to provide a 1.50 TIER. Based on the forecasted test year, the revenue deficiency is $49,375,429. EKPC's proposed wholesale rates to its members are projected to produce increased revenues of $49,377,447 based on estimated billing determinants for the forecasted test year. The calculation yielded a slight over-recovery ($2,018.)

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 December 31, 2011. 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 July 1, 2010, the first 12 consecutive calendar months after the 6 month suspension period corresponds to the 12 months beginning January 1, 2011, and ending on December 31, 2011.

The base period for the filing is the 12 months ended August 31, 2010. 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 September 1, 2010, 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 May 27, 2010 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. Have you prepared an exhibit that shows how EKPC's revenue deficiency is calculated?

A. Yes. Wood Exhibit 1 shows the calculation of EKPC's revenue deficiency.

Q. Please walk us through Wood Exhibit 1.

A. The purpose of Wood Exhibit 1 is to calculate the difference between EKPC's adjusted net margin for the forecasted test year and the margin necessary for EKPC to achieve a 1.50 TIER. The exhibit begins with Operating Revenue and Patronage Capital from EKPC's forecast for the 12 months ended December 31, 2011 (line 1). This amount is obtained from the 2011 forecast presented to EKPC's Board of Directors ("Board") and used as the basis for their approval of this rate increase. The monthly and 12-month total amounts for the forecasted test year are shown in Exhibit 1 to Mr. Oliva'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 34 of the exhibit. Adjusted Cost of Service, which reflects the pro-forma expense adjustments, is shown on line 37.

Adjusted Operating Margins (line 39) is calculated by subtracting Adjusted Cost of Service (line 37) from Adjusted Revenue (line 9). Interest income (line 42), other non-operating expense (line 43), and other capital credits/patronage dividends (line 45), along with one pro-forma adjustment, are added to Adjusted Operating Margins (line 39) to determine EKPC's Adjusted Net Margin (Line 55). For the forecasted test-period, EKPC is projected to a have an Adjusted Net Margin of $6,794,534.

The Revenue Deficiency is calculated on lines 53 to 61 of Wood Exhibit 1. To achieve a 1.50 TIER, EKPC needs a net margin requirement of $56,169,963 (Line 59.) EKPC's $49,375,429 revenue deficiency corresponds to the difference between this net margin requirement of $56,169,963 and EKPC's adjusted net margin of $6,794,534.

Q. Why was a 1.50 TIER used to determine EKPC's revenue requirement?

A. As explained in the prepared direct testimonies of Mr. Oliva and Mr. Walker, a 1.50 TIER is consistent 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. Three other adjustments were required to amortize or re-amortize certain expenses. Two other adjustments were required to reflect changes in circumstances between the time the forecast used for the test year was prepared and the time of the filing. Support for each adjustment is contained in Schedules 1.01 through 1.22 of Wood Exhibit 1. The pro-forma adjustments are identified as follows:

(a) Eliminate costs recoverable through the FAC and associated revenues (Schedules 1.01 and 1.02).

(b) Remove the impact of revenues and expenses included in the environmental surcharge (Schedules 1.03, 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) Eliminate or add expenses resulting from changes in circumstances relating timing of forecasted test year preparation and rate case filing (Schedules 1.15 and 1.16).

(e) Amortize expenses (Schedules 1.17, 1.18, 1.19, 1.20, 1.21).

(f) Normalize PSC assessment (Schedule 1.22)

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 1.02).

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 (Wood Exhibit 1, line 6), to adjust off-system sales environmental surcharge revenue (Schedule 1.03), 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 1.03) in greater detail.

A. In determining the environmental surcharge, a portion of EKPC's environmental compliance costs recovered through the surcharge is 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, an adjustment was made to reduce revenues to reflect the environmental surcharge methodology for allocating environmental costs to off-system sales.

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. EKPC is removing directors' severance expenses ($16,000) from the forecasted test-year revenue requirement. This portion of directors' expenses is readily identifiable in EKPC's budget. EKPC is retaining the remaining directors' fees and expenses, as the number of board meetings and the level of training have increased as a result of management audit recommendations.

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 and income 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 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). Please note that the employee-related expenses removed as a result of Commission practice total $164,000. These expenses are individually projected in developing the budget and are therefore readily identifiable.

Q. Please describe the remaining adjustment outlined in Schedule 1.15.

A. During the budgeting process, EKPC included a pension debt reduction expense of $3.5 million. National Rural Electric Cooperative Association ("NRECA"), the administrator of EKPC's defined benefit pension plan, notified EKPC and other members of the plan group, that the plan was significantly underfunded. EKPC included the $3.5 million in the budget as consideration for this probable, ongoing expenditure. Since the time the budget was finalized, NRECA has indicated that, as a result of improvements in the financial markets, a debt reduction payment is no longer needed for 2011. Although circumstances could change dependent upon market conditions, EKPC has removed this expense from this rate proceeding as it is no longer probable that this expenditure will occur.

Q. Please describe the adjustment to include outage insurance in Schedule 1.16.

A. As part of the management audit process, Liberty Consulting Group ("Liberty") recommended that EKPC purchase unit outage insurance to mitigate the impacts of a forced outage on one of EKPC's generating units. At the time the test year budget was finalized, EKPC had not completed its receipt of quotes for such insurance. Since that time, EKPC has received quotes for outage insurance and plans to purchase such insurance annually. Therefore, outage insurance expense was determined to be an appropriate addition to arrive at the revenue requirements.

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. EKPC included the re-amortization of these expenses over three years in Case No. 2008-00409. Considering that the Spurlock 1 forced outage occurred in 2004, EKPC has proposed amortizing the remaining unamortized balance at December 31, 2010 ($4,748,691) over two years versus three years. This amortization results in an increase of expenses of $2,374,346.

Q. Please describe the adjustments relating to the amortization of unrecoverable forced outage replacement power expenses in Schedules 1.18 and 1.19.

A. The Commission approved EKPC's establishing a regulatory asset to consider unrecoverable forced outage replacement power expenses (Case No. 2008-00436.) As part of the settlement agreement reached in Case No. 2008-00409, the Commission allowed the amortization of this regulatory asset over a three-year period. Schedule 1.18 provides the detailed calculations of the amortization and reflects the unamortized balance as of December 31, 2010 of $5,125,000, which is prior to the start of the forecasted test year. EKPC has proposed amortizing the remaining unamortized balance over three years, which results in an increase of expenses of $1,708,333. During the budgeting process, EKPC inadvertently included a portion of the amount of the current amortization in the forecasted test year. Schedule 1.19 reflects the removal of this expense from the revenue requirements calculation.

Q. Please describe the adjustment to reflect the amortization of management audit expenses in Schedule 1.20.

A. As part of the Order in Case No. 2008-00436, the Commission ordered that EKPC would be subject to a comprehensive management audit, specifically examining the involvement of EKPC's Board in the strategic planning, decision making and management of EKPC. As allowed by KRS 278.255, EKPC has accumulated the management audit expenses in a regulatory asset account and has included the estimated amortization of $333,333 as an increase to expenses. EKPC recognizes that only verifiable costs incurred in the management audit process are eligible for cost recovery, and EKPC will provide such documentation.

Q. Please describe the adjustment to reflect an amortization of rate case expenses in Schedule 1.21.

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.

Q. Please explain the adjustment to normalize the PSC assessment in Schedule 1.22.

A. This adjustment reflects the increase in the PSC assessment that would result from the increase in revenues.

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. 2010-00167**

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 27th day of May, 2010.

Notary Public

MY COMMISSION EXPIRES NOVEMBER 30, 2013
NOTARY ID #409352

EAST KENTUCKY POWER COOPERATIVE, INC.
Calculation of Revenue Requirement
Based on Forecasted Revenues and Expenses
For the 12 Month Period Ended December 31, 2011

Line	Description	Reference		Amount
1	**Total Operating Revenue & Patronage Capital Per Budget**	Oliva Exhibit 1, Page 1, Line 8		$ 946,340,857
2				
3	Adjustments to Revenue:			
4	To Remove Fuel In Base Rates	Schedule 1.01		(499,738,400)
5	To Remove Fuel Adjustment Clause Revenue	Schedule 1.01		48,873,789
6	To Remove Environmental Surcharge Revenue	*Oliva Exhibit 1, Page 1, Line 3*		*(102,331,164)*
7	To Adjust Off-System Sales Environmental Surcharge Revenue	Schedule 1.03		(491,972)
8				
9	**Adjusted Revenue**	Lines 1 through 7		$ 392,653,110
10				
11				
12	***Total Cost of Service***	Oliva Exhibit 1, Page 2, Line 26		$ 938,607,464
13				
14	Adjustments to Cost of Service:			
15	To Remove Fuel Expense Recoverable through the FAC	Schedule 1.01		$ (427,631,417)
16	To Remove Purchased Power Expense Recoverable through the FAC	Schedule 1.02		(29,812,073)
17	To Remove O&M Expenses Recoverable through the Environmental Surcharge	Schedule 1.04		(29,646,934)
18	To Remove Emissions Allowance Expense Recoverable through the Environmental Surcharge	Schedule 1.05		(4,845,860)
19	To Remove Property Taxes and Property Insurance Recoverable through the Environmental Surcharge	Schedule 1.06		(1,817,040)
20	To Remove Depreciation Expenses Recoverable through the Environmental Surcharge	Schedule 1.07		(18,275,052)
21	To Remove Interest Expenses Recoverable through the Environmental Surcharge	Schedule 1.08		(34,976,871)
22	To Remove Promotional Advertising Expense pursuant to Commission Rule KAR 5:016	Schedule 1.09		(444,104)
23	To Remove Directors' Severance Expenses	Schedule 1.10		(16,000)
24	To Remove Donations	Schedule 1.11		(74,165)
25	To Remove Lobbying Expenses	Schedule 1.13		(25,628)
26	To Remove Touchstone Energy Dues	Schedule 1.14		(414,000)
27	To Remove Other Miscellaneous Expenses	Schedule 1.15		(3,664,000)
28	To Allow for Outage Insurance	Schedule 1.16		900,000
29	Amortize 2004 Spur 1 Forced Outage Balance	Schedule 1.17		2,374,346
30	Amortize Regulatory Asset - Non-FAC-Recovable Replacement Power	Schedule 1.18		1,708,333
31	To Remove Regulatory Asset Expense Included in Test Year	Schedule 1.19		(3,185,760)
32	Amortize Management Audit Expenses	Schedule 1.20		333,333
33	To Normalize Rate Case Expenses	Schedule 1.21		208,333
34	To Adjust for Change in PSC Assessment	Schedule 1.22		65,817
35				
36				
37	**Adjusted Cost of Service**	Lines 15 through 34		$ 389,368,723
38				
39	**Adjusted Operating Margins**	Line 9 less Line 37		$ 3,284,387
40				
41	**Non-Operating Items**			
42	Interest Income	Oliva Exhibit 1, Page 2, Line 32		$ 3,417,879
43	Other Non-Operating Income	Oliva Exhibit 1, Page 2, Line 34		(69,488)
44	*To Remove Affiliate Transactions*	Schedule 1.12		11,756
45	Other Capital Credits/Patronage Dividends	Oliva Exhibit 1, Page 2, Line 35		150,000
46				
47	**Total Non-Operating Items**	Lines 42 through 45		$ 3,510,147
48				
49	**Adjusted Net Margin (Deficit)**	Line 39 plus Line 47		$ 6,794,534
50				
51				
52				
53	**Calculation of Revenue Deficiency**			
54				
55	Adjusted Net Margin (Deficit)	Line 49		$ 6,794,534
56				
57	Interest on Long-Term Debt (Oliva Exhibit 1, Page 2, Line 19 less Line 21 above)		112,339,926	
58				
59	**Net Margin Requirement at 1.50 TIER (0.50 x Line 57)**			$ 56,169,963
60				
61	Revenue Deficiency (Line 59 - Line 55)			$ 49,375,429

EAST KENTUCKY POWER COOPERATIVE, INC.

Wood Exhibit 1
Schedule 1.01

Adjustment to Remove FAC Base Rate Revenue

		MWh Sales Subject to FAC	Fuel Cost in Base Rates*	FAC Base Rate Revenue	Member FAC Billings**	Member FAC Billings - Steam	Total
January	2011	$ 1,390,824	$ 36.53	$ 50,806,801	$ (204,796)	$ (3,690)	$ (208,486)
February	2011	1,189,219	36.53	43,442,170	(1,235,982)	(23,746)	(1,259,728)
March	2011	1,159,567	36.53	42,358,983	(4,600,290)	(92,688)	(4,692,978)
April	2011	968,042	36.53	35,362,574	(4,512,416)	(102,421)	(4,614,837)
May	2011	980,955	36.53	35,834,286	(5,645,341)	(128,897)	(5,774,238)
June	2011	1,081,531	36.53	39,508,327	(5,580,566)	(105,105)	(5,685,671)
July	2011	1,204,539	36.53	44,001,810	(4,984,708)	(83,745)	(5,068,453)
August	2011	1,200,560	36.53	43,856,457	(5,167,257)	(88,358)	(5,255,615)
September	2011	1,036,482	36.53	37,862,687	(6,472,098)	(126,572)	(6,598,670)
October	2011	989,319	36.53	36,139,823	(3,468,166)	(81,360)	(3,549,526)
November	2011	1,117,402	36.53	40,818,695	(5,245,783)	(103,210)	(5,348,993)
December	2011	1,361,779	36.53	49,745,787	(801,842)	(14,752)	(816,594)
Total		$ 13,680,219		$ 499,738,400	$ (47,919,245)	$ (954,544)	$ (48,873,789)

* As approved in Case No. 2008-00519, dated July 24, 2009
** Oliva Exhibit 1, Page 1, Line 2

Adjustment to Remove Fuel Costs Recoverable Through the FAC

Total Fuel Costs Excluding Handling -- Oliva Exhibit 1, Page 1, Line 3	$431,387,233
Less: Fuel Costs Assigned to Off-System Sales	3,755,816
Fuel Costs Recoverable Through FAC	$427,631,417

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
January	2011	$ 9,929,548	$ 833,300	$ 9,096,248
February	2011	8,597,258	833,300	7,763,958
March	2011	1,531,580	833,300	698,280
April	2011	1,249,066	833,300	415,766
May	2011	1,119,981	833,300	286,681
June	2011	1,243,830	833,300	410,530
July	2011	1,446,746	833,300	613,446
August	2011	1,354,095	833,300	520,795
September	2011	1,159,133	833,300	325,833
October	2011	1,130,332	833,300	297,032
November	2011	1,365,106	833,300	531,806
December	2011	9,685,398	833,700	8,851,698
Total		$ 39,812,073	$ 10,000,000	**$ 29,812,073**

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
January	2011	$ 416,573	12.09%	$ 50,364
February	2011	713,812	9.17%	65,457
March	2011	173,138	7.64%	13,228
April	2011	351,732	10.63%	37,389
May	2011	203,748	12.01%	24,470
June	2011	104,176	13.54%	14,105
July	2011	209,328	14.47%	30,290
August	2011	752,295	13.46%	101,259
September	2011	331,111	12.01%	39,766
October	2011	237,331	12.20%	28,954
November	2011	252,316	14.76%	37,242
December	2011	332,313	14.88%	49,448
Total		$ 4,077,873		$ 491,972

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

Descr	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Total
Ash Storage	$ 242,574	$ 242,574	$ 242,574	$ 242,574	$ 242,574	$ 242,574	$ 242,574	$ 242,574	$ 242,574	$ 242,574	$ 242,574	$ 242,566	$ 2,910,880
Ammonia	302,000	278,000	287,000	219,000	252,000	292,000	300,000	302,000	279,000	242,000	291,000	302,000	$ 3,346,000
Limestone	1,014,366	932,729	896,992	870,183	963,547	951,862	1,014,366	1,018,600	946,414	803,820	985,741	1,018,593	$ 11,417,213
Magnesium	64,000	55,000	61,000	44,000	59,000	56,000	70,000	55,000	70,000	47,000	55,000	55,000	$ 691,000
Units 3 and 4 Boiler Controls Maint	93,636	176,968	176,968	176,968	176,968	589,468	589,468	251,968	251,968	514,468	1,000,468	260,315	$ 4,259,631
Unit 1 Precipitator Maint	3,164	3,789	3,789	3,789	178,789	3,789	3,789	3,789	3,789	3,789	3,789	4,417	$ 220,471
Baghouse, SNCR (Units 3 and 4)	24,129	32,045	32,045	47,601	87,601	147,601	47,601	247,601	47,601	92,601	72,601	55,521	$ 934,548
Unit 1 SCR Maint	3,060	5,144	5,144	5,144	5,144	65,144	5,144	5,144	5,144	5,144	5,144	7,215	$ 121,715
Unit 2 SCR Maint	3,060	5,144	5,144	5,144	5,144	5,144	5,144	5,144	5,144	5,144	77,144	7,215	$ 133,715
Unit 1 Scrubber Maint	49,423	91,619	91,619	91,619	91,619	91,619	294,619	91,619	91,619	91,619	91,619	133,814	$ 1,302,427
Unit 2 Scrubber Maint	73,354	138,992	138,992	138,992	138,992	138,992	138,992	138,992	138,992	138,992	357,492	204,627	$ 1,886,401
Air Permit Fees	-	-	-	-	-	-	-	-	-	-	-	1,551,000	$ 1,551,000
Stack Monitoring Supplies	10,673	21,345	21,345	21,345	21,345	21,345	21,345	21,345	21,345	21,345	21,345	32,010	$ 256,133
Stack Monitoring Consulting	23,199	46,401	46,401	46,401	46,401	46,401	46,401	46,401	46,401	46,401	46,401	69,591	$ 556,800
Stack Monitoring Maintenance	2,458	4,916	4,916	4,916	4,916	4,916	4,916	4,916	4,916	4,916	4,916	7,382	$ 59,000
Totals by Month	$ 1,909,096	$ 2,034,666	$ 2,013,929	$ 1,917,676	$ 2,274,040	$ 2,656,855	$ 2,784,359	$ 2,435,093	$ 2,154,907	$ 2,259,813	$ 3,255,234	$ 3,951,266	$ 29,646,934

Wood Exhibit 1
Schedule 1.04

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

		Amount
January	2011	$ 457,872
February	2011	384,246
March	2011	416,136
April	2011	385,240
May	2011	334,498
June	2011	357,534
July	2011	479,904
August	2011	488,620
Septembei	2011	375,573
October	2011	384,824
November	2011	345,095
December	2011	436,318
Total		**$ 4,845,860**

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

		Amount
January	2011	$ 151,420
February	2011	151,420
March	2011	151,420
April	2011	151,420
May	2011	151,420
June	2011	151,420
July	2011	151,420
August	2011	151,420
Septembei	2011	151,420
October	2011	151,420
November	2011	151,420
December	2011	151,420
Total		**$ 1,817,040**

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

		Amount
January	2011	$ 1,522,921
February	2011	1,522,921
March	2011	1,522,921
April	2011	1,522,921
May	2011	1,522,921
June	2011	1,522,921
July	2011	1,522,921
August	2011	1,522,921
September	2011	1,522,921
October	2011	1,522,921
November	2011	1,522,921
December	2011	1,522,921
		$ 18,275,052

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

		Amount
January	2011	$ 2,709,995
February	2011	2,737,081
March	2011	2,760,880
April	2011	2,809,485
May	2011	2,839,363
June	2011	2,884,383
July	2011	2,907,318
August	2011	2,939,109
September	2011	3,050,317
October	2011	3,077,280
November	2011	3,122,550
December	2011	3,139,110
		$ 34,976,871

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

Month	Amount
January	$ 118,980
February	13,980
March	201,591
April	19,980
May	15,180
June	9,091
July	8,980
August	8,980
September	9,091
October	15,180
November	8,980
December	14,091
Total	**$ 444,104**

Wood Exhibit 1
Schedule 1.10

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

		Amount
January	2011	$ 1,333
February	2011	1,333
March	2011	1,334
April	2011	1,333
May	2011	1,333
June	2011	1,334
July	2011	1,333
August	2011	1,333
September	2011	1,334
October	2011	1,333
November	2011	1,333
December	2011	1,334
		$ 16,000

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Donations

		Amount
January	2011	$ 4,428
February	2011	6,280
March	2011	5,885
April	2011	5,885
May	2011	5,885
June	2011	6,535
July	2011	6,545
August	2011	5,885
September	2011	6,045
October	2011	5,985
November	2011	5,885
December	2011	8,922
		$ 74,165

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

		ACES Expenses	Propane Expenses	Envision Expenses	Int Income Nonreg	Total
January	2011	$ 146	$ 104	$ 7,440	$ (2,405)	$ 5,285
February	2011	292	129	5,653	(4,811)	1,263
March	2011	292	130	6,021	(4,811)	1,632
April	2011	292	129	4,821	(4,811)	431
May	2011	292	129	4,953	(4,811)	563
June	2011	292	131	5,045	(4,811)	657
July	2011	292	131	4,972	(4,811)	584
August	2011	292	132	4,965	(4,811)	578
September	2011	292	212	5,065	(4,811)	758
October	2011	292	135	5,175	(4,811)	791
November	2011	292	133	4,978	(4,811)	592
December	2011	434	155	5,250	(7,217)	(1,378)
		$ 3,500	$ 1,650	$ 64,338	$ (57,732)	**$ 11,756**

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

		Amount
January	2011	$ 1,983
February	2011	2,078
March	2011	2,154
April	2011	2,072
May	2011	2,118
June	2011	2,159
July	2011	2,160
August	2011	2,200
September	2011	2,159
October	2011	2,194
November	2011	2,109
December	2011	2,242
Total		**$ 25,628**

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

		Amount
January	2011	**$ 414,000**

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

	Forecasted Expense Calendar Year 2011	
Executive Retirement Plan	$	45,000
Pension Funding		3,500,000
Employee Recognition Dinner		40,000
Employee Food Certificates		30,000
Vending Supplies		30,000
Employee Recreation		19,000
Total	**$**	**3,664,000**

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Allow for Outage Insurance

Estimated Outage Insurance Premium	$900,000

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	$ 569,843		
Amortization December 2007- March 2009			$ 9,117,487
Unamortized Balance--April 1, 2009			$ 11,396,859
Period for Amortizing Remaining Balance		3 Years	
Annual Amortization beginning 4/1/09	$ 3,798,953		
Monthly Amortization	$ 316,579		
Amortization April 2009 - December 2010			$ 6,648,168
Unamortized Balance December 31, 2010			$ 4,748,691
Period for Amortizing Remaining Balance		2 Years	
Annual Amortization Beginning 1/1/2011			**$ 2,374,346**

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Amortize 2008 Non-FAC-Recoverable Replacement Power Costs

Non-FAC-Recoverable Replacement Power Costs-- Allowance for 3-Year Amortization per Order in Case No. 2008-00436, dated December 23, 2008			$ 12,300,000
Monthly Amortization as allowed in Order in Case No. 2008-00409	$ 341,667		
Amortization April 2009 - Dec 2010			$ 7,175,000
Unamortized Balance--December 31, 2010			$ 5,125,000
Period for Amortizing Remaining Balance		3 Years	
Annual Amortization			**$ 1,708,333**

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment Amortization of Regulatory Assets included in 2011 Budget

Amortization balance included in forecasted test year	$	3,185,760
As approved in Case No. 2008-00436		

Estimated Management Audit Expenses
Ordered in Case 2008-00436

EKPC Legal Consultants	$	570,000
Legal Consultant to Board		25,000
NRECA Board Consultant		75,000
Liberty Consultants		265,000
Special Board Meetings, Supplies		65,000
Total	$	1,000,000
Amortization Period		3
Annual Amortized Amount	$	333,333

Estimated Rate Case Expenses
Case No. 2010-00167

Legal Consultant	$ 310,000
Rate Case Consultant	200,000
TIER and Equity Consultant	25,000
Advertising Member Cooperatives	50,000
Supplies, Expenses, Shipping	40,000
Total	$ 625,000
Amortization Period	3 Years
Annual Amortized Amount	$ 208,333

East Kentucky Power Cooperative, Inc.
Adjustment to Estimate Change in PSC Assessment

Rate Increase Requested	$	49,375,429
Budgeted Sales to Members		925,001,553
% Change		5.34%
Budget PSC Assessment 2011		1,339,703
Estimated Increase in PSC Assessment	$	71,512
Estimate included in Exhibit 2		$65,817