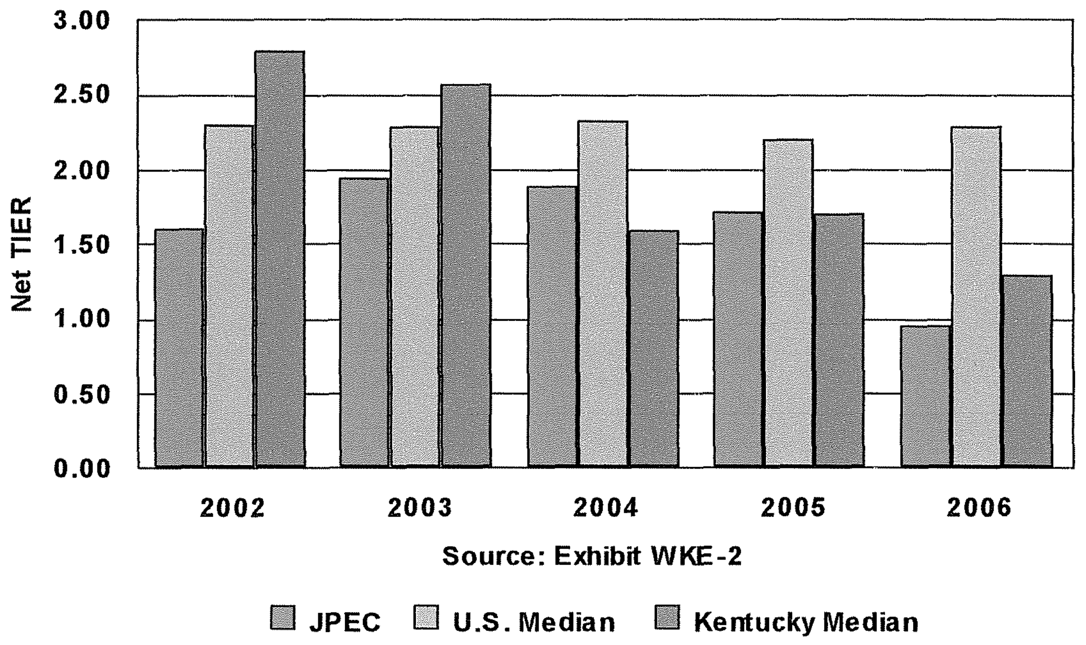
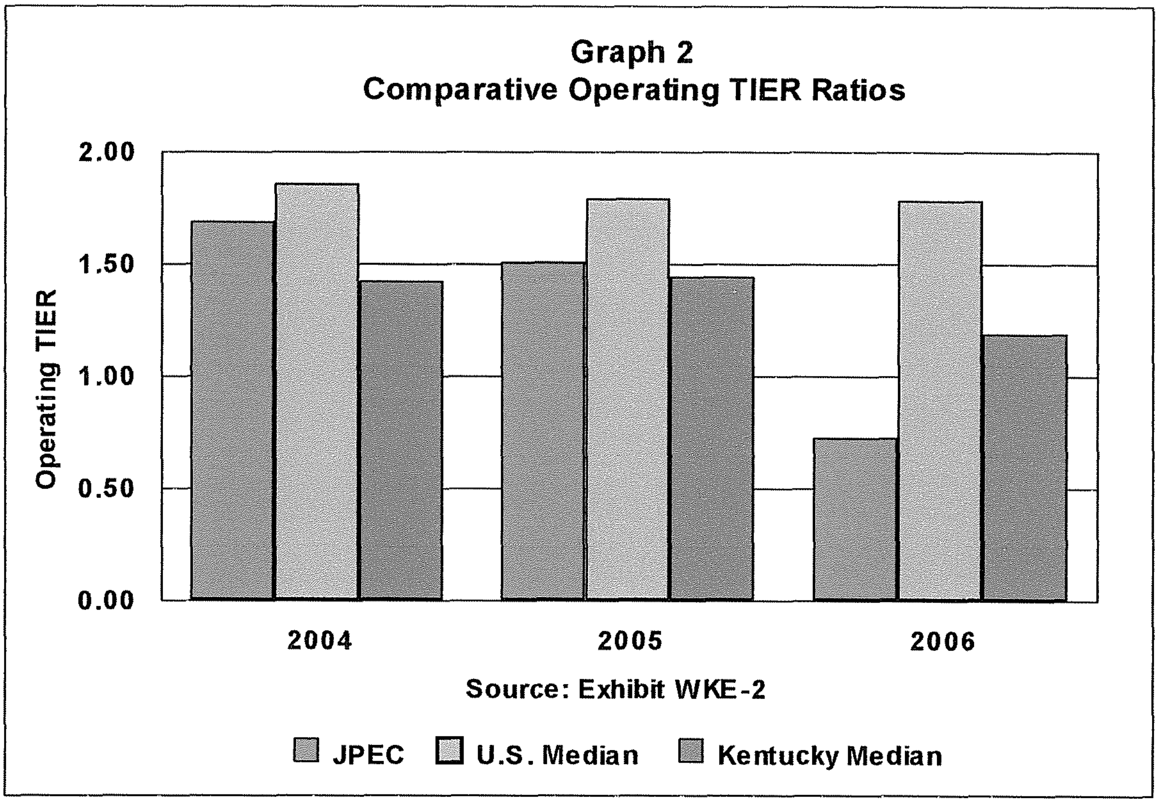
Graph 1
Comparative Net TIER Ratios



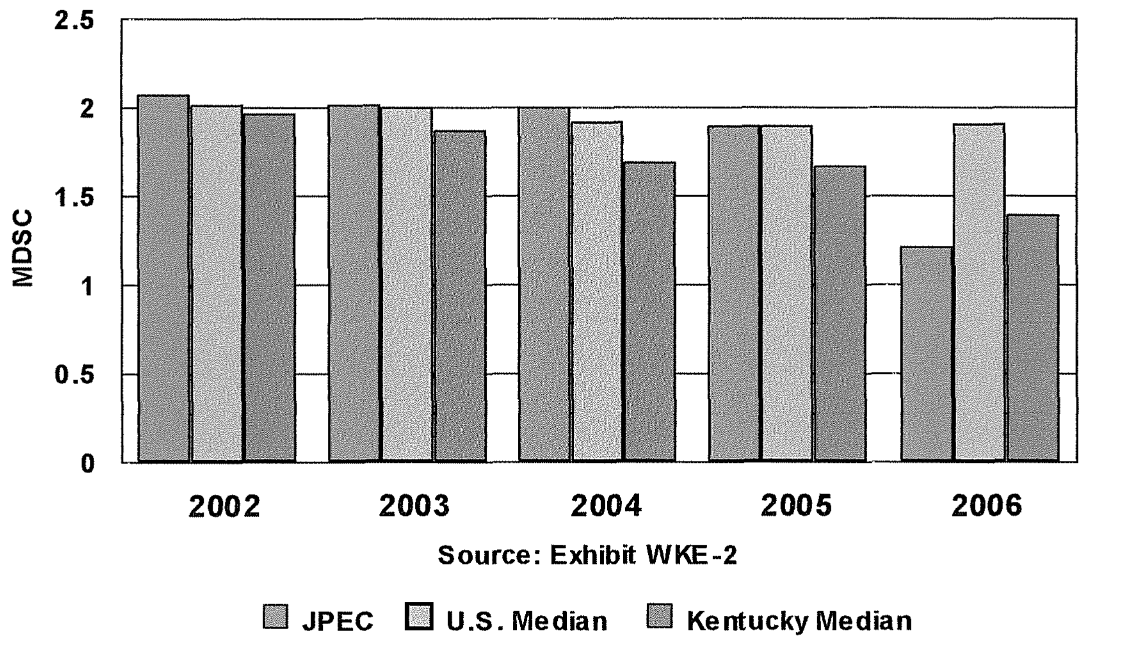
Source: Exhibit WKE-2

The company is seeking rate relief adequate enough to produce a 2.00 Net TIER (See Direct testimony of Charles G. Williamson, III), which is below the 2006 median value of net TIER of 2.29 which is composed of 819 distribution cooperatives across the country. The company's 2006 as booked net TIER ratio was 0.96. The normalized adjusted Net TIER value is 0.69. Both of these values are appreciably below the default value of 1.25 required by the RUS.



In Graph 2, the Operating TIER for 2006 for JPEC is 0.73 which is appreciably below the 1.10 minimum default value established by the RUS. The national median value of operating TIER is 1.79. In Graph 2, the data is limited to three years because CFC has only recently begun to collect this data.

Graph 3
Comparative MDSC Ratios



In Graph 3, the 2006 as booked financial statements yield a MDSC value for JPEC of 1.23. The normalized test year for JPEC yields a MDSC of 1.21. Both of these figures are below the default value of 1.35 required by CFC. By contrast, the national median value of MDSC is 2.02.

Q. Why is there a difference in the comparative results between Net TIER and MDSC?

A. Net TIER and MDSC are illustrated below in equations 1 and 2 respectively.

Eq.(1) Net TIER = (Net Margins + L-T Interest Expense)/ L-T Interest Expense

Eq.(2) MDSC = (Depreciation and Amortization + Operating Margins + Non-operating Margins [Interest] + L-T Interest Expense + Patronage Capital Received in Cash)/Total L-T Debt Service

MDSC is simply a broader measure of coverage.

Q. Is equity an important consideration in securing private source capital?

A. Yes. CFC attempts to work closely with all its borrowers by making recommendations and providing courses to assist them in building an appropriate equity level in order to achieve a capital structure that will allow them to attract capital at reasonable rates.

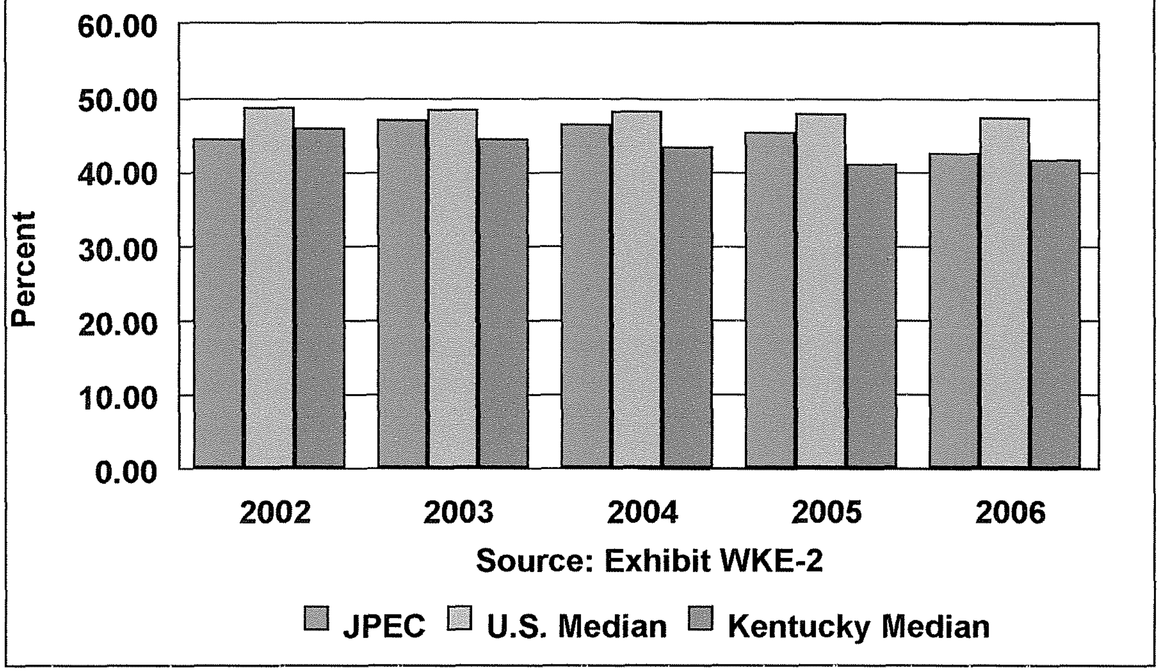
Q. Does CFC have an interest in JPEC's equity ratio?

A. Yes. CFC is vitally interested in JPEC 's equity ratio as well as that of every other cooperative that seeks financing from CFC. This interest is on an individual as well as a collective basis since the overall position of the borrowers as a group is what CFC provides to the market. The industry's equity ratios affect the attitudes of investors of CFC securities. Should the overall equity position of electric cooperative utilities change, investors can be expected to react toward CFC securities, as they would towards the securities of an IOU. For example, if the overall equity ratio of electric cooperatives materially declines, the investors would perceive an increase in risk and would demand a higher risk premium associated with the cost of debt.

Q. How Does JPEC 's equity ratio compare to other cooperatives?

A. I have calculated the test year equity ratio to be approximately 42.44% as shown in the table below. The company's equity ratio has been declining since 2003. The 2006 industry average was 47.27% (See Exhibit WKE-2 ratio 18). This information is summarized in a graph (see Graph 4) below.

Graph 4
Comparative Equity Ratios



Over the last five years the distribution cooperative industry has maintained an equity ratio between 47 to 50 percent.

Over the last five years the distribution cooperative industry has maintained an equity ratio between 47 to 50 percent.

Q. Why is it important for JPEC to maintain a strong equity base?

A. The lower the equity ratio, the higher the annual charges for interest expense, and the greater the margin requirements to maintain adequate TIER and MDSC ratios. As the blended cost of long-term debt rises, the requirements to achieve an adequate TIER will become more difficult unless the equity ratio is increased. The rate of return on equity capital required to maintain an acceptable Net/Operating TIER will increase dramatically as equity falls and the blended cost of outstanding long-term debt increases.

Q. What is your recommendation for an appropriate TIER ratio at this time for JPEC?

A. JPEC is seeking a 2.0 net TIER return in this proceeding. I believe this to be the minimum TIER ratio for JPEC at this time. I understand that the Board of Directors and senior management are concerned with the magnitude of the resulting rate increase and have constrained their request to a minimal 2.0 TIER in an attempt to strike a balance between the equity-owners and financial prudence.

In order to more directly measure the required return and effect on equity, I have prepared estimates of the earned test year rate of return on equity (ROE) required for JPEC.

Earned ROE

Q. Have you prepared a calculation of Utility Operating Income for the Test Period?

A. Yes, I have. The calculation of Utility Operating Income for the test period, 12 months ended December 2006, as adjusted by normalizing adjustments for known and measurable changes, is presented below in Table 1.

Q. How did you determine the Test Period Amounts and pro forma adjustments?

A. The test period amounts and pro forma adjustments associated with the Income Statement are based on Exhibit S, included in and sponsored by the testimony of JPEC witness Charles G. Williamson, III, Vice President and Chief Financial Officer.

Table 1
Calculation of Utility Operating Income for the 12 months ended December 31, 2006 with Normalizing Adjustments

Line No.	Description	12 Months Ended Dec 31, 2006	Normalizing Adjustments	Adjusted Amounts
1	Revenues at Existing Rates	$36,457,369	$0	$36,457,369
2	Other Revenues	$939,005	$0	$939,005
3	**Utility Operating Revenues**	**$37,396,373**	**$0**	**$37,396,373**
4	Cost of Purchased Power	$23,655,944	$0	$23,655,944
5	Transmission Expense	$0	$0	$0
6	Distribution Expense - Operation	$1,761,777	$53,689	$1,815,466
7	Distribution Expense - Maintenance	$3,413,939	$54,782	$3,468,721
8	Consumer Accounts Expense	$1,088,682	$20,121	$1,108,803
9	Customer Service & Inform. Expense	$220,972	$6,638	$227,610
10	Sales Expense	$56,695	($38,038)	$18,657
11	A&G Expense	$1,992,235	($52,882)	$1,939,353
12	Depreciation & Amortization Expense	$3,235,100	$594,972	$3,830,072
13	Tax Expense - Property & Gr. Receipts	$0	$0	$0
14	Other Tax Expense	$41,657	$0	$41,657
15	**Total Operating Expenses**	**$35,467,001**	**$639,282**	**$36,106,283**
16	**Operating Income**	**$1,929,372**	**($639,282)**	**$1,290,090**
17	Other Interest & Deductions	($82,906)	$1,424	($81,482)
18	Non-Operating Revenues	$706,511	($41,097)	$665,414
19	**Adjusted Operating Expenses**	**$34,843,396**	**$678,955**	**$35,522,351**
20	**Adjusted Operating Income**	**$2,552,977**	**($678,955)**	**$1,874,022**

Q. What do the Adjusted Operating Expenses and Adjusted Income represent in Table 1 above?

A. The Adjusted Operating Expenses reflect additional expenses and Non-Operating Revenues of JPEC that are typically below the line of traditional Operating Income. These expenses and non-operating revenues are reflected in the Adjusted

Operating Income to better compare with the measure of Net TIER which also includes these items. Many cooperatives like JPEC have non-operating revenues that are stable over time and as a matter of philosophy are considered by many cooperatives as a credit to the required revenues.

Q. Does the $37,396,376 represent total Utility Operating Revenues for the 12 months ended December 31, 2006?

A. Yes, it does.

Q. Did you prepare a calculation of Rate Base for the Test Period and with pro forma adjustments for known and measurable changes?

A. Yes. The calculation is attached as Exhibit WKE-3, which is summarized below in Table 2.

Table 2
Summary of Rate Base

Line No.	Description	Average Balances as of 12/31/2005 and 12/31/2006	Adjustments	Adjusted Amounts
1	Net Utility Plant	$74,500,268	($517,314)	$73,982,954
2	Materials & Supplies	$1,687,521	$6,431	$1,693,952
3	Prepayments	$429,880	$7,271	$437,151
4	Cash Working Capital	$1,059,701		$1,059,701
5	Deferred Debits	$1,390,539		$1,390,539
6	Customer Deposits	($1,119,209)		($1,119,209)
7	Deferred Credits	($175,052)		($175,052)
8	**Total Rate Base**	**$77,773,649**	**($503,612)**	**$77,270,037**

Q. What is the source of the Net Utility Plant amount in Table 2?

A. That amount is the average balance column of Exhibit WKE-3, page 2 of 2, line 64.

Q. How did you prepare Exhibit WKE-3?

A. I prepared Exhibit WKE-3 from copies of their Trial Balances as of December 31, 2005 and 2006 provided me by JPEC personnel. From these Trial Balances, I identified the amounts of each Utility Plant account and Accumulated Depreciation or Amortization account. I have accepted the following normalizing adjustments proposed by Mr. Williamson:

- A $77, 266 adjustment to CWIP,
- A $10,769 adjustment to Materials & Supplies, and
- A $7,271 adjustment to Prepayments.

Q. Did you make any changes to Construction Work in Progress ("CWIP")?

A. None beyond the $77,266 normalizing adjustment proposed by Mr. Williamson.

Q. Should CWIP be allowed in the rate base?

A. Yes. Although some commissions permit CWIP in rate base and some do not, I believe in this instance that inclusion of CWIP in rate base is appropriate. In a cooperative, the rate payers are the equity owners of the utility; hence there is no conflict between the customers and equity owners as is the case in an investor owned utility. Therefore, construction projects that have not yet become "used and useful" have a carrying cost that should be borne by the equity investors, which are the customers.

Q. How did you calculate the Allowance for Plant Materials and Operating Supplies?

A. From JPEC 's Trial Balances as of December 31, 2005 and 2006, I identified the amounts of all Plant Materials and Operating Supplies accounts to Exhibit WKE-3.

Q. Did you make any adjustment from the amounts shown on JPEC 's Trial Balances in the Plant Materials and Operating Supplies accounts to the applicable amounts shown in your Exhibit WKE-3?

A. I made one adjustment to eliminate the amounts shown in the trial balances for Account 156, Other Materials and Supplies, from the allowance for plant materials and operating supplies since this account typically reflects non-utility materials and supplies. I have also accepted a normalizing adjustment made by Mr. Williamson in the amount of $10,769.

Q. How did you calculate the Allowance for Prepayments?

A. From JPEC 's Trial Balances as of December 31, 2005 and 2006, I scheduled the amounts in Prepayments accounts to Exhibit WKE-3.

Q. Did you make any adjustments from the amounts shown on JPEC 's Trial Balances in the Prepayment accounts to the applicable amounts shown in WKE-3?

A. I accepted a $7, 271 adjustment made by Mr. Williamson.

Q. How did you calculate the Cash Working Capital Allowance?

A. I used the standard 45-day formula approach that the Kentucky Commission has used applied to Total Operation and Maintenance expenses less Purchase Power and Sales Expense. I multiplied the ratio ⅛ (that is, 45/360 days) times the $8,477,605, which results in a cash working capital allowance of $1,059,701.

Q. How did you calculate the amounts of Deferred Debits?

A. From JPEC 's Trial Balances as of December 31, 2005 and 2006,as shown in Exhibit WKE-3.

Q. Did you make any adjustments from the amounts shown on JPEC 's Trial Balances in the Deferred Debit accounts to the applicable amounts shown in your Exhibit WKE-3?

A. No.

Q. How did you calculate the amounts of Deferred Credits?

A. From JPEC 's Trial Balances as of December 31, 2005 and 2006,as shown in Exhibit WKE-3.

Q. Did you make any adjustments from the amounts shown on JPEC 's Trial Balances for Deferred Credit accounts to the applicable amounts shown in your Exhibit WKE-3?

A. No.

Q. Have you calculated a capital structure?

A. Yes. I have computed a capital structure using the company's adjusted test year as shown in Table 3 below.

Table 3 Jackson Purchase Energy Capital Structure (12 M.E. 12/31/2006)			
Line No.	Component	Normalized 2006	Percent Capitalization
1	Long-Term Debt	$48,718,372	58.58%
2	Equity	$34,444,409	41.42%
3	Total	$83,162,781	100.00%

In the Balance Sheet filed in a number of exhibits with the application, certain adjustments were made that reflect the inclusion of proposed rates as if they were present for the entire year. This potentially affects the return on equity because there is an adjustment of approximately $3.5 million to patronage capital, which if used to calculate the equity ratio, would inappropriately skew it higher. For this reason I have used the approximate $34.4 million as of December 31, 2006 for the purpose of computing the capital structure as illustrated in Table 3.

Q. Have you computed the cost of debt?

A. I have computed the cost of debt, which represents a weighted cost calculated by taking the long-term interest expense for the test year divided by the average of the outstanding debt at the beginning and end of the test year. Additionally I have added $53,526 to the interest expense on long-term debt to reflect the normalizing adjustment sponsored by Mr. Williamson in his direct testimony. The weighted average cost of debt is 5.88%.

Q. Have you calculated the earned return on equity for the test period?

A. Yes. Table 4 illustrates the ROE for the Test Period (unadjusted) and the test period as adjusted for normalizing adjustments.

Table 4
Calculation of Return on Rate Base & Equity

Line No.	Description	As Booked 2006 W/O Rate Inc.	Adjustments	Normalized 2006 W/O Rate Inc.
1	Rate Base	$77,773,649	($503,612)	$77,270,037
2	Return on Rate Base	3.28%		2.43%
3	Return	$2,552,977	($678,955)	$1,874,022
4	Adj. Operating Expenses	$34,843,396	$678,955	$35,522,351
5	Revenues	$37,396,373	$0	$37,396,373
6	Revenue Difference			$0
7	Increase/(Decrease)			0.00%
	Return on Rate Base	3.28%		2.43%
8	Return on Equity	-0.10%		-2.47%

Q. What is the company's requested return?

A. The company is requesting a 2.0 Net TIER which is equivalent to a 7.02% return on rate base and an 8.64% return on equity as shown in Table 5 below.

Table 5
Calculation of Return on Rate Base & Equity

Line No.	Description	Normalized 2006 W/O Rate Inc.	Adjustments	Normalized 2006 W/ Rate Inc.
1	Rate Base	$77,270,037	$0	$77,270,037
2	Return on Rate Base	2.43%		7.02%
3	Return	$1,874,022	$3,554,064	$5,428,086
4	Adj. Operating Expenses	$35,522,351	$0	$35,522,351
5	Revenues	$37,396,373	$3,554,064	$40,950,437
6	Revenue Difference			$3,554,064
7	Increase/(Decrease)			9.50%
	Return on Rate Base	2.43%		7.02%
8	Return on Equity	-2.47%		8.64%

Q. Is this an adequate return?

A. Yes, but is it likely leans toward the lower end of a reasonable range of returns.

Q. Will the proposed increase adequately improve the financial ratios?

A. JPEC will likely have adequate financial ratios. As shown below, JPEC's test year financial ratios are close to the median industry values with the proposed 9.5% increase.

	JPEC W/ Proposed Increase	Industry Median 2006
TIER	2.00	2.29
Operating TIER	1.75	1.79
MDSC	1.96	1.91

Optimal Cost of Equity

Q. Can you estimate the optimal cost of equity capital for a cooperative that does not sell equity in the public markets?

A. Yes. The distribution customers who own JPEC invested equity capital in the form of patronage capital in the company through the retention of excess margins over costs. The equity holder's patronage capital investments may be jeopardized when JPEC loses money or only meets its minimum payment obligations, and the equity portion of the balance sheet is reduced or impaired. Consistent with the regulatory and economic standards identified in the Bluefield (1923) and Hope (1944) decisions, I believe the return should be sufficient to return past capital investment in the utility, enable the company to attract new capital, and maintain the company's financial integrity inclusive of maintaining a prudent equity ratio. Absent an adequate return sufficient to return capital pursuant to its capital rotation policy, JPEC and its customer-owners would be harmed.

The Bluefield and Hope decisions, as applied to cooperatives, are slightly different than as applied to IOU. In an IOU, common equity is traded in very competitive markets largely to investors who are not customers of the utility. Therefore, with respect to IOU, a return is required commensurate with the opportunity cost and risk of equity in a competitive financial market. With respect to cooperatives, because they do not trade equity in the market but retain margins for a period of time before returning them to the owner customers, the conceptual return should be adequate enough to allow JPEC the opportunity to meet its operating requirements, provide for access to the debt capital markets and enable JPEC to return the patronage capital pursuant to a reasonable schedule.

Q. Why should a distribution cooperative like JPEC be entitled to an equity return? Isn't JPEC a not-for-profit cooperative?

A. JPEC is a not-for-profit tax-exempt cooperative. As such, JPEC provides service to its members at rates that are essentially at cost. However, equity capital has a cost associated with its rotation and JPEC 's growth and the determination of that cost becomes the basis of the return on equity recommendation contained in the company's request. This concept, when applied to a cooperative, is different from an IOU application. In an IOU, the cost of equity is the opportunity cost of equity in the market place. For this reason, the cost of equity for a cooperative is typically significantly less than the cost of equity for a cooperative.

Q. Are there different methods to estimate the return on equity for a cooperative like JPEC ?

A. There are several formulas useful for determining the cost of equity capital from a cooperative like JPEC . These formulas have been developed over the last 30 plus years. Much of the original work in this field is attributable to Mr. James W. Goodwin during the late 1960s and early 1970s. Mr. Goodwin worked for the REA (now the Rural Utilities Service, or RUS) as chief of the REA Retail Rate Branch and wrote several papers on the subject of equity costs associated with cooperatives. The original formula proffered by Mr. Goodwin is illustrated below in equation 3.

Eq(3): $K_e = [(1+g)^n - (1-g)^{n-1}] / (1+g)^{n-1} - 1$

Where:
K_e = Return On Equity
g = Growth Rate in Rate Base
n = Patronage Capital Rotation Period

Subsequent work by both the RUS and CFC has resulted in a modification to the original formula to reflect a more forward-looking analysis. The modified formula is shown as equation 4 below.

Eq(4): $Ke = [(1+g)^{n+1} - (1-g)^n] / (1+g)^n$

These formulas produce a minimum return required to hold the equity ratio at its present level while growing at a fixed level of growth (g) and revolving capital credits an a specific cycle (n years). The formulas also implicitly assume a retirement of patronage capital schedule, which grows as margins grow over time. However, should the equity ratio be appreciably below (above) its target level, then either the "Goodwin" model or its successor (the modified "Goodwin" model) will not produce a return that will allow the cooperative to achieve its target level.

Another derivative of the Goodwin model permits adjustments to the cost of equity that will permit it to achieve the target ratio in a fixed number of years. Because the equity ratio is appreciably below the target equity ratio for JPEC , the adjustment component in the model will produce a premium in the return on equity to permit the cooperative a higher return than it would ordinarily require. This is necessary to protect the existing equity of members. Additionally, the customer-owners of JPEC would be subject to higher financing costs if the return on equity did not permit such a premium (see equation 5).

Eq(5): $$Ke = [((1+g)^{(n+1)}-(1+g)^{n})/((1+g)^{n})-1] + (1+g)*((We^*/We)^{(1/t)})-1]$$

Where:

Ke = Require Return On Equity
g = Anticipated Growth Rate In Plant
n = Patronage Capital Rotation Period

We* = The Target Equity Ratio
We = The Actual Equity Ratio
t = Target Number Of Years To Reach We*

Q. Have you used these models to estimate the cost of equity capital for JPEC ?

A. Yes. Exhibit WKE-4 contains the assumptions and estimates of the growth rate for plant, which the capital structure will support. The growth in utility plant has averaged 4.56 % over the last 5 years. A growth rate (and subsequent ROE) should be set on a forward-looking basis because it is the basis upon which rates will be set, and is the basis upon which patronage capital will be refunded to the equity-owners of JPEC . After reviewing ten years of historical growth data and based on conversations with the company, I believe that a 4.56% growth rate is a reasonable expectation of the immediate future. I have also assumed a 20 year capital rotation cycle. Furthermore, I have targeted a 45% equity ratio, which is slightly below the industry average. Given these parameters, equation 5 produces a ROE of 8.97% (See Exhibit WKE-4), which I believe better represents the true cost of equity for JPEC at this time. Based on the 8.97% return on equity, the weighted cost of capital then becomes 7.16% as shown in Exhibit 6 below.

Table 6
Jackson Purchase Energy
Capital Structure

Line No.	Component	Pro Forma 2006	Percent Capitalization	Cost	Weighted Cost
1	Long-Term Debt	$48,718,372	58.58%	5.88%	3.45%
2	Equity	$34,444,409	41.42%	8.97%	3.72%
3	Total	$83,162,781	100.00%		7.16%

Based on test year parameters, a return on rate base of 7.16% would result in an increase of $3,661,365 (9.79%) as shown below in Table 7.

Table 7
Calculation of Return on Rate Base & Equity

Line No.	Description	Normalized 2006 W/O Rate Inc.	Adjustments	Normalized 2006 W/ Rate Inc.
1	Rate Base	$77,270,037	$0	$77,270,037
2	Return on Rate Base	2.43%		7.16%
3	Return	$1,874,022	$3,661,365	$5,535,388
4	Adj. Operating Expenses	$35,522,351	$0	$35,522,351
5	Revenues	$37,396,373	$3,661,365	$41,057,739
6	Revenue Difference			$3,661,365
7	Increase/(Decrease)			9.79%
	Return on Rate Base	2.43%		7.16%
8	Return on Equity	-2.47%		8.97%

Q. What are your recommendations?

A. I recommend that the Commission accept JPEC's proposed test year, the proposed normalizing adjustments, the proposed 2.0 net TIER, and the revenue increase it generates -- $3,554,064, or a 9.50% increase over existing test year operating revenues. The difference between the company's proposed increase and that developed around an optimal ROE are not that different. For this reason, the members of JPEC should have the lesser of the two methods. I believe the company's request constitutes a reasonable request consist with the minimum required increase.

Q. Is a 9.50% increase excessive?

A. No. It is not excessive when one considers that it has been approximately 10 years since JPEC has had a rate increase. On an average annual basis, this rate increase averages about 0.91% per year since JPEC's last increase. I don't know many businesses whose costs have increased only 0.91% per year over the last decade.

Q. Does this conclude your testimony at this time?

A. Yes.

State of Virginia)
Fairfax County)

I, William K. Edwards, being duly sworn, deposes and says that the statements contained in the foregoing prepared testimony and the exhibits attached hereto are true and correct to the best of my knowledge, information and belief, and that such prepared testimony constitutes his sworn testimony in this proceeding.

William K. Edwards

SWORN TO AND ASCRIBED BEFORE ME THIS THE 6th DAY OF NOVEMBER A.D., 2007.

Notary Public

My Commission Expires:

LEONARD LEO SKATOFF, JR.
Notary Public
Commonwealth of Virginia
My Commission Expires Apr 30, 2009

WILLIAM K. EDWARDS

Mr. Edwards is the Vice President of Regulatory Affairs at the National Rural Utilities Cooperative Finance Corporation. Mr. Edwards' primary focus is the public utility industry. His areas of expertise include regulation, load forecasting, planning, cost and rate design, and mergers & acquisitions. Mr. Edwards has previously worked for the firm of Ernst & Whinney as a consultant, Mississippi Power & Light Company an operating company of Entergy as a supervisor in the Rate Department, Central Louisiana Electric Company as Director of Rates & Regulation, and Air Liquide America Corporation as an Energy Manager.

PROFESSIONAL EXPERIENCE

Mr. Edwards has extensive experience in the above listed areas. Representative projects are listed below for each of these areas.

Regulation. Mr. Edwards has broad and extensive experience in regulatory matters both as a consultant and as a utility executive. As Director of Rates for Central Louisiana Electric Company, Mr. Edwards had the responsibility for planning and successful execution of a number of dockets before both the Louisiana Commission and the FERC. Such experience includes, but is not limited to the following projects.

- Indiana Power & Light Rate Design Efforts Before the Indiana Commission
- ISES 1 & 2 rate proceedings before the Mississippi Public Service Commission
- Grand Gulf Rate proceeding before the Mississippi Public Service Commission
- Dolet Hills rate proceeding before the Louisiana Public Service Commission
- Wholesale rate proceeding before the FERC on behalf of Mississippi Power & Light Company
- Wholesale rate proceeding before the FERC on behalf of Central Louisiana Electric Company
- Transmission rate proceeding before the FERC on behalf of Central Louisiana Electric Company
- Antitrust case before the FERC on behalf of Central Louisiana Electric Company
- Rate complaint before the FERC involving rate of return and cost support.

Load Forecasting. Mr. Edwards has been involved in many load forecasting efforts with the utility industry and has participated in the industry debates regarding the evolution of methodologies for forecasting. Some of the companies Mr. Edwards has been involved with include the following.

- Wisconsin Public Service Commission - A review of the forecasting methodologies of the Wisconsin Utilities
- Delmarva Power & Light - Advance Plan Proceedings before the Delaware Commission
- Entergy - Forecasting Committee

- Central Louisiana Electric Company - Development of an econometric load forecast 1985-1995
- Aluminum Association of America - electric end-use and econometric approaches to load forecasting.

Planning. Mr. Edwards has extensive knowledge and experience with production costing models (e.g. PROMOD and POWRSYM) and load flow models (PTI and Westinghouse).

- Entergy - determination of fuel savings attributable to load and unit changes
- Central Louisiana Electric Company:
  - Fuel Budgets,
  - Analysis of Savings from Joint Dispatching,
  - Generation Planning
  - Rate Studies, and
  - Loss Studies.

Cost & Rate Design. Mr. Edwards has had extensive experience with cost analysis/determination and rate design for a number of companies including:

- Northern Indiana Public Service Company
- Delmarva Power & Light
- Arkansas Power & Light
- Mississippi Power & Light
- Louisiana Power & Light
- New Orleans Public Service Company
- Missouri Public Service Company
- Iowa Public Service Company
- Wisconsin Public Service Company
- Empire District Power Company
- New York State Gas & Electric Company
- Iowa Power & Light Company
- Allegheny Power System
- Central Louisiana Electric Company
- Air Liquide America Corporation

Mergers & Acquisitions. Mr. Edwards has performed a number of merger & acquisitions studies for various clients including:

- Central Louisiana Electric Company
- MidWest Energy
- Acquisition of Montana Power Company's hydroelectric facilities

TESTIMONY

Mr. Edwards has testified before the following Commissions on a broad range of topics:

Company	Jurisdiction	Subject
NIPSCO	Indiana	Long-Run Marginal Cost
IP&L	Indiana	Long-Run Marginal Cost
MP&L	Mississippi	Econometric Forecasts

MP&L	FERC	Financial Model/Rate of Return
CLECO	Louisiana	Rate Design/Revenue Recovery
CLECO	Louisiana	FASB 106 Issues
CLECO	Louisiana	Securities Issuances
CLECO	Louisiana	Securities Issuances
CLECO	Louisiana	Securities Issuances
CLECO	FERC	Cost of Service/Rate of Return
CLECO	FERC	Cost of Service/Rate of Return
CLECO	FERC	Cost of Service /Rate of Return
CLECO	FERC	Antitrust Issues (Predatory Pricing)
Air Liquide	Washington	Restructuring
Air Liquide	Texas	Restructuring
Air Liquide	Arizona	Rates/Corporate Structure
Air Liquide	Louisiana	Short-Run Marginal Costs and Non-Firm Rates
Idaho Co-ops	Idaho	Restructuring
Central Elect Co-op	Montana	Antitrust
Arizona Elect Power	Arizona	Stranded Costs
Montana Co-ops	Montana	Restructuring
Four County Elect	North Carolina Superior Court	Monopolization
CFC/Deseret G&T	FERC	Cost of Service/Rate of Return
Wayne-White	FERC	Market Power
Navopache EMC	Arizona	Rate of Return/TIER
Midwest Energy	Kansas	Rate of Return
Vermont Electric	Vermont	Financing/Rate of Return
Arizona Elect Power	Arizona	Rate of Return
S.W. Transmission	Arizona	Rate of Return
Wayne-White	FERC	Cost of Service
Big Horn	Wyoming	Rate of Return
Vermont Electric	Vermont	Rate of Return/Revenue Requirements
Vermont Electric	Vermont	Rate of Return
Maine Legislature	Maine	Service Territory Integrity

Mr. Edwards has testified before the Idaho Legislature regarding electric utility restructuring and before the Transition Advisory Committee of the Montana Legislature regarding restructuring of electric distribution companies.

EDUCATION

Mr. Edwards holds a B.S. degree in Economics from Christopher Newport College of the College of William & Mary (with distinction) and a M.A. degree from Old Dominion University in Economics. Mr. Edwards' fields of concentration include econometrics, mathematical economics, and microeconomics. Mr. Edwards has completed the majority of requirements for the Ph.D. degree in economics at Virginia Polytechnic Institute & State University.

PUBLICATIONS AND PRESENTATIONS

Mr. Edwards has published or has spoken at the following industry conferences:

- Equity Management And The Ratemaking Process: An Overview of Theory and Practice, June 2004.
- "Restructuring At The Crossroads: The Wake of SMD", CFC Forum Meeting with Sue Kelly, Esq., and Rich Meyer, Esq., June 2003
- "The SMD NOPR: A policy At War With Itself?" CFC Independent Borrowers Meeting, in conjunction with John T. Stough and Rodney L. Nefsky, November 2002.
- "The SMD NOPR And Its Potential Effect On Cooperatives: It's Not Your Father's Electric Power Industry Anymore", GE's MAPS User's Conference, October 24, 2002.
- "Ratemaking In A Time Of Restructuring", CFC Forum, In conjunction with Carl Stover, July 2001.
- " PURPA: An Old Law With New Twists", Montana Electric Cooperative Manager's Meeting, June 2001.
- "FERC & Distribution Cooperatives", Tri-State Office Managers & Accountants Meeting, Sponsored by the South Dakota Rural Electric Association, Inc. August 24, 2000.
- "Inferences of Restructuring On The Electric Utility Industry", Association of Illinois Cooperatives, Springfield, Illinois, July 2000.
- "Strategic Planning And Recent Changes In FERC Policy Regarding The Regulation Of Cooperatives", <u>Comments before the Arkansas Electric Cooperative Corporation</u>, Little Rock, Arkansas, December 1999.
- "Cooperative Regulatory Issues at the FERC", <u>National Rural Utilities Cooperative Finance Corporation</u> Forum in New York, New York, 1999.
- "Changes In Regulatory Jurisdiction Resulting From Restructuring", <u>Montana Association of Electric Cooperatives</u>, June 1999.
- "Regulatory Restructuring and Economies of Scale & Scope", <u>Montana Association of Electric Cooperatives</u>, June 1998.
- "Role of Antitrust Laws in the Restructuring Process", <u>Kentucky Association of Electric Cooperatives</u>, September 1997.
- "FERC Regulation of Cooperatives", <u>National Rural Utilities Cooperative Finance Corporation</u> Seminars in Denver, Washington, and Atlanta February/March 1997.
- "FERC Regulation: Services & Financial Solutions, Proceedings from CFC Borrowers Interim Meetings", In conjunction with John T. Stough, Jr. Esq., N. Beth Emery, Esq., Geoffry Hobday, Esq., March 1997.
- "The Essentials of FERC Regulation of Cooperatives", In conjunction with N. Beth Emery, Esq. And Daniel E. Frank, Esq. On behalf of the <u>National Rural Utilities Cooperative Finance Corporation</u>, February 1997.
- "Unresolved FERC Rate Making Issues", <u>National Rural Utilities Cooperative Finance Corporation</u> Independent Borrowers Conference, July 2, 1997.
- "Major Issues Facing the Electric Utility Industry As A Result of Restructuring", <u>Texas Cooperative Accounting Association</u>, June 1997.
- "FERC's New Merger Policy", <u>National Rural Utilities Cooperative Finance Corporation</u>, March 1997.
- Acquisitions and the Future of Electric Distribution Cooperatives", Presentation Before the <u>Indiana Statewide Association of Electric Cooperatives</u>, August, 1996.
- The Economics of Acquisitions, Presentation Before the <u>National Rural Electric Cooperative Association</u>, June 1996.

- "Comments Regarding Electric Industry Restructuring", on behalf of Air Liquide America Corporation for the FERC 1995.
- "Non-Firm Industrial Rates: Economic Justification Vs Marketing Justification", Presentation Before the Southeastern Electric Exchange, April 1992.
- "Econometric Elasticity Measures Using Directly Estimated Differential Equations", Presentation Before the Southeastern Electric Exchange, October 1989.
- "Role of Marginal Costs in the Rate Making Process", Entergy Rate Conference, June 1984.
- "An Inverse Limit Theorem to the Core of the Economy", Old Dominion University Thesis for the Degree of Master of Arts in Economics, Summer 1979.

PROFESSIONAL AFFILIATIONS

Mr. Edwards is a member of the American Economic Association (AEA), and the American Law and Economics Society. In 1993, Mr. Edwards served as chairman of the Southeastern Electric Exchange's Rate Section. Mr. Edwards has additionally been a member of the Edison Electric Institute's Rate Committee.

2006 Key Ratio Trend Analysis (KRTA)
Jackson Purchase Energy Corporation (KY020)

Line No.	Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank
1	BASE GROUP (RATIOS 1-5)							
2								
3	RATIO 1 --- AVERAGE TOTAL CONSUMERS SERVED							
4	2002	27,087	11,545	821	168	25,084	23	11
5	2003	27,343	11,779	817	175	25,553	23	11
6	2004	27,704	12,167	818	178	26,118	23	11
7	2005	28,105	12,361	819	181	26,515	23	11
8	2006	28,461	12,605	818	183	27,008	23	11
9								
10	RATIO 2 --- TOTAL KWH SOLD (1,000)							
11	2002	607,779	218,960	821	141	607,779	23	12
12	2003	594,991	224,215	817	149	594,991	23	12
13	2004	608,568	232,994	818	154	608,568	23	12
14	2005	648,361	243,131	819	148	648,361	23	12
15	2006	630,211	250,709	818	158	630,211	23	12
16								
17	RATIO 3 --- TOTAL UTILITY PLANT (1,000)							
18	2002	89,548.87	42,396.81	823	171	65,441.95	23	9
19	2003	92,183.35	44,626.10	820	180	68,572.49	23	9
20	2004	95,605.03	46,942.59	818	180	73,516.43	23	9
21	2005	101,827.93	49,101.95	820	179	79,833.29	23	9
22	2006	108,466.68	52,313.13	819	177	84,022.86	23	9
23								
24	RATIO 4 --- TOTAL NUMBER OF EMPLOYEES (FULL TIME ONLY)							
25	2002	73	44	821	228	72	23	11
26	2003	73	44	815	229	73	23	11
27	2004	73	45	818	238	73	23	11
28	2005	75	45	819	226	71	23	11
29	2006	79	46	815	212	71	23	10
30								
31	RATIO 5 --- TOTAL MILES OF LINE							
32	2002	3,108	2,419	821	269	3,277	23	13
33	2003	3,142	2,459	817	271	3,324	23	13
34	2004	3,180	2,490	818	271	3,386	23	13
35	2005	3,213	2,510	818	272	3,421	23	13
36	2006	3,244	2,536	816	273	3,456	23	13
37								
38	FINANCIAL (RATIOS 6-32)							
39								
40	RATIO 6 --- TIER							
41	2002	1.61	2.3	823	679	2.8	23	20
42	2003	1.94	2.28	820	524	2.57	23	19
43	2004	1.89	2.33	818	541	1.59	23	7
44	2005	1.72	2.2	820	616	1.71	23	9
45	2006	0.96	2.29	819	794	1.29	23	18
46								
47	RATIO 7 --- TIER (2 OF 3 YEAR HIGH AVERAGE)							
48	2002	1.63	2.35	823	718	2.75	23	22
49	2003	1.8	2.42	820	672	2.9	23	22
50	2004	1.92	2.53	818	641	2.9	23	20
51	2005	1.92	2.47	820	620	2.04	23	16
52	2006	1.8	2.49	819	665	1.72	23	10
53								
54	RATIO 8 --- OTIER							

2006 Key Ratio Trend Analysis (KRTA)
Jackson Purchase Energy Corporation (KY020)

Line No.	Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank
55	2002	N/A	N/A	N/A	N/A	N/A	N/A	N/A
56	2003	N/A	N/A	N/A	N/A	N/A	N/A	N/A
57	2004	1.69	1.86	818	473	1.43	23	6
58	2005	1.51	1.8	820	563	1.45	23	11
59	2006	0.73	1.79	819	794	1.19	23	18
60								
61	RATIO 9 --- OTIER (2 OF 3 YEAR HIGH AVERAGE)							
62	2002	N/A	N/A	N/A	N/A	N/A	N/A	N/A
63	2003	N/A	N/A	N/A	N/A	N/A	N/A	N/A
64	2004	1.69	1.86	818	473	1.43	23	6
65	2005	1.6	1.84	820	532	1.41	23	9
66	2006	1.6	1.99	819	621	1.52	23	10
67								
68	RATIO 10 --- MODIFIED DSC (MDSC)							
69	2002	2.08	2.02	823	386	1.97	23	8
70	2003	2.02	2.01	820	400	1.87	23	8
71	2004	2	1.92	818	377	1.7	23	5
72	2005	1.9	1.9	820	408	1.67	23	8
73	2006	1.22	1.91	819	779	1.4	23	17
74								
75	RATIO 11 --- MDSC (2 OF 3 YEAR HIGH AVERAGE)							
76	2002	2.12	2.15	823	434	1.95	23	7
77	2003	2.05	2.14	820	455	1.95	23	9
78	2004	2.05	2.12	818	438	1.94	23	7
79	2005	2.01	2.06	820	436	1.81	23	6
80	2006	1.95	2.02	819	464	1.63	23	8
81								
82	RATIO 12 --- DEBT SERVICE COVERAGE (DSC)							
83	2002	1.99	2.15	823	495	2.49	23	21
84	2003	2.02	2.13	820	464	2.25	23	18
85	2004	2	2.09	818	462	1.63	23	5
86	2005	1.91	2.07	820	490	1.64	23	8
87	2006	1.23	2.11	819	784	1.48	23	17
88								
89	RATIO 13 --- DSC (2 OF 3 YEAR HIGH AVERAGE)							
90	2002	2.08	2.28	823	508	2.45	23	19
91	2003	2	2.27	820	552	2.5	23	21
92	2004	2.01	2.3	818	548	2.41	23	21
93	2005	2.01	2.24	820	531	2.01	23	12
94	2006	1.95	2.23	819	555	1.66	23	8
95								
96	RATIO 14 --- ODSC							
97	2002	N/A	N/A	N/A	N/A	N/A	N/A	N/A
98	2003	N/A	N/A	N/A	N/A	N/A	N/A	N/A
99	2004	1.88	1.85	818	388	1.61	23	6
100	2005	1.79	1.82	820	430	1.6	23	8
101	2006	1.1	1.8	819	785	1.36	23	18
102								
103	RATIO 15 --- ODSC (2 OF 3 YEAR HIGH AVERAGE)							
104	2002	N/A	N/A	N/A	N/A	N/A	N/A	N/A
105	2003	N/A	N/A	N/A	N/A	N/A	N/A	N/A
106	2004	1.88	1.85	818	388	1.61	23	6
107	2005	1.83	1.85	820	419	1.62	23	6
108	2006	1.83	1.93	819	476	1.62	23	8

2006 Key Ratio Trend Analysis (KRTA)
Jackson Purchase Energy Corporation (KY020)

Line No.	Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank
109								
110	RATIO 16 --- EQUITY AS A % OF ASSETS							
111	2002	40.78	43.34	823	479	39.28	23	9
112	2003	42.47	43.29	820	435	39.01	23	8
113	2004	42.56	42.78	818	414	38.01	23	8
114	2005	41.35	42.32	820	432	36.14	23	6
115	2006	38.5	42.01	819	498	36.48	23	8
116								
117	RATIO 17 --- DISTRIBUTION EQUITY (EXCLUDES EQUITY IN ASSOC. ORG'S PATRONAGE CAPITAL)							
118	2002	40.46	38.26	823	362	30.08	23	5
119	2003	42.17	38.49	820	326	30.39	23	5
120	2004	42.25	37.86	818	312	30.08	23	5
121	2005	41.04	36.92	820	328	28.25	23	4
122	2006	38.18	36.38	819	375	27.38	23	5
123								
124	RATIO 18 --- EQUITY AS A % OF TOTAL CAPITALIZATION							
125	2002	44.61	48.73	823	515	45.79	23	14
126	2003	47.11	48.6	820	442	44.41	23	8
127	2004	46.57	48.2	818	455	43.36	23	10
128	2005	45.31	47.82	820	472	41.16	23	8
129	2006	42.47	47.27	819	532	41.59	23	10
130								
131	RATIO 19 --- LONG TERM DEBT AS A % OF TOTAL ASSETS							
132	2002	50.64	45.79	815	292	48.64	23	9
133	2003	47.69	45.72	813	363	48.71	23	14
134	2004	48.82	46	812	328	48.82	23	12
135	2005	49.91	46.01	814	309	50.16	23	13
136	2006	52.15	45.87	813	248	51.52	22	9
137								
138	RATIO 20 --- LONG TERM DEBT PER KWH SOLD (MILLS)							
139	2002	60.32	82.45	814	545	54.6	23	9
140	2003	58.98	84.35	811	570	59.47	23	13
141	2004	62.21	87.86	812	568	61.07	23	11
142	2005	64.36	88.12	814	557	61.95	23	11
143	2006	74.03	91.99	813	515	74.63	22	12
144								
145	RATIO 21 --- LONG TERM DEBT PER CONSUMER ($)							
146	2002	1,353.50	1,463.29	814	476	1,171.00	23	9
147	2003	1,283.49	1,551.43	811	529	1,283.49	23	12
148	2004	1,366.47	1,607.37	812	530	1,343.60	23	11
149	2005	1,484.68	1,699.03	814	489	1,414.31	23	10
150	2006	1,639.22	1,777.28	813	462	1,601.47	22	10
151								
152	RATIO 22 --- NON-GOVERNMENT DEBT AS A % OF TOTAL LONG TERM DEBT							
153	2002	13.53	46.65	806	735	47.01	23	23
154	2003	31.22	55.18	802	599	59.39	22	18
155	2004	20.59	32.59	783	562	24.67	22	14
156	2005	17.11	30.48	781	579	21.92	22	14
157	2006	13.82	28.11	791	621	19.39	22	15
158								
159	RATIO 23 --- BLENDED INTEREST RATE (%)							
160	2002	5.2	5.01	814	305	4.62	23	5
161	2003	5.25	4.8	812	214	4.07	23	2
162	2004	5.24	4.58	811	140	3.74	23	1

2006 Key Ratio Trend Analysis (KRTA)
Jackson Purchase Energy Corporation (KY020)

Line No.	Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank
163	2005	5.33	4.92	812	181	4.52	23	1
164	2006	5.77	5.13	813	129	5.08	23	2
165								
166	RATIO 25 --- LONG-TERM INTEREST AS A % OF REVENUE							
167	2002	5.49	5.15	814	370	3.93	23	6
168	2003	5.39	4.83	812	342	3.53	23	4
169	2004	5.6	4.75	811	297	3.7	23	1
170	2005	5.83	4.9	812	297	4.09	23	4
171	2006	7.11	5.15	813	202	4.95	23	3
172								
173	RATIO 27 --- RATE OF RETURN ON EQUITY (%)							
174	2002	4	6.56	823	648	10.97	23	19
175	2003	5.69	5.85	820	428	7.55	23	19
176	2004	5.37	5.86	818	458	3.58	23	5
177	2005	4.59	6.08	820	565	4.59	23	12
178	2006	-0.31	6.51	819	789	2.09	23	17
179								
180	RATIO 28 --- RATE OF RETURN ON TOTAL CAPITALIZATION (%)							
181	2002	4.72	5.69	823	605	6.89	23	19
182	2003	5.52	5.27	820	364	5.52	23	12
183	2004	5.31	5.12	818	374	3.43	23	2
184	2005	4.98	5.37	820	509	4.6	23	10
185	2006	3.15	5.82	819	766	3.9	23	15
186								
187	RATIO 29 --- CURRENT RATIO							
188	2002	0.97	1.32	823	574	1.04	23	14
189	2003	0.77	1.29	820	654	1.11	23	19
190	2004	1.14	1.27	818	477	1.09	23	11
191	2005	1.24	1.26	820	427	1.12	23	10
192	2006	1.29	1.29	819	418	1.04	23	11
193								
194	RATIO 30 --- GENERAL FUNDS PER TUP (%)							
195	2002	0.54	3.98	823	773	2.71	23	22
196	2003	0.18	3.74	820	808	3.74	23	23
197	2004	1.23	3.77	818	674	2.21	23	16
198	2005	1.05	4	819	712	1.75	23	20
199	2006	3.48	3.99	819	447	3.05	23	10
200								
201	RATIO 31 --- PLANT REVENUE RATIO (PRR) ONE YEAR							
202	2002	7.15	6.19	823	166	6.06	23	2
203	2003	7.09	6.32	820	199	6.19	23	3
204	2004	7.31	6.45	818	182	6.26	23	4
205	2005	7.24	6.42	820	204	6.2	23	3
206	2006	7.89	6.39	819	93	6.51	23	1
207								
208	REVENUE & MARGINS (RATIOS 33-59)							
209								
210	RATIO 33 --- TOTAL OPERATING REVENUE PER KWH SOLD (MILLS)							
211	2002	58.13	74.19	821	750	58.93	23	14
212	2003	58.75	76.78	817	752	61.54	23	17
213	2004	58.4	78.83	818	770	65.5	23	20
214	2005	58.49	83.4	819	776	72.04	23	22
215	2006	59.34	88.12	818	777	78.61	23	22
216								

2006 Key Ratio Trend Analysis (KRTA)
Jackson Purchase Energy Corporation (KY020)

Line No.	Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank
217	RATIO 34 --- TOTAL OPERATING REVENUE PER TUP INVESTMENT (CENTS)							
218	2002	39.45	39.01	823	403	51.59	23	22
219	2003	37.92	38.66	820	442	50.93	23	22
220	2004	37.17	38.58	818	451	52.31	23	23
221	2005	37.24	40.25	820	502	56.46	23	23
222	2006	34.48	40.76	819	573	56.47	23	23
223								
224	RATIO 35 --- TOTAL OPERATING REVENUE PER CONSUMER ($)							
225	2002	1,304.26	1,422.03	821	533	1,245.92	23	10
226	2003	1,278.42	1,450.10	817	580	1,273.29	23	11
227	2004	1,282.78	1,499.83	818	613	1,348.81	23	16
228	2005	1,349.41	1,624.06	819	633	1,571.14	23	21
229	2006	1,313.95	1,724.30	818	690	1,628.85	23	22
230								
231	RATIO 36 --- ELECTRIC REVENUE PER KWH SOLD (MILLS)							
232	2002	57.14	72.95	821	751	57.42	23	13
233	2003	57.39	75.3	817	755	59.74	23	18
234	2004	57.12	77.27	818	772	63.65	23	20
235	2005	56.98	81.77	819	781	70.54	23	22
236	2006	57.85	86.75	818	778	76.39	23	22
237								
238	RATIO 37 --- ELECTRIC REVENUE PER CONSUMER ($)							
239	2002	1,282.02	1,394.32	821	531	1,219.42	23	10
240	2003	1,248.90	1,422.65	817	585	1,248.36	23	11
241	2004	1,254.67	1,467.93	818	614	1,319.21	23	16
242	2005	1,314.48	1,593.01	819	641	1,542.53	23	21
243	2006	1,280.96	1,686.67	818	696	1,601.85	23	22
244								
245	RATIO 38 --- RESIDENTIAL REVENUE PER KWH SOLD (MILLS)							
246	2002	62.06	78.62	821	763	62.19	23	14
247	2003	62.54	81.23	817	771	64.07	23	16
248	2004	62.45	83.39	818	789	68.49	23	22
249	2005	62.07	88.31	818	799	75.76	23	22
250	2006	62.29	94.46	817	800	81.48	23	22
251								
252	RATIO 39 --- NON-RESIDENTIAL REVENUE PER KWH SOLD (MILLS)							
253	2002	49.34	65.18	819	730	54	23	16
254	2003	49.46	67.17	815	731	54.45	23	17
255	2004	49.08	68.69	815	742	58.77	23	20
256	2005	49.07	72.3	817	762	65.94	23	22
257	2006	50.98	76.82	816	761	69.89	23	21
258								
259	RATIO 41 --- IRRIGATION REVENUE PER KWH SOLD (MILLS)							
260	2002	133.76	83.22	404	31	133.76	1	1
261	2003	89.54	84.93	403	164	89.54	1	1
262	2004	79.66	90.33	403	275	79.66	1	1
263	2005	82.07	95.42	402	287	82.07	1	1
264	2006	99.28	93.86	400	174	99.28	1	1
265								
266	RATIO 42 --- SMALL COMMERCIAL REVENUE PER KWH SOLD (MILLS)							
267	2002	54.06	73.16	819	785	59.96	23	22
268	2003	53.83	75.52	815	786	61.76	23	23
269	2004	53.87	77	815	792	66.27	23	23
270	2005	53.83	81.62	817	797	73.47	23	23

2006 Key Ratio Trend Analysis (KRTA)
Jackson Purchase Energy Corporation (KY020)

Line No.	Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank
271	2006	54.8	86.43	814	796	77.87	23	23
272								
273	RATIO 43 --- LARGE COMMERCIAL REVENUE PER KWH SOLD (MILLS)							
274	2002	41.14	50.4	656	530	42.74	23	14
275	2003	41.66	51.74	656	555	43.05	22	15
276	2004	40.53	52.94	656	591	47.27	22	19
277	2005	39.65	57	667	621	53.76	22	21
278	2006	41.48	61.53	673	620	58.47	22	21
279								
280	RATIO 45 --- STREET & HIGHWAY LIGHTING REVENUE PER KWH SOLD (MILLS)							
281	2002	121.5	102.22	596	217	93.55	18	4
282	2003	122.25	106.06	589	218	100.16	18	3
283	2004	121.4	108.99	587	240	100.6	18	5
284	2005	119.54	115.3	585	275	108.47	18	7
285	2006	120.13	119.66	589	294	114.73	18	7
286								
287	RATIO 47 --- OPERATING MARGINS PER KWH SOLD (MILLS)							
288	2002	2.21	3.42	821	542	1.54	23	9
289	2003	2.54	2.91	817	461	1.39	23	7
290	2004	2.2	2.73	818	488	0.77	23	6
291	2005	1.64	2.8	819	576	1.11	23	10
292	2006	-1.27	2.94	818	779	0.31	23	18
293								
294	RATIO 48 --- OPERATING MARGINS PER CONSUMER ($)							
295	2002	49.54	63.53	821	501	44.02	23	9
296	2003	55.33	55.91	817	412	36.72	23	6
297	2004	48.43	54.1	818	447	16.74	23	5
298	2005	37.8	56.3	819	544	33.23	23	10
299	2006	-28.09	56.57	818	780	9.64	23	18
300								
301	RATIO 49 --- NON-OPERATING MARGINS PER KWH SOLD (MILLS)							
302	2002	-0.43	0.42	819	752	0.14	23	23
303	2003	0.35	0.39	817	451	0.25	23	5
304	2004	0.57	0.45	818	352	0.24	23	3
305	2005	0.64	0.57	819	372	0.31	23	4
306	2006	0.92	0.72	818	320	0.45	23	4
307								
308	RATIO 50 --- NON-OPERATING MARGINS PER CONSUMER ($)							
309	2002	-9.73	7.69	819	756	2.74	23	22
310	2003	7.55	7.39	817	402	5.46	23	4
311	2004	12.44	8.44	818	310	4.58	23	5
312	2005	14.84	10.92	819	326	7.2	23	7
313	2006	20.33	13.85	818	300	11.92	23	4
314								
315	RATIO 51 --- TOTAL MARGINS LESS ALLOCATIONS PER KWH SOLD (MILLS)							
316	2002	1.77	3.85	821	632	1.74	23	11
317	2003	2.89	3.46	817	484	1.62	23	7
318	2004	2.77	3.32	818	484	1.04	23	6
319	2005	2.28	3.49	819	558	1.76	23	10
320	2006	-0.35	3.89	818	776	0.73	23	18
321								
322	RATIO 52 --- TOTAL MARGINS LESS ALLOCATIONS PER CONSUMER ($)							
323	2002	39.81	72.37	821	606	39.81	23	12
324	2003	62.88	66.25	817	429	45.88	23	6

2006 Key Ratio Trend Analysis (KRTA)
Jackson Purchase Energy Corporation (KY020)

Line No.	Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank
325	2004	60.87	63.66	818	430	29.3	23	4
326	2005	52.64	70.95	819	528	41.27	23	10
327	2006	-7.76	77.51	818	778	14.44	23	18
328								
329	RATIO 54 --- ASSOCIATED ORGANIZATION'S CAPITAL CREDITS PER KWH SOLD (MILLS)							
330	2002	0.17	0.92	761	637	3.7	21	17
331	2003	0.1	0.92	764	664	2.98	22	18
332	2004	0.14	0.98	770	661	0.12	21	10
333	2005	0.17	1.12	769	661	0.13	21	7
334	2006	0.18	1.32	768	684	0.18	21	11
335								
336	RATIO 55 --- ASSOCIATED ORGANIZATION'S CAPITAL CREDITS PER CONSUMER ($)							
337	2002	3.76	16.88	761	603	73.27	21	17
338	2003	2.13	16.68	764	638	57.07	22	17
339	2004	3.11	16.82	770	631	2.5	21	8
340	2005	3.84	21.92	769	648	2.86	21	7
341	2006	3.98	26	768	682	3.55	21	10
342								
343	RATIO 56 --- TOTAL MARGINS PER KWH SOLD (MILLS)							
344	2002	1.94	5.08	821	708	4.6	23	18
345	2003	2.99	4.58	817	600	3.5	23	17
346	2004	2.91	4.71	818	605	1.08	23	6
347	2005	2.45	4.91	819	662	1.87	23	10
348	2006	-0.17	5.71	818	791	0.95	23	18
349								
350	RATIO 57 --- TOTAL MARGINS PER CONSUMER ($)							
351	2002	43.57	100.54	821	681	106.1	23	19
352	2003	65.01	88.12	817	546	81.29	23	19
353	2004	63.98	87.31	818	538	30.53	23	4
354	2005	56.48	99.8	819	636	42.83	23	10
355	2006	-3.78	112.2	818	792	20.94	23	18
356								
357	RATIO 58 --- A/R OVER 60 DAYS AS A % OF OPERATING REVENUE							
358	2002	0.28	0.25	807	376	0.13	23	5
359	2003	0.27	0.23	804	349	0.13	23	6
360	2004	0.26	0.22	797	353	0.11	23	7
361	2005	0.21	0.23	803	418	0.13	23	8
362	2006	0.21	0.2	808	389	0.1	23	8
363								
364	RATIO 59 --- AMOUNT WRITTEN OFF AS A % OF OPERATING REVENUE							
365	2002	0.41	0.21	792	139	0.33	23	7
366	2003	0.24	0.21	791	344	0.34	23	17
367	2004	0.25	0.2	787	308	0.26	23	15
368	2005	0.2	0.18	784	352	0.26	23	18
369	2006	0.18	0.18	791	406	0.31	23	20
370								
371	SALES (RATIOS 60-76)							
372								
373	RATIO 60 — TOTAL MWH SOLD PER MILE OF LINE							
374	2002	195.55	95.78	821	136	189.85	23	11
375	2003	189.37	96.01	817	151	185.52	23	11
376	2004	191.37	98.7	818	159	187.93	23	11
377	2005	201.79	102.85	818	155	197.49	23	11
378	2006	194.27	104.88	816	159	192.94	23	11

2006 Key Ratio Trend Analysis (KRTA)
Jackson Purchase Energy Corporation (KY020)

Line No.	Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank
379								
380	RATIO 61 --- AVERAGE RESIDENTIAL USAGE KWH PER MONTH							
381	2002	1,260.16	1,154.80	821	277	1,246.43	23	11
382	2003	1,212.17	1,136.65	817	317	1,215.29	23	13
383	2004	1,217.66	1,136.19	818	304	1,225.53	23	13
384	2005	1,298.51	1,186.35	818	252	1,307.84	23	13
385	2006	1,245.88	1,167.95	817	308	1,243.73	23	11
386								
387	RATIO 63 --- AVERAGE IRRIGATION KWH USAGE PER MONTH							
388	2002	351.85	2,026.10	404	386	351.85	1	1
389	2003	1,046.30	2,025.69	401	309	1,046.30	1	1
390	2004	1,708.33	1,752.12	400	203	1,708.33	1	1
391	2005	1,357.14	1,875.00	401	263	1,357.14	1	1
392	2006	773.81	2,182.87	400	354	773.81	1	1
393								
394	RATIO 64 --- AVERAGE SMALL COMMERCIAL KWH USAGE PER MONTH							
395	2002	4,991.42	3,266.21	819	182	4,775.79	23	8
396	2003	4,866.59	3,252.23	815	187	4,044.62	23	8
397	2004	4,775.44	3,233.06	815	201	3,891.32	23	8
398	2005	4,988.57	3,269.57	817	190	4,004.76	23	6
399	2006	5,079.16	3,299.90	814	184	4,191.85	23	5
400								
401	RATIO 65 --- AVERAGE LARGE COMMERCIAL KWH USAGE PER MONTH							
402	2002	740,325.00	435,783.33	655	224	1,295,333.33	23	17
403	2003	606,333.33	435,465.28	656	260	1,165,914.06	22	17
404	2004	626,881.94	480,248.66	656	261	1,229,834.70	22	19
405	2005	916,760.42	505,125.00	666	194	1,239,096.19	22	14
406	2006	881,369.05	487,916.67	673	201	1,099,289.35	22	15
407								
408	RATIO 66 --- AVERAGE STREET & HIGHWAY LIGHTING KWH USAGE PER MONTH							
409	2002	10,937.50	1,671.28	594	33	2,452.75	18	3
410	2003	10,875.00	1,666.67	583	28	2,554.94	18	3
411	2004	11,208.33	1,666.67	585	26	2,355.77	18	3
412	2005	11,708.33	1,633.88	581	21	2,237.95	18	3
413	2006	8,125.00	1,554.61	584	41	2,602.61	18	3
414								
415	RATIO 69 --- RESIDENTIAL KWH SOLD PER TOTAL KWH SOLD (%)							
416	2002	61.27	63.09	821	445	61.44	23	13
417	2003	60.67	62.48	817	450	61.37	23	13
418	2004	60.1	61.86	818	450	60.83	23	14
419	2005	60.88	62.23	818	434	62.25	23	15
420	2006	60.75	61.39	817	425	62.5	23	14
421								
422	RATIO 71 --- IRRIGATION KWH SOLD PER TOTAL KWH SOLD (%)							
423	2002	0.01	1.43	404	396	0.01	1	1
424	2003	0.02	1.38	403	380	0.02	1	1
425	2004	0.03	1.27	403	373	0.03	1	1
426	2005	0.02	1.46	402	381	0.02	1	1
427	2006	0.01	1.73	400	390	0.01	1	1
428								
429	RATIO 72 --- SMALL COMMERCIAL KWH SOLD PER TOTAL KWH SOLD (%)							
430	2002	24.02	16.68	819	203	16.62	23	3
431	2003	24.55	16.64	815	191	16.5	23	2
432	2004	24.95	16.91	815	187	16.51	23	2

2006 Key Ratio Trend Analysis (KRTA)
Jackson Purchase Energy Corporation (KY020)

Line No.	Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank
433	2005	25.45	17.09	817	179	16.94	23	2
434	2006	27.4	17.38	814	142	17.39	23	1
435								
436	RATIO 73 --- LARGE COMMERCIAL KWH SOLD PER TOTAL KWH SOLD (%)							
437	2002	14.62	11.77	656	288	19.02	23	14
438	2003	14.67	12.5	656	293	21.8	22	14
439	2004	14.83	13	656	302	23.01	22	14
440	2005	13.57	12.88	667	325	20.2	22	14
441	2006	11.75	13.4	673	366	19.76	22	16
442								
443	RATIO 74 --- STREET & HIGHWAY LIGHTING KWH SOLD PER TOTAL KWH SOLD (%)							
444	2002	0.09	0.13	596	369	0.09	18	9
445	2003	0.09	0.13	589	367	0.09	18	9
446	2004	0.09	0.13	587	363	0.09	18	9
447	2005	0.09	0.13	585	357	0.09	18	9
448	2006	0.09	0.13	590	349	0.09	18	9
449								
450	CONTROLLABLE EXPENSES (RATIOS 77-87)							
451								
452	RATIO 77 --- O & M EXPENSES PER TOTAL KWH SOLD (MILLS)							
453	2002	5.5	8.52	821	682	5.87	23	14
454	2003	6.26	8.79	817	635	6.26	23	12
455	2004	5.99	9.12	818	671	6.29	23	15
456	2005	6.73	9	819	601	6.25	23	9
457	2006	8.21	9.32	818	499	6.64	23	8
458								
459	RATIO 78 --- O & M EXPENSES PER DOLLARS OF TUP (MILLS)							
460	2002	37.31	42.85	823	574	48.43	23	22
461	2003	40.43	44.05	820	502	47.66	23	23
462	2004	38.13	43.49	818	552	50.42	23	22
463	2005	42.84	43.19	820	423	46.96	23	17
464	2006	47.72	42.85	819	294	47.72	23	12
465								
466	RATIO 79 --- O & M EXPENSES PER CONSUMER ($)							
467	2002	123.34	158.46	821	648	125.34	23	14
468	2003	136.32	164.76	817	584	131.28	23	8
469	2004	131.59	169.06	818	649	138.3	23	15
470	2005	155.21	173.3	819	521	137.58	23	8
471	2006	181.85	181.28	818	404	145.48	23	4
472								
473	RATIO 80 --- CONSUMER ACCOUNTING EXPENSES PER TOTAL KWH SOLD (MILLS)							
474	2002	1.76	2.52	821	652	1.93	23	16
475	2003	1.81	2.63	817	649	1.95	23	16
476	2004	1.84	2.72	818	650	2.05	23	16
477	2005	1.72	2.62	819	681	1.99	23	17
478	2006	1.73	2.71	818	685	2.19	23	19
479								
480	RATIO 81 --- CONSUMER ACCOUNTING EXPENSES PER CONSUMER ($)							
481	2002	39.57	48.17	821	602	44.52	23	18
482	2003	39.35	49.41	817	640	46.15	23	20
483	2004	40.39	50.31	818	626	46.94	23	17
484	2005	39.66	51.67	819	661	50.59	23	21
485	2006	38.25	53.03	818	701	50.45	23	22
486								

2006 Key Ratio Trend Analysis (KRTA)
Jackson Purchase Energy Corporation (KY020)

Line No.	Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank
487	RATIO 82 --- CUSTOMER SALES AND SERVICE PER TOTAL KWH SOLD (MILLS)							
488	2002	0.3	0.8	807	684	0.42	23	17
489	2003	0.36	0.85	804	659	0.45	23	15
490	2004	0.31	0.82	805	681	0.41	23	17
491	2005	0.44	0.79	805	609	0.42	23	11
492	2006	0.44	0.82	807	605	0.39	23	11
493								
494	RATIO 83 --- CUSTOMER SALES AND SERVICE PER CONSUMER ($)							
495	2002	6.73	15.31	807	668	8.44	23	18
496	2003	7.83	15.96	804	622	9.29	23	17
497	2004	6.83	15.69	805	660	7.58	23	17
498	2005	10.11	15.99	805	555	8.65	23	7
499	2006	9.76	16.31	807	572	8.32	23	9
500								
501	RATIO 84 --- A & G EXPENSES PER TOTAL KWH SOLD (MILLS)							
502	2002	2.24	4.95	821	747	2.59	23	16
503	2003	2.55	5.2	817	736	2.73	23	14
504	2004	2.73	5.26	818	721	2.78	23	14
505	2005	2.76	5.2	819	717	2.72	23	11
506	2006	3.16	5.32	818	682	2.99	23	9
507								
508	RATIO 85 --- A & G EXPENSES PER CONSUMER ($)							
509	2002	50.3	92.21	821	740	52.23	23	15
510	2003	55.4	95.79	817	717	55.4	23	12
511	2004	59.87	97.92	818	695	57.17	23	9
512	2005	63.57	100.22	819	689	57.02	23	10
513	2006	70	106.25	818	657	59.57	23	7
514								
515	RATIO 86 --- TOTAL CONTROLLABLE EXPENSES PER TOTAL KWH SOLD (MILLS) (SAME AS RATIO #103)							
516	2002	9.8	17.23	821	749	10.79	23	16
517	2003	10.98	17.92	817	716	11.56	23	14
518	2004	10.87	18.27	818	734	11.61	23	15
519	2005	11.64	18.12	819	703	11.64	23	12
520	2006	13.54	18.66	818	648	13.54	23	12
521								
522	RATIO 87 --- TOTAL CONTROLLABLE EXPENSES PER CONSUMER ($) (SAME AS RATIO #104)							
523	2002	219.94	313.29	821	761	236.89	23	19
524	2003	238.9	327.14	817	734	253.74	23	17
525	2004	238.67	337.61	818	746	249.79	23	17
526	2005	268.55	345.95	819	679	268.55	23	12
527	2006	299.86	361.64	818	617	271.63	23	7
528								
529	FIXED EXPENSES (RATIOS 88-102)							
530								
531	RATIO 88 --- POWER COST PER KWH PURCHASED (MILLS)							
532	2002	35.51	40.25	821	584	38.03	23	20
533	2003	34.94	42.83	817	642	39.8	23	22
534	2004	35.05	44.15	816	653	43.68	23	22
535	2005	35.21	48.8	817	663	50.82	23	22
536	2006	35.63	53.22	817	679	55.06	23	22
537								
538	RATIO 89 --- POWER COST PER TOTAL KWH SOLD (MILLS)							
539	2002	37.53	43.28	821	593	39.98	23	18
540	2003	36.89	45.73	817	649	41.94	23	22

2006 Key Ratio Trend Analysis (KRTA)
Jackson Purchase Energy Corporation (KY020)

Line No.	Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank
541	2004	36.9	47.17	818	668	45.69	23	22
542	2005	36.79	51.67	819	676	53.68	23	22
543	2006	37.54	56.53	818	681	57.35	23	22
544								
545	RATIO 90 --- POWER COST AS A % OF REVENUE							
546	2002	64.56	57.96	823	195	68.59	23	17
547	2003	62.79	58.89	820	266	68.95	23	18
548	2004	63.19	59.33	818	262	70.6	23	19
549	2005	62.9	60.83	820	351	73.23	23	22
550	2006	63.26	61.44	819	362	73.86	23	22
551								
552	RATIO 91 --- LONG-TERM INTEREST COST PER TOTAL KWH SOLD (MILLS)							
553	2002	3.19	4.01	813	513	2.41	23	6
554	2003	3.17	3.85	810	511	2.22	23	6
555	2004	3.27	3.88	811	502	2.44	23	6
556	2005	3.41	4.27	812	523	2.92	23	9
557	2006	4.22	4.7	813	448	3.76	23	8
558								
559	RATIO 92 --- LONG-TERM INTEREST COST AS A % OF TUP							
560	2002	2.17	2	814	317	2.15	23	11
561	2003	2.04	1.9	812	325	1.95	23	10
562	2004	2.08	1.87	811	286	1.9	23	9
563	2005	2.17	2.04	812	345	2.2	23	13
564	2006	2.45	2.17	813	261	2.5	23	13
565								
566	RATIO 93 --- LONG-TERM INTEREST COST PER CONSUMER ($)							
567	2002	71.64	72.31	813	413	54.18	23	6
568	2003	68.89	70.83	810	431	53.29	23	3
569	2004	71.86	71.98	811	408	51.58	23	2
570	2005	78.69	81.06	812	431	64.63	23	7
571	2006	93.48	90.4	813	382	76.06	23	7
572								
573	RATIO 94 --- DEPRECIATION EXPENSE PER TOTAL KWH SOLD (MILLS)							
574	2002	5.25	5.58	820	462	3.64	23	4
575	2003	4.99	5.82	816	536	3.74	23	7
576	2004	4.97	5.97	818	552	3.9	23	7
577	2005	4.83	5.96	819	572	3.96	23	7
578	2006	5.13	6.14	818	559	4.3	23	7
579								
580	RATIO 95 --- DEPRECIATION EXPENSE AS A % OF TUP							
581	2002	3.56	2.87	822	44	3.22	23	5
582	2003	3.22	2.88	819	109	3.2	23	9
583	2004	3.17	2.87	818	140	3.17	23	12
584	2005	3.08	2.86	820	191	3.13	23	14
585	2006	2.98	2.84	819	261	3.12	23	16
586								
587	RATIO 96 --- DEPRECIATION EXPENSE PER CONSUMER ($)							
588	2002	117.79	102.42	820	292	85.08	23	1
589	2003	108.56	106.88	816	387	87.89	23	4
590	2004	109.27	109.89	818	416	91.49	23	4
591	2005	111.43	113.31	819	437	95.12	23	4
592	2006	113.67	118.22	818	446	100.11	23	5
593								
594	RATIO 97 --- ACCUMULATIVE DEPRECIATION AS A % OF PLANT IN SERVICE							

2006 Key Ratio Trend Analysis (KRTA)
Jackson Purchase Energy Corporation (KY020)

Line No.	Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank
595	2002	27.44	30.52	823	546	24.74	23	9
596	2003	28.29	30.69	819	513	25.93	23	9
597	2004	29.24	31.11	818	474	26.03	23	7
598	2005	29.89	31.4	820	460	25.9	23	7
599	2006	30.13	31.4	819	449	24.92	23	7
600								
601	RATIO 98 --- TOTAL TAX EXPENSE PER TOTAL KWH SOLD (MILLS)							
602	2002	0.07	0.9	594	469	0.08	22	13
603	2003	0.07	0.94	591	471	0.08	22	12
604	2004	0.07	0.98	593	471	0.07	22	11
605	2005	0.06	0.95	589	473	0.07	22	14
606	2006	0.07	0.94	590	473	0.08	22	18
607								
608	RATIO 99 --- TOTAL TAX EXPENSE AS A % OF TUP							
609	2002	0.05	0.47	596	461	0.06	22	20
610	2003	0.05	0.47	594	462	0.06	22	20
611	2004	0.04	0.45	593	462	0.05	22	18
612	2005	0.04	0.44	590	462	0.05	22	20
613	2006	0.04	0.43	591	466	0.05	22	21
614								
615	RATIO 100 --- TOTAL TAX EXPENSE PER CONSUMER							
616	2002	1.62	16.6	594	465	1.53	22	10
617	2003	1.58	17.68	591	465	1.57	22	11
618	2004	1.53	17.91	593	465	1.52	22	10
619	2005	1.46	18.64	589	467	1.52	22	14
620	2006	1.46	18.78	590	469	1.59	22	17
621								
622	RATIO 101 --- TOTAL FIXED EXPENSES PER TOTAL KWH SOLD (MILLS)							
623	2002	46.12	53.64	821	659	46.97	23	15
624	2003	45.23	55.96	817	691	48.18	23	20
625	2004	45.33	57.41	818	716	53.08	23	21
626	2005	45.21	61.46	819	732	60.42	23	22
627	2006	47.07	67.45	818	731	65.12	23	22
628								
629	RATIO 102 --- TOTAL FIXED EXPENSES PER CONSUMER ($)							
630	2002	1,034.78	1,033.15	821	407	980.92	23	10
631	2003	984.19	1,055.50	817	501	998.49	23	14
632	2004	995.68	1,099.12	818	530	1,083.79	23	16
633	2005	1,043.06	1,220.60	819	564	1,300.32	23	21
634	2006	1,042.18	1,293.88	818	605	1,382.05	23	22
635								
636	TOTAL EXPENSES (RATIOS 103-107)							
637								
638	RATIO 103 --- TOTAL OPERATING EXPENSES PER TOTAL KWH SOLD (MILLS)							
639	2002	9.8	17.23	821	749	10.79	23	16
640	2003	10.98	17.92	817	716	11.56	23	14
641	2004	10.87	18.27	818	734	11.61	23	15
642	2005	11.64	18.12	819	703	11.64	23	12
643	2006	13.54	18.66	818	648	13.54	23	12
644								
645	RATIO 104 --- TOTAL OPERATING EXPENSES PER CONSUMER ($)							
646	2002	219.94	313.29	821	761	236.89	23	19
647	2003	238.9	327.14	817	734	253.74	23	17
648	2004	238.67	337.61	818	746	249.79	23	17

2006 Key Ratio Trend Analysis (KRTA)
Jackson Purchase Energy Corporation (KY020)

Line No.	Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank
649	2005	268.55	345.95	819	679	268.55	23	12
650	2006	299.86	361.64	818	617	271.63	23	7
651								
652	RATIO 105 --- TOTAL COST OF SERVICE (MINUS POWER COSTS) PER TOTAL KWH SOLD (MILLS)							
653	2002	18.39	28.16	821	697	18.13	23	11
654	2003	19.32	28.99	817	687	18.8	23	11
655	2004	19.29	29.41	818	693	19.29	23	12
656	2005	20.06	29.81	819	686	19.84	23	11
657	2006	23.07	30.71	818	621	22.27	23	11
658								
659	RATIO 106 --- TOTAL COST OF ELECTRIC SERVICE PER TOTAL KWH SOLD (MILLS)							
660	2002	55.92	70.65	821	744	57.94	23	16
661	2003	56.21	73.38	817	750	60.84	23	18
662	2004	56.19	75.59	818	766	63.7	23	20
663	2005	56.86	80.74	819	771	71.12	23	22
664	2006	60.61	85.45	818	752	78.5	23	22
665								
666	RATIO 107 --- TOTAL COST OF ELECTRIC SERVICE PER CONSUMER ($)							
667	2002	1,254.72	1,350.76	821	515	1,215.82	23	11
668	2003	1,223.09	1,390.11	817	581	1,241.37	23	13
669	2004	1,234.35	1,436.68	818	612	1,333.59	23	17
670	2005	1,311.61	1,564.65	819	625	1,543.85	23	21
671	2006	1,342.04	1,654.67	818	642	1,596.14	23	21
672								
673	EMPLOYEES (RATIOS 108-113)							
674								
675	RATIO 108 --- AVERAGE WAGE RATE PER HOUR ($)							
676	2002	21.97	21.42	819	340	21.04	23	10
677	2003	22.73	22.11	814	350	22.43	23	11
678	2004	23.65	23.08	815	357	23.14	23	9
679	2005	24.41	24.12	819	376	24.41	23	12
680	2006	25.14	24.84	814	384	25.05	23	11
681								
682	RATIO 109 --- TOTAL WAGES PER TOTAL KWH SOLD (MILLS)							
683	2002	5.91	9.41	820	706	5.91	23	12
684	2003	6.28	9.68	814	693	6.28	23	12
685	2004	6.57	9.87	816	684	6.45	23	11
686	2005	6.59	9.98	819	686	6.48	23	11
687	2006	6.96	9.95	815	659	6.55	23	10
688								
689	RATIO 110 --- TOTAL WAGES PER CONSUMER ($)							
690	2002	132.54	177.47	820	673	123.95	23	8
691	2003	136.74	181.56	814	666	127.05	23	8
692	2004	144.37	185.96	816	647	131.38	23	6
693	2005	152.1	193.28	819	632	133.63	23	6
694	2006	154.04	196.57	815	617	132.7	23	6
695								
696	RATIO 111 --- OVERTIME HOURS/TOTAL HOURS (%)							
697	2002	6.08	4.8	819	228	5.91	23	11
698	2003	6.63	4.65	814	171	6.86	23	13
699	2004	8.14	4.94	816	122	7.24	23	8
700	2005	9.25	5.8	816	94	6.82	23	5
701	2006	9.25	4.98	811	42	6.32	23	5
702								

2006 Key Ratio Trend Analysis (KRTA)
Jackson Purchase Energy Corporation (KY020)

Line No.	Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank
703	RATIO 112 --- CAPITALIZED PAYROLL / TOTAL PAYROLL (%)							
704	2002	29.9	22.75	819	156	26.48	23	10
705	2003	31.19	22.48	812	112	25.94	23	6
706	2004	35.01	22.6	815	54	28.05	23	1
707	2005	33.27	22.87	816	93	26.12	23	4
708	2006	31.87	23.67	814	116	27.07	23	6
709								
710	RATIO 113 --- AVERAGE CONSUMERS PER EMPLOYEE							
711	2002	371.05	264.51	821	108	374.52	23	14
712	2003	374.56	267.94	815	112	394.69	23	15
713	2004	379.51	268.54	818	130	394.41	23	15
714	2005	374.73	274.5	819	140	393.51	23	14
715	2006	360.27	276.41	815	168	391.58	23	17
716								
717	GROWTH (RATIOS 114-121)							
718								
719	RATIO 114 --- ANNUAL GROWTH IN KWH SOLD (%)							
720	2002	4.52	4.78	816	436	4.52	23	12
721	2003	-2.1	1.05	810	689	0.38	23	20
722	2004	2.28	2.02	814	378	2.43	23	14
723	2005	6.54	4.66	815	260	5.94	23	9
724	2006	-2.8	1.78	817	742	-1.42	23	17
725								
726	RATIO 115 --- ANNUAL GROWTH IN NUMBER OF CONSUMERS (%)							
727	2002	1.65	1.54	820	388	2.2	23	18
728	2003	0.95	1.47	811	579	1.66	23	19
729	2004	1.32	1.54	814	481	1.79	23	19
730	2005	1.45	1.5	815	427	1.47	23	13
731	2006	1.27	1.51	817	490	1.55	23	16
732								
733	RATIO 116 --- ANNUAL GROWTH IN TUP DOLLARS (%)							
734	2002	3.12	4.83	819	678	5.3	23	22
735	2003	2.94	4.64	812	669	5.1	23	23
736	2004	3.71	4.79	816	583	5.2	23	22
737	2005	6.51	4.99	816	242	5.79	23	7
738	2006	6.52	5.6	818	278	6.15	23	8
739								
740	RATIO 117 --- CONST. W.I.P. TO PLANT ADDITIONS (%)							
741	2002	16.52	22.23	805	489	10.62	23	7
742	2003	7.67	24.11	807	661	15.54	23	19
743	2004	10.5	25.34	801	618	13	23	15
744	2005	57.32	26.81	805	195	22.58	23	3
745	2006	43.44	24.72	793	247	19.77	23	3
746								
747	RATIO 118 --- NET NEW SERVICES TO TOTAL SERVICES (%)							
748	2002	1.29	1.67	819	535	2.31	23	21
749	2003	1.73	1.63	811	375	2.01	23	16
750	2004	1.77	1.63	815	358	1.84	23	14
751	2005	1.73	1.63	816	376	1.73	23	12
752	2006	1.42	1.58	816	459	1.73	23	17
753								
754	RATIO 119 --- ANNUAL GROWTH IN TOTAL CAPITALIZATION (%)							
755	2002	-0.17	3.43	819	672	6.01	23	22
756	2003	0.25	3.22	812	639	7.43	23	19

2006 Key Ratio Trend Analysis (KRTA)
Jackson Purchase Energy Corporation (KY020)

Line No.	Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank
757	2004	6.79	4.29	816	250	3.03	23	5
758	2005	7.67	5.35	816	259	5.37	23	7
759	2006	6.29	5.12	818	326	4.49	23	8
760								
761	RATIO 120 --- 2 YR. COMPOUND GROWTH IN TOTAL CAPITALIZATION (%)							
762	2002	2.53	4.23	806	543	9.03	22	18
763	2003	0.04	3.85	814	720	7.85	23	21
764	2004	3.47	4.19	809	468	4.23	23	15
765	2005	7.23	5.13	815	244	4.51	23	4
766	2006	6.98	5.6	814	289	5.13	23	5
767								
768	RATIO 121 --- 5 YR. COMPOUND GROWTH IN TOTAL CAPITALIZATION (%)							
769	2002	2.41	4.81	785	642	7.18	21	20
770	2003	2.99	4.55	793	591	7.18	21	18
771	2004	4.65	4.63	798	395	6.51	22	17
772	2005	3.92	4.65	805	498	6.76	22	19
773	2006	4.11	4.93	810	524	6.3	23	17
774								
775	PLANT (RATIOS 122-145)							
776								
777	RATIO 122 --- TUP INVESTMENTS PER TOTAL KWH SOLD (CENTS)							
778	2002	14.73	19.44	821	631	11.2	23	7
779	2003	15.49	20.09	817	612	12.01	23	7
780	2004	15.71	20.69	818	619	12.75	23	7
781	2005	15.71	20.84	819	620	13	23	7
782	2006	17.21	21.62	818	591	14.2	23	7
783								
784	RATIO 123 --- TUP INVESTMENT PER CONSUMER ($)							
785	2002	3,305.97	3,573.43	821	479	2,607.94	23	3
786	2003	3,371.37	3,711.19	817	505	2,717.53	23	3
787	2004	3,450.95	3,830.69	818	512	2,776.55	23	3
788	2005	3,623.13	3,954.35	819	505	2,878.77	23	3
789	2006	3,811.06	4,114.77	818	491	3,086.27	23	2
790								
791	RATIO 124 --- TUP INVESTMENT PER MILE OF LINE ($)							
792	2002	28,812.38	19,086.04	821	151	23,096.82	23	3
793	2003	29,339.07	19,910.36	817	163	24,041.83	23	4
794	2004	30,064.48	20,714.35	818	171	24,864.78	23	4
795	2005	31,692.48	21,564.30	818	170	26,132.54	23	5
796	2006	33,436.09	22,567.64	816	176	28,196.08	23	5
797								
798	RATIO 125 --- AVERAGE CONSUMERS PER MILE							
799	2002	8.72	5.66	821	173	8.72	23	12
800	2003	8.7	5.7	817	179	8.7	23	12
801	2004	8.71	5.78	818	180	8.71	23	12
802	2005	8.75	5.82	818	183	9.01	23	13
803	2006	8.77	5.84	816	181	9.05	23	13
804								
805	RATIO 126 --- DISTRIBUTION PLANT PER TOTAL KWH SOLD (MILLS)							
806	2002	135.83	163.86	785	544	103.89	23	7
807	2003	143.92	170.03	817	548	109.32	23	7
808	2004	146.16	174.76	818	561	113.48	23	7
809	2005	142.47	174.91	819	567	113.51	23	7
810	2006	156.12	179.56	818	530	122.27	23	7

2006 Key Ratio Trend Analysis (KRTA)
Jackson Purchase Energy Corporation (KY020)

Line No.	Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank
811								
812	RATIO 127 --- DISTRIBUTION PLANT PER CONSUMER ($)							
813	2002	3,047.75	2,929.40	785	360	2,371.57	23	3
814	2003	3,131.64	3,066.27	817	391	2,434.35	23	3
815	2004	3,210.62	3,161.01	818	396	2,533.16	23	3
816	2005	3,286.67	3,290.37	819	411	2,623.14	23	3
817	2006	3,456.90	3,452.99	818	409	2,770.59	23	3
818								
819	RATIO 128 --- DISTRIBUTION PLANT PER EMPLOYEE ($)							
820	2002	1,130,882.12	806,768.35	785	55	969,314.23	23	4
821	2003	1,172,991.53	854,655.76	815	67	1,012,010.75	23	4
822	2004	1,218,453.37	881,431.50	818	73	1,061,871.69	23	4
823	2005	1,231,623.55	925,911.49	819	95	1,088,358.06	23	4
824	2006	1,245,402.91	972,132.93	815	118	1,085,503.42	23	4
825								
826	RATIO 129 --- GENERAL PLANT PER TOTAL KWH SOLD (MILLS)							
827	2002	7.02	14.85	819	735	7.02	23	12
828	2003	7	14.55	816	730	7.3	23	13
829	2004	6.69	14.26	816	735	7.24	23	13
830	2005	6.89	14.32	818	730	6.89	23	12
831	2006	7.52	14.61	817	713	7.42	23	10
832								
833	RATIO 130 --- GENERAL PLANT PER CONSUMER ($)							
834	2002	157.58	266.45	819	717	135.19	23	7
835	2003	152.41	264.95	816	721	138.77	23	10
836	2004	147.02	263.77	816	727	147.02	23	12
837	2005	159.06	269.07	818	714	156.88	23	11
838	2006	166.61	281.41	817	708	157.17	23	9
839								
840	RATIO 131 --- GENERAL PLANT PER EMPLOYEE ($)							
841	2002	58,469.52	69,080.37	819	577	52,030.44	23	7
842	2003	57,085.59	69,160.05	814	607	55,458.64	23	10
843	2004	55,794.21	71,014.60	816	652	57,767.38	23	15
844	2005	59,604.85	74,126.87	818	610	59,604.85	23	12
845	2006	60,023.94	77,029.18	814	635	61,609.58	23	13
846								
847	RATIO 132 --- HEADQUARTERS PLANT PER TOTAL KWH SOLD (MILLS)							
848	2002	N/A	N/A	N/A	N/A	N/A	N/A	N/A
849	2003	N/A	N/A	N/A	N/A	N/A	N/A	N/A
850	2004	3.47	6.85	746	634	3.52	23	13
851	2005	3.28	6.78	760	663	3.84	23	15
852	2006	3.39	6.97	765	666	4.04	23	16
853								
854	RATIO 133 --- HEADQUARTERS PLANT PER CONSUMER ($)							
855	2002	N/A	N/A	N/A	N/A	N/A	N/A	N/A
856	2003	N/A	N/A	N/A	N/A	N/A	N/A	N/A
857	2004	76.11	126.15	746	591	76.11	23	12
858	2005	75.69	130.44	760	622	81.01	23	15
859	2006	74.98	137.14	765	642	112.93	23	16
860								
861	RATIO 134 --- HEADQUARTERS PLANT PER EMPLOYEE ($)							
862	2002	N/A	N/A	N/A	N/A	N/A	N/A	N/A
863	2003	N/A	N/A	N/A	N/A	N/A	N/A	N/A
864	2004	28,885.75	33,204.05	746	446	33,867.12	23	14

2006 Key Ratio Trend Analysis (KRTA)
Jackson Purchase Energy Corporation (KY020)

Line No.	Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank
865	2005	28,364.27	34,640.60	760	499	36,408.20	23	15
866	2006	27,011.46	36,798.76	763	544	43,528.72	23	17
867								
868	RATIO 138 --- IDLE SERVICES TO TOTAL SERVICE (%)							
869	2002	12.84	7.96	802	219	8.52	23	8
870	2003	13.38	8.05	796	202	9.33	23	8
871	2004	13.69	7.91	797	192	8.58	23	4
872	2005	14.09	7.84	797	183	8.34	23	3
873	2006	14.38	7.88	794	163	9.32	23	4
874								
875	RATIO 139 --- LINE LOSS (%)							
876	2002	5.35	6.6	821	598	5.32	23	11
877	2003	5.26	6.56	817	609	5.13	23	10
878	2004	4.99	6.49	815	628	5.32	23	14
879	2005	4.28	6.22	817	688	4.89	23	18
880	2006	5.06	5.86	817	532	4.77	23	9
881								
882	RATIO 140 --- SYSTEM AVG. INTERRUPTION DURATION INDEX (SAIDI) - POWER SUPPLIER							
883	2002	N/A	N/A	N/A	N/A	N/A	N/A	N/A
884	2003	N/A	N/A	N/A	N/A	N/A	N/A	N/A
885	2004	0	0.26	818	694	0.29	23	20
886	2005	0.02	0.26	820	603	0.09	23	18
887	2006	0.01	0.26	819	611	0.12	23	16
888								
889	RATIO 141 --- SYSTEM AVG. INTERRUPTION DURATION INDEX (SAIDI) - EXTREME STORM							
890	2002	N/A	N/A	N/A	N/A	N/A	N/A	N/A
891	2003	N/A	N/A	N/A	N/A	N/A	N/A	N/A
892	2004	1.12	0.53	818	298	1.23	23	13
893	2005	0.5	0.52	820	415	0.18	23	7
894	2006	4.02	0.21	819	66	0.71	23	5
895								
896	RATIO 142 --- SYSTEM AVG. INTERRUPTION DURATION INDEX (SAIDI) - PREARRANGED							
897	2002	N/A	N/A	N/A	N/A	N/A	N/A	N/A
898	2003	N/A	N/A	N/A	N/A	N/A	N/A	N/A
899	2004	0.04	0.02	818	330	0.02	23	7
900	2005	0.03	0.02	820	371	0.06	23	15
901	2006	0.05	0.02	819	327	0.05	23	11
902								
903	RATIO 143 --- SYSTEM AVG. INTERRUPTION DURATION INDEX (SAIDI) - ALL OTHER							
904	2002	N/A	N/A	N/A	N/A	N/A	N/A	N/A
905	2003	N/A	N/A	N/A	N/A	N/A	N/A	N/A
906	2004	2.17	1.49	818	259	2.61	23	14
907	2005	1.29	1.53	820	481	1.47	23	15
908	2006	2.48	1.63	819	228	2.29	23	7
909								
910	RATIO 144 --- SYSTEM AVG. INTERRUPTION DURATION INDEX (SAIDI) - TOTAL							
911	2002	N/A	N/A	N/A	N/A	N/A	N/A	N/A
912	2003	N/A	N/A	N/A	N/A	N/A	N/A	N/A
913	2004	3.33	3.26	818	402	4.19	23	19
914	2005	1.84	3.26	820	626	2.11	23	16
915	2006	6.56	3	819	138	3.58	23	6
916								
917	RATIO 145 --- AVG. SERVICE AVAILABILITY INDEX (ASAI) - TOTAL (%)							
918	2002	N/A	N/A	N/A	N/A	N/A	N/A	N/A

2006 Key Ratio Trend Analysis (KRTA)
Jackson Purchase Energy Corporation (KY020)

Line No.	Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank
919	2003	N/A	N/A	N/A	N/A	N/A	N/A	N/A
920	2004	99.96	99.96	818	417	99.95	23	5
921	2005	99.98	99.96	820	195	99.98	23	8
922	2006	99.93	99.97	819	682	99.96	23	18

Jackson Purchase Energy Coprporation
Rate Base Determination

Line No.	Acct No.	Description	Balance as of 12/31/2005	Balance as of 12/31/2006	Average	Adjustments	Adjusted Average
		Plant					
1	360	DIST. PLT. - LAND AND LAND RIGHTS	$223,945	$235,871	$229,908		$229,908
2	362	DIST. PLT. - STATION EQUIPMENT	$10,328,072	$12,008,367	$11,168,220		$11,168,220
3	364	DIST. PLT.- POLES, TOWERS, FIXTURES	$27,199,878	$28,486,552	$27,843,215		$27,843,215
4	365	DIST. PLT. - O/H CONDUCT. & DEVICES	$16,377,025	$17,054,966	$16,715,996		$16,715,996
5	366	DIST. PLT. - UNDERGROUND CONDUIT	$3,813,594	$4,106,735	$3,960,164		$3,960,164
6	367	DIST. PLT. - U/G CONDUCT. & DEVICES	$8,796,410	$9,423,467	$9,109,938		$9,109,938
7	368	DIST. PLT. - LINE TRANSFORMERS	$14,899,469	$15,623,839	$15,261,654		$15,261,654
8	369	DIST. PLT. - SERVICES	$5,946,218	$6,468,811	$6,207,514		$6,207,514
9	370	DIST. PLT. - METERS	$2,824,069	$2,934,243	$2,879,156		$2,879,156
10	371	DIST PLT - INSTAL. ON CUST. PREMISE	$1,431,186	$1,484,794	$1,457,990		$1,457,990
11	372	DIST PLT - LSD. PROP. ON CUST. PREM	$1,048	$1,048	$1,048		$1,048
12	373	DIST PLT - ST. LIGHT. & SIGN. SYS.	$530,852	$558,138	$544,495		$544,495
13	389	GEN PLT - LAND AND LAND RIGHTS	$86,866	$86,866	$86,866		$86,866
14	390	GEN PLT - STRUCTURES & IMPROVEMENTS	$2,040,453	$2,047,039	$2,043,746		$2,043,746
15	391	GEN PLT - OFFICE FURNITURE & EQUIP	$292,024	$292,326	$292,175		$292,175
16	391.1	GEN PLT - COMPUTER EQUIP/ SOFTWARE	$413,275	$322,290	$367,782		$367,782
17	392	GEN PLT - UTILITY TRANSP. EQUIP.	$1,825,870	$2,079,856	$1,952,863		$1,952,863
18	392.1	GEN PLT - LIGHT DUTY TRANSP. EQUIP	$346,140	$375,930	$361,035		$361,035
19	393	GEN PLT - STORES EQUIPMENT	$79,008	$79,008	$79,008		$79,008
20	394	GEN PLT - TOOLS, SHOP, GARAGE EQUIP	$429,355	$451,976	$440,665		$440,665
21	395	GEN PLT - LABORATORY EQUIPMENT	$167,198	$169,060	$168,129		$168,129
22	396	GEN PLT - POWER OPERATED EQUIPMENT	$282,543	$287,695	$285,119		$285,119
23	397	GEN PLT - COMMUNICATIONS EQUIPMENT	$540,789	$589,509	$565,149		$565,149
24	398	GEN PLT - MISCELLANEOUS EQUIPMENT	$94,163	$94,242	$94,202		$94,202
25		Total Utility Plant In Service	$98,969,450	$105,262,626	$102,116,038	$0	$102,116,038
26		CWIP	$2,858,480	$3,204,054	$3,031,267		$3,031,267
27		Normalizing Adjustment				$77,266	$77,266
28		Total CWIP	$2,858,480	$3,204,054	$3,031,267	$77,266	$3,108,533
29		Total Utility Plant	$101,827,930	$108,466,680	$105,147,305	$77,266	$105,224,571
		Accumulated Depreciation					
30	108.662	ACCUM DEPR-STATION EQUIPMENT	$1,164,968	$1,264,923	$1,214,946		$1,214,946
31	108.664	ACCUM DEPR-POLES, TOWERS, & FIXTURE	$9,860,117	$10,628,842	$10,244,479		$10,244,479
32	108.665	ACCUM DEPR-O/H CONDUCTOR & DEVICES	$5,255,456	$5,642,593	$5,449,024		$5,449,024
33	108.666	ACCUM DEPR-UNDERGOUND CONDUIT	$583,417	$652,016	$617,717		$617,717
34	108.667	ACCUM DEPR-U/G CONDUCTOR & DEVICES	$2,187,176	$2,448,411	$2,317,793		$2,317,793
35	108.668	ACCUM DEPR-LINE TRANSFORMERS	$3,568,221	$3,610,938	$3,589,580		$3,589,580
36	108.669	ACCUM DEPR- SERVICES	$2,293,694	$2,415,868	$2,354,781		$2,354,781
37	108.67	ACCUM DEPR-METERS	$1,066,821	$1,163,276	$1,115,049		$1,115,049
38	108.671	ACCUM DEPR-INSTALLATIONS ON CUST PR	$620,867	$668,690	$644,779		$644,779
39	108.672	ACCUM DEPR-LEASED PROP CUST PREMISI	($102,078)	($101,973)	($102,026)		($102,026)
40	108.673	ACCUM DEPR-STREET LIGHT & SIGN	$96,340	$103,136	$99,738		$99,738
41	108.71	ACCUM DEPR FOR OFFICE FURN. & EQUIP	$165,761	$177,198	$171,480		$171,480
42	108.711	ACC DEPR FOR COMPUTER EQUIP/SOFTWF	$330,311	$242,531	$286,421		$286,421
43	108.715	CONTRA ACCUM DEPR -OFFICE FURNITURE	($12,425)	($9,940)	($11,182)		($11,182)
44	108.716	CONTRA ACCUM DEPR - COMPUTERS	$83,107	$66,486	$74,796		$74,796
45	108.72	ACCUM DEPR - UTILITY TRANSP. EQUIP.	$886,929	$918,600	$902,764		$902,764
46	108.721	ACCUM DEPR - LIGHT DUTY TRANS EQUIP	$200,234	$223,423	$211,829		$211,829

47	108.723	ACCUM DEPR - CONTRA TRANSP. EQUIP	($301,499)	($241,081)	($271,290)		($271,290)
48	108.73	ACCUM DEPR FOR STRUCTURES & IMPROV	$1,152,581	$1,203,593	$1,178,087		$1,178,087
49	108.735	CONTRA - ACCUM DEPR STRUCT & IMPRV	$55,258	$44,207	$49,733		$49,733
50	108.74	ACCUM DEPR FOR SHOP EQUIPMENT	$289,731	$310,883	$300,307		$300,307
51	108.745	CONTRA - ACCUM DEPR - TOOLS, SHOP	($41,384)	($33,107)	($37,246)		($37,246)
52	108.75	ACCUM DEPR FOR LABORTORY EQUIPMEN	$112,039	$121,303	$116,671		$116,671
53	108.755	CONTRA ACCUM DEPR - LABORATORY	($10,258)	($8,207)	($9,232)		($9,232)
54	108.76	ACCUM DEPR FOR COMMUNICATIONS EQUI	$192,461	$214,539	$203,500		$203,500
55	108.765	CONTRA ACCUM DEPR - COMMUNICATION	($348,231)	($278,584)	($313,408)		($313,408)
56	108.77	ACCUM DEPR FOR STORES EQUIPMENT	$54,036	$57,258	$55,647		$55,647
57	108.775	CONTRA ACCUM DEPR - STORES	($5,142)	($4,114)	($4,628)		($4,628)
58	108.78	ACCUM DEPR FOR MISCELLANEOUS EQUIP	$52,059	$57,973	$55,016		$55,016
59	108.785	CONTRA - ACCUM DEPR - MISC EQUIP.	($7,772)	($6,217)	($6,995)		($6,995)
60	108.79	ACCUM DEPR FOR POWER OPERATED EQU	$48,495	$48,826	$48,660		$48,660
61	108.791	ACCUM DEPR - PWR EQUIP TRENCHER,ETC	$88,484	$111,970	$100,227		$100,227
62	108.795	CONTRA ACCUM DEPR - POWER OPERATEI	$22	$18	$20		$20
63	108.8	RETIRE. WIP-JPECC CREWS	$0	$0	$0		$0
64	108.81	RETIRE. WIP-CONTRACTORS	$0	$0	$0		$0
		NORMALIZING ADJUSTMENT FOR DEPR.	$0	$0	$0	$594,580	$594,580
65		Total Accumulated Depreciation	$29,579,797	$31,714,276	$30,647,037	$594,580	$31,241,617
66		Net Plant	$72,248,133	$76,752,404	$74,500,268	($517,314)	$73,982,954
		Materials & Supplies					
67	154	PLT MATERIALS & OPERATING SUPPLIES	$2,188,377	$1,177,989	$1,683,183	$0	$1,683,183
68	156	OTHER MATERIALS AND SUPPLIES	$3,570	$5,107	$4,338	($4,338)	$0
		NORMALIZING ADJUSTMENT	$0	$0	$0	$10,769	$10,769
69			$2,191,946	$1,183,096	$1,687,521	$6,431	$1,693,952
		Prepayments					
70	165.1	PREPAYMENTS - INSURANCE	$305,203	$349,795	$327,499		$327,499
71	165.15	PREPAID HEALTH INSURANCE-BENEFIT	$61,800	$64,272	$63,036		$63,036
72	165.2	PREPAYMENTS - OTHER	$46,560	$43,857	$45,209		$45,209
73	165.21	PREPAID RETIREMENT FUND/CO PD BENE	$0	($1)	($1)		($1)
74	165.211	PREPAID LIFE INSURANCE/CO PAID BEN	$0	($182)	($91)		($91)
75	165.22	PREPAID L T D FUND/CO. PD. BENEFIT	$0	$0	$0		$0
76	165.24	PREPAID SAVINGS PLAN/CO PD BENEFIT	($2,477)	($1,422)	($1,949)		($1,949)
77	165.25	RETIREMENT FUND-IBEW/BARG CO PD BEN	$0	($0)	($0)		($0)
78	165.26	PAST SERVICE LIABILITY FUND	$0	$0	$0		$0
79	165.27	PREPAID 401K LOAN REPAYMENTS	($4,332)	($3,316)	($3,824)		($3,824)
80	165.28	PREPAID INSURANCE - RETIREES	$0	$1	$1		$1
		NORMALIZING ADJUSTMENT	$0	$0	$0	$7,271	$7,271
81			$406,755	$453,005	$429,880	$7,271	$437,151
80		*Cash Working Capital*		$1,059,701	$1,059,701		$1,059,701
81	183	Deferred Charges	$1,489,863	$1,291,215	$1,390,539	$0	$1,390,539
		Customer Deposits					
82	235	CUSTOMER DEPOSITS	($985,631)	($1,249,212)	($1,117,422)		($1,117,422)
83	235.001	ATHLETIC FIELD FEES	($1,440)	($1,590)	($1,515)		($1,515)
84	235.11	JPEC - GIFT CERTIFICATES	($300)	($245)	($273)		($273)
85			($987,371)	($1,251,047)	($1,119,209)	$0	($1,119,209)
86		Deferred Credits	($156,569)	($193,534)	($175,052)	$0	($175,052)
87		Total Rate Base	$75,192,757	$79,294,840	$77,773,649	($503,612)	$77,270,037

JPEC Cost of Equity Calculations

Line No.	Year	Total Utility Plant	Growth Rate
1	1995	$61,971,420	
2	1996	$66,113,660	6.68%
3	1997	$70,256,892	6.27%
4	1998	$74,545,828	6.10%
5	1999	$78,489,645	5.29%
6	2000	$83,957,209	6.97%
7	2001	$86,838,000	3.43%
8	2002	$89,548,876	3.12%
9	2003	$92,183,357	2.94%
10	2004	$95,605,035	3.71%
11	2005	$101,827,930	6.51%
12	2006	$108,466,681	6.52%
13	Average (2002-2006)		4.56%
14	Standard Deviation		1.68%
15	t-Statistic		2.71

16	Growth Rate	g	4.56%
17	Current Equity Level	We	41.42%
18	Target Equity Level	We*	45.00%
19	Time to Reach Target Equity (yrs)	t	7
20	Cap. Credits Rotation Cycle (yrs)	n	20

Modified "Goodwin" Model:

21 Ke = ((1+g)^(n+1)-(1+g)^n)/((1+g)^n)-1 = 7.73%

Modified "Goodwin" Model with Equity Ratio Adjuster:

22 Ke = [((1+g)^(n+1)-(1+g)^n)/((1+g)^n)-1]
23 +[(1+g)*((We*/We)^(1/t))-1] = 8.97%

Jackson Purchase Energy
Cost of Equity Calculations

Line No.	Year	Total Utility Plant	Growth Rate	
1	1995	$61,971,420		
2	1996	$66,113,660	6.68%	
3	1997	$70,256,892	6.27%	
4	1998	$74,545,828	6.10%	
5	1999	$78,489,645	5.29%	
6	2000	$83,957,209	6.97%	
7	2001	$86,838,000	3.43%	
8	2002	$89,548,876	3.12%	
9	2003	$92,183,357	2.94%	
10	2004	$95,605,035	3.71%	
11	2005	$101,827,930	6.51%	
12	2006	$108,466,681	6.52%	
13	Average (2002-2006)		4.56%	
14	Standard Deviation		1.68%	
15	t-Statistic		2.71	
16	Growth Rate		g	4.56%
17	Current Equity Level		We	41.42%
18	Target Equity Level		We*	45.00%
19	Time to Reach Target Equity (yrs)		t	7
20	Cap. Credits Rotation Cycle (yrs)		n	20

Modified "Goodwin" Model:

21 Ke = ((1+g)^(n+1)-(1+g)^n)/((1+g)^n)-1 = 7.73%

Modified "Goodwin" Model with Equity Ratio Adjuster:

22 Ke = [((1+g)^(n+1)-(1+g)^n)/((1+g)^n)-1]
23 +[(1+g)*((We*/We)^(1/t))-1] = 8.97%

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION

APPLICATION OF JACKSON PURCHASE	)	
ENERGY CORPORATION FOR AN	)	Case No. 2007-00116
ADJUSTMENT IN RATES	)	

PREFILED TESTIMONY OF THOMAS E. KANDEL

ON BEHALF OF

JACKSON PURCHASE ENERGY CORPORATION

NOVEMBER 6, 2007

Purpose of Testimony

Mr. Kandel testifies in support of the distribution plant depreciation methodology, prudent application of the data and reasonableness of the results.

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Thomas E. Kandel. My business address is 2201 Cooperative Way, Herndon, Virginia 20171.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by National Rural Utilities Cooperative Finance Corporation ("CFC") as a Senior Accountant, Regulatory Affairs.

Q. DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I was awarded a Bachelor of Science degree in Business from Miami University, Oxford, Ohio in 1970 and a Master of Business Administration degree from Xavier University, Cincinnati, Ohio in 1977. I majored in accounting during my undergraduate program at Miami University and concentrated on a management curriculum in the master's degree program at Xavier University.

I commenced employment with CFC in August 2006 as Senior Accountant, Regulatory Affairs. In this position, I provide accounting and regulatory expertise to CFC and its member cooperatives. This includes reviewing and interpreting Financial Accounting Standards Board pronouncements and other authoritative accounting guidance, participating in regulatory ratemaking activities and proceedings and representing CFC on several industry-related accounting and tax committees.

Prior to joining CFC, I acquired extensive accounting and financial experience with a number of electric utilities. From 1996 to 2006, I was employed by Southern Maryland Electric Cooperative (SMECO), Hughesville, Maryland. I was initially employed as Vice President, Finance and Administration in 1996 and was promoted to Senior Vice President, Finance and Administration in 1997. Following a reorganization in 2003, I assumed the position of Vice President, Financial Services and Chief Financial Officer. During all or part of the ten years with SMECO, I was responsible for the organization's accounting, financial reporting, cash management, financing, ratemaking, billing, credit and collections, budgeting and financial forecasting activities.

From 1993 to 1996, I served as Consultant to the Comptroller and as Acting Chief Financial Officer for the Virgin Islands Water and Power Authority in St. Thomas, U.S. Virgin Islands. I was employed as Controller for Indiana Municipal Power Agency, Indianapolis, Indiana from 1983 to 1992. From 1979 to 1983, I served as Administrative Assistant to the Chief Accounting Officer of American Electric Power Service Corporation, Columbus, Ohio. I was employed as Controller for Madison Gas and Electric Company, Madison, Wisconsin from 1977 to 1979. From 1970 to 1977, I held the staff positions of Accountant and Report Accountant with Columbus and Southern Ohio Electric Company (now, Columbus Southern Power Company), Columbus, Ohio.

I have passed the Certified Public Accountant exam and am a member of the American Institute of Certified Public Accountants, Maryland Association of Certified Public Accountants and National Society of Accountants for Cooperatives.

I have attached Exhibit TEK-1 summarizing my professional qualifications and experience as an expert witness in regulatory proceedings.

Q. FOR WHOM ARE YOU PROVIDING TESTIMONY?

A. I am providing testimony on behalf of Jackson Purchase Electric Corporation (JPEC).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support the depreciation methodology, prudent application of data and reasonableness of the resulting proposed depreciation rates applicable to JPEC's distribution plant as of December 31, 2006.

Q. WHAT IS THE ORIGIN OF JPEC'S EXISTING DEPRECIATION RATES?

A. The current depreciation rates were approved by the Public Service Commission of the Commonwealth of Kentucky (the "Commission") in Case No. 2002-00485, dated December 30, 2003. The applicable depreciation rates were made retroactively effective to January 1, 2003. The current depreciation rates are the result of two separate depreciation studies. The distribution plant rates were developed by way of a 2001 depreciation study conducted jointly by the Rural Utilities Service (RUS), an agency of the U.S. Department of Agriculture, and JPEC. The 2001 Depreciation Study used utility plant accounting information as of December 31, 2001. Depreciation rates applicable to general plant were developed as a result of another depreciation study performed strictly by JPEC.

Q. IS JPEC OBLIGATED TO USE THE RUS UNIFORM SYSTEM OF ACCOUNTS PRESCRIBED FOR ELECTRIC BORROWERS?

A. Yes. As an electric borrower of RUS, JPEC is required to maintain its books and records of accounts in accordance with the RUS Uniform System of Accounts.

Q. HOW DOES RUS DEFINE "DEPRECIATION'?

A. In Subpart B—Uniform System of Accounts, part 1767, section 10 (7 CFR 1767.10), Definitions, depreciation is defined as follows:

> "*Depreciation,* as applied to depreciable electric plant, is the loss of service value, not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities."

The RUS definition of depreciation describes the nature of physical and functional depreciation.

Q. HOW IS DEPRECIATION ACCOUNTING DEFINED?

A. One of the most popular definitions of depreciation accounting is provided by the American Institute of Certified Public Accountants (AICPA) in Accounting Research Terminology Bulletin #1 which states:

> "Depreciation accounting is a system of accounting which aims to distribute the cost or other basic value of tangible capital assets, less salvage (if any), over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation."

In REA (which stands for the Rural Electrification Administration, the predecessor agency which became RUS) Bulletin 183-1, Depreciation Rates and Procedures, RUS addresses the objectives of depreciation accounting as:

> "The objective of depreciation accounting is to charge to expense the capital investment in certain fixed assets, less salvage at time of retirement, over their useful lives. Thus it may be said that the cost of capital investments in plant is recovered by means of proper depreciation accounting. The useful life of such assets is dependent upon such factors as use, misuse, maintenance and obsolescence. The charge to expense is accomplished by establishing depreciation rates as a percentage. This percentage is applied to the asset cost to yield a monthly or annual amount of depreciation expense."

> "Depreciation accounting provides for the systematic, periodic writedown or allocation of the cost of a limited-life asset or an asset group. The established rate of depreciation should recognize useful life and recovery values. Depreciation is not intended to provide funds for replacement, nor is it to be legitimately

considered as a means to make a desirable showing on the revenue and expense statement."

REA Bulletin 183-1, Depreciation Rates and Procedures, is attached as Exhibit TEK-2.

Q. ARE THESE DEFINITIONS COMPATIBLE?

A. Yes. The associated regulatory accounting prescribed by RUS is compatible with the AICPA definition of cost allocation. In the regulatory context, depreciation provides a means of capital cost recovery of the original investment in utility assets.

Q. IF NOT FOR A COMMISSION REQUIREMENT, COULD JPEC USE OTHER DEPRECIATION RATES THAT WOULD BE ACCEPTABLE TO RUS ?

A. Yes. Under Bulletin 183-1, RUS borrowers have the option of using annual depreciation rates that fall within a range in Bulletin 183-1 or, alternatively, may perform a special depreciation rate study, such as the 2006 depreciation study, that results in rates based on the actual experience of the respective cooperative as to service life and net salvage.

Q. DID THE 2003 COMMISSION ORDER IMPOSE OTHER REQUIREMENTS ON JPEC?

A. Yes. The 2003 order also directed JPEC to account for salvage value and cost of removal by distribution account and issue a report to the Commission, no less than annually from the date of the December 30, 2003 order, depicting the existing balance in each of these accounts.

Additionally, the order required JPEC to provide updated supplements to each of the two respective depreciation studies by the earlier of the fifth anniversary of the 2003 order or a filing for a general rate adjustment.

Q. HAS THE DEPRECIATION STUDY APPLICABLE TO DISTRIBUTION PLANT BEEN UPDATED?

A. Yes. JPEC , with the assistance of RUS, has performed a 2006 depreciation study for distribution plant (i.e., using plant accounting information as of December 31, 2006).

Q. HAVE YOU REVIEWED THE 2006 DEPRECIATION STUDY?

A. Yes. I have. The 2006 Depreciation Study is included in the Application as Exhibit P.

Q. WHO PERFORMED THE 2006 DEPRECIATION STUDY?

A. As with the 2001 depreciation study, the 2006 depreciation study was jointly performed by JPEC and RUS. RUS has regulatory oversight of electric distribution borrowers, such as JPEC, and RUS personnel performing such studies have significant depreciation technical expertise. They worked closely with JPEC personnel to obtain applicable data and ensure that cooperative management retained the decision making authority. As a matter of policy, RUS personnel do not testify in depreciation matters.

Q. PLEASE SUMMARIZE THE NATURE OF THE DEPRECIATION METHODOLOGY USED IN THE 2006 DEPRECIATION STUDY.

A. A depreciation system is comprised of a combination of a method, procedures and techniques. The selection of each is dependent on a number of facts and circumstances.

The depreciation method refers to the pattern of accrued depreciation relative to the respective accounting periods and, in certain instances, the usage of the related assets. The more popular methods include (a) straight-line, (b) compound interest, (c) units-of-production and (d) accelerated or liberalized, which further includes declining balance and sum-of-the-years digits. The straight-line method, which has been incorporated in the 2006 depreciation study, is the most commonly used method in the electric utility industry for book accounting and ratemaking purposes. The straight-line depreciation accrual is computed by taking the original cost of an asset less the net salvage value, which is simply salvage less cost of removal, divided by the estimated service life of the respective asset in years.

Each of the depreciation methods may be used with a combination of one or more procedures. Procedures include (a) item, (b) broad group, (c) vintage group and (c) equal

life group. Due to the multitude of utility plant assets, it is typically impractical to account for depreciation on an individual item basis. Accordingly, it has become common place to use what is referred to as a group concept. Under the group concept, an average service life is determined for the respective group, which may include an individual account or functional group such as distribution plant, based a measurement of mortality characteristics. Vintage refers to the year the plant asset was placed in service.
The 2006 depreciation study reflects the use of a vintage group procedure or a modified version of the vintage group. Due to certain underlying recordkeeping, JPEC presently uses a first-in, first-out vintage system for pricing retirements for items placed in service prior to March 1, 1989, which is the date JPEC converted their continuing property records from an assembly-unit to record units basis. Once all items placed in service prior to March 1, 1989 are retired, they will eventually be on the more traditional vintage year basis.

Although "technique" refers to several other depreciation related decisions that must be made, the primary distinction focus here is the choice between whole life and remaining life in depreciation computations. Under the whole life technique, asset costs are allocated over the entire life of the plant by adjusting the average service life in the depreciation calculations. However, in some circumstances, the whole life technique may be modified to adjust for an expected accumulated depreciation reserve imbalance. In contrast, under the remaining life technique, any unrecovered plant cost, which is defined as the cost of plant less accumulated provision for depreciation, is allocated over the estimated remaining life. The 2006 depreciation study is on a whole life basis.

Q. ARE THERE SIMILARITIES BETWEEN THE 2006 AND 2001 DEPRECIATION STUDIES?

A. Yes. The 2006 and 2001 depreciation studies were both performed jointly by JPEC and RUS personnel and were conducted in accordance with REA Bulletin 183-1, Depreciation Rate and Procedures. Each study focused on depreciation applicable to JPEC's distribution plant and use the same straight-line method and, in general, the same procedures and techniques.

Q. PLEASE IDENTIFY THE PRINICPAL COMPONENTS OF JPEC'S DEPRECIABLE PORTION OF DISTRIBUTION PLANT BY PRIMARY ACCOUNT AS OF DECEMBER 31, 2006?

A. Table 1, Distribution Utility Plant, depicts plant balance, accumulated depreciation and net utility plant by primary account as of December 31, 2006. The difference between depreciable and non-depreciable distribution plant is the $235,871 of non-depreciable items contained in Account 360, Land and Land-Rights. JPEC's Plant Balance of $98,150,959 as of December 31, 2006 is $18,521,561 or 23.3% higher than the Plant Balance of $79,629,398 as of December 31, 2001.

Table 1
Distribution Utility Plant
As of December 31, 2006

Acct. No.	Description	Plant Balance	Accumulated Depreciation	Net Utility Plant
362	Station Equipment	$12,008,367	$1,264,923	$10,743,444
364	Poles, Towers and Fixtures	28,486,552	10,628,842	17,857,710
365	Overhead Conductors and Devices	17,054,966	5,642,593	11,412,373
366	Underground Conduit	4,106,734	652,016	3,454,718
367	Underground Conductors and Devices	9,423,467	2,448,411	6,975,056
368	Line Transformers	15,623,839	3,610,938	12,012,901
369	Services	6,468,811	2,415,868	4,052,943
370	Meters	2,934,243	1,163,276	1,770,967
371	Installations on Customers' Premises	1,484,794	668,690	816,104
372	Leased Property on Customers' Premises	1,048	(101,973)	103,021
373	Street Lights and Signal Systems	558,138	103,137	455,001
		$98,150,959	$28,496,721	$69,654,238

Q. HOW DO THE DEPRECIATION RATES RESULTING FROM THE 2006 DEPRECIATION STUDY COMPARE TO THE CURRENT DEPRECIATION RATES FOR DISTRIBUTION PLANT?

A. Table 2, Depreciation Rate Comparisons Between Current and Proposed Rates, provides a comparison between the current or existing rates and proposed depreciation rates, represented as percentages, by each applicable distribution plant account. Based on the depreciable distribution plant balance as of December 31, 2006, the overall composite depreciation rate will increase from 3.21% to 3.69%.

Table 2 Depreciation Rate Comparisons Between Current and Proposed Rates				
Acct. No.	**Description**	**Current Rate**	**Proposed Rate**	**Difference**
362	Station Equipment	1.53 %	1.60 %	.07 %
364	Poles, Towers and Fixtures	4.19 %	4.31 %	.12 %
365	Overhead Conductors and Devices	3.47 %	3.59 %	.12 %
366	Underground Conduit	1.77 %	1.69 %	(.08)%
367	Underground Conductors and Devices	3.19 %	2.90 %	(.29)%
368	Line Transformers	2.75 %	5.31 %	2.56 %
369	Services	2.23 %	1.48 %	(.75)%
370	Meters	4.34 %	3.99 %	(.35)%
371	Installations on Customers' Premises	6.42 %	12.09 %	5.67 %
372	Leased Property on Customers' Premises	10.00 %	-- %	(10.00)%
373	Street Lights and Signal Systems	1.44 %	3.47 %	2.03 %
	Composite Rate (as of 12/31/06)	3.21 %	3.69 %	.48 %

Q. HOW DO THE ANNUALIZED DEPRECIATION ACCRUALS RESULTING FROM THE 2006 DEPRECIATION STUDY COMPARE TO ANNUALIZED AMOUNTS USING CURRENT DEPRECIATION RATES?

A. Table 3, Annualized Depreciation Accrual Comparison, provides a comparison of current rates and the proposed rates resulting from the 2006 depreciation study. The annualized depreciation accrual or expense amounts are calculated by applying the respective current and proposed rates to the applicable distribution plant balances as of December 31, 2006. Under this approach, the annualized expense will increase from the current amount of

$3,147,142 to the proposed amount of $3,616,908. The aggregated annualized increase of $469,766 is comprised of an increase in base depreciation expense of $229,079 and an additional annualized amount of $240,687 to adjust for or amortize the reserve imbalance, the difference between the computer-calculated or theoretical accumulated depreciation reserve and the actual recorded or book reserve as of December 31, 2006.

Table 3
2006 Depreciation Study
Annualized Depreciation Accrual Comparison

Acct. No.	Description	Current Rate	Proposed Rate	Difference
362	Station Equipment	$183,728	$192,051	$8,323
364	Poles, Towers and Fixtures	1,193,587	1,228,879	35,292
365	Overhead Conductors and Devices	591,807	612,167	20,360
366	Underground Conduit	72,689	69,281	(3,408)
367	Underground Conductors and Devices	300,609	273,216	(27,393)
368	Line Transformers	429,656	829,658	400,002
369	Services	144,254	95,819	(48,435)
370	Meters	127,346	117,020	(10,326)
371	Installations on Customers' Premises	95,324	179,451	84,127
372	Leased Property on Customers' Premises	105	--	(105)
373	Street Lights and Signal Systems	8,037	19,366	11,329
		$3,147,142	$3,616,908	$469,766

Q. DO YOU AGREE WITH THE CONCLUSIONS OF THE 2006 DEPRECIATION STUDY?

A. Yes. I do agree with the overall conclusions.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

State of Virginia)
Fairfax County)

I, Thomas E. Kandel, being duly sworn, deposes and says that the statements contained in the foregoing prepared testimony and the exhibits attached hereto are true and correct to the best of my knowledge, information and belief, and that such prepared testimony constitutes my sworn testimony in this proceeding.

Thomas E. Kandel

Thomas E. Kandel

SWORN TO AND ASCRIBED EFORE ME THIS THE 6th DAY OF NOVEMBER A.D., 2007.

Leonard L. Skatoff Jr.

Notary Public

My Commission Expires:

LEONARD LEO SKATOFF, JR.
Notary Public
Commonwealth of Virginia
My Commission Expires Apr 30, 2009

EXHIBIT TEK-1

STATEMENT OF PROFESSIONAL QUALIFICATIONS

THOMAS E. KANDEL

Mr. Kandel is employed as Senior Accountant, Regulatory Affairs at National Rural Utilities Cooperative Finance Corporation (CFC), Herndon, Virginia. In this position, he provides regulatory accounting and ratemaking expertise to CFC and its cooperative members including representing CFC on several industry accounting and tax committees. His areas of expertise include accounting, finance, ratemaking and other regulatory related subjects.

PROFESSIONAL EXPERIENCE

2006 – Present	National Rural Utilities Cooperative Finance Corporation Senior Accountant, Regulatory Affairs
1996 – 2006	Southern Maryland Electric Cooperative Vice President, Financial Services and Chief Financial Officer Senior Vice President, Finance and Administration Vice President, Finance and Administration
1993-1996	Virgin Islands Water and Power Authority Acting Chief Financial Officer Consultant to the Comptroller
1983 – 1992	Indiana Municipal Power Agency Controller
1979 – 1983	American Electric Power Administrative Assistant (To Chief Accounting Officer)
1977 – 1979	Madison Gas and Electric Company Controller
1970 – 1977	Columbus and Southern Ohio Electric Company Report Accountant Accountant

TESTIMONY

Mr. Kandel has testified in the following matters:

Southern Maryland Electric Cooperative (SMECO):

Jurisdiction	Subject	Case No./Date
Maryland Public Service Commission	Electric Purchased Power Cost Adjustment Charges	8504(s), 3/20/97 8504(t), 3/16/98 8504(u), 3/22/99 8504(v), 3/10/00 8504(w), 3/5/01 8504(x), 3/4/02 8504(y), 2/28/03 8504(z), 3/5/04 8504(aa), 3/4/05
	Retail Choice/Stranded Cost Quantification Mechanism; Price Protection Mechanism and Unbundled Rates	8817, 9/1/99

Indiana Municipal Power Agency (IMPA):

Jurisdiction	Subject	Cause No./Date
Indiana Utility Regulatory Commission	Sale of Bonds to Finance Construction of Generation and Other Facilities	38850, 3/7/90

EDUCATION

Xavier University, Master of Business Administration, 1977
Miami University, Bachelor of Science in Business, 1970

PROFESSIONAL STANDING AND AFFILIATIONS

Passed the Certified Public Accountant exam
American Institute of Certified Public Accountants
Maryland Association of Certified Public Accountants
National Society of Accountants for Cooperatives

UNITED STATES DEPARTMENT OF AGRICULTURE
Rural Electrification Administration

October 28, 1977
Supersedes 11/3/69

REA BULLETIN 183-1

SUBJECT: Depreciation Rates and Procedures

I. General: This bulletin is issued to aid borrowers in their accounting for depreciation. Specific rates are prescribed for production and transmission plant. Ranges of rates are prescribed for distribution plant and recommended for general plant. A method is furnished for borrowers to appraise their reserve ratio for distribution plant. Borrowers may continue to use rates which have received specific REA approval since January 1, 1967. Otherwise, no deviations are to be made from these depreciation procedures and prescribed rates without specific approval of REA except where other rates or procedures are required by a regulatory agency having jurisdiction over the borrower. Borrowers under commission jurisdiction should inform REA of depreciation rates prescribed by the Commission.

II. Depreciation Defined: Depreciation is defined in the REA Uniform System of Accounts as "the loss in service value of depreciable plant not restored by current maintenance resulting from causes against which no insurance is carried, such as wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and requirements of public authorities."

III. Objectives of Depreciation Accounting:

A. The objective of depreciation accounting is to charge to expense the capital investment in certain fixed assets, less salvage at time of retirement, over their useful lives. Thus it may be said that the cost of capital investments in plant is recovered by means of proper depreciation accounting. The useful life of such assets is dependent upon such factors as use, misuse, maintenance and obsolescence. The charge to expense is accomplished by establishing depreciation rates as a percentage. This percentage is applied to the asset cost to yield a monthly or annual amount of depreciation expense.

B. Depreciation accounting provides for the systematic, periodic writedown or allocation of the cost of a limited-life asset or asset group. The established rate of depreciation should recognize useful life and recovery values. Depreciation is not intended to provide funds for replacement, nor is it to be legitimately considered as a means to make a desirable showing on the revenue and expense statement.

IV. Methods of Depreciation:

A. REA recommends the straight-line method of computing depreciation for use by its borrowers to provide uniform accounting and reporting practices. The REA Uniform System of Accounts defines straight-line depreciation as "a method for periodically computing the expense represented by loss in service value of depreciable plant, under which the objective is to prorate such loss in equal installments over the estimated or remaining estimated service life."

B. The REA Uniform System of Accounts, in conformity with the practice of electric and other utility industries, provides for the use of composite rates for each class of property including general plant. This is commonly referred to as "group method depreciation." Although the use of the unit method of computing depreciation is not consistent with general utility practices nor recognized in the Uniform System of Accounts Prescribed for Electric Borrowers of the Rural Electrification Administration (REA Bulletin 181-1), REA will not object to this method of computing depreciation for general plant where boards of directors approve this procedure as being necessary to meet their management needs.

C. The group method differs from the unit depreciation method in that a number of units of property are grouped for depreciation accounting purposes; depreciation is computed for the whole group. The units may be grouped by primary accounts or by functions, the essential requirement being that the property included in each group have some homogeneity. Under the group method, when retirement of a depreciable unit of plant occurs, the cost of the unit less net salvage is charged to the appropriate accumulated provision for depreciation account. No recognition is given to so-called gain or loss until all the units included in the particular group are abandoned.

V. Depreciation Guideline Curves - Distribution Plant: The ratio of the accumulated provision for depreciation to gross plant in service (reserve ratio), has been widely recognized as an important measure of the propriety of depreciation rates and practices. Guideline curves are supplied in Section V.C. for use as a screening tool to determine whether a borrower's reserve ratio is consistent with normal experience. Using the procedure outlined in V.C. below, the cooperative should, on an annual basis, prepare an analysis of the adequacy of its accumulated provision for depreciation of distribution plant. This analysis should be maintained in the cooperative files and be made available for review by REA field personnel.

A. Underlying Theory:

1. Electric distribution plant is an example of a "continuous class" of property, consisting of many individual units of property, each of which is replaced when it reaches the end of its useful life. For such a "continuous class" of property, and with proper depreciation accounting, the reserve ratio for a particular company will be determined by the following factors:

a. Its history of growth.

b. Its age.

c. Its experience with respect to retirements and replacements. This involves not only the average useful life of the plant, but also the dispersion in the average useful life of the individual plant items.

d. Its experience with net salvage.

e. Its rate of depreciation.

2. The depreciation guideline curves are a simplified application of this underlying theory. The factor of growth is taken into account by the horizontal scale at the bottom of the chart which is a ratio comparing the present plant with plant ten years ago. The factor of age is taken into account by the fact that the curve is recommended for use only by borrowers with an elapsed age since energization of at least 20 years. The factors of experience with replacements and salvage are taken into account by the provision of a range between maximum and minimum

which encompasses the range in average life and in patterns of replacement dispersion which is most commonly experienced by REA borrowers. These ranges were determined by reference to industry experience, both public and private, and through simulated plant-record analyses made of a number of REA borrowers. The applicability of the basic factors of growth, age, and history of retirements to REA distribution borrowers' reserve ratios has been confirmed by statistical analysis, and it has been determined that the experience of most distribution borrowers which have followed good depreciation accounting practices will place their reserve ratio within the "normal" area between the maximum curve and the minimum curve.

3. It will be noted that there is a considerable spread between the maximum and the minimum guideline curves. It is significant that conditions which may result in fairly high reserve ratios for certain borrowers at the present time should lead to lower reserve ratios as these borrowers become older. It is more likely, therefore, that in later years the maximum curve may be lowered.

B. Application of Depreciation Guideline Curves:

1. Depreciation guideline curves can be used very easily by the borrower. Following the detailed procedure for use of the guideline curves (Section V C), the reserve ratio and rate of growth of distribution plant in service are determined for the latest ten year period. Reference to the depreciation guideline curves will immediately indicate whether the borrower's reserve ratio lies between the maximum and minimum curves for plant growing at such a rate.

2. If a borrower is above the maximum, or below the minimum, this is an indication of an unusual condition which warrants a more detailed study. Such a study may indicate need for correction in accounting procedures or a change in depreciation rates or both. In some instances, detailed study may reveal exceptional conditions which justify the unusually high or low reserve ratio.

3. It is also important to consider the change in the reserve ratio during the last several years, and the future reserve ratio as predicted in a long range financial projection. If the reserve ratio is below the minimum curve, but increasing, and if the financial projection indicates that it will soon reach the minimum curve, no corrective action may be required, though subsequent progress should be watched to see that it corresponds to the estimates.

4. Similarly, if the reserve ratio falls between the maximum and minimum guide curves, but the financial projection indicates that the reserve ratio is expected to increase within a few years to a point well above the maximum curve, a special study of the depreciation practices should be made to determine whether there is a need for corrective action.

C. Procedure for Use of the Depreciation Guideline Curves:

1. The chart which follows, shows depreciation guideline curves with suggested levels of depreciation reserve ratios at various growth rates. The solid curves indicate the upper and lower limits of normal reserve ratios for distribution plant. The curve shown by dashes indicates the optimum level of reserve ratios which might be expected in the case of a typical distribution borrower.

2. To check the accumulated provision for depreciation of distribution plant against the depreciation guideline curves, four steps are necessary:

   a. Determine whether the elapsed age since energization is at least 20 years. If it is less than 20 years, the guideline curves are not applicable.

   b. Determine the current reserve ratio by dividing the accumulated provision for depreciation on distribution plant by the distribution plant in service. Typical figures might be $855,220 divided by $2,861,150, which gives a reserve ratio of 29.9%.

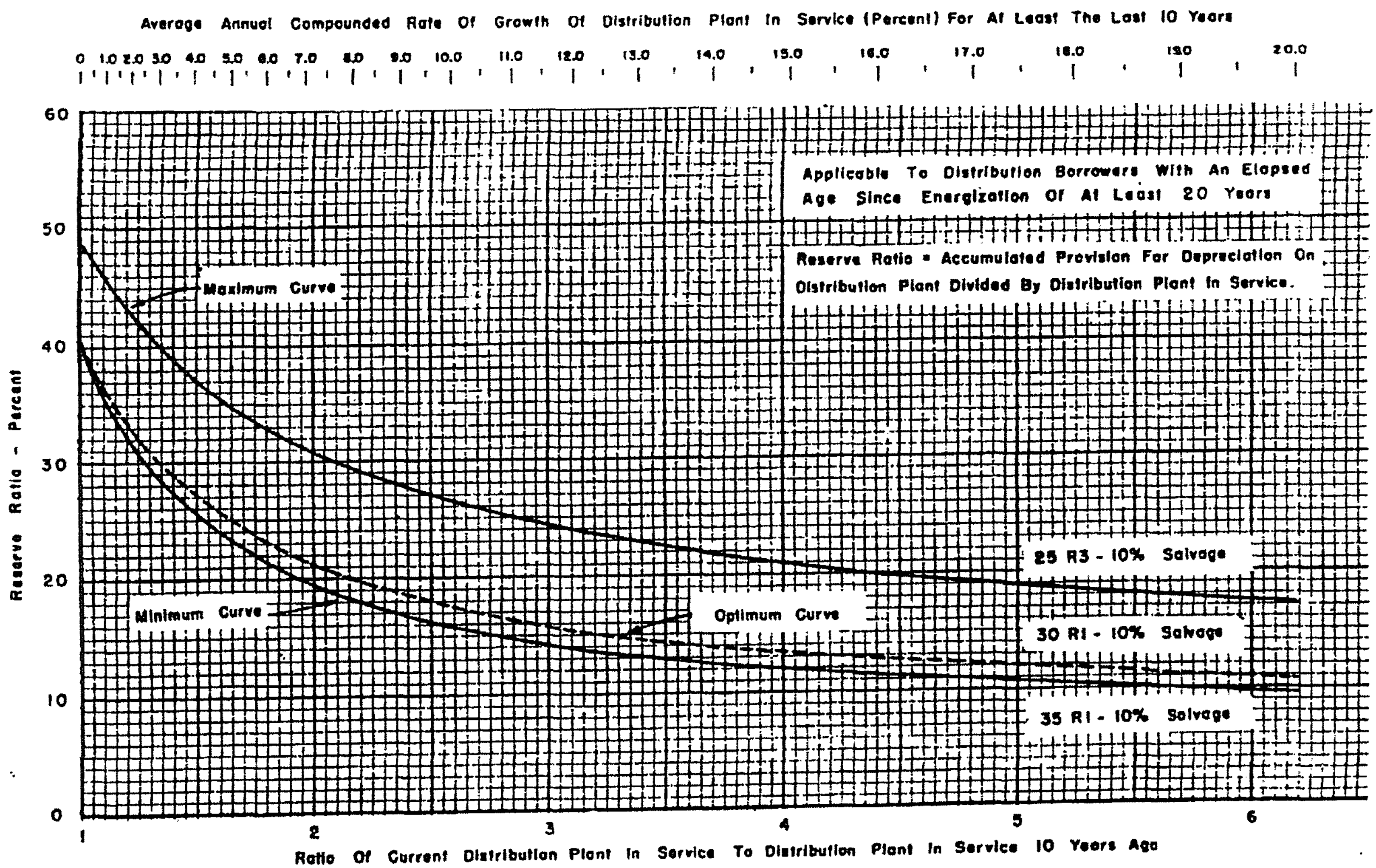
   c. Determine the ratio of current distribution plant in service to distribution plant in service ten years before. To do this, divide the current distribution plant in service by the distribution plant in service ten years earlier. Typical figures might be \$2,861,150 divided by \$1,540,350, which gives a ratio of 1.86.

d. Refer to the depreciation guideline curves. For a ratio of current distribution plant in service to distribution plant 10 years ago of 1.86, the maximum curve is about 32% and the minimum curve is about 21%. The example of 29.9%, in paragraph 2 above, lies within this range.

3. It may be desirable to use the depreciation guideline curve with a growth period of more than 10 years. In that case, it will be necessary to use compound interest tables to obtain the average annual compounded rate of growth of distribution plant in service for the particular number of years involved. Then the horizontal scale at the top of the chart will be used.

4. References: For general information on depreciation of a "continuous class" of property, see Report of the Committee on Depreciation, 1960, National Association of Railroad and Utilities Commissioners. For information on the "Iowa Curves" of plant mortality dispersion, which were used in the development of the REA depreciation guideline curve, see Statistical Analysis of Industrial Property Retirements by Robley Winfrey, Iowa Engineering Experiment Station, Bulletin No. 125, 1935, and Depreciation of Group Properties by Robley Winfrey, Iowa Engineering Station, Bulletin No. 155, 1942. For information on the simulated plant-record and other methods of life analysis, see Methods of Estimating Utility Plant Life, Publication 51-23, Published 1952, Edison Electric Institute. A more extensive bibliography can be obtained from REA on request.

DEPRECIATION GUIDELINE CURVES



VI. Prescribed Depreciation Rates for Distribution Plant: The table below (paragraph C) sets forth the range of depreciation rates for distribution plant. Within this range each borrower should select the rate, or rates, which in its judgment would be most suitable in measuring expiration of the service life of its depreciable plant on a straight-line basis. Such judgment is essential since depreciation rates cannot be determined precisely through application of exact formulas.

A. Calculation of Composite Depreciation Rates for Groups: The primary plant accounts required by the REA Uniform System of Accounts represent groupings of plant units which are suitable for depreciation accounting purposes. Although not all units in a given account have identical characteristics or similar service lives, it is possible to calculate a composite rate for each primary account and, in turn, by utilizing the rates for each primary account, to arrive at a composite rate for a functional group, such as distribution property. The rate for a primary account is computed by first determining a rate for each group of similar materials within an account; secondly, the cost of each group of similar materials is multiplied by the rate selected for that group; and finally, the products of these multiplications are totaled and divided by the balance in the primary account. This same procedure is followed in determining the composite rate for the functional group; that is, the balances in the respective primary accounts are multiplied by the individual rates selected for the various accounts and the products added to arrive at a total which, divided by the aggregate cost of the depreciable plant accounts involved, produces a composite rate for the functional group.

B. Selection of Appropriate Rates Within Range:

1. Review Composition of Each Account: Rates for individual accounts, within the ranges set forth in Section VI.C. below, are to be used in calculating composite rates for functional plant groups. In selecting the rates for individual accounts, plant accounts should be reviewed to determine the composition of each. (For example, in Account 364, Poles, Towers and Fixtures, the types and relative proportions of poles, crossarms, and anchor-guys should be ascertained.) Estimates should be made as to the expected life, removal costs and material

to be salvaged for the various types of material comprising the property in each account. These data will form a basis for judgment as to the rate of depreciation within the recommended range to be applied to each account in computing the composite rate for the functional group.

2. Consider External Factors: Differences in geographical location, climate, operating practices, maintenance policy, load conditions and similar factors may justify differences in depreciation rates since any of these variables may affect or limit the service life of distribution plant.

   a. Factors and conditions contributing to the use of the upper range of the rate for poles would be (1) growing conditions favorable for decay, fungi (and vegetation in general) such as in southeastern states with high average humidity and rainfall, or where irrigation and crop fertilization are widely practiced and (2) large numbers of substandard poles such as were produced in 1946 through 1948.

   b. Factors and conditions contributing to the use of the lower range of the rate for poles are growing conditions that are slow or poor; for example, in dry and unirrigated areas, in northern states and at higher altitudes.

3. Select Rate for Each Account Within the Range: It is recommended that borrowers whose systems are operated under normal conditions select a rate for each account which is near the middle of the range. For systems operating under extreme conditions, such as prevail in coastal or sleet areas, or in extremely arid localities, the rate should be selected from near the top or bottom of the range as appropriate. However, in no case should the low end nor the high end of the range be selected unless extraordinary conditions exist which lead to long or to exceptionally short service life.

Illustrations of rate computations and accounting procedures to be followed by borrowers are included in the Appendix.

4. Review Prior Practices:

Consideration should be given to adjusting rates to compensate for the under or over accumulation of the provisions for depreciation resulting from inadequate accounting practices, procedures or improper rates. The guideline curves discussed in Section V above provide a basis for evaluating the need for changes in depreciation rates for distribution plant.

For instance, when it is determined that the accumulated provision for depreciation is excessive because high depreciation rates have been used, or incorrect accounting has been followed, corrective action should be taken. Accounting procedures should be checked and, if necessary, corrected. It may be necessary to reduce the depreciation rate. The reduction should be sufficient to bring the reserve ratio into line with the depreciation guideline curves on a gradual basis over a number of years.

C. Range of Rates - Distribution Plant:

Acct. No.	Account	Annual Depreciation Rate
361	Structures and Improvements	See Account 390
362	Station Equipment	2.7 - 3.2%*
364	Poles, Towers, and Fixtures	3.0 - 4.0%
365	Overhead Conductor and Devices	2.3 - 2.8%
366	Underground Conduit	1.8 - 2.3%
367	Underground Conductor and Devices	2.4 - 2.9%
368	Line Transformers	2.6 - 3.1%
369	Services	3.1 - 3.6%
370	Meters	2.9 - 3.4%
371	Installation on Consumers' Premises	3.9 - 4.4%
372	Leased Property on Consumers' Premises	3.6 - 4.1%
373	Street Lighting and Signal Systems	3.8 - 4.3%

* Power type borrowers should use 2.88% for distribution station equipment.

Requests for REA approval to use rates below or above the composite rate computed by using the ranges recommended must be supported by a clear statement of the factors and conditions which justify such rates.

VII. Recommended Depreciation Rates for General Plant: The table below sets forth the range of recommended depreciation rates for general plant.

General plant is subdivided into six functional groups for depreciation purposes. Separate decimal subaccounts of the accumulated provision for depreciation of general plant should be maintained for each group. The six groups and the ranges of rates are:

Functional Group	Annual Depreciation Rates
Structures and Improvements	2.0 - 3.0%
Office Furniture and Equipment	5.0 - 7.0%*
Transportation Equipment	14.0 - 17.0%
Power Operated Equipment	11.0 - 16.0%
Communications Equipment	5.0 - 8.0%
Other General Plant	3.6 - 6.0%

A. Account 390, Structures and Improvements:

A composite rate should be computed for this account by selecting a rate appropriate for each structure recorded in it. A new composite rate should be computed when a structure is added or deleted. A rate at or near the lower side of the range should generally be used when structures are new or of masonry construction or in areas normally having favorable climatic conditions. A rate at or near the upper side of the range should normally be used when structures are frame type construction, or remodeled or in areas subject to severe climatic conditions.

B. Account 391, Office Furniture and Equipment:

In the computation of a composite rate, office furniture and equipment may be divided into three groups: (a) furniture and miscellaneous office fixtures and equipment,

*Upper limit of range increased to 12.5% when data processing and automatic accounting machines are included.

(b) office machines such as addressographs, typewriters, calculators and adding machines, and (c) data processing equipment and automatic accounting machines. If data processing equipment and automatic accounting machines are included, the annual composite rate may be greater than 7.0% but it should not exceed 12.5%.

To the amount of each group mentioned above a rate within the following ranges should be applied:

	Estimated Service Life-Years	Range Depreciation Rate
Furniture and Miscellaneous Office Fixtures and Equipment	15 to 25	4.0 to 6.0%
Adding Machines, Typewriters, Addressographs and Calculators	9 to 15	6.0 to 10.0%
Data Processing Equipment and Automatic Accounting Machines	6 to 10	10.0 to 16.0%

C. Account 392, Transportation Equipment:

The computation of annual depreciation on a composite basis may be in accordance with the following schedule:

Type	Estimated Service Life-Years	Estimated Percent Salvage Value	Range Depreciation Rates
Automobiles	3 to 5	20 to 40	16.0 to 20.0%
Pickups, Light Trucks, including Auxiliary Equipment	4 to 6	10 to 30	15.0 to 17.5%
Heavy Trucks, including Auxiliary Equipment	5 to 10	Zero to 20	10.0 to 16.0%
Trailers	8 to 14	Zero	7.0 to 12.5%

D. Account 396, Power Operated Equipment:

Ordinarily, depreciation should be computed on this account using an appropriate composite rate. However, units of exceptionally high cost which are used only occasionally, should be depreciated on a time basis, subject to a minimum monthly charge. Estimated life and salvage should be used in arriving at the time rate.

E. Account 397, Communications Equipment:

A composite depreciation rate on the low side of the range should be selected if towers and base stations for two-way radio systems and miscellaneous equipment represent a larger portion of the account balance. If, on the other hand, mobile radio units represent a larger portion of the balance, a rate on the high side should be used. When the account contains a considerable investment in such items as telephone, carrier, or supervisory and load control equipment properly included in general plant, a rate on the low side of the range should be used.

F. Other General Plant:

This group includes Accounts 393, Stores Equipment; 394, Tools, Shop and Garage Equipment; 395, Laboratory Equipment and 398, Miscellaneous Equipment.

VIII. Prescribed Depreciation Rates for Production and Transmission Plant: The tables below set forth the depreciation rates for various types of production and transmission plant. These rates are to be used by borrowers and REA except where regulatory commissions prescribe other rates or unusual conditions justify special rates. A detailed depreciation study should be made for the special cases and submitted to REA for approval of appropriate rates. The rates shown below should be used unless the special rates as determined by the study are more than 0.1 percentage point greater or less than the recommended rates.

B. Rates for Production Plant:

Functional Group or Type of Facility	Annual Depreciation Rate
Steam Production	3.10%
Diesel Production:	
720 RPM and below	3.00%
Above 720 RPM	7.00%
Hydro Production	2.00%
Gas Turbine Production	3.00%

Nuclear Production
A proposed composite rate for nuclear production plant shall be submitted to REA for approval. For joint participation projects in which the borrower is a minor participant, the rate being used by the other participant(s), shall be used. Justification, including supporting studies and regulatory commission's order, for the proposed rate, shall be submitted to REA.

C. Rates for Transmission Plant:

Functional Group or Type of Facility	Annual Depreciation Rate
Transmission Lines	2.75%
Transmission Station Equipment	2.75%

When the amount of communication equipment recorded in Account 353, Station Equipment, is significant (7.5 percent or more of the account total), the depreciation on the communication equipment is computed using the same rate used for Account 397, Communication Equipment.

D. Depreciation Rates for Production and Certain Transmission Facilities to be Included in Loan Agreements:

1. To assure consistency in the use of depreciation rates by REA in its review and analyses of loan applications and by the borrower in its computation of depreciation expense, loan agreements, where production or certain

transmission facilities are involved, will include a provision that the borrower (a) shall adopt as its depreciation rates only those which have previously been approved for the borrower by the Administrator unless other depreciation rates are required by regulatory bodies having jurisdiction in the premises, and (b) shall not file with or submit for approval of regulatory bodies any proposed depreciation rates which have not previously been approved for the borrower by the Administrator.

2. Loan agreements will contain the above provisions for transmission facilities when:

   a. The borrower will own both generation and transmission facilities; or

   b. When more than 50 percent of the borrower's plant investment is in transmission facilities; or

   c. When REA determines in other cases that the depreciation rates should be specified in the loan agreement.

IX. Periodic Review:

Depreciation guideline curves should [illegible]ared to evaluate the adequacy of current depreciation pra[illegible]ces and rates for distribution plant. Under the group [illegible]od of depreciation, it is especially necessary to re-ex[illegible] depreciation accounting practices periodically. (Ever[illegible]r is recommended for general plant.) Incorrect accounting [illegible]ocedures found should be corrected immediately. Rates should be altered where necessary to give effect to justifiable changes in estimates of service life or net salvage. When frequent reviews are made only modest changes in depreciation rates are necessary to keep the reserve ratio in line with the guideline curves.

Joseph Vellom
Acting
Administrator

Attachment:
Appendix - Illustrations of Rate Computations and Accounting Procedures to be Followed by Borrowers

Index:
DEPRECIATION:
Rates and Procedures

APPENDIX

ILLUSTRATIONS OF RATE COMPUTATIONS AND ACCOUNTING PROCEDURES TO BE FOLLOWED BY BORROWERS

1. Calculating a composite rate for distribution plant:

   a. Showing effect of change in rate for each primary account:

Account	Balance	Rate A	Depreciation Amount A	Rate B	Depreciation Amount B
362	$ 30,000	2.7%	$ 810	3.2%	$ 960
364	340,000	3.0	10,200	4.0	13,600
365	290,000	2.3	6,670	2.8	8,120
368	210,000	2.6	5,460	3.1	6,510
369	50,000	3.1	1,550	3.6	1,800
370	40,000	2.9	1,160	3.4	1,360
	$960,000		$25,850		$32,350

$25,850 ÷ $960,000 = 2.7%, composite rate A
$32,350 ÷ $960,000 = 3.3%, composite rate B

   b. Showing effect of change in composition of functional plant group with reference to respective proportions of cost in the various primary accounts:

Account	Rate	Balance A	Depreciation Amount A	Balance B	Depreciation Amount B
362	2.7%	$ 30,000	$ 810	$ 20,000	$ 540
364	3.5	340,000	11,900	375,000	13,125
365	2.3	290,000	6,670	280,000	6,440
368	2.6	210,000	5,460	125,000	3,250
369	3.6	50,000	1,800	100,000	3,600
370	3.4	40,000	1,360	60,000	2,040
		$960,000	$28,000	$960,000	$28,995

$28,000 ÷ $960,000 = 2.9%, composite rate A
$28,995 ÷ $960,000 = 3.0%, composite rate B

2. <u>Calculating a composite rate for transportation equipment:</u>

Equipment	Estimated Life	Quantity	Total Cost	Estimated Salvage	Depreciable Cost	Annual Depreciation
A	10 yrs.	1	$18,000	$ - 0 -	$18,000	$ 1,800
B	5 yrs.	6	54,000	7,200	46,800	9,360
C	4 yrs.	2	8,000	2,000	6,000	1,500
			$80,000	$9,200	$70,800	$12,660

$12,660 ÷ $80,000 = 15.8% composite rate

3. <u>Accounting procedure for trade-in of truck:</u> (Note that under the group depreciation procedure the net book cost of any particular item of general plant is not ascertainable, as depreciation charges are not allocated to the individual items as is done under the unit depreciation method.)

   a. Given a situation in which a truck with original cost of $2,000 is traded for a $2,600 new truck, with $600 being allowed on the old truck:

   b. Accounting procedure:

Account 392
Transportation Equipment

17,000	2,000 (a)
(b) 2,600	

Account 108.7
Accumulated Provision for Depreciation of General Plant

(a) 2,000	9,000
	600 (b)

Account 131
Cash-General

	17,000
	2,000 (b)

USDA Rural Development

United States Department of Agriculture
Rural Development

July 3, 2007

Mr. Gary Joiner, Chairman
Jackson Purchase Energy Corporation
P.O. Box 4030
Paducah, Kentucky 42002-4030

Dear Mr. Joiner:

We have completed the depreciation study of the Jackson Purchase Energy Corporation using historical data of the Corporation from January 1, 1939 through December 31, 2006. The study was conducted jointly by the Rural Utilities Service (RUS) and staff from the Corporation. Please find a copy of the study enclosed.

Two items were noted during the depreciation study field work which have a significant impact on depreciation rates. In a previous study, it was found that Corporation personnel were not properly allocating labor between construction and retirement on their time sheets. This incorrect labor reporting had a significant impact on the depreciation reserves. Proper time reporting was discussed in detail with Corporation staff in July 2002 and the procedures were corrected. During a follow-up review of the labor reporting process in September 2002, it was noted that the Corporation had made considerable improvement in labor reporting for those three months. However, during the current study, our review of labor reporting practices indicated that Corporation personnel reverted to the previous practices of recording labor. Therefore, this study relied on the actual, current labor reporting practices. Second, the Corporation uses a modified vintage system to maintain its Continuing Property Records (CPRs). Plant retired is priced on a first-in, first-out basis using the average price for each annual vintage of additions. The amounts in existence at March 1, 1989, the date of the conversion from assembly units to record units, are considered the first vintage. Once those amounts are completely retired, the remaining 1989 amounts will be retired and then each yearly additions will be retired. Generally, RUS borrowers use a moving average of all years' additions to price retirements rather than a vintage system. Both of these items should be monitored closely for their effects on depreciation rates and reserves.

The Corporation may select from two alternatives for setting depreciation rates at its discretion. The first alternative is that the Corporation may use rates from within the range of rates contained in RUS Bulletin 183-1, Depreciation Rates and Procedures, issued October 28, 1977. No specific RUS approval is required for selecting rates from within the RUS range of rates. The second alternative is that the Corporation may adopt, in their entirety, the rates developed by this study. If neither of these alternatives is adopted, the Corporation should contact RUS as soon as possible.

Based on the information provided in this study, RUS approves the depreciation rates for the primary plant accounts as detailed below:

Account Number	Account Title	Annual Depreciation Rate
362	Station Equipment	1.60%
364	Pole Towers and Fixtures	4.31%
365	Overhead Conductor and Devices	3.59%
366	Conduit	1.69%
367	U/G Conductor and Devices	2.90%
368	Line Transformers	5.31%
369	Services	1.48%
370	Meters	3.99%
371	Installations on Customers' Premises	12.09%
373	Street Lighting and Signal Systems	3.47%

These rates are approved for a five year period beginning January 1, 2007. If the Corporation wishes to continue to utilize depreciation rates that fall outside of RUS' prescribed ranges of rates beyond the five year period, a revised depreciation study updating this information must be performed.

If you have any questions or if we can be of any further assistance, please contact me at (870) 424-7147.

Sincerely,

Anthony S Bunch

ANTHONY S. BUNCH
Field Accountant
Rural Development Utilities Programs

Enclosure

Cc:
Mr. G. Kelly Nuckols, President/CEO
Mr. Chuck Williamson, Vice-President-Finance & Administration

JACKSON PURCHASE ENERGY CORPORATION
PADUCAH, KENTUCKY
(KENTUCKY 20 MCCRACKEN)

DEPRECIATION STUDY
DECEMBER 31, 2006

Performed By:

Robert M. Benson
Anthony S. Bunch
Elizabeth M. Johnston

TABLE OF CONTENTS

Description	Page
Introduction	2
Summary	3
Analysis of Distribution Plant Accounts	7
Exhibit A - Iowa Curve and Average Service Life	19
Exhibit B - Allocation of Salvage, Cost of Removal and Net Salvage	20
Exhibit C - Theoretical Reserve Compared to Actual Reserve	21
Exhibit D - Computed Annual Depreciation Rate and Composite Rate	22
Exhibit E – Summary of Remaining Lives	23
Exhibit F – Summary of Current & Proposed Depreciation Rates	24
Exhibit G – Schedule of Depreciable Property	25

INTRODUCTION

We have performed a depreciation study at Jackson Purchase Energy Corporation in Paducah, Kentucky (KY 20). This study was a joint effort between personnel of the Corporation and RUS. The purpose of the study was:

1. To recommend appropriate depreciation rates based on estimates of average-life mortality characteristics and net salvage that will fully recover the cost of the property, adjusted for net salvage, over its estimated life.

2. To determine the adequacy of the book reserve for depreciation at a point in time by comparing it with a theoretical reserve based on the same average lives, mortality characteristics, and net salvage as used to determine the recommended depreciation rates.

3. To determine, if necessary, some method to adjust the book reserve for past over or under-accruals as indicated by comparison with the theoretical depreciation reserve calculation.

4. To review in detail the history, status, procedures, and policies of the Corporation's depreciation functions, records, and operating techniques.

Since there are many factors affecting estimates of depreciation rates and accrued depreciation and these factors are constantly changing, a depreciation study represents only the best judgment at the time the study is made. Actual results may vary from the forecasts and variations may be material. A review of depreciation should be made at least every five years so that the Corporation's depreciation practices reflect these changes.

SUMMARY

The overall results of the study indicate a proposed change to depreciation rates that will increase annual depreciation expense by approximately $469,766, when compared to the rates used by the Corporation during 2006. These rates were implemented January 1, 2002 as the result of a depreciation study conducted by RUS and KY20 personnel. The rates implemented in 2002 replaced rates implemented by order of the Kentucky Public Service Commission (PSC) in Case No. 2000-527. This order reversed a prior PSC order of May 6, 1998 which implemented much higher depreciation rates based on a previous depreciation study.

Our study included a review of construction and retirement activity for distribution plant from inception (1939) through December 31, 2006. Prior to March 1989, the Corporation maintained its continuing property records (CPRs) on an assembly-unit basis. In March 1989, the Corporation converted its CPRs to a record-unit basis. The record-unit basis of maintaining CPRs is in accordance with the Uniform System of Accounts as issued by the Rural Utilities Service. The CPRs, having been maintained on an assembly-unit basis prior to March 1989, presented obstacles to conducting this study. There were considerably more units on the assembly-unit method and the conversion to record units sometimes resulted in several different record units from a single assembly unit. Additionally, at the time the conversion was made, dollar amounts were transferred among certain distribution plant accounts. Because of the complexity of the conversion of the assembly-unit method to record units, it was decided to perform this study as a combination of both the dollar method and unit method. Either of these conventions is accepted for depreciation studies.

General ledgers were available from 1939 for each individual plant account. Dollar additions and retirements data were collected from the general ledgers for use in the study. Additions and retirements on a unit basis were available from the CPRs back to 1939 for most items. This was on both an assembly-unit and record-unit basis. For those items that converted directly from assembly units to record units, the unit data was used in this study. For those other items that did not convert so readily, the dollar method was utilized.

The Corporation presently prices retirements using a first-in first-out vintage system where the items in service at March 1, 1989, the time of the conversion to record units, are considered the first vintage. Once all items from the pre-March 1989 era are retired, then the remaining year 1989 vintage will be retired and then each subsequent year additions will be retired. Although the Corporation is maintaining CPRs on a vintage basis for additions, no association of retirements is made to the year installed. Therefore, the Corporation does not have true vintage property records. This retirement pricing method results in less dollars being retired for current retirements than most other RUS borrowers that use the current moving average cost method for pricing retirements. This first-in first-out vintage method of pricing retirements results in a higher negative net salvage as a percentage of plant retired than the moving average method would and, therefore, higher depreciation rates.

This study was performed utilizing the "Iowa Type Survivor Curves". These curves are frequently used by utilities for analyzing depreciation of property recorded on a mass unit basis. The curves analyze the life of mass property accounted for on the vintage basis. Vintage accounting is a system where plant is accounted for by year of installation and its life is identified as such through retirement. Since vintage accounting is not required by the uniform system of accounts, this type of record was not maintained for the mass plant items. Our study therefore used the technique of creating simulated plant records on a vintage basis.

The computer program that was utilized incorporates the Simulated Plant Record (SPR) method of analyzing data. Studies have shown that mass property kept on a vintage record basis generally fits the pattern of one of 31 Iowa survivor curves. Through additional studies it has been shown that, if plant is retired but not recorded on a vintage basis, it would still follow the pattern of one of these 31 curves. The SPR method of analyzing data tests the additions, retirements, and plant balances for each year to fit the data to the best curve for analysis.

The study of depreciation also utilizes the estimates of net salvage for the primary plant accounts. Net salvage is the result of combining salvage received for plant removed from service and the cost of removal. The Corporation maintains depreciation reserves for each of its distribution plant accounts. To calculate the net salvage percentages used in the depreciation study, an analysis of the RUS Form 7, Financial and Statistical Report, was made for the period 1989 through 2006. As a supplement to the RUS Form 7, the Corporation maintains detailed plant account and reserve data for the Kentucky Public Service Commission. This data was used along with the RUS Form 7 data. However, based on the Corporation's FIFO vintage CPRs and its method of recording and accounting for labor, the determination was made that the calculated net salvage percentages resulted in inappropriate depreciation rates. Generally the net salvage component of depreciation is derived by dividing the salvage estimate by the respective plant balance. However, two problems are noted in applying this methodology in Jackson Purchase's case and these problems would result in inaccurate depreciation rates and improper allocation of costs. The first problem is the Corporation's use of its hybrid FIFO/vintage method of pricing retirements. The second problem is its practices of time reporting and resulting accounting for labor associated with capitalized projects and costs of removal. Therefore, for the purposes of this study and developing depreciation rates that reflect a proper allocation of costs for Jackson Purchase, techniques were developed to calculate the net salvage percentages which result in the most appropriate measure of depreciation. (Refer to Exhibit B, Net Salvage Study.)

The prior depreciation study net salvage percentages were adjusted due to the fact that labor allocations between construction and retirement were not proper. The Corporation was overallocating time to cost of removal on the basis of what appeared to be arbitrary allocation of time between construction and removal. Prior to completion of the 2002 study, the Corporation was requested to maintain specific detail of time by the outside crews on the time sheets and this was done for latest period. At the conclusion of the test period, it was determined that the Corporation had changed its labor reporting to result in a proper allocation of labor between construction and retirement. Net salvage percentages were adjusted to reflect the proper allocation of labor between construction and retirement. This resulted in a substantial decrease in the annual depreciation accrual. However, during the current study, an analysis of the depreciation reserve and labor reporting during the time period from 2002 through 2006 indicated that in fact the time reporting changes initiated during our last visit in 2002 to correct labor reporting was in fact short lived and not maintained through 2006. Time reporting reverted to an arbitrary percentage allocation. Thus, the actual results of the current net salvage study, which was calculated based on actual cost of removal, salvage, and original cost of plant retired, resulted in high negative net salvage percentages. The current net salvage component is based on the time reporting practices currently in use. As time reporting has a significant effect on the value of plant and depreciation rates, the Corporation should take steps to improve its time reporting practices.

Due to the fact that in future years, plant retired will be priced at higher prices, because of the hybrid FIFO vintage method, adjustments were made to the net salvage study to more properly reflect the expected results in the upcoming years. Our estimate for net salvage is a composite percentage based on the relative expected cost to remove each vintage. This methodology will need to be closely reviewed and adjusted as necessary in future depreciation studies.

For this study we utilized the whole life technique. The whole-life technique bases the depreciation rate on the estimated average service life of the plant category. Whole-life depreciation results in the allocation of a gross plant base over the total life of the investment. To the extent that the estimated average service life or net salvage assumption assigned turns out to be incorrect, the whole-life technique will result in a depreciation reserve imbalance. However, when a depreciation reserve excess or deficiency is reasonably certain, the whole-life technique may be modified to include an adjustment to the accrual rate designed to eliminate the reserve imbalance in the future.

Thus, when utilizing the whole-life method of accounting for depreciation, it is necessary to determine the adequacy of the depreciation reserve for each account. (Refer to Exhibit C, Comparison of Computer Calculated Depreciation Reserve to Actual Book Reserve.)

The depreciation reserve maintained by the Corporation as of December 31, 2006 was on an account level. The Kentucky Public Service Commission requires that an individual depreciation reserve be maintained for each plant account. This was not always the case for the Corporation and, when individual depreciation reserves were established, it was accomplished based on a percentage of the plant account balance at the time. (Refer to Exhibit D, Computed Annual Depreciation Rate for Property Group.)

By simulating the plant balances and the depreciation reserve and allocating the net salvage, we were able to develop the average plant lives and calculate the plant balances, reserve balances, and annual depreciation accruals for distribution assets in service.

The most likely retirement patterns and average service lives were developed based on the SPR analysis. This information was then analyzed for appropriateness and a curve and service life were selected for each account. (Refer to Exhibit A, SPR Results.)

The simulated plant method indicated that for the year ended December 31, 2006 the annual composite depreciation rate for distribution plant should be 3.69% and the depreciation reserve should be $33,278,723. The Corporation's present composite rate for distribution plant is 3.25% and the depreciation reserve for distribution plant per the books at December 31, 2006 was $28,496,721.

The Cooperative's total current annual depreciation expense accrual for distribution plant is $3,147,142. The proposed rates would yield an annual depreciation accrual of $3,616,908, or $469,766 more than the current rate.

Following is a summary of the proposed composite depreciation rates, current rates and the RUS recommended maximum and minimum rates for distribution plant:

Plant Account	Proposed Rate	Current Rate	RUS Low	RUS High
Distribution				
362 Substations	1.60%	1.53%	2.7	3.2
364 Poles Towers and Fixtures	4.31%	4.19%	3.0	4.0
365 O/H Conductor and Devices	3.59%	3.47%	2.3	2.8
366 Conduit	1.69%	1.77%	1.8	2.3
367 U/G Conductor and Devices	2.90%	3.19%	2.4	2.9
368 Line Transformers	5.31%	2.75%	2.6	3.1
369 Services	1.48%	2.23%	3.1	3.6
370 Meters	3.99%	4.34%	2.9	3.4
371 Installation on Customer's Premises	12.09%	6.42%	3.9	4.4
372 Leased Property	0.00%	10.00%	3.6	4.1
373 Street Lights	3.47%	1.44%	3.8	4.3

1. The "Proposed" rates are the rates determined from this depreciation study.

2. The "Current" rates are those currently in effect at the Corporation as of the date of this study. These rates were implemented January 1, 2001 resulting from the prior depreciation study conducted by RUS and KY20.

3. The RUS "High and Low" ranges of rates are those included in RUS Bulletin 183-1, Depreciation Rates and Procedures. As per the Bulletin, rates may be selected from within the range of rates without prior RUS approval. The bulletin, however, also provides for rates higher or lower than those in the range when supported by an RUS approved depreciation study.

As noted above, the whole-life technique was used for allocating the gross cost of plant over the estimated useful life. To the extent the previous estimates of average life, salvage, or cost of removal were incorrect, this would cause an imbalance in the accumulated depreciation reserve. The theoretical reserve balance was, therefore, compared to the actual recorded reserve balance. The reserve imbalance at December 31, 2006 was $4,782,002. The differences between the book reserves and the theoretical reserves are being amortized over the remaining useful life by functional groups. The amortization of the reserve imbalances over the remaining lives of the plant was included in the proposed depreciation rates. (Refer to Exhibit C, Comparison of Computer Calculated Depreciation Reserve to Actual Book Reserve, and Exhibit D, Computed Annual Depreciation Rate for Property Group.)

The study findings are based on many factors and assumptions that were discussed with the Corporation's personnel during our visit. Any changes in the assumptions could significantly impact the results of the study findings. In the future, as plant is added and retired and methods and technology change, appropriate revisions to the study findings may be necessary. The Corporation should consider the effects of such changes on an ongoing basis.

ANALYSIS OF DISTRIBUTION ACCOUNTS:

(Note: During the study it was necessary to merge accounts with minimal activity but with similar life characteristics in order to get statistically valid results. Such accounts are listed below with multiple descriptions following a single account number.)

Account 362 – Substations

The account has a plant balance of $12,008,367.10, which is 12.23% of total distribution plant as of December 31, 2006.

Using the simulated plant method with the Iowa curves, the average service life of assets within Account 362, Substations, is 42 years. The specific curve selection can be found in Exhibit A. The composite depreciation rate was calculated to be 1.60% compared to the current composite rate of 1.53%.

The proposed rate of 1.60% would yield a depreciation expense of $192,051.12. The current rate of 1.53% yields a depreciation expense of $183,728.02 for an increase in annual depreciation expense for this account of $8,323.10.

The estimated net salvage for this account is positive 27.38 percent. A positive net salvage is the result of the salvage value of retired assets exceeding the cost of removing them. The net salvage percentage was derived through an analysis of both gross salvage and cost of removal for a five-year period ending December 31, 2006. (See Exhibit B for complete details.)

Account 364 - Poles, Towers and Fixtures

The account has a plant balance of $28,486,552.14, which is 29.02% of total distribution plant as of December 31, 2006.

Description	Value	% of Account
364.1 Poles	$18,471,716.24	64.84%
364.2 Anchors & Guys	5,647,812.71	19.83%
364.3 Crossarms	4,367,023.19	15.33%
Totals	$28,486,552.14	100.00%

Using the simulated plant method with the Iowa curves, the average service life of assets within Account 364, Poles Towers and Fixtures, is 36 years. For this account, unit data for both poles and anchors & guys was utilized to obtain the optimization calculations. In addition, the dollar-unit basis was utilized to obtain optimization calculations for account 364 as a whole (which included poles, anchor guys, and crossarms.) Based on the results of these calculations, it was determined that the curve and life selection generated by the pole analysis on a unit basis yielded the most valid results. This curve and life was then applied to the entire account on a dollar basis. As noted above, the poles units constitute 64.84 percent of account 364. The anchor guy units, which represent 19.83 percent of the account, had a similar result to the poles. Therefore, the curve and life selection were applied to the overall account. The composite depreciation rate was calculated to be 4.31% compared to the current composite rate of 4.19%.

The proposed rate of 4.31% would yield a depreciation expense of $1,228,878.55.
The current rate of 4.19% yields a depreciation expense of $1,193,586.53 for an increase in annual depreciation expense for this account of $35,292.01.

The estimated net salvage for assets within this account is negative 49.17 percent. A negative salvage rate is the result of the cost of removal exceeding the salvage. The net salvage percentage was derived through an analysis of both gross salvage and cost of removal for a ten-year period ending December 31, 2006. The net salvage percentage was adjusted to reflect the effect of the FIFO vintage method of maintaining CPRs. (See Exhibit B for complete details.)

The Corporation had an unusual situation in 1989-1990 when it purchased and installed approximately 4,000 poles that were of a poor quality and had to be replaced within a very short period of time. Owing to this unusual one-time event, data for both dollars and units relative to these poles were deleted from both additions and retirements during 1991 through 1995 for purposes of the study.

Account 365 - Overhead Conductors and Devices

The account has a plant balance of $17,054,966.32, which is 17.37% of total distribution plant as of December 31, 2006.

Description	Value	% of Account
365.1 Copper wire	$145,453.44	0.85%
365.2 Aluminum wire	11,064,150.23	64.87%
365.3 Grounds	1,717,982.11	10.07%
365.4 Insulator strings	1,928,239.42	11.31%
365.5 Switches	1,317,229.37	7.72%
365.6 Cutouts and arresters	881,911.75	5.17%
Totals	$17,054,966.32	100.00%

Using the simulated plant method with the Iowa curves, the average service lives of assets within Account 365, Overhead Conductors and Devices, range from 25 years to 47 years. The specific curve selection for each account listed above can be found in Exhibit A. The composite depreciation rate was calculated to be 3.59% compared to the current composite rate of 3.47%.

The proposed rate of 3.59% would yield a depreciation expense of $612,166.89. The current rate of 3.47% yields a depreciation expense of $591,807.33 for an increase in annual depreciation expense for this account of $20,359.56.

The estimated net salvage for assets within this account is negative 33 percent. A negative salvage rate is the result of the cost of removal exceeding the salvage. The net salvage percentage was derived through an analysis of both gross salvage and cost of removal for a ten-year period ending December 31, 2006. The net salvage percentage was adjusted to reflect the effect of the FIFO vintage method of maintaining CPRs. (See Exhibit B for complete details.)

The Corporation serves approximately 28,000 customers and has approximately 3,000 miles of line which is a mixture of 1-phase and 3-phase. About 500 customers are added annually. The wire is predominantly ACSR as indicated by the above totals. The current work plan indicates that approximately 500 miles of copper wire and 500 miles of #4 ACSR will be replaced in the next 4 years.

Account 366 – Conduit

The account has a plant balance of $4,106,734.85, which is 4.18% of total distribution plant as of December 31, 2006.

Description	Value	% of Account
366.1 Conduit	$3,848,148.05	93.70%
366.2 Enclosures and covers	258,586.80	6.30%
Totals	$4,106,734.85	100.00%

Using the simulated plant method with the Iowa curves, the average service life of assets included in Account 366, Conduit, is 58 years. The specific curve selection for each account listed above can be found in Exhibit A. The composite depreciation rate was calculated to be 1.69% compared to the current composite rate of 1.77%

The proposed rate of 1.69% would yield a depreciation expense of $69,280.71. The current rate of 1.77% yields a depreciation expense of $72,689.21. This gives a decrease in depreciation expense for this account of $3,408.49 per year.

The net salvage for this account is negative 2.60%. A negative net salvage is the result of the cost of removal exceeding the salvage value of retired plant. The net salvage percentage was derived through an analysis of both gross salvage and cost of removal for a ten-year period ending December 31, 2006. The net salvage percentage was adjusted to reflect the effects of the FIFO vintage method of maintaining CPRs. (Refer to Exhibit B for an analysis of net salvage.)

Account 367 - Underground Conductors and Devices

The account has a plant balance of $9,423,486.53, which is 9.60% of total distribution plant as of December 31, 2006.

Description	Value	% of Account
367.1 Cable	$5,846,080.62	62.04%
367.2 Termination	1,748,371.48	18.55%
367.3 Switching Equipment	817,647.07	8.68%
367.4 Pads	1,011,367.36	10.73%
367.5 Conduit riser	0.00	0.00%
Totals	$9,423,466.53	100.00%

Using the simulated plant method with the Iowa curves, the average service lives of assets included in Account 367, Underground Conductors and Devices, range from 25 to 35 years. The specific curve selection for each account listed above can be found in Exhibit A. The composite depreciation rate was calculated to be 2.90% compared to the current composite rate of 3.19%

The proposed rate of 2.90% would yield a depreciation expense of $273,215.99. The current rate of 3.19% yields a depreciation expense of $300,608.58. This gives a decrease in depreciation expense for this account of $27,392.59 per year.

The net salvage for this account is negative 2.40%. A negative net salvage is the result of the cost of removal exceeding the salvage value of retired plant. The net salvage percentage was adjusted to reflect the effects of the FIFO vintage method of maintaining CPRs. (Refer to Exhibit B for an analysis of net salvage.)

The majority of the old specification (old spec) underground cable that has caused the Corporation problems has been replaced with new jacketed cable. Any remaining old spec cable will be replaced in the near future. At this time, the reserve appears to be sufficient to cover this replacement but should be monitored as the replacement program proceeds.

Account 367.5, conduit riser, balance was moved to account 366.

Account 368 - Line Transformers

This account has a plant balance of $15,623,839.04, which is 15.92% of total distribution plant as of December 31, 2006.

Description	Value	% of Account
368.1 Transformers	$13,329,066.81	85.31%
368.2 Cutouts and arresters	1,928,406.42	12.34%
368.3 Capacitors	62,176.06	0.40%
368.4 Regulators	304,189.75	1.95%
Totals	$15,623,839.04	100.00%

Using the simulated plant method with the Iowa curves, the average service life of assets in Account 368, Line Transformers, is 38 years. For purposes of the depreciation study, the model was run on this account entirely on a dollars basis. The specific curve selection for the account can be found in Exhibit A. The composite depreciation rate was calculated to be 5.31% compared to the current composite rate of 2.75%.

The proposed rate of 5.31% would yield a depreciation expense of $829,658.18. The current rate of 2.75% yields a depreciation expense of $429,655.57 for an increase in annual depreciation expense for this account of $400,002.61.

The estimated net salvage for this account is negative 58.49%. A negative net salvage rate is the result of the cost of removal exceeding the salvage value of retired plant. The net salvage percentage was adjusted to reflect the effects of the FIFO vintage method of maintaining CPRs. (Refer to Exhibit B for an analysis of net salvage.)

The Corporation accounts for the retirement of transformers differently than most rural electric cooperatives. As special equipment items, only the initial installation is capitalized. Subsequent retirements and installations are charged to expense. However, the Corporation records an entry transferring an amount from expense to the depreciation reserve when a transformer is permanently removed from service. Very few rural electric cooperatives record this journal entry. Although this entry results in a more proper accounting for the removal of plant, it does result in a substantially higher cost of removal and thus a higher net salvage percent. The higher net salvage percent results in much higher depreciation rates for this account.

The Corporation purchases line transformers using a least-loss evaluation criteria. An effort is being made to more efficiently manage transformer loading by changing out transformers that are over- or under-sized for their current load.

Account 369 - Services

The account has a plant balance of $6,468,810.85, which is 6.59% of total distribution plant as of December 31, 2006.

Description	Value	% of Account
369.1 Overhead Services	$1,643,334.31	25.40%
369.2 Underground Services	4,825,476.54	74.60%
Totals	$6,468,810.85	100.00%

Using the simulated plant method with the Iowa curves, the average service life of assets in Account 369, Services, is 40 years for overhead and 55 years for underground. The specific curve selection for each account listed above can be found in Exhibit A. The composite depreciation rate was calculated to be 1.48% compared to the current composite rate of 2.23%.

The proposed rate of 1.48% would yield a depreciation expense of $95,819.33. The current rate of 2.23% yields a depreciation expense of $144,254.48 for a decrease in annual depreciation expense for this account of $48,435.15.

The estimated net salvage is a negative 32.63% for the overhead service and 0% for underground services.. A negative net salvage rate is the result of the salvage value of retired plant being less than the cost of removal. Zero is used for underground since the cable is abandoned in the ground. (Refer to Exhibit B for an analysis of net salvage.)

Account 370 – Meters

The account has a plant balance of $2,934,243.34 which is 2.99% of total distribution plant as of December 31, 2006.

Description	Value	% of Account
370.1 Meters	$1,792,432.32	61.09%
370.2 Sockets	1,141,811.02	38.91%
Totals	$2,934,243.34	100.00%

Using the simulated plant method with the Iowa curves, the average service life of assets in this account is 28 years. The specific curve selection for the account can be found in Exhibit A. The composite depreciation rate was calculated to be 3.99% compared to the current composite rate of 4.34%.

The proposed rate of 3.99% would yield a depreciation expense of $117,020.39. The current rate of 4.34% yields a depreciation expense of $127,346.16 for a decrease in annual depreciation expense for this account of $10,325.77.

The estimated net salvage for this account is projected to be a negative 6.81%. Although meters are special equipment items that do not have a cost of removal charged to the depreciation reserve, a small amount is charged to the depreciation reserve for non special equipment items maintained in this account. Also, Corporation accounting for meters is similar to that of transformers in that an amount is transferred from expense to the depreciation reserve when a meter is retired for the final time. (Refer to Exhibit B for an analysis of net salvage.)

The Corporation is in the early stages of implementing an automatic meter reading system. The implementation of such a system could have a substantial impact on the depreciation rates for this account. This situation should be monitored very closely in the future and rates should be adjusted to reflect the implementation of the automatic meter reading system, if necessary.

Account 371 – Installation on Customer's Premises

The account has a balance of $1,484,793.67, which is 1.51% of total distribution plant as of December 31, 2006.

Description	Value	% of Account
371.1 Security lights	$1,399,605.27	94.30%
371.2 Generator	85,188.40	5.70%
	$1,484,793.67	100.00%

Using the simulated plant method with the Iowa curves, the average service life of the assets in this account is 24 years. The specific curve selection for this account can be found in Exhibit A. The composite depreciation rate was calculated to be 12.09% compared to the current composite rate of 6.42%.

The proposed rate of 12.09% would yield a depreciation expense of $179,450.43. The current rate of 6.42% yields a depreciation expense of $95,323.75 for an increase in annual depreciation expense for this account of $84,126.67.

The estimated net salvage for this account was determined to be negative 90.42%. This results from cost of removal of these items exceeding the salvage value of the retired items. The net salvage percentage was adjusted to reflect the effects of the FIFO vintage method of maintaining CPRs. (Refer to Exhibit B for an analysis of net salvage.)

This account includes only security lights installed on customers' premises and excludes the poles and wire associated with the security lights. The poles and wire are included in accounts 364 and 365, respectively. The security lights include both mercury vapor and high-pressure sodium with no problems being experienced with either type.

The generator included in this account is the one from account 372 in the prior study. This item was moved to this account during the current study period along with the related accumulated depreciation.

There is a substantial increase in the depreciation rate for this account. The net salvage study resulted in a much higher negative amount due to the fact that the price of the security lights for the vintages subsequent to 1989 are lower. The fact that the price of security lights has decreased over the years means that the net salvage percent will increase as these lower priced lights are retired.

Account 372 – Leased Property

This account has a balance of $1,047.60. The only items in this account are some temporary services. The depreciation reserve, per the Corporation's general ledger for this account, is a negative $101,973. This resulted from the retirement of temporary services which were previously included in this account. On Schedule C, this deficiency was taken from Account 369 since this account was significantly over-depreciated. The balances in this account for both plant and accumulated depreciation should be moved to account 369 and the related depreciation reserve. That will result in the balances for account 372 being zero.

Account 373 – Street Lights

The account has a plant balance of $558,137.96, which is .57% of total distribution plant as of December 31, 2006.

Description	Value	% of Account
373.1 Street lights	$558,137.96	100.00%

Using the simulated plant method with the Iowa curves, the average service life of assets in this account is 42 years. The specific curve selection for the account can be found in Exhibit A. The composite depreciation rate was calculated to be 3.47% compared to the current composite rate of 1.44%.

The proposed rate of 3.47% would yield a depreciation expense of $19,365.96. The current rate of 1.44% yields a depreciation expense of $8,037.19 for an increase in annual depreciation expense for this account of $11,328.78.

The estimated net salvage for this account is projected to be a negative 36.06%. A negative net salvage results when the cost of removing the plant exceeds the gross salvage of the retired plant. The net salvage percentage was adjusted to reflect the effects of the FIFO vintage method of maintaining CPRs. (Refer to Exhibit B for an analysis of net salvage.)

SPR Results

Account Number	Property Group Name	Analysis Method	Iowa Curve	Average Service Life Years	Composite Remaining Life	Net Salvage Value	Conformance Index	Retirement Exper. Index
Distribution Plant:								
362.1	Substations	S	L 0	42	34	27.38	37.52	73.80
364.1	Poles, Towers & Fixtures	S	L 0	36	28	(49.17)	14.82	81.92
365.1	Copper Wire	S	L 0	35	16	(33.00)	23.53	83.54
365.2	Aluminum Wire	S	L 1	47	30	(33.00)	10.57	63.90
365.3	Grounds	S	L 0	37	26	(33.00)	45.50	80.56
365.4	Insulator Strings	S	L 3	28	14	(33.00)	15.91	100.00
365.5	Switches	S	S 1.5	30	16	(33.00)	42.77	90.65
365.6	Cutouts and Arresters	J		25	15	(33.00)		
366.1	Conduit	S	S C	58	54	(2.60)	18.39	30.70
366.2	Covers	J	S C	58	53	(2.60)	0.37	20.30
367.1	Cable	S	S 1	35	25	(2.40)	107.87	58.13
367.2	Terminators	S	R 1	28	22	(2.40)	53.79	65.00
367.3	Switching Equipment	S	R 4	25	14	(2.40)	38.12	100.00
367.4	Pads	S	R 1	35	28	(2.40)	81.30	49.19
367.5	Conduit Risers	Moved to account 366.1, conduit						
368.1	Transformers	S	R 1.5	38	25	(58.49)	63.53	89.13
369.1	O/H Services	S	L 0	40	23	(32.63)	12.26	91.42
369.2	U/G Services	S	R 2.5	55	42	0.00	58.62	18.51
370.1	Meters	S	R 2.5	28	14	(6.81)	18.26	100.00
371.1	Security Lights	S	S C	24	14	(90.42)	13.45	94.80
372.1	Leased Property	Moved to account 371.1						
373.1	Street Lights	S	R 2	42	33	(36.06)	51.57	84.06

Net Salvage Study

The amounts used for net salvage percentages used in calculating depreciation rates for the Corporation were calculated as follows:

Account 362 used a historical analysis of the past 17 years to calculate a rate. Since account 362 is a substantially different account than the other distribution accounts a different methodology was used in calculating the net salvage rate. This methodology was consistent with that used in the prior depreciation study.

For the other distribution plant accounts, in order to adjust for the fact that the FIFO vintage method of maintaining CPRs used by the Corporation, items retired in 2006 were repriced at each of the vintages maintained in the CPRs. The net salvage percentage for each of the 19 vintages was then averaged to come up with the net salvage percentage used for this depreciation study.

The following schedule details the methodology for calculating the net salvage percentage for each account.

	Account 364 2006 retirements priced at vintage	Annual Net Salvage Percentage	Account 365 2006 retirements priced at vintage	Annual Net Salvage Percentage	Account 366 2006 retirements priced at vintage	Annual Net Salvage Percentage	Account 367 2006 retirements priced at vintage	Annual Net Salvage Percentage
1988	$158,282.52	-136.62%	$114,959.19	-62.63%	$468.16	-5.98%	$21,081.33	-1.95%
1989	374,098.17	-57.81%	168,786.42	-42.79%	1,214.40	-2.31%	13,961.28	-2.95%
1990	398,341.16	-54.29%	196,036.33	-36.84%	1,214.40	-2.31%	14,399.96	-2.86%
1991	404,228.18	-53.50%	191,632.81	-37.69%	1,214.40	-2.31%	14,633.60	-2.82%
1992	390,033.69	-55.44%	188,711.68	-38.27%	1,214.40	-2.31%	15,217.41	-2.71%
1993	492,895.03	-43.87%	212,729.49	-33.95%	1,214.40	-2.31%	15,058.38	-2.74%
1994	514,722.47	-42.01%	221,451.57	-32.62%	1,939.52	-1.44%	15,733.08	-2.62%
1995	448,405.07	-48.23%	178,580.53	-40.45%	1,682.56	-1.66%	17,688.37	-2.33%
1996	525,980.90	-41.11%	286,457.23	-25.21%	2,013.44	-1.39%	22,005.73	-1.87%
1997	461,682.01	-47.88%	248,675.96	-29.04%	6,392.32	-0.44%	19,881.79	-2.07%
1998	495,613.84	-43.63%	267,270.52	-28.07%	1,436.16	-1.95%	18,690.94	-2.20%
1999	494,267.65	-43.75%	241,305.47	-29.93%	894.08	-3.13%	18,486.54	-2.23%
2000	420,779.51	-51.39%	222,129.46	-32.52%	1,510.08	-1.85%	17,390.74	-2.37%
2001	507,777.49	-42.59%	233,233.30	-30.97%	1,112.32	-2.52%	16,458.53	-2.50%
2002	594,333.28	-36.39%	271,561.82	-26.60%	1,182.72	-2.37%	22,212.16	-1.85%
2003	650,214.16	-33.26%	302,624.45	-23.87%	343.55	-8.15%	23,181.13	-1.78%
2004	553,352.79	-39.08%	285,496.47	-25.30%	746.24	-3.75%	24,147.25	-1.71%
2005	572,355.51	-37.78%	273,992.13	-26.36%	1,175.68	-2.38%	21,913.37	-1.88%
2006	845,797.46	-25.57%	304,545.10	-23.72%	1,362.24	-2.06%	25,711.91	-1.60%
Average net salvage percentage		-49.17%		-33.00%		-2.60%		-2.40%
Cost of remo	235,163.00		122,912.00		87.00		10,523.00	
Salvage	18,913.00		50,685.00		59.00		10,111.00	
Net salvage	(216,250.00)		(72,227.00)		(28.00)		(412.00)	

	Account 368 2006 retirements priced at vintage	Annual Net Salvage Percentage	Account 369 2006 retirements priced at vintage	Annual Net Salvage Percentage	Account 370 2006 retirements priced at vintage	Annual Net Salvage Percentage	Account 371 2006 retirements priced at vintage	Annual Net Salvage Percentage	Account 373 2006 retirements priced at vintage	Annual Net Salvage Percentage
1988	$224,211.38	-68.60%	$8,660.90	-84.89%	$25,318.53	-12.64%	$24,102.96	-87.96%	$663.27	-27.74%
1989	245,535.74	-62.64%	19,183.72	-38.32%	43,912.29	-7.28%	19,833.56	-106.69%	663.27	-27.74%
1990	256,482.33	-59.97%	21,034.03	-34.95%	49,245.06	-6.50%	21,752.90	-97.46%	663.27	-27.74%
1991	262,302.76	-58.64%	19,937.60	-36.88%	47,901.68	-6.68%	22,109.80	-95.89%	663.27	-27.74%
1992	252,481.34	-60.92%	19,420.65	-37.86%	46,470.34	-6.88%	22,271.61	-95.19%	663.27	-27.74%
1993	261,790.90	-58.75%	23,689.51	-31.03%	48,294.60	-6.62%	23,199.39	-91.39%	663.27	-27.74%
1994	271,359.28	-56.68%	23,630.99	-31.11%	47,672.15	-6.71%	23,490.54	-90.25%	663.27	-27.74%
1995	257,314.66	-59.78%	23,032.98	-31.92%	41,079.93	-7.79%	22,216.57	-95.42%	412.89	-44.56%
1996	260,540.21	-59.04%	25,409.42	-28.93%	51,017.78	-6.27%	23,255.95	-91.16%	412.89	-44.56%
1997	257,493.58	-59.73%	25,462.98	-28.87%	49,034.04	-6.52%	24,036.12	-88.20%	412.89	-44.56%
1998	269,420.49	-57.09%	26,073.45	-28.20%	51,928.72	-6.16%	25,310.31	-83.76%	412.89	-44.56%
1999	263,714.18	-58.32%	25,537.23	-28.79%	42,696.93	-7.49%	23,947.99	-88.53%	412.89	-44.56%
2000	256,414.58	-59.98%	21,671.63	-33.92%	53,412.85	-5.99%	22,031.96	-96.22%	435.14	-42.29%
2001	267,167.02	-57.57%	26,670.78	-27.57%	56,238.17	-5.69%	22,664.25	-93.54%	435.14	-42.29%
2002	280,661.35	-54.80%	29,791.26	-24.66%	50,989.84	-6.27%	23,723.30	-89.36%	435.14	-42.29%
2003	271,902.17	-56.57%	30,785.12	-23.88%	49,283.40	-6.49%	26,837.13	-79.00%	435.14	-42.29%
2004	260,936.61	-58.95%	26,223.71	-28.04%	54,069.49	-5.92%	24,073.62	-88.06%	435.14	-42.29%
2005	271,684.16	-56.61%	33,199.36	-22.15%	57,076.65	-5.60%	25,025.08	-84.72%	638.44	-28.82%
2006	329,838.53	-46.63%	40,558.81	-18.13%	53,973.68	-5.93%	28,264.61	-75.01%	659.57	-27.90%
Average net salvage percentage		-58.49%		-32.63%		-6.81%		-90.42%		-36.06%
Cost of remo	177,255.00		20,947.00		3,244.00		23,615.00		184.00	
Salvage	23,445.00		13,595.00		45.00		2,415.00		0.00	
Net salvage	(153,810.00)		(7,352.00)		(3,199.00)		(21,200.00)		(184.00)	

Comparsion of Computer Calculated Depreciation Reserve (Including Net Salvage) to Actual Book Reserve

Account Number	Property Group Name	Computer Calculated Reserve	Actual Book Reserve	Difference Computer To Book	Composite Remaining Life	Amortization of Reserve (Excess)/Deficiency
Distribution Plant:						
362.1	Substations	$665,415.46	$1,264,923.01	($599,507.55)	34	($17,575.71)
364.1	Poles, Towers & Fixtures	11,996,242.93	10,628,841.71	1,367,401.22	28	48,506.61
365.1	Copper wire	367,803.41				
365.2	Aluminum Wire	3,847,741.10				
365.3	Grounds	328,413.72				
365.4	Insulator String	1,002,647.85				
365.5	Switches	772,564.54				
365.6	Cutouts and Arresters	282,211.52	5,642,593.18	958,788.96	26	36,881.02
366.1	Conduit	374,210.04				
366.2	Covers	83,425.24	652,016.38	(194,381.10)	54	(3,617.38)
367.1	Cable	1,012,152.18				
367.2	Terminators	386,572.11				
367.3	Switching Equipment	353,003.68				
367.4	Pads	136,045.06				
367.5	Conduit Risers	-	2,448,410.75	(560,637.72)	24	(23,819.85)
368.1	Transformers	8,165,323.95	3,610,938.32	4,554,385.63	25	179,731.08
369.1	O/H Services - Wire 1/	251,452.50				
369.2	U/G Services - Wire	370,749.42	2,313,895.09	(1,691,693.17)	37	(45,771.99)
370.1	Meters & Equipment	1,210,639.37	1,163,276.09	47,363.28	14	3,467.30
371.1	Lights	1,527,396.90	628,183.82	858,706.81	14	61,644.42
371.2	Generator 2/		40,506.27			
372.1	Leased Property 1/ 2/	-	-	0.00		
373.1	Street Lights	144,711.77	103,136.37	41,575.40	33	1,241.80
		$33,278,722.75	$28,496,720.99	$4,782,001.76		$240,687.29

1/ The actual accumulated provision for depreciation for Account 369, Services, amounted to $2,415,868.34 at 12/31/06. For purposes of this study, the negative accumulated provision for depreciation of $101,973.25 in Account 372, Leased Property on Customers' Premises, was reclassified to the accumulated provision for depreciation for Account 369. Also for purposes of this study, the $1,047.60 asset balance in Account 372 was reclassified to Account 369. Except for a standby generator (see 2/ below) located on a customer's premises, Account 372 was being used to account for temporary service assets. Thus, we elected to allocate the non-standby generator asset and negative accumulated depreciation balances in Account 372 to Account 369 for purposes of this study.

2/ The actual accumulated provision for depreciation for Account 371, Installations on Customer Premises, amounts to $668,690.09. Of this amount, $85,188.40 pertains to a standby generator installed on a customer's premises in December 1999 and the balance of the account represents the investment in security lights. In February 2005, the cost of the standby generator ($85,188.40) was reclassified from Account 372 to Account 371 and the associated accumulated depreciation ($30,023.84) was transferred from Account 108.672 to Account 108.671, respectively. An additional $10,482.43 of depreciation was accrued on the standby generator from February 2005 through December 2006 increasing the accumulated depreciation on the standby generator to $40,506.27. Using the current annual depreciation rate of 6.42% for all assets in Account 371, it will take slightly in excess of 8 years to fully depreciate the generator. Thus, the generator is expected to have a total estimated service life of 15 years.

Computed Annual Depreciation Rate for Property Group

Account Number	Account Title and Property Group	CPR Balance	Net Salvage	Computed Service Life	Depreciation Rate	Depreciation Expense	Amortization of Reserve (Excess)/Deficiency	Composite Rate
362.1	Substations	$12,008,367.10	27.38%	41.6	1.75%	$209,626.83	($17,575.71)	1.60%
364.1	Poles, Towers & Fixtures	28,486,552.14	-49.17%	36	4.14%	1,180,371.94	48,506.61	4.31%
365.1	Copper Wire	145,453.44	-33.00%	34.9	3.81%	5,543.07		
365.2	Aluminum Wire	11,064,150.23	-33.00%	47.4	2.81%	310,449.78		
365.3	Grounds	1,717,982.11	-33.00%	36.9	3.60%	61,921.85		
365.4	Insulator Strings	1,928,239.42	-33.00%	27.8	4.78%	92,250.30		
365.5	Switches	1,317,229.37	-33.00%	30.1	4.42%	58,203.16		
365.6	Cutouts and Arresters	881,911.75	-33.00%	25	5.32%	46,917.71		
	Subtotal Acct. 365	17,054,966.32				575,285.87	36,881.02	3.59%
366.1	Conduit	3,848,148.05	-2.60%	57.8	1.78%	68,307.96		
366.2	Covers	258,586.80	-2.60%	57.8	1.78%	4,590.14		
	Subtotal Acct. 366	4,106,734.85				72,898.10	(3,617.38)	1.69%
367.1	URD - Cable	5,846,080.63	-2.40%	35.3	2.90%	169,586.02		
367.2	Terminators	1,748,371.48	-2.40%	28	3.66%	63,940.44		
367.3	Switching Equipment	817,647.07	-2.40%	25	4.10%	33,490.82		
367.4	Arresters & Pads	1,011,367.36	-2.40%	34.5	2.97%	30,018.56		
367.5	Conduit Risers							
	Subtotal Acct. 367	9,423,466.54				297,035.84	(23,819.85)	2.90%
368.1	Transformers	15,623,839.04	-58.49%	38.1	4.16%	649,927.10	179,731.08	5.31%
369.1	O/H Services	1,643,334.31	-32.63%	40	3.32%	54,488.86		
369.2	U/G Services	4,825,476.54	0.00%	55.4	1.81%	87,102.46		
	Subtotal Acct. 369	6,468,810.85				141,591.32	(45,771.99)	1.48%
370.1	Meters	2,934,243.34	-6.81%	27.6	3.87%	113,553.09	3,467.30	3.99%
371.1	Security Lights	1,484,793.67	-90.42%	24	7.93%	117,806.00	61,644.42	12.09%
372.1	Leased Property	1,047.60	0.00%					
373.1	Street Lights	558,137.96	-36.06%	41.9	3.25%	18,124.16	1,241.80	3.47%
	Total Distribution Plant	$98,150,959.41				$3,376,220.26	$240,687.29	3.69%

Jackson Purchase Energy Corporation Exhibit E

SUMMARY OF REMAINING LIVES

Account Number	Account Title	Composite Remaining Life	Gross Investment	Rem. Life x Investment	Composite Rem. Life by Account
	Distribution Plant:				
362.1	Substations	34	$12,008,367.10	$409,605,401.78	34
364.1	Poles, Towers & Fixtures	28	28,486,552.14	803,035,904.83	28
365.1	Copper Wire	16	145,453.44	2,369,436.54	
365.2	Aluminum Wire	30	11,064,150.23	336,571,450.00	
365.3	Grounds	26	1,717,982.11	44,272,398.97	
365.4	Insulator Strings	14	1,928,239.42	26,146,926.54	
365.5	Switches	16	1,317,229.37	20,785,879.46	
365.6	Cutouts and Arresters	15	881,911.75	13,228,676.25	
	Total Account 365		17,054,966.32	443,374,767.75	26
366.5	Conduit	54	3,848,148.05	206,953,402.13	
366.6	Covers	53	258,586.80	13,723,201.48	
	Total Account 366		4,106,734.85	220,676,603.61	54
367.1	Cable	25	5,846,080.63	144,047,426.72	
367.2	Terminators	22	1,748,371.48	38,289,335.41	
367.3	Switching Equipment	14	817,647.07	11,201,764.86	
367.4	Pads	28	1,011,367.36	28,257,604.04	
367.5	Conduit Risers	0	0.00	0.00	
	Total Account 367		9,423,466.54	221,796,131.03	24
368.1	Transformers	25	15,623,839.04	395,908,081.27	25
369.1	O/H Services	23	1,643,334.31	37,714,522.41	
369.2	U/G Services	42	4,825,476.54	201,367,136.01	
	Total Account 369		6,468,810.85	239,081,658.43	37
370.1	Meters	14	2,934,243.34	40,081,764.02	14
371.1	Security Lights	14	1,484,793.67	20,683,175.82	14
372.1	Leased Property	0	1,047.60	0.00	-
373.1	Street Lights	33	558,137.96	18,686,458.90	33
	Total Distribution Plant		$98,150,959.41	$2,812,929,947.45	

Summary of Current & Proposed Depreciation Rates

Class and Title of Plant Account	Account Number	Depreciation Rate Current Rate	Depreciation Rate Proposed Rate	Annual Depreciation at Curr. Rate	Annual Depreciation at Prop. Rate	Difference
Distribution Plant:						
Substations	362.00	1.53%	1.60%	$183,728.02	$192,051.12	$8,323.10
Poles, Towers & Fixtures	364.00	4.19%	4.31%	1,193,586.53	1,228,878.55	35,292.01
OH Conductor & Devices	365.00	3.47%	3.59%	591,807.33	612,166.89	20,359.56
Conduit	366.00	1.77%	1.69%	72,689.21	69,280.71	(3,408.49)
URD Conductor & Devices	367.00	3.19%	2.90%	300,608.58	273,215.99	(27,392.59)
Transformers	368.00	2.75%	5.31%	429,655.57	829,658.18	400,002.61
Services	369.00	2.23%	1.48%	144,254.48	95,819.33	(48,435.15)
Meters	370.00	4.34%	3.99%	127,346.16	117,020.39	(10,325.77)
Installation Customer's Premises	371.00	6.42%	12.09%	95,323.75	179,450.43	84,126.67
Leased Property	372.00	10.00%	0.00%	104.76	0.00	(104.76)
Lights and Signal Systems	373.00	1.44%	3.47%	8,037.19	19,365.96	11,328.78
				$3,147,141.59	$3,616,907.55	$469,765.96

Schedule of Depreciable Property
As of December 31, 2006

Class and Title of Plant Account	Account Number	Account Balance	Depreciation Reserve Balance	Net Plant
Distribution Plant:				
Substations	362.00	$12,008,367.10	$1,264,923.01	$10,743,444.09
Poles, Towers & Fixtures	364.00	28,486,552.14	10,628,841.71	17,857,710.43
OH Conductor & Devices	365.00	17,054,966.32	5,642,593.18	11,412,373.14
Conduit	366.00	4,106,734.85	652,016.38	3,454,718.47
URD Conductor & Devices	367.00	9,423,466.54	2,448,410.75	6,975,055.79
Transformers	368.00	15,623,839.04	3,610,938.32	12,012,900.72
Services	369.00	6,468,810.85	2,415,868.34	4,052,942.51
Meters	370.00	2,934,243.34	1,163,276.09	1,770,967.25
Installation Customer's Premises	371.00	1,484,793.67	668,690.09	816,103.58
Leased Property	372.00	1,047.60	(101,973.25)	103,020.85
Lights and Signal Systems	373.00	558,137.96	103,136.37	455,001.59
		$98,150,959.41	$28,496,720.99	$69,654,238.42

COMMONWEALTH OF KENTUCKY

PUBLIC SERVICE COMMISSION

Case No. 2007-00116

**APPLICATION OF JACKSON PURCHASE)
ENERGY CORPORATION FOR AN)
ADJUSTMENT IN RATES)**

PREFILED TESTIMONY
OF
GARY C. STEPHENS
ON BEHALF OF
JACKSON PURCHASE ENERGY CORPORATION (JPEC)

Summary of Testimony

Mr. Stephens' prefiled testimony is to support the Allocated Cost of Service Study and the Proposed Rates.

Q. What is your name and business address?

A. My name is Gary C. Stephens. My business address is 2201 Cooperative Way, Herndon, Virginia 20171.

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

A. I am employed as a Senior Rate and Business Analyst with the National Rural Utilities Cooperative Finance Corporation (CFC). My areas of expertise include Rate-Related projects, Cost of Service and Regulatory Issues.

Q. What is your educational background and experience?

A. I received my BS degree in Business Administration from the University of Maryland and have continued my education through the National Rural Electric Cooperative Association (NRECA), American Public Power Association (APPA) and other energy-related organizations.

I have worked for CFC for over 21 years. I was instrumental in creating CFC's Cost of Service and the Unbundling Cost of Service computer models. I jointly developed and conduct CFC's Cost of Service Workshops and Unbundling Cost of Service Workshops. I have completed in excess of 90 specialized Cost of Service Studies for individual electric cooperatives across the country. I have also provided rate consulting in both wholesale and retail rate designs, and have created specialty rates for time-of-use, interruptible, load control and demand-side management. A more comprehensive description of my experiences can be found in Exhibit H, Witness – Gary C. Stephens, Attachment 1.

In addition, I have been involved in numerous regulatory issues, including filing testimony, and I have assisted in the preparation of written testimony for rate filings, streamlined filing procedures, and specialized rate issues.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support the Cost of Service Study that is included in this Jackson Purchase Energy Corporation (JPEC) filing and to support the proposed rates. I will also discuss a new rate for new Large Commercial customers.

Q. Why did you include two Cost of Service Studies in this filing?

A. There are two Cost of Services Studies because JPEC receives a credit from Big Rivers Electric Corporation (JPEC's power supplier) every year and JPEC passes this credit directly to the customers. The financial effect of this credit is correctly included in JPEC's annual financial statements as well as in the financial values used in this filing. Exhibit T-1 is the Cost of Service Study that is based on these financial values. However, JPEC believes that this credit will expire soon and desires to develop its proposed rates without the impact of the credit. Accordingly, Exhibit T is the Cost of Service Study that excludes the effect of the Big Rivers credit and is the study on which the proposed rates are based.

Q. What are the differences between the two Cost of Service Studies?

A. The only difference between the two Cost of Service Studies is that the study in Exhibit T excludes the impact of the credit by adding $798,990 to the existing revenues figure (thereby increasing the existing revenue figure to $38,195,363) and also adding $798,990 to the energy portion of the purchased power costs (thereby increasing the purchased power costs to $24,454,934). The $798,990 was the amount of the credit for 2006. There were no other changes to the financial data or to the assumptions.

Q. What impact did the increases in Existing Revenue and Power Costs have on the results of the Study?

A. As can be seen in Table 1 below, the only notable difference is that the overall proposed percent increase changes to 9.30% from 9.50%. This change is the direct result of increasing the existing revenue while maintaining the same dollar amount of increase.

Table 1

Results of the Two Cost of Service Studies

Classification	**With Credit (Dollars)**	**With Credit (Percent)**	**Without Credit (Dollars)**	**Without Credit (Percent)**
Residential	$26,485,563	11.56%	$26,961,963	11.19%
Sm Com 1 Ph	$1,882,378	13.90%	$1,914,180	13.40%
Sm Com 3 Ph	$304,732	0.69%	$310,830	0.56%
Lg Com-Existing	$1,807,464	6.97%	$1,856,345	7.56%
Com & Industrial	$9,451,259	3.20%	$9,675,552	3.44%
Outdoor Lighting	$1,019,041	19.52%	$1,030,557	18.35%
TOTAL	$40,950,437		$41,749,427	
Increase	$3,554,064	9.50%	$3,554,064	9.30%

Q. What method did you employ in preparing this Cost of Service Study?

A. The Cost of Service Study used in this filing is a fully distributed cost allocation based on a return on rate base study. The objective of the Cost of Service Study is to allocate fairly JPEC expense and rate base items to each class of service depending on their cost causation.

Q. How have you divided the members into classifications?

A. I divided the members based on JPEC's Rate Codes, as illustrated in Table 2. Through discussions with the staff at JPEC, it was decided that Rate Code 8R - Seasonal Power should be combined into Rate Code 3R - C & I (No Demand) since the cooperative intends to combine the two rate codes (this rate classification was renamed Small Commercial Three Phase). Staff also recommended that Rate Code 4 – Community Street Lights and Rate Code 5 – Security Lights be combined into one classification since their costs were essentially similar and because their associated expenses could not be isolated and assigned to one of the light-related classifications with a reasonable degree of certainty (this rate classification was renamed Outdoor Lighting). There were additional changes to the schedules and names used for the rate classifications as illustrated in Table 2.

Table 2

Rate Classifications

Code	Schedule	Title	New Schedule	New Title
1R	R	Residential	R	Residential
2R	C	Small Commercial	C-1	Small Com 1 Phase
3R	ND	C&I (No Demand)	C-3	Small Com 3 Phase
8R	SP	Seasonal Power	C-3	Small Com 3 Phase
7R	I	Industrial	I-E	Large Com – Existing
9R	D	Large Commercial	D	Commercial & Industrial (Less Than 3,000KW)
			L	Large Commercial (*)
4	CSL	Street Lights	OL	Outdoor Lighting
5		Security Lights	OL	Outdoor Lighting

(*) Proposed Schedule L Large Commercial is a new rate for new members. Since there are no members in this classification, it was not modeled in the Cost of Service Study.

Q. What test year did you use for this cost of service study?

A. The test year was the twelve months ended December 31, 2006, as established by JPEC for this proceeding. Adjustments were made for known and measurable changes. Most adjustments were developed by JPEC and will be supported by their testimony. Some rate base adjustments were developed by Mr. William K. Edwards, and those adjustments will be supported by his testimony.

Q. What is the source of your test year data?

A. Test year data came directly from JPEC, through spreadsheets and discussions with JPEC personnel.

Q. How are the Customer Allocation Factors developed?

A. The Customer Allocation Factors are based on the number of members in each rate classification. These allocation factors are used to allocate customer specific costs.

Q. How are the Weighted Customer Allocation Factors developed?

A. The Weighted Customer Allocation Factors are weighted based upon the number of members in each rate classification, the differences in the costs for the meters among the rate classifications, and the differences in the estimated costs of processing bills among the rate classifications.

Q. How did you develop the load data used in this Cost of Service Study?

A. JPEC provided the load data shown in Exhibit H, Witness - Gary C. Stephens, Attachment 2 and Attachment 3.

Q. How are the Demand Allocation Factors (identified in this Cost of Service Study as D1A and D1B) developed?

A. The Demand Allocation Factors are based on the estimated average monthly coincident demand adjusted for losses at the delivery point into the JPEC system for each rate classification. These demand values were provided by JPEC and are listed in Exhibit H, Witness - Gary C. Stephens, Attachment 2.

Q. How are the Primary Demand Allocation Factors (identified in this Cost of Service Study as D2A) developed?

A. The Primary Demand Allocation Factors are based on the average of the estimated coincident peak demands and the estimated non-coincident peak demands. These allocation factors are used to allocate the distribution plant related to the primary lines to the individual customer classifications. Typically, members taking service at higher voltage levels do not use any part of the lower voltage systems, and therefore are not assigned any of the costs of the lower voltage systems.

Q. How are the Secondary Demand Allocation Factors (identified in this Cost of Service Study as D3A and D4A) developed?

A. The Secondary Demand Allocation Factors are based on an estimate of the 12-month average of the non-coincident peak demands adjusted for losses at the delivery point into the JPEC system. These allocation factors are used to allocate the distribution plant related to the secondary lines to the customer classifications. These demand values were provided by JPEC and are listed in Exhibit H, Witness - Gary C. Stephens, Attachment 3.

Q. How are the Energy Allocation Factors (identified in this Cost of Service Study as E1A) developed?

A. The Energy Allocation Factors are based on the MWH adjusted for losses at the delivery point into the JPEC system for each rate classification. These MWH values were based on the MWH Sales provided by JPEC with a proportionate share of the line losses added to each rate classification, except for the Industrial classification, which was allocated zero line losses since it is metered at the substation. The calculations for determining the Energy Allocation Factors are illustrated in Exhibit H, Witness - Gary C. Stephens, Attachment 4.

Q. How were the wages and salaries spread?

A. The wages and salaries were spread between the distribution and general functions based upon the actual dollar amount of the wages and salaries that JPEC has booked to each function. This determination is detailed in Exhibit H, Witness - Gary C. Stephens, Attachment 5.

Q. How have you allocated the distribution plant?

A. Distribution plant was functionalized into Primary Demand, Secondary Demand, and Customer components.

Q. How did you determine the Customer component of the distribution plant?

A. The dollars associated with the Customer component were determined using the minimize size method. The minimum size method assumes that there is a minimum-size distribution system that is only capable of serving members the minimum requirements. Since the costs of this hypothetical system are driven by the number of members and not by demand, these costs are considered to be customer costs. In order to create the Customer Allocation Factor, I averaged together the individual minimum size allocation factors for poles, towers, and fixtures (Account 364), overhead conductor (Account 365), underground conduit (Account 366), underground conductor (Account 367), and transformers (Account 368). For JPEC, the minimum size allocation factor was 49.86%, so 49.86% of the distribution plant costs were functionalized to the Customer component. The calculation of the minimum size allocation factor is illustrated in Exhibit H, Witness - Gary C. Stephens, Attachment 6.

After the dollars associated with the Customer component of the distribution plant were determined, the dollars were allocated into the individual rate classifications based upon the weighted average number of members in each rate classification.

Q. How did you allocate the Primary Demand and Secondary Demand components of the distribution plant?

A. The dollars associated with the Primary Demand component and with the Secondary Demand component were allocated based on the number of miles of primary distribution line and the number of miles of secondary distribution line. The calculation is illustrated in Table 3, below:

Table 3

Primary Demand and Secondary Demand Allocation Factors

Distribution Line	Number of Miles	Percent of Total	Allocation Factor
Primary	2,064	72.30%	72.30%
Secondary	791	27.70%	27.70%
Total	2,855	100.00%	100.00%

Q. What were the results of your study?

A. The study confirms that JPEC should consider an overall rate increase of at least $3,554,064, which is a 9.30% increase over the test year revenue (without the Big Rivers discount, or 9.50% including the Big Rivers discount). In addition, the study indicated that the different rate classifications yielded different overall rates of return, which was neither surprising nor unique. The study also indicated that differing rate adjustments could be made to each rate classification. The complete Cost of Service Study is included in Exhibit T, while a summary of the results is in Table 4, below:

Table 4
Summary of Results from the Cost of Service Study

Classification	Existing Revenue	Cost Of Service Allocation	Difference (Dollars)	Difference (Percent)
Residential	$24,247,477	$26,961,963	$2,714,486	11.19%
Sm Com 1 Ph	$1,688,015	$1,914,180	$226,165	13.40%
Sm Com 3 Ph	$309,099	$310,830	$1,731	0.56%
Lg Com (Existing)	$1,725,798	$1,856,345	$130,547	7.56%
Com & Industrial	$9,354,175	$9,675,552	$321,377	3.44%
Outdoor Lighting	$870,799	$1,030,557	$159,758	18.35%
Total	$38,195,363	$41,749,427	$3,554,064	9.30%

PROPOSED RATES

Q. What were the basic goals underlying the proposed rates?

A. The proposed rates were designed to incorporate the following considerations:

1) The results of the Revenue Requirements Study;
2) The cost components of the Cost of Service Study;
3) Management's long-term goals;
4) The impact of the proposed rate changes on the members; and
5) Continuity in the rate structure.

Q. How does the overall increase produced by the proposed rates compare to the overall increase suggested in the Cost of Service Study?

A. The Cost of Service Study suggested that JPEC would need a rate increase of $3,554,064, which is a 9.30% increase over the existing revenue (excluding the effect of the Big Rivers credit), in order to produce the requested 2.00 Net TIER and 8.64% return on equity. The proposed rates are designed to produce an increase of $3,554,064, which is a 9.30% increase over the existing rates (excluding the effect of the Big Rivers credit).

Q. Please describe the results of the Cost of Service Study and the existing, cost based, and proposed rates for the Residential (Schedule R) tariff.

A. The Cost of Service Study suggested that the Residential rates could be increased by $2,714,486, which is an 11.19% increase. Instead, we are proposing an increase of $2,242,079, which is a 9.25% increase. The existing, cost based, and proposed rates are illustrated below in Table 5.

Table 5

Proposed Residential (Schedule R) Rates

Description	Existing Rate	Cost Based Rate	Proposed Rate
Facility Charge	$7.00	$26.77	$9.00
Energy Charge	$0.05729	$0.04947	$0.06252

Q. Please describe the results of the Cost of Service Study and the existing, cost based, and proposed rates for the Small Commercial Single Phase (Schedule C-1) tariff.

A. The Cost of Service Study suggested that the Small Commercial Single Phase rates could be increased by $226,165, which is a 13.40% increase. Instead, we are proposing an increase of $167,900, which is a 9.95% increase. The existing, cost based, and proposed rates are illustrated below in Table 6.

Table 6

Proposed Small Commercial Single Phase (Schedule C-1) Rates

Description	Existing Rate	Cost Based Rate	Proposed Rate
Facility Charge	$7.00	$26.51	$10.00
Energy Charge	$0.05883	$0.05015	$0.06365

Q. Please describe the results of the Cost of Service Study and the existing, cost based, and proposed rates for the Small Commercial Three Phase (Schedule C-3) tariff.

A. The Cost of Service Study suggested that the Small Commercial Three Phase rates could be increased by $1,731, which is a 0.56% increase. Instead, we are proposing an increase of $20,011, which is a 6.47% increase. The existing, cost based, and proposed rates are illustrated below in Table 7.

Table 7

Proposed Small Commercial Three Phase (Schedule C-3) Rates

Description	Existing Rate	Cost Based Rate	Proposed Rate
Facility Charge	$15.00	$28.52	$18.00
Energy Charge	$0.05583	$0.05142	$0.05980

Q. Please describe the results of the Cost of Service Study and the existing, cost based, and proposed rates for the Large Commercial – Existing (Schedule I-E) tariff.

A. The Cost of Service Study suggested that the Large Commercial - Existing rates could be increased by $130,547, which is a 7.56% increase. Instead, we are proposing an increase of $164,825, which is a 9.55% increase. We are also proposing the addition of a $300.00 per month service charge. The existing, cost based, and proposed rates are illustrated below in Table 8.

Table 8
Proposed Large Commercial – Existing (Schedule I-E) Rates

Description	Existing Rate	Cost Based Rate	Proposed Rate
Service Charge		$2,687.70	$300.00
Energy Charge	$0.01545	$0.01986	$0.01735
Demand Charge		$9.61	
First 3,000 KW	$10.48		$11.50
Additional KW	$10.48		$11.50

Q. Please describe the results of the Cost of Service Study and the existing, cost based, and proposed rates for the Commercial and Industrial Demand Less Than 3,000 KW (Schedule D) tariff.

A. The Cost of Service Study suggested that the Commercial and Industrial Demand Less Than 3,000 KW rates could be increased $321,377, which is a 3.44% increase. Instead, we are proposing an increase of $870,428, which is a 9.31% increase. The existing, cost based, and proposed rates are illustrated below in Table 9.

Table 9

Proposed Commercial and Industrial Demand Less than 3,000 KW (Schedule D) Rates

Description	Existing Rate	Cost Based Rate	Proposed Rate
Facility Charge	$25.00	$81.27	$35.00
Energy Charge		$0.02069	
First 200 KWH/KW	$0.03757		$0.03422
Next 200 KWH/KW	$0.03027		$0.02692
Next 200 KWH/KW	$0.02657		$0.02321
Over 600 KWH/KW	$0.02297		$0.01961
Demand Charge	$4.95	$7.73	$6.50

Q. Please describe the results of the Cost of Service Study and the existing, cost based, and proposed rates for the Outdoor Lighting (Schedule OL) tariff.

A. The Cost of Service Study suggested that the Outdoor Lighting rates could be increased by $159,758, which is an 18.35% increase. Instead, we are proposing an increase of $88,540, which is a 10.17% increase. The existing, cost based, and proposed rates are illustrated below in Table 10.

Table 10

Proposed Outdoor Lighting (Schedule OL) Rates

Description	Existing Rate	Cost Based Rate	Proposed Rate
Street Lights		$9.18	
175 w MV	$6.73		$7.53
400 w MV	$10.02		$11.22
100 w HPS	$6.73		$7.53
Energy	$0.03377		
Security Lights		$9.18	
175 w MV	$6.73		$7.53
100 w HPS	$6.73		$7.53
250 w HPS Flood	$9.43		$10.56
250 w HPS	$8.93		$10.00
175 w Metal Halide	$11.32		$12.67
400 w Metal Halide	$15.91		$17.82
400 w MV	$10.02		$11.22
1,000 w Metal Halide	$22.36		$25.04

Q. Please describe the design and purpose of the proposed new Large Commercial (Schedule L) tariff.

A. The proposed new Large Commercial tariff is designed to be similar to the existing Large Commercial (Schedule I-E) tariff but without the allowance for substation facilities. The existing and proposed Large Commercial (Schedule I-E) tariff allows for a substation investment of $11.00 per KW. Going forward, management at JPEC has indicated that they are interested in having new large commercial customers with a capacity of 3,000 to 10,000 KW 1) provide their own substation facilities, or 2) pay for any necessary investment through a contribution in aid of construction, or 3) pay for any necessary facilities through a negotiated monthly facility charge. Since the potential members in this tariff pay for their own substation and/or any other necessary investments, they should have a lower demand rate.

Q. How is the elimination of the substation investment allowance reflected in the proposed Large Commercial (Schedule L) tariff?

A. The $11.00 per KW allowance in the Large Power – Existing (Schedule I-E) tariff is incorporated in the demand charge. For the Large Power – Existing (Schedule I-E) tariff, approximately $0.20 of the demand charge supports the substation allowance. The $0.20 was determined by multiplying the $11.00 substation investment allowance by the 20% annual carrying costs and then dividing the product by 12 months. This calculation results in a cost of $0.18 cents per month, which is then rounded to $0.20. Therefore, the appropriate demand rate for the proposed new Large Commercial (Schedule L) tariff is $11.30 per KW (The proposed demand charge of $11.50 minus substation investment allowance of $0.20 equals the proposed demand charge of $11.30 for the Large Commercial (Schedule L) tariff).

Q. Are there any other differences between the Large Commercial – Existing (Schedule I-E) and the Large Commercial (Schedule L) tariffs?

A. No.

Q. What are the proposed rates for the Large Commercial (Schedule L) tariff?

A. The proposed rates are shown in Table 11 below.

Table 11

Proposed Large Commercial (Schedule L) Rates

Description	Existing Rate	Cost Based Rate	Proposed Rate
Service Charge			$300.00
Energy Charge			$0.01735
Demand Charge			
First 3,000 KW			$11.30
Additional KW			$11.30

Q. Does this conclude your testimony at this time?

A. Yes.

State of Virginia)
Fairfax County)

I, Gary C. Stephens, being duly sworn, deposes and says that the statements contained in the foregoing prepared testimony and the exhibits attached hereto are true and correct to the best of my knowledge, information and belief, and that such prepared testimony constitutes his sworn testimony in this proceeding.

Gary C. Stephens

SWORN TO AND ASCRIBED BEFORE ME THIS 6TH DAY OF NOVEMBER 2007, A.D.

Notary Public

My Commission Expires:

LEONARD LEO SKATOFF, JR.
Notary Public
Commonwealth of Virginia
My Commission Expires Apr 30, 2009

GARY C. STEPHENS

Mr. Stephens is a Business Consultant for the National Rural Utilities Cooperative Finance Corporation (CFC). He has over 21 years experience in the electric utility industry and his areas of expertise include Cost of Service and Rate-Related Projects, Regulatory Issues and Acquisitions.

PROFESSIONAL EXPERIENCE

Cost of Service and Rate-Related Projects – Mr. Stephens has extensive experience in Cost of Service and Rate-Related Projects. He was instrumental in creating CFC's Cost of Service and the Unbundling Cost of Service computer models. Mr. Stephens developed and conducts CFC's highly regarded Cost of Service Workshops and Unbundling Cost of Service Workshops. He has completed in excess of 90 specialized Cost of Service Studies for individual cooperatives across the country. Mr. Stephens has provided rate consulting in both wholesale and retail rate designs and has created specialty rates for time-of-use, interruptible, load control and demand-side management.

Following is a selection of workshops and presentations where Mr. Stephens developed unique cost of service studies:

- Accountants' Spring Conference (Iowa)
- Alabama Electric Cooperative
- Arkansas Electric Cooperative
- Hoosier Energy Rural Electric Cooperative (Indiana)
- Kentucky Association of Electric Cooperatives
- New Mexico Rural Electric Cooperative Association
- Pennsylvania Accountants' Meeting
- PNJ Management Association (Pennsylvania)
- Seminole Electric Cooperative (Florida)
- Oglethorpe Power Corporation (Georgia)
- Oregon Rural Electric Cooperative Association
- Old Dominion Electric Cooperative (Virginia)
- North Carolina Association of Electric Cooperatives
- Tennessee Electric Cooperative Association
- Wyoming Rural Electric Association
- Heartland Rural Electric Cooperative
- Valley Electric Association

Regulatory Issues – Mr. Stephens has been involved in numerous regulatory issues and has filed testimony as well as assisted in the preparation of written testimony for rate filings, streamlined filing procedures, specialized rate issues, territorial integrity and FERC filings. Mr. Stephens has continuously monitored the activities of the state commissions and his report on the Status of State Regulation has been widely used throughout the industry.

Acquisitions – Mr. Stephens has completed over 30 acquisition and feasibility studies on electric municipals, investor-owned utilities, propane companies, natural gas companies, water/wastewater systems, and telecommunication companies. His technical support includes an analysis of the contemplated business, financial feasibility of the consolidated entity and an integration analyses,

EDUCATION

Mr. Stephens holds a BS degree in Business Administration from the University of Maryland and has continued his education through NRECA, APPA and other energy-related organizations.

JPEC
Cost of Service Study for the Twelve Months Ended December 31, 2006
Determination of the Demand Allocation Factor
(Page 2, Line 13 of the Cost of Service Study)

Average Coincident KW Demand at Delivery Point into JPEC System:

Line No.	Month	Total	Residential	Sm Commercial (1 Phase)	Sm Commercial (3 Phase)	Lg Commercial (Existing)	Commercial and Industrial	Outdoor Lighting
1	January	109,266	67,504	4,283	779	4,767	30,435	1,498
2	February	125,681	81,843	5,058	842	6,865	31,073	0
3	March	96,503	60,798	3,778	678	5,170	24,687	1,393
4	April	98,728	58,146	4,015	807	4,952	30,808	0
5	May	127,166	68,103	5,497	1,329	8,073	44,164	0
6	June	143,748	82,193	5,828	1,463	6,077	48,186	0
7	July	154,145	94,464	6,277	1,332	7,335	44,738	0
8	August	150,779	98,677	6,151	1,281	5,525	39,145	0
9	September	111,133	69,686	4,789	924	7,103	28,631	0
10	October	110,768	62,623	4,959	894	4,330	37,962	0
11	November	100,406	57,389	4,350	806	3,578	34,283	0
12	December	131,476	84,211	5,504	1,028	4,795	34,046	1,892
13	Average	121,650	73,803	5,041	1,013	5,714	35,680	399
14	**Demand Allocation Factor**		60.668%	4.144%	0.833%	4.697%	29.330%	0.328%

Source: All demand values were provided by JPEC.

JPEC
Cost of Service Study for the Twelve Months Ended December 31, 2006
Determination of the Secondary Demand Allocation Factor
(Page 2, Lines 19 and 21 of the Cost of Service Study)

Average Non-Coincident Demand at Delivery Point into JPEC System

Line No.	Month	Total	Residential	Sm Commercial (1 Phase)	Sm Commercial (3 Phase)	Lg Commercial (Existing)	Commercial and Industrial	Outdoor Lighting
1	January	116,767	68,649	4,356	792	10,496	30,951	1,523
2	February	129,797	81,767	5,053	841	11,091	31,044	0
3	March	134,142	84,346	5,241	940	7,433	34,249	1,933
4	April	116,130	67,570	4,665	938	7,155	35,802	0
5	May	135,952	72,141	5,823	1,407	9,799	46,783	0
6	June	150,742	84,396	5,984	1,502	9,383	49,477	0
7	July	165,436	100,225	6,660	1,413	9,672	47,466	0
8	August	161,183	103,471	6,450	1,343	8,872	41,047	0
9	September	128,723	79,860	5,488	1,059	9,504	32,811	0
10	October	121,797	67,358	5,334	962	7,311	40,833	0
11	November	114,300	63,706	4,829	894	6,814	38,056	0
12	December	142,942	89,143	5,826	1,088	8,842	36,040	2,002
13	Average	134,826	80,219	5,476	1,098	8,864	38,713	455
14	**Secondary Demand Allocation Factor**		59.498%	4.061%	0.815%	6.575%	28.714%	0.337%

Source: All demand values were provided by JPEC.

JPEC

Cost of Service Study for the Twelve Months Ended December 31, 2006

Calculation of the Energy Allocation Factor

(Page 2, Line 23 of Cost of Service Study)

Line No.	Description	Total Company	Residential	Sm Commercial (1 Phase)	Sm Commercial (3 Phase)	Lg Commercial (Existing)	Commercial and Industrial	Outdoor Lighting
1	MWH Sales	638,496	379,715	25,348	4,861	40,619	178,774	9,180
2	MWH Sales for Line Loss Calculation	597,877	379,715	25,348	4,861	0	178,774	9,180
3	Percent of Total	100.00%	63.51%	4.24%	0.81%	0.00%	29.90%	1.54%
4	MWH Purchases (from Form 7)	663,944						
5	Less: MWH Sales	-638,496						
6	Line Losses to Allocate	25,448						
7	Allocated Line Losses	25,448	16,162	1,079	207	0	7,609	391
8	MWH Sales	638,496	379,715	25,348	4,861	40,619	178,774	9,180
9	Allocated Line Losses	25,448	16,162	1,079	207	0	7,609	391
10	MWH at Busbar	663,944	395,877	26,427	5,067	40,619	186,384	9,570

NOTE: The Industrial classification is metered at the substation, so no line losses were allocated to that classification.

JPEC

Cost of Service Study for the Twelve Months Ended December 31, 2006

Adjustment to Balance Revenue from Billing Determinants to Revenue in the Income Statement

(Page 3, Line 37 of Cost of Service Study in Exhibit T-1)

Line No.	Description	Total Company	Residential	Sm Commercial (1 Phase)	Sm Commercial (3 Phase)	Lg Commercial (Existing)	Commercial and Industrial	Outdoor Lighting
1	Revenue from Billing Determinants	$37,663,872	$23,910,072	$1,664,526	$304,798	$1,701,783	$9,224,012	$858,682
2	Percent of Total	100.00%	63.48%	4.42%	0.81%	4.52%	24.49%	2.28%
3	Revenue from Income Statement	$37,396,373						
4	Rev Adjusted to Match Inc Statement	$37,396,373	$23,740,256	$1,652,704	$302,633	$1,689,696	$9,158,500	$852,583

NOTE: These revenue values are used only in the Cost of Service in Exhibit T-1.

JPEC

Cost of Service Study for the Twelve Months Ended December 31, 2006

Adjustment to Remove the Credit Provided by Big Rivers

(Page 3, Line 37 of Cost of Service Study in Exhibit T)

Line No.	Description	Total Company	Residential	Sm Commercial (1 Phase)	Sm Commercial (3 Phase)	Lg Commercial (Existing)	Commercial and Industrial	Outdoor Lighting
1	Adjusted Revenue	$37,396,373	$23,740,256	$1,652,704	$302,633	$1,689,696	$9,158,500	$852,583
2	Adjusted Revenue	$37,396,373						
3	Removing the Credit from Big Rivers	$798,990						
4	Adjusted Revenue Without Credit	$38,195,363						
5	Adjusted Revenue Without Credit	$38,195,363	$24,247,477	$1,688,015	$309,099	$1,725,798	$9,354,175	$870,799

NOTE: These revenue values are used only in the Cost of Service in Exhibit T.

JPEC
Cost of Service Study for the Twelve Months Ended December 31, 2006
Functionalization of Wages and Salaries
(Page 3, Lines 27 through 31 of Cost of Service Study)

Allocation Factors

Line No.	Description	Amount	Allocation Factor
1	Total Distribution Plant	$98,386,830	93.47%
2	Total General & Headquarters Plant	$6,875,796	6.53%
3	Total Utility Plant in Service	$105,262,626	100.00%

Line No.	Acct	Description	Amount	Distribution-Related	General-Related
4	107.100	CWIP - Contractors	$22,268	$22,268	
5	107.200	CWIP - JPEC Crews	$1,178,969	$1,178,969	
6	108.664	Accum Depr - Poles, Towers, & Fixture	$8,357	$8,357	
7	108.800	Retire. WIP - JPEC Crews	$228,400	$228,400	
8	108.810	Retire. WIP - Contractors	$389	$389	
9	143.000	Other Accounts Receivable	$343	$343	
10	143.320	A/R - Winter Storm Assistance	$7,257	$7,257	
11	143.700	Other Accts Rec/Employee Cash Payments	$0	$0	
12	163.000	Stores Expense-Undistributed	$198,339	$198,339	
13	184.100	Transportation Expense/Clearing	$133,904	$133,904	
14	417.110	Customer Service Costs - Long Distance	$46	$46	
15	580.000	Operation Supervision & Engineering	$107,129	$107,129	
16	582.000	Station Expenses	$7,947	$7,947	
17	583.000	Overhead Line Expenses	$58,045	$58,045	
18	583.100	O/H Line Exp. - PCB Test & Inspection	$177	$177	
19	583.200	Overhead Line Expense - Line Patrol	$5,387	$5,387	
20	583.300	O/H Line Exp. - Oil SP Cleanup/100 Reg.	$281	$281	
21	584.000	Underground Line Expenses	$29,467	$29,467	
22	586.000	Meter Expenses	$48,648	$48,648	
23	586.100	Meter Exp. - Routine Conn. & Disconnects	$146,774	$146,774	
24	586.200	Meter Records - Prep. & Maint.	$1,002	$1,002	
25	587.000	Customer Installation Expenses	$1,924	$1,924	

JPEC
Cost of Service Study for the Twelve Months Ended December 31, 2006
Functionalization of Wages and Salaries
(Page 3, Lines 27 through 31 of Cost of Service Study)

Line No.	Acct	Description	Amount	Distribution-Related	General-Related
26	588.000	Misc. Dist. Expenses - Labor & O/H	$176,850	$176,850	
27	588.100	Misc. Dist. Exp - Office Supplies/Exp	$1,085	$1,085	
28	588.200	Other Miscellaneous Distribution Expense	$94,463	$94,463	
29	588.300	Misc. Distribution - Mapping Costs	$47,621	$47,621	
30	590.000	Maintenance Supervision & Engineering	$47,487	$47,487	
31	592.000	Maintenance of Station Equipment	$51,264	$51,264	
32	593.000	Maintenance of Overhead Lines	$483,535	$483,535	
33	593.000	Maint. Of Overhead lines - Storms	$19,154	$19,154	
34	594.000	Maintenance of Underground Lines	$59,268	$59,268	
35	596.000	Maintenance of Street Lights	$11,302	$11,302	
36	598.000	Maint of Misc Dist. Plant - Telephone Lines	$78,106	$78,106	
37	901.000	Supervision of Customer Accounts	$8,837	$8,260	$577
38	902.000	Meter Reading Expenses	$40,092	$37,473	$2,619
39	902.100	Meter Reading Expenses - System	$7,939	$7,420	$519
40	903.000	Customer Records & Collection Expense	$145,266	$135,777	$9,489
41	903.200	Cust Rcds & Collection - Complaints, Adj.	$48,284	$45,130	$3,154
42	903.300	Cust Rcds & Collection - Connects & Dis	$61,540	$57,520	$4,020
43	903.400	Cust Rcds & Collection - Delinquent Accts	$37,528	$35,077	$2,451
44	903.410	Delinquent Accts Over 30 Days	$103	$96	$7
45	903.500	Cust. Records - Document Scanning	$20,611	$19,265	$1,346
46	907.000	Customer Service - Supervision	$49,799	$46,546	$3,253
47	908.000	Customer Assistance Expenses	$38	$36	$2
48	910.000	Misc. Customer Svc & Information Exp.	$73,334	$68,544	$4,790
49	920.000	Administrative & General Salaries	$495,722	$463,341	$32,381
50	920.010	Admin. & General - Joint Use Salaries	$3,528	$3,298	$230
51	920.100	Admin. & General Salaries - Manager	$143,964	$134,560	$9,404
52	925.000	Injuries and Damages	$26,438	$24,711	$1,727
53	926.200	Other Employee Pensions & Benefit	$31,028	$29,001	$2,027
54	930.220	Annual Meeting Expenses	$5,845	$5,463	$382
55	930.230	News letter Expense	$11,322	$10,582	$740
56	935.000	Maintenance of G/P Expense	$39,999		$39,999
57	935.500	Maint of G/P - Miscellaneous	$542		$542
58		TOTAL	$4,506,947	$4,387,289	$119,658

JPEC

Cost of Service Study for the Twelve Months Ended December 31, 2006

Calculation of Distribution Plant - Consumer, Primary Line and Secondary Line Allocation Factors

(Page 4, Lines 7 through 9 of Cost of Service Study)

Minimum Size Determination - Poles, Towers, and Fixtures

Line No.	Account Number	Description	CPR Cost (as Dec 31, 2006)	Quantity	Unit Cost
1	364.425	25 FT POLE	$875,813.46	7,687	$113.934
2	364.430	30 FT POLE	$4,831,179.20	16,377	$294.998
3	364.435	35 FT POLE	$2,495,391.75	13,594	$183.566
4	364.440	40 FT POLE	$7,689,597.04	17,443	$440.841
5	364.445	45 FT POLE	$1,887,495.50	4,244	$444.744
6	364.450	50 FT POLE	$504,747.49	765	$659.801
7	364.451	50 FT STL POLE	$1,701.41	2	$850.705
8	364.455	55 FT POLE	$85,186.46	159	$535.764
9	364.460	60 FT POLE	$55,244.20	55	$1,004.440
10	364.465	65 FT POLE	$14,179.49	20	$708.975
11	364.470	70 FT POLE	$5,289.52	6	$881.587
12	364.475	75 FT UP	$25,093.14	5	$5,018.628
13		TOTAL	$18,470,918.66	60,357	

Calculation of the Consumer Allocation	
CPR Value (25 ft Pole)	$113.934
Quantity	60,357
Total	$6,876,714
Total	$6,876,714
Amount in Account 364	$28,486,552
Consumer Percent	24.14%

JPEC

Cost of Service Study for the Twelve Months Ended December 31, 2006

Calculation of Distribution Plant - Consumer, Primary Line and Secondary Line Allocation Factors

(Page 4, Lines 7 through 9 of Cost of Service Study)

Minimum Size Determination - Overhead Conductor

Line No.	Account Number	Description	CPR Cost (as Dec 31, 2006)	Quantity	Unit Cost
1	365.100	2/0 ACSR	$8,467.84	72,432	$0.117
2	365.101	4 ACSR	$436,935.13	3,156,223	$0.138
3	365.102	2 ACSR	$4,143,432.14	10,054,084	$0.412
4	365.103	1/0 ACSR	$840,072.16	3,557,498	$0.236
5	365.104	3/0 ACSR	$535,185.41	2,644,058	$0.202
6	365.105	4/0 ACSR	$333,622.94	857,695	$0.389
7	365.106	336.4 AAAC	$1,763,526.78	4,642,301	$0.380
8	365.107	397.5 AAAC	$22,882.68	36,786	$0.622
9	365.110	652.4 MCM	$61,226.09	51,559	$1.187
10	365.111	STD C	$6,129.94	31,345	$0.196
11	365.120	STATIC WIRE	$5,396.15	13,188	$0.409
12	365.123	CWC	$98,680.03	2,048,307	$0.048
13	365.129	4 TPX	$18,015.65	97,015	$0.186
14	365.130	# 6 DPX	$91,216.53	181,356	$0.503
15	365.131	2 TPX	$749,379.60	404,232	$1.854
16	365.132	1/0 TPX	$1,453,939.44	789,897	$1.841
17	365.133	2/0 TPX	$35,457.87	18,077	$1.961
18	365.134	3/0 TPX	$8,423.02	4,345	$1.939
19	365.135	4/0 TPX	$51,369.28	14,231	$3.610
20	365.136	336.4 TPX	$11,963.12	2,215	$5.401
21	365.142	2 QUAD	$75,210.85	4,157	$18.093

Calculation of the Consumer Allocation	
CPR Value (#6 DPX)	$0.503
Quantity	29,386,732
Total	$14,781,526
Total	$14,781,526
Amount in Account 365	$17,054,966
Consumer Percent	86.67%

JPEC

Cost of Service Study for the Twelve Months Ended December 31, 2006

Calculation of Distribution Plant - Consumer, Primary Line and Secondary Line Allocation Factors

(Page 4, Lines 7 through 9 of Cost of Service Study)

Minimum Size Determination - Overhead Conductor (continued)

Line No.	Account Number	Description	CPR Cost (as Dec 31, 2006)	Quantity	Unit Cost
22	365.143	1/0 QUAD	$105,084.35	10,978	$9.572
23	365.144	2/0 QUAD	$6,990.15	3,561	$1.963
24	365.145	3/0 QUAD	$1,731.90	1,430	$1.211
25	365.146	4/0 QUAD	$49,742.64	8,926	$5.573
26	365.147	336 MCM QUAD	$48,924.18	5,617	$8.710
27	365.150	8 WEATHERPR(	$19,575.32	263,168	$0.074
28	365.178	500 MCM ALUM	$3,070.08	1,185	$2.591
29	365.179	6 SOLID BARE (	$394.59	18,542	$0.021
30	365.180	6 HARD DRAWN	$8,998.74	176,073	$0.051
31	365.181	6 A STEEL	$41.55	2,393	$0.017
32	365.183	3 # 6 AWC	$6,237.12	18,559	$0.336
33	365.184	7 ALUM	$291.84	462	$0.632
34	365.200	12 TW	$87.72	1,000	$0.088
35	365.415	1/0 7 STR AERIA	$14,362.42	16,139	$0.890
36	365.416	252 AWA MSGR	$17,791.28	16,065	$1.107
37	365.417	336.4 AERIAL	$13,446.89	1,910	$7.040
38	365.419	397 AERIAL	$137,988.81	119,797	$1.152
39	365.425	052 AWA MSGR	$24,311.44	39,926	$0.609
40		TOTAL	$11,209,603.67	29,386,732	

JPEC

Cost of Service Study for the Twelve Months Ended December 31, 2006

Calculation of Distribution Plant - Consumer, Primary Line and Secondary Line Allocation Factors

(Page 4, Lines 7 through 9 of Cost of Service Study)

Minimum Size Determination - Underground Conduit

Line No.	Account Number	Description	CPR Cost (as Dec 31, 2006)	Quantity	Unit Cost
1	366.660	5" & UP	$785,896.75	104,848	$7.496
2	366.662	3/4"	$395.74	668	$0.592
3	366.663	1"	$930,945.68	36,507	$25.500
4	366.664	1 1/4"	$24.65	40	$0.616
5	366.665	1 1/2"	$2,083.45	720	$2.894
6	366.666	2"	$1,370,120.10	339,833	$4.032
7	366.667	3"	$15,561.63	10,372	$1.500
8	366.668	4"	$565,886.10	131,617	$4.299
9	366.825	2-2 1/2" POLYPI	$129,863.67	42,688	$3.042
10	366.840	4" POLYPIPE	$30,349.45	6,656	$4.560
11	366.860	6" POLYPIPE	$17,128.21	2,240	$7.647
12		TOTAL	$3,848,255.43	676,189	

Calculation of the Consumer Allocation	
CPR Value (1")	$3.862
Quantity	676,189
Total	$2,611,442
Total	$2,611,442
Amount in Account 366	$4,106,735
Consumer Percent	63.59%

NOTE: The underground conduit used in Account Number 369 was reviewed since there appeared to be an inconsistency in the CPR value for the 1" in Account Number 366. Since the value for the 1" in Account Number 369 appeared to be more reasonable, it was decided to use that CPR value in this calculation.

13	369.662	3/4"	$369.55	222	$1.665
14	369.663	1"	$23,062.55	5,971	$3.862
15	369.664	1 1/4"	$322.30	90	$3.581
16	369.665	1 1/2"	$498.77	140	$3.563
17	369.666	2"	$787,498.17	158,195	$4.978
18	369.667	3"	$43,070.98	23,869	$1.804
19	369.668	4"	$298,895.18	65,793	$4.543
20	369.840	4" POLYPIPE	$6,773.09	200	$33.865

JPEC

Cost of Service Study for the Twelve Months Ended December 31, 2006

Calculation of Distribution Plant - Consumer, Primary Line and Secondary Line Allocation Factors

(Page 4, Lines 7 through 9 of Cost of Service Study)

Minimum Size Determination - Underground Conductor

Line No.	Account Number	Description	CPR Cost (as Dec 31, 2006)	Quantity	Unit Cost
1	367.640	# 2 COPPER	$7,489.64	11,313	$0.662
2	367.641	1/0 ALUM	$2,146,436.89	1,103,585	$1.945
3	367.642	# 2 ALUM	$767,378.24	638,557	$1.202
4	367.643	750 ALUM	$42,388.67	3,261	$12.999
5	367.644	750 COPPER	$471.06	86	$5.477
6	367.645	4/0 ALUM	$175,473.10	71,954	$2.439
7	367.646	500 COPPER	$114,582.56	42,361	$2.705
8	367.647	500 ALUM	$1,259,438.72	135,183	$9.317
9	367.648	500 COPPER	$6,618.50	1,897	$3.489
10	367.651	# 1/0 TPX (URD)	$7,712.65	7,734	$0.997
11	367.652	2/0 TPX	$680.77	200	$3.404
12	367.654	4/0 TPX	$39,973.02	13,510	$2.959
13	367.656	350 TPX	$159,848.85	46,482	$3.439
14	367.657	1/0 QUAD	$272.37	92	$2.961
15	367.740	10/2 UF W/GRD	$2,430.82	1,495	$1.626
16	367.742	10/2 UF	$324.87	231	$1.406
17	367.743	8 UF	$5,519.66	3,009	$1.834
18	367.745	6 UF	$4,927.25	2,774	$1.776
19	367.746	# 6 DPX	$81,149.05	68,949	$1.177
20		TOTAL	$4,823,116.69	2,152,673	

Calculation of the Consumer Allocation	
CPR Value (#1/0 TPX)	$0.997
Quantity	2,152,673
Total	$2,146,215
Total	$2,146,215
Amount in Account 367	$9,423,467
Consumer Percent	22.78%

000666

JPEC

Cost of Service Study for the Twelve Months Ended December 31, 2006

Calculation of Dist Plant - Consumer, Primary Line & Secondary Line Allocation Factors

(Page 4, Lines 7 through 9 of Cost of Service Study)

Minimum Size Determination - Transformers

Line	Acct No.	Description	CPR Cost	Quantity	Unit Cost
1	368.917	1 KVA CONV	$55,939.85	115	$486.433
2	368.918	1.5 KVA CONV	$139,039.92	219	$634.885
3	368.924	10 KVA CONV	$2,455.79	3	$818.597
4	368.925	15 KVA CONV	$3,641,581.55	6,074	$599.536
5	368.926	25 KVA CONV	$1,854,831.43	2,822	$657.275
6	368.927	37.5 KVA CONV	$503,776.13	616	$817.818
7	368.928	50 KVA CONV	$344,615.04	393	$876.883
8	368.929	75 KVA CONV	$208,987.10	170	$1,229.336
9	368.930	100 KVA CONV	$149,778.89	107	$1,399.803
10	368.931	167 KVA CONV	$209,293.01	87	$2,405.667
11	368.932	250 KVA CONV	$146,105.23	49	$2,981.739
12	368.933	333 KVA CONV	$203,714.55	53	$3,843.671
13	368.934	500 KVA CONV	$90,062.60	18	$5,003.478
14	368.938	833 KVA CONV	$54,832.00	4	$13,708.000
15	368.951	5 KVA SP	$2,956.58	20	$147.829
16	368.953	10 KVA SP	$370,214.58	1,993	$185.757
17	368.954	15 KVA SP	$784,703.43	2,981	$263.235
18	368.955	25 KVA SP	$458,408.76	1,401	$327.201
19	368.956	37.5 KVA SP	$58,391.35	147	$397.220
20	368.973	25 KVA PDMT	$1,678,690.72	1,682	$998.033
21	368.974	37.5 KVA PDMT	$45,339.90	39	$1,162.562
22	368.975	50 KVA PDMT	$670,983.91	619	$1,083.980
23	368.976	75 KVA PDMT	$253,194.78	124	$2,041.893
24	368.977	100 KVA PDMT	$76,565.03	47	$1,629.043
25	368.978	150 KVA PDMT	$13,260.00	3	$4,420.000
26	368.979	167 KVA PDMT	$181,980.63	83	$2,192.538
27	368.980	112.5 KVA PDM	$84,532.16	23	$3,675.311

Calculation of the Consumer Allocation	
CPR Value (15 KVA Conv	$599.536
Quantity	20,037
Transformers / Customers	67.78%
Total	$8,142,105
Total	$8,142,105
Amount in Account 368	$15,623,839
Consumer Percent	52.11%

000667

JPEC

Cost of Service Study for the Twelve Months Ended December 31, 2006

Determination of the Distribution Plant Value

(Page 4, Lines 7 through 9 of Cost of Service Study)

Line No.	Account Number	Description	As of 12/31/05	As of 12/31/06	Average
1	360	Land & Land Rights	$223,945	$235,871	$229,908
2	362	Substations	$10,328,072	$12,008,367	$11,168,220
3	364	Poles Towers & Fixtures	$27,199,878	$28,486,552	$27,843,215
4	365	Overhead Conductors	$16,377,025	$17,054,966	$16,715,996
5	366	Underground Conduit	$3,813,594	$4,106,735	$3,960,164
6	367	Underground Conductors	$8,796,410	$9,423,467	$9,109,938
7	368	Transformers	$14,899,469	$15,623,839	$15,261,654
8	369	Service Entrants	$5,946,218	$6,468,811	$6,207,514
9	370	Meters	$2,824,069	$2,934,243	$2,879,156
10	371	Install On Cust Premises	$1,431,186	$1,484,794	$1,457,990
11	372	Leased Property	$1,048	$1,048	$1,048
12	373	Street Lighting	$530,852	$558,138	$544,495
13		TOTAL	$92,371,766	$98,386,830	$95,379,298

JPEC

Cost of Service Study for the Twelve Months Ended December 31, 2006

Determination of the General Plant Value

(Page 4, Lines 13 through 16 of Cost of Service Study)

Line No.	Account Number	Description	As of 12/31/05	As of 12/31/06	Average
1	389	Land & Land Rights	$86,866	$86,866	$86,866
2	390	Structures & Improve	$2,040,454	$2,047,039	$2,043,746
3	391	Office Equipment	$292,024	$292,326	$292,175
4	391.1	Office Equipment - Computer	$413,275	$322,290	$367,782
5	392	Transportation Equip	$1,825,870	$2,079,856	$1,952,863
6	392.1	Transportation Equip - Light Duty	$346,140	$375,930	$361,035
7	393	Stores Equipment	$79,008	$79,008	$79,008
8	394	Tools & Shop Equipment	$429,355	$451,976	$440,665
9	395	Lab Equipment	$167,198	$169,060	$168,129
10	396	Power Equipment	$282,543	$287,695	$285,119
11	397	Communication Equip	$540,789	$589,509	$565,149
12	398	Misc. Equipment	$94,163	$94,242	$94,202
13		TOTAL	$6,597,685	$6,875,795	$6,736,740

Cost of Service Study for the Twelve Months Ended December 31, 2006

Calculation of Distribution Plant - Consumer, Primary Line and Secondary Line Allocation Factors

Functionalization of the Accumulated Depreciation

ACCUMULATED DEPRECIATION - GENERAL PLANT-RELATED

(Page 5, Line 17 of Cost of Service Study)

Line	Account	Description	As of 12/31/05	As of 12/31/06	Average
1	108.710	Office & Furniture Equipment	$165,761	$177,198	$171,480
2	108.711	Computer Equipment	$330,311	$242,531	$286,421
3	108.715	Contra - Office Furniture	($12,425)	($9,940)	($11,182)
4	108.716	Contra - Computers	$83,107	$66,486	$74,796
5	108.720	Utility Transportation Equip	$886,929	$918,600	$902,764
6	108.721	Light Duty Transportation	$200,234	$223,423	$211,829
7	108.723	Contra - Transportation Equip	($301,499)	($241,081)	($271,290)
8	108.730	Structures & Improvements	$1,152,581	$1,203,593	$1,178,087
9	108.735	Contra - Structures & Improvements	$55,258	$44,207	$49,733
10	108.740	Shop Equipment	$289,731	$310,883	$300,307
11	108.745	Contra - Tools & Shop Equipment	($41,384)	($33,107)	($37,246)
12	108.750	Laboratory Equipment	$112,039	$121,303	$116,671
13	108.755	Contra - Laboratory Equipment	($10,258)	($8,207)	($9,232)
14	108.760	Communications Equipment	$192,461	$214,539	$203,500
15	108.765	Contra - Communications Equipment	($348,231)	($278,584)	($313,408)
16	108.770	Stores Equipment	$54,036	$57,258	$55,647
17	108.775	Contra - Stores Equipment	($5,142)	($4,114)	($4,628)
18	108.780	Miscellaneous Equipment	$52,059	$57,973	$55,016
19	108.785	Contra - Miscellaneous Equipment	($7,772)	($6,217)	($6,995)
20	108.790	Power Operated Equipment	$48,495	$48,826	$48,660
21	108.791	Power Equipment	$88,484	$111,970	$100,227
22	108.795	Contra - Power Operated Equipment	$22	$18	$20
23		Normalization Adjustment (Allocated)			$60,323
24		TOTAL	$2,984,797	$3,217,558	$3,161,500

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION

APPLICATION OF JACKSON PURCHASE ENERGY CORPORATION FOR AN ADJUSTMENT IN RATES	**)))**	**CASE No. 2007-00116**

PREFILED TESTIMONY
OF
TRACY A. BENSLEY
ON BEHALF OF
JACKSON PURCHASE ENERGY CORPORATION

Summary of Testimony

Mr. Bensley testifies to the effect of the proposed rates and Rules and Regulations on the operations of JPEC's distribution system.

Q1. State your name and business address.

A1. Tracy A. Bensley
2900 Irvin Cobb Drive
Paducah, KY 42003

Q2. Where are you employed?

A2. Jackson Purchase Energy Corporation ("JPEC").

Q3. In what capacity are you employed by JPEC?

A3. I am Vice President of Engineering and Operations.

Q4. What are the responsibilities and duties?

A4. I oversee engineering, construction of all of JPEC's substations and distribution lines, system maintenance crews, and warehouse operations.

Q5. How long have you been employed as Vice President?

A5. One year and ten months.

Q6. How long have you been an employee of JPEC?

A6. One year and ten months.

Q7. In what other capacities have you been employed by JPEC?

A7. None.

Q8. Briefly describe your educational background.

A8. I received a Bachelor of Science degree in Electrical Engineering from the Florida State University in 1991. I am a registered Professional Engineer in the States of Kentucky, North Carolina, and Virginia.

Q9. Are you a part of the management team that prepared the application and exhibits filed herein?

A9. Yes.

Q10. Describe the role you played in this preparation.

A10. As Vice President of Engineering and Operations for JPEC, I devoted my attention to matters pertaining to how the rates and Rules and Regulations would affect the operations of JPEC's distribution system.

Q11. What is the purpose of an "underground differential" fee?

A11. An underground differential fee prevents Members served by overhead facilities from subsidizing Members served by higher cost underground facilities.

Q12. What do JPEC's current Rules and Regulations require in regard to this fee?

A12. JPEC is currently charging the Applicant/Member for the difference in the cost of underground facility installations versus overhead facility installations based on the average cost differential per foot of installation for the prior year.

Q13. What changes have been proposed to the underground line extension portion of JPEC's Rules and Regulations?

A13. JPEC is requesting a change in its Rules and Regulations to require an Applicant/Member to install a conduit system for use in installing JPEC's conductor in lieu of charging the Applicant/Member with a differential fee.

Q14. Who will own the conduit system once installation is complete?

A14. JPEC will assume ownership upon completion.

Q15. What liability will the Applicant/Member installing the conduit system incur due to this proposed change?

A15. None. However, JPEC shall not accept ownership of the conduit system nor install conductor in it unless JPEC representatives have been allowed to inspect the entire installation prior to the backfilling of the trench. This inspection will be used to verify the system meets JPEC specifications and National Electrical Safety Code standards. Liability for the conduit system will be transferred to JPEC upon its completion and acceptance by JPEC.

Q16. What impact will this proposed change have on Applicants/Members wishing to have facilities on their property installed underground?

A16. This proposed change will have several positive impacts for the Applicant/Member requesting the underground extension.

First, the cost to the member in installing the conduit system is expected to be similar to or less than the underground differential cost charged by JPEC since trenching is already being performed at the Applicant/Member's facility. This change creates an advantage to the Applicant/Member of having only one trench dug on his/her property for installing underground utilities.

Also, the Applicant/Member could have the facilities installed more promptly due to installing the conduit system at their convenience. Scheduling multiple installations of utilities can be eliminated.

Finally, grading of the Applicant/Member's property can be performed more efficiently. By providing the Applicant/Member with control over the trench installation, he/she can better plan for final grading of the property upon completion of the conduit installation.

Q17. Are there other advantages associated with this proposed change?

A17. A fuel conservation element would be associated with this proposed change since contractor's equipment already on the job site could be used to install the conduit system for JPEC.

Q18. What impact will this proposed change have on the revenue of JPEC associated with the underground differential fee?

A18. The proposed change represents neither a significant revenue increase nor a significant revenue decrease to JPEC.

Q19. What operational impact will this proposed change have on the operations of JPEC?

A19. JPEC will realize advantages in not being responsible for the work load associated with the installation of the conduit system. Because the demand for underground facilities continues to increase in proportion to overall facility installations, having the Applicant/Member install the conduit system could postpone the addition of workforce required for underground installations. Also, since digging on the property would be reduced by installing multiple utilities in a single trench, JPEC would experience fewer "dig-ins" to its facilities during construction.

Q20. What impact will this proposed change have on Applicants/Members wishing to have facilities on their property installed or continue to remain overhead?

A20. I do not believe the proposed change will have any impact on Applicants/Members with overhead facilities.

Q21. Does this conclude your testimony?

A21. Yes.

The undersigned has prepared the foregoing direct testimony and swears that it is true and correct to the best of his knowledge and belief.

Tracy A. Bensley

STATE OF KENTUCKY

COUNTY OF McCRACKEN

The foregoing instrument was acknowledged before me this 28 day of November, 2007, by Tracy A. Bensley, Vice President of Engineering and Operations of Jackson Purchase Energy Corporation.

My commission expires April 9, 2011.

Stacie Jean Hatton

Notary Public, State at Large