COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

GENERAL ADJUSTMENT OF ELECTRIC RATES) CASE NO.
OF KENTUCKY POWER COMPANY) 2005-00341

NOTICE OF FILING AND CERTIFICATION OF SERVICE

I hereby give notice that, in accord with the Order of November 23, 2005, I have filed the original and eleven true copies of the foregoing with the Executive Director of the Kentucky Public Service Commission at 211 Sower Boulevard, Frankfort, Kentucky, 40601 this the 9th day of January, 2006, and certify that this same day I have served the parties by mailing a true copy, postage prepaid, to the following:

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COMMONWEALTH OF KENTUCKY
BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

GENERAL ADJUSTMENT IN	)	
ELECTRIC RATES OF	)	**CASE NO. 2005-00341**
KENTUCKY POWER COMPANY	)	

DIRECT TESTIMONY

AND EXHIBITS

OF

ROBERT J. HENKES

**ON BEHALF OF THE OFFICE OF RATE INTERVENTION
OF THE ATTORNEY GENERAL FOR
THE COMMONWEALTH OF KENTUCKY**

January 9, 2006

Kentucky Power Company
Case No. 2005-00341
Direct Testimony and Exhibits of Robert J. Henkes

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I. STATEMENT OF QUALIFICATIONS

Q. WOULD YOU STATE YOUR NAME AND ADDRESS?

A. My name is Robert J. Henkes, and my business address is 7 Sunset Road, Old Greenwich, Connecticut, 06870.

Q. WHAT IS YOUR PRESENT OCCUPATION?

A. I am Principal and founder of Henkes Consulting, a financial consulting firm that specializes in utility regulation.

Q. WHAT IS YOUR REGULATORY EXPERIENCE?

A. I have prepared and presented numerous testimonies in rate proceedings involving electric, gas, telephone, water and wastewater companies in jurisdictions nationwide including Arkansas, Delaware, District of Columbia, Georgia, Kentucky, Maryland, New Jersey, New Mexico, Pennsylvania, Vermont, the U.S. Virgin Islands, and before the Federal Energy Regulatory Commission. A complete listing of jurisdictions and rate proceedings in which I have been involved is provided in Appendix I attached to this testimony.

Q. WHAT OTHER PROFESSIONAL EXPERIENCE HAVE YOU HAD?

A. Prior to founding Henkes Consulting in 1999, I was a Principal of The Georgetown Consulting Group, Inc. for over 20 years. At Georgetown Consulting, I performed the same type of consulting services that I am currently rendering through Henkes Consulting. Prior to my association with Georgetown Consulting, I was employed by the American Can

Company as Manager of Financial Controls. Before joining the American Can Company, I was employed by the management consulting division of Touche Ross & Company (now Deloitte & Touche) for over six years. At Touche Ross, my experience, in addition to regulatory work, included numerous projects in a wide variety of industries and financial disciplines such as cash flow projections, bonding feasibility, capital and profit forecasting, and the design and implementation of accounting and budgetary reporting and control systems.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I hold a Bachelor degree in Management Science received from the Netherlands School of Business, The Netherlands in 1966; a Bachelor of Arts degree received from the University of Puget Sound, Tacoma, Washington in 1971; and an MBA degree in Finance received from Michigan State University, East Lansing, Michigan in 1973. I have also completed the CPA program of the New York University Graduate School of Business.

II. SCOPE AND PURPOSE OF TESTIMONY

Q. WHAT IS THE SCOPE AND PURPOSE OF YOUR TESTIMONY?

A. I was engaged by the Office of Rate Intervention of the Attorney General of Kentucky ("AG") to conduct a review and analysis and present testimony regarding the petition of Kentucky Power Company ("KPCo" or the "Company") for an increase in its base rates for electric service.

The purpose of this testimony is to present to the Kentucky Public Service Commission ("KPSC" or "the Commission") the appropriate capitalization, overall rate of return, rate base and pro forma operating income, as well as the appropriate revenue requirement for the Company in this proceeding.

In the determination of the recommended revenue requirement for KPCo in this proceeding, I have relied on and incorporated the recommendations of other AG witnesses as follows:

- Dr. J. Randall Woolridge, concerning the appropriate cost rates for long- and short-term debt, A/R financing and the return on equity rate for the Company in this proceeding;
- Mr. Michael J. Majoros, Jr., concerning the appropriate depreciation rates and annualized depreciation expenses to be reflected for ratemaking purposes in this proceeding; and
- Mr. David Brown Kinloch, concerning certain miscellaneous service charge revenue adjustments.

Q. WHAT INFORMATION HAVE YOU RELIED UPON IN THE DEVELOPMENT OF YOUR TESTIMONY?

A. In developing this testimony, I have reviewed and analyzed the Company's petition; testimonies, exhibits, workpapers and filing requirements; responses to AG, KIUC and KPSC initial and supplemental interrogatories; and other relevant financial documents and data.

III. SUMMARY OF FINDINGS AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS IN THIS CASE

A. The findings and conclusions reached by me in this case are as follows:

1. KPCo's appropriate jurisdictional capitalization in this case amounts to $845,760,172. This is $7,322,778 lower than the Company's proposed jurisdictional capitalization of $853,082,950 (Schedule RJH-1, line 1 and Schedule RJH-3).

2. The appropriate jurisdictional rate base for KPCo in this case amounts to $855,953,678 which is $2,490,082 lower than the Company's proposed jurisdictional rate base of $858,443,760 (Schedule RJH-4).

3. The appropriate overall rate of return on jurisdictional capitalization for KPC in this case is 6.81%. This recommended overall rate of return incorporates the capital cost rates recommended by the AG's expert rate of return witness, Dr. J. Randall Woolridge, including his recommended return on equity of 8.75%. This overall rate of return is equivalent to a rate of return of 6.73%[1] as measured based on the Company's jurisdictional rate base. (Schedule RJH-1, line 2 and Schedule RJH-2).

   By comparison, the Company has proposed an overall rate of return on jurisdictional

[1] Sch. RJH-1, line 3: $57,585,817 divided by rate base of $855,953,678 (Sch. RJH-4) = 6.73%.

capitalization of 7.89%, including a proposed return on equity of 11.50%, which is equivalent to a rate of return of 7.84%[2] as measured based on the Company's proposed jurisdictional rate base.

4. The appropriate pro forma test year net after-tax operating income amounts to $48,425,147, which is $20,018,492 higher than KPCo's proposed net after-tax operating income of $28,406,655 (Schedule RJH-1, line 4 and Schedule RJH-7).

5. The appropriate gross revenue conversion factor to be used for rate making purposes in this case is 1.6479. This recommended conversion factor, which incorporates a phased-down state income tax rate of 6.20%, is lower than KPCo's proposed conversion factor of 1.6656, which includes a state income tax rate of 7.20%. (Schedule RJH-1, line 6).

6. The application of the recommended overall rate of return of 6.81% to the recommended jurisdictional capitalization of $845,760,172, combined with the recommended pro forma test year operating income of $48,425,147 and the gross revenue conversion factor of 1.6479 indicates that the Company has the need for an annual rate increase of $15,095,832. This is $49,700,407 lower than the Company's proposed rate increase request of $64,796,239 (Schedule RJH-1, lines 1-7).

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[2] Sch. RJH-1, line 3: $67,308,245 divided by rate base of $858,443,760 (Sch. RJH-4) = 7.84%.

IV. REVENUE REQUIREMENT ISSUES

A. GROSS REVENUE CONVERSION FACTOR

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN THE COMPANY'S PROPOSED AND THE AG'S RECOMMENDED GROSS REVENUE CONVERSION FACTORS SHOWN ON SCHEDULE RJH-1, LINE 6.

A. As indicated in the first column of footnote (2) on Schedule RJH-1, the Company's proposed gross revenue conversion factor incorporates an effective state income tax rate of 7.20%. Section V, WP S-2, page 2 shows that this proposed state income tax rate consists of a Kentucky state income tax rate of 7.00% and a combined West Virginia and Ohio state income tax rate of approximately 0.20%. By contrast, the AG's recommended gross revenue conversion factor incorporates an effective phased-down Kentucky income tax rate of 6.20% and excludes the combined West Virginia and Ohio state income tax rate of approximately 0.20%.

The recommended phased-down Kentucky income tax rate of 6.20% was calculated by the Company in its response to AG-1-4. The reason for using this phased-down Kentucky income tax rate for ratemaking purposes in this case is discussed in a subsequent section of this testimony.

With regard to the exclusion of the combined West Virginia and Ohio state income tax rate of approximately 0.20%, I do not believe that an increase in KPCo's retail revenues will result in an associated increase in Ohio and West Virginia franchise taxes. In its response to KPSC-3-35, the Company confirms that,

> AEP system sales transactions are processed, contracted, and confirmed in Ohio.... Therefore, Kentucky Power is obligated to pay Ohio state franchise tax on the portion of its apportioned taxable income that relates to the system sales transactions.
>
> .... The presence of these [KPCo] workers in West Virginia creates nexus with the state, thereby obligating Kentucky Power to pay West Virginia state income tax on its West Virginia apportioned taxable income.

The Kentucky retail rate increase requested in this case will not increase the Ohio apportioned taxable income relating to system sales transactions or the West Virginia apportioned taxable income. On the contrary, as conceded by KPCo in its response to KIUC-2-5, the Kentucky retail rate increase requested in this case will actually result in a *decrease* in Ohio franchise tax "due to the lower apportionment caused by the increased [retail] revenues and income." For the foregoing reasons, I have removed the combined West Virginia and Ohio state income tax rate of approximately 0.20% from the gross revenue conversion factor.

B. OVERALL RATE OF RETURN

Q. PLEASE DESCRIBE THE AG'S RECOMMENDED OVERALL RATE OF RETURN.

A. As shown on Schedule RJH-2, the AG's recommended overall rate of return is 6.81%. This recommended rate of return was calculated based on my recommended capital structure and the capital cost rates and return on equity recommended by the AG's expert rate of return witness, Dr. J. Randall Woolridge. Dr. Woolridge has recommended a return on equity rate of 8.75%, an embedded cost of long-term debt rate of 5.70%, a short-term debt cost rate of 3.34%, and an Accounts Receivable (A/R) financing rate of 2.99%. These latter three capital cost rates are the same as those proposed by KPCo in this case. The derivation of my recommended capital structure is further detailed on Schedule RJH-3.

C. CAPITALIZATION

Q. PLEASE DESCRIBE THE METHODOLOGY USED BY THE COMPANY TO DETERMINE ITS PROPOSED JURISDICTIONAL CAPITALIZATION IN THIS CASE.

A. As shown in the first column of the top part of Schedule RJH-3, the starting point of the Company's proposed jurisdictional capitalization is KPCo's actual total company long-term and short-term debt, A/R financing and common equity balances for the test year ended June 30, 2005. The Company then added the capital associated with its proposed pro forma Big Sandy coal stock adjustment, pension equity contribution adjustment, and Reliability Program adjustment, and removed the capital associated with the Franklin Real Estate Company investment, the Carrs Site investment and its non-utility property.

Next, the Company applied a jurisdictional allocation factor of 99% to the adjusted total company capitalization in order to arrive at the adjusted jurisdictional capitalization. Finally, the Company added the jurisdictional Job Development Tax Credit ("JDTC") balance to arrive at its proposed adjusted jurisdictional capitalization.

Q. PLEASE DESCRIBE THE AG'S RECOMMENDED JURISDICTIONAL CAPITALIZATION IN THIS CASE.

A. The AG's recommended jurisdictional capitalization is shown in the bottom part of Schedule RJH-3. It has been calculated in a manner consistent with the previously described methodology proposed by KPCo and reflects two adjustments to the capitalization proposed by KPCo. The first adjustment concerns a reduced capital addition for the pro forma Big Sandy coal stock adjustment, as well as the removal of capital related to certain prepayments. This recommended adjustment is detailed in Schedule RJH-6 which will be discussed later in this testimony. The second adjustment concerns the removal of the Company's proposed capital addition for the Reliability Program. This adjustment is detailed in Schedule RJH-5 which will also be discussed later in this testimony.

In summary, the AG's recommended adjusted jurisdictional capitalization balance amounts to $845,760,172, which is $7,322.778 lower than the Company's proposed adjusted jurisdictional capitalization balance of $853,082,950.[1]

D. RATE BASE

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED AND THE AG'S RECOMMENDED JURISDICTIONAL NET RATE BASE INVESTMENT LEVELS

[1] Also, see Schedule RJH-1, line 1.

FOR THE TEST YEAR IN THIS CASE.

A. The Company's proposed jurisdictional rate base of $858,443,760 is summarized by specific rate base component in first column of Schedule RJH-4. As shown in the middle column of Schedule RJH-4, I have recommended five rate base adjustments involving the rate base components for utility plant in service, depreciation reserve, prepayments, materials and supplies, and accumulated deferred income taxes. These recommended rate base adjustments reduce the Company's proposed gas jurisdictional rate base by $2,490,082 to a recommended jurisdictional rate base level of $855,953,678. Each of the recommended rate base adjustments will be discussed in detail in the subsequent sections of this testimony.

- **Reliability Adjustment**

Q. **PLEASE EXPLAIN THE COMPANY'S PROPOSAL IN THIS CASE WITH REGARD TO ESTIMATED EXPENSES AND CAPITAL EXPENDITURES ASSOCIATED WITH THE PROPOSED VEGETATION MANAGEMENT PROGRAM.**

A. As discussed in the testimony of Company witness Phillips, in response to certain recommendations made in a 2003 Focused Management Audit, the Company in this case is proposing to increase capital expenditures and O&M expenses to improve its vegetation management program and maintain and improve its service reliability. In this regard, Mr. Phillips states on page 19 of his testimony:

The total cost of implementing this recommended cycle program is significantly

> above the levels in KPCo's historical expenditures and current test period. It is important for KPCo and our customers that the Commission approve recovery of the expenditures associated with KPCo's proposal to place its T&D system on a cycle-based vegetation management program to enable us to continue our work to maintain and improve transmission and distribution system reliability.

As shown in Section V, WP S-4, page 29, in order to implement this program the Company is proposing to charge the ratepayers with estimated incremental annual expenses of approximately $6.1 million and estimated additional investment expenditures of approximately $5.5 million. The estimated annual O&M expense amount of $6.1 million represents the 3-year average of the annual incremental expense amounts estimated for the next three years. The estimated investment expenditure of $5.5 million represents the 3-year average of the cumulative investment expenditures estimated to be made in the next three years.

Q. WILL THE COMPANY IMPLEMENT THIS PROGRAM AND INCUR THE ASSOCIATED O&M EXPENSES AND INVESTMENT EXPENDITURES WHETHER OR NOT THE COMMISSION APPROVES THE RATEMAKING TREATMENT PROPOSED BY THE COMPANY IN THIS CASE?

A. No. In its response to KPSC-3-30, the Company states that, "Kentucky Power will not implement the enhanced vegetation management programs described in Mr. Phillips testimony absent the ratemaking treatment proposed in this case."

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED RATEMAKING TREATMENT FOR THIS ISSUE?

A. No. I do not believe it is appropriate to require ratepayers to pay for projected annual O&M

expenses and investment expenditures extending three years beyond the end of the test year prior to the Company actually expending any funds for the program. Moreover, the Company's proposal is based on projected financial information for the next three years that cannot be considered known and measurable at this time.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO THIS ISSUE IN THIS CASE?

A. For the reasons discussed previously, I recommend that the Company's proposed ratemaking treatment associated with the vegetation management program be rejected by the Commission. Instead, KPCo should seek rate recovery from the Commission only *after* it has actually incurred the costs associated with the implementation of the program. This rate recovery should take place in accordance with traditional ratemaking principles in a future base rate review after a showing by the Company that the incremental program costs for which it is seeking rate recovery were prudently incurred.

As shown on Schedule RJH-5, my recommendation with regard to this issue decreases the Company's proposed jurisdictional rate base and capitalization by approximately $5.5 million and increases the Company's proposed test year operating income by approximately $3.7 million.

- **<u>Depreciation Reserve</u>**

Q. PLEASE EXPLAIN THE RECOMMENDED DEPRECIATION RESERVE

ADJUSTMENT SHOWN ON LINE 2 OF SCHEDULE RJH-4.

A. This adjustment is a direct "flow-through" result of the annualized depreciation expense adjustment discussed later in this testimony. As shown in more detail on schedule RJH-29, the adjustment reflects the pro forma impact on the Company's proposed test year jurisdictional per books depreciation reserve balance of the AG's recommended annualized depreciation expense adjustment. This recommended depreciation reserve adjustment is consistent with similar depreciation reserve adjustments adopted by the Commission in recent base rate proceedings involving other Kentucky gas and electric utilities. Consistent with previously established KPSC ratemaking policy, I have only reflected this depreciation reserve adjustment for purposes of determining the appropriate rate base and have not made a corresponding adjustment to the capitalization to be used for ratemaking purposes in this case.

- **Prepayments**

Q. PLEASE EXPLAIN THE DERIVATION OF THE RECOMMENDED PREPAYMENT BALANCE ADJUSTMENT OF $139,353 SHOWN ON SCHEDULE RJH-4, LINE 5.

A. As shown in more detail on Schedule RJH-6, lines 4 – 6, the recommended prepayment adjustment of $139,353 is the result of using a 13-month average test year per books prepayment balance as the starting point and removing from this starting point balance the 13-month average prepayment balances associated with KPSC assessments. Due to the fluctuations in the prepayment balance during the year, it is more appropriate to reflect a

13-month average test year prepayment balance rather than the test year-end prepayment balance proposed by KPCo. I removed the prepayment balance associated with KPSC assessments to reflect long-standing KPSC policy that such assessment balances are not considered to be prepayments.

Q. WHAT IS THE IMPACT OF THE RECOMMENDED PREPAYMENT ADJUSTMENT ON YOUR RECOMMENDED CAPITALIZATION SHOWN ON SCHEDULE RJH-3?

A. As shown on Schedule RJH-6, line 8, I have reduced the recommended capitalization for the removal of the prepayment balance associated with KPSC assessments. I have not made a capitalization adjustment for the difference between my recommended 13-month average test year prepayment balance and KPCo's proposed test year-end prepayment balance based on my understanding that the KPSC only makes this type of adjustment in determining the appropriate rate base, but not in determining the appropriate capitalization to be used for ratemaking purposes.

- **<u>Materials and Supplies</u>**

Q. PLEASE EXPLAIN THE DERIVATION OF THE RECOMMENDED MATERIALS AND SUPPLIES ("M&S") BALANCE ADJUSTMENT OF APPROXIMATELY $3.8 MILLION SHOWN ON SCHEDULE RJH-4, LINE 6.

A. As shown in more detail on Schedule RJH-6, lines 1 – 3, the recommended M&S adjustment of approximately $3.8 million is the result of using a 13-month average test year per books M&S balance and a pro forma Big Sandy coal stock adjustment that is smaller than KPCo's proposed Big Sandy coal stock adjustment. Due to the fluctuations in the M&S balance during the year, it is more appropriate to reflect a 13-month average test year M&S balance than the test year-end M&S balance proposed by KPCo. The recommended Big Sandy coal stock adjustment is further detailed on Schedule RJH-6A.

Q. PLEASE EXPLAIN THE RECOMMENDED BIG SANDY COAL STOCK ADJUSTMENT SHOWN ON SCHEDULE RJH-6A.

A. As shown in the first column of Schedule RJH-6A, the Company has proposed a pro forma Big Sandy coal stock balance of $13,809,600 based on a targeted 35 days of coal-supply-on-hand and an assumed average daily burn rate of 8,000 tons. While I take no exception to the targeted 35 days of coal supply on hand, I believe that an average daily burn rate of 7,048 tons should be used for purposes of calculating the appropriate pro forma Big Sandy coal stock balance to be used for ratemaking purposes in this case. KPCo states in response to AG-1-17b1 that "The daily burn rate of 8,000 tons is in accordance with the Coal Inventory Policy issued in September 2003." However, the same response also shows that during the 26-month period from September 2003 through October 2005,[2] the actual average daily burn rate has been 7,048 tons. I recommend that the pro forma coal stock balance in this case be calculated using this average daily burn rate as that has been KPCo's actual experience since it issued its Coal Inventory Policy in September 2003. The second column of Schedule RJH-6A shows that this recommendation results in a recommended total company coal stock balance adjustment of $1,949,495, which is $1,643,342 lower than

[2] The latest month for which actual results are available.

KPCo's proposed coal stock balance adjustment of $3,592,837.

Q. WHAT IS THE IMPACT OF THE RECOMMENDED M&S ADJUSTMENT ON YOUR RECOMMENDED CAPITALIZATION SHOWN ON SCHEDULE RJH-3?

A. As shown on Schedule RJH-6, line 7, I have included the recommended reduced Big Sandy coal stock adjustment balance as a pro forma adjustment to my recommended capitalization. I have not made a capitalization adjustment for the difference between my recommended 13-month average test year M&S balance and KPCo's proposed test year-end M&S balance based on my understanding that the KPSC only makes this type of adjustment in determining the appropriate rate base, but not in determining the appropriate capitalization to be used for ratemaking purposes.

- **Cash Working Capital**

Q. PLEASE DESCRIBE THE METHODOLOGY USED BY THE COMPANY TO DETERMINE ITS PROPOSED CASH WORKING CAPITAL, SHOWN ON SCHEDULE RJH-4, LINE 7.

A. The Company has proposed to calculate the cash working capital in this case based on the so-called "1/8th formula" method. This method assumes that 1/8th of the pro forma test year operation and maintenance expenses represents a reasonable cash working capital approximation. I believe that only a properly performed detailed lead/lag study would generate an accurate approximation of a utility's cash working capital. However, based on my review of the KPSC's previously allowed cash working capital rate treatment for this company and other Kentucky electric and gas utilities, it is my understanding that the Commission has consistently allowed cash working capital to be determined based on the 1/8th formula method. I have therefore chosen not to challenge this cash working capital calculation method in this case.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING THIS ISSUE?

A. Yes. While, at this time, I have not adjusted the Company's proposed cash working capital amount to reflect the cash working capital impact of all of the AG's recommended O&M expense adjustments, the appropriate cash working capital that should eventually be reflected for ratemaking purposes should be based on 1/8th of the Commission's allowed pro forma test year O&M expenses in this case.

- **Accumulated Deferred Income Taxes**

Q. PLEASE EXPLAIN THE REASON FOR THE RECOMMENDED ACCUMULATED DEFERRED INCOME TAX ADJUSTMENT SHOWN ON SCHEDULE RJH-4, LINE 11.

A. This recommended accumulated deferred income tax adjustment is a direct "flow-through" result of my recommended depreciation reserve adjustment reflected on Schedule RJH-4, line 2. The calculation for this recommended deferred tax adjustment is shown on Schedule RJH-29, line 11.

E. PRO FORMA OPERATING INCOME

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED AND THE AG'S RECOMMENDED TEST YEAR PRO FORMA NET AFTER-TAX OPERATING INCOME LEVELS.

A. The Company has proposed pro forma net after-tax operating income of $28,406,655 for the test year. On Schedule RJH-7, lines 2 through 26, I show that I have made numerous adjustments to the Company's proposed pro forma operating income. Each of these recommended net after-tax operating income adjustments will be discussed in the following sections of this testimony.

Schedule RJH-7, line 27 shows that, after considering all of the recommended pro forma operating income adjustments, the AG's recommended pro forma operating income for the test year amounts to $48,425,147.

- **Kentucky Income Tax Adjustment**

Q. PLEASE EXPLAIN THE RECOMMENDED OPERATING INCOME ADJUSTMENT FOR THE KENTUCKY INCOME TAX RATE REDUCTION, SHOWN ON SCHEDULE RJH-8.

A. As part of House Bill 272 that was passed by the Kentucky General Assembly and signed by the Governor on March 15, 2005, the Kentucky corporate income tax rate of 8.25% was reduced to 7.00% for the years 2005 and 2006 and will be further reduced to 6.00%

effective January 1, 2007. KPCo's proposed gross revenue conversion factor and pro forma adjusted test year income taxes in this case reflect a Kentucky income tax rate of 7.00%. In recognition of the fact that this tax rate will be phased down to 6.00% effective January 1, 2007, the Company, in its response to AG-1-4, calculated an effective phased-down tax rate of 6.20% and indicated that "we do not believe that a phase down factor would be inappropriate." I, too, believe it is appropriate to use this phased-down Kentucky income tax rate for ratemaking purposes in this case in order to reflect the reduced tax rate of 6.00% effective January 1, 2007. The use of the recommended phased-down Kentucky income tax rate of 6.20% changes the Company's proposed gross revenue conversion factor and pro forma adjusted income taxes in the following respects:

1. Decrease in the gross revenue conversion factor from 1.6656 to 1.6512.[3] The impact of this conversion factor reduction has been reflected on Schedule RJH-1, line 6;
2. Net increase of $98,263 in the Company's proposed pro forma adjusted test year state and federal income taxes.

The calculations for this latter recommended net income tax increase are shown on Schedule RJH-8, and the impact of this income tax adjustment on the Company's proposed test year operating income is shown on Schedule RJH-7, line 2.

- **<u>Reliability O&M Expense Adjustment</u>**

[3] The AG's recommended gross revenue conversion factor is further reduced from 1.6512 to 1.6479 (Sch. RJH-1, line 6) as a result of excluding the Ohio and West Virginia state franchise taxes.

Q. PLEASE EXPLAIN THE RECOMMENDED OPERATING INCOME ADJUSTMENT FOR RELIABILITY O&M EXPENSES, SHOWN ON SCHEDULE RJH-7, LINE 3.

A. The reason for this adjustment was discussed in an earlier (rate base) section of this testimony. The derivation of the operating income impact of this recommended O&M expense adjustment is shown on Schedule RJH-5, lines 7 – 14.

- <u>Interest Synchronization Adjustment</u>

Q. IN THE FIRST COLUMN OF SCHEDULE RJH-9 YOU HAVE SUMMARIZED THE COMPANY'S PROPOSED INTEREST SYNCHRONIZATION ADJUSTMENT. DO YOU AGREE WITH THIS PROPOSED ADJUSTMENT?

A. While I agree with the general methodology used by the Company to calculate its proposed interest synchronization adjustment, there are three adjustments that I recommend be made to the Company's proposed calculations. Two of the calculation adjustments, shown on Schedule RJH-9, lines 1 and 2, are merely "flow-through" adjustments resulting from the differences between the Company's proposed and the AG's recommended capitalization balances and weighted cost of debt rates. The third adjustment, shown on lines 3 and 6, is to correct for the fact that the Company did not consider Accounts Receivable ("A/R") financing interest cost in the interest synchronization adjustment calculation. In its response to AG-1-19, the Company conceded that this was an inadvertent oversight and included a corrected interest synchronization adjustment calculation that recognized A/R financing cost as tax-deductible interest. My recommended adjustments on lines 3 and 6 of

Schedule RJH-9 have been derived from the Company's proposed corrected interest synchronization adjustment calculation in the response to AG-1-19.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDED INTEREST SYNCHRONIZATION ADJUSTMENTS ON THE COMPANY'S PROPOSED TEST YEAR OPERATING INCOME?

A. As shown on Schedule RJH-9, lines 7 – 9, my recommended adjustments decrease the Company's proposed test year jurisdictional operating income by $52,820

- **Operation & Maintenance Expense Ratio Adjustment**

Q. WHAT ARE THE ACTUAL PAYROLL COSTS BOOKED BY THE COMPANY FOR THE TEST YEAR AND WHAT PORTION OF THESE PAYROLL COSTS WAS CHARGED TO THE COMPANY'S O&M EXPENSES?

A. The Company's actual payroll costs for the test year amount to $29,767,000, of which $18,606,916 was charged to O&M expense.[4] This equates to a payroll O&M expense ratio of 62.51%.[5] This payroll distribution for the test year, as well as for all years prior to the test year, is in accordance with FERC and Uniform System of Accounts (USOA) reporting requirements,[6] is reported annually to the KPSC in the Company's FERC Form 1 Report, and has been reported to the Commission in this case for the test year and the historic years 2002 through 2004 in the Company's response to KPSC-1-23c, page 17.

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4 Response to KPSC-1-23c, page 17, lines 9-13 and response to AG-1-26b, page 4.
5 $18,606.916 / $29,767,000 = 62.51%.
6 See response to AG-2-6d.

Q. HAS THE COMPANY USED THIS TEST YEAR PAYROLL DISTRIBUTION FOR RATEMAKING PURPOSES IN THIS CASE?

A, No. As shown on Section V, WP S-7, pages 3 and 4, for ratemaking purposes in this case, the Company has proposed that of the actual test year payroll cost of $29,767,000 an amount of $20,137,863 is chargeable to O&M expense. This equates to a payroll O&M ratio of 67.65%[7] and results in a test year payroll O&M expense number that is $1,530,947 higher than the test year payroll O&M expense actually reported in accordance with FERC and the USOA, and reported to the KPSC in the FERC Form 1 Report.

Q. WHAT IS THE REASON FOR THE DIFFERENCE BETWEEN THE TEST YEAR PAYROLL O&M EXPENSE OF $18,606,916, DETERMINED AND REPORTED IN ACCORDANCE WITH FERC AND USOA ACCOUNTING REQUIREMENTS, AND THE TEST YEAR PAYROLL O&M EXPENSE OF $20,137,863 USED BY THE COMPANY FOR RATEMAKING PURPOSES IN THIS CASE?

A. Under FERC and USOA reporting requirements, payroll amounts initially charged to "Other Accounts" 163 (stores expense undistributed) and 184 (clearing accounts) are eventually cleared to O&M, Construction, and Plant Removal.[8] The payroll expenses charged to the remaining "Other Accounts," including accounts 152 (fuel stock expense undistributed), 186 (miscellaneous deferred debits), 188 (Research & Development) and 242 (miscellaneous current & accrued liabilities) are *not* cleared to O&M, Construction,

[7] $20,137,863 / $29,767,000 = 67.65%.
[8] Responses to AG-1-26b, page 4; AG-1-26c; and AG-2-6a.

and Plant Removal. Rather, they remain payroll expenses in "Other Accounts" (as opposed to O&M Accounts) in the reporting to FERC and the KPSC of the Company's annual payroll distribution and in the determination of the annual payroll O&M expense ratio.

However, for ratemaking purposes in this case, the Company has not only cleared to O&M expenses payroll amounts initially charged to accounts 163 and 184, it has also assumed that 100% of the payroll amounts charged to "Other Accounts" 152, 186, 188, and 242 are cleared to O&M expenses. In this regard, the Company states in its response to AG-2-6a:

> For ratemaking purposes the Company recognizes that a portion[9] of the payroll amounts originally charged to accounts 152, 186, 188 and 242, in addition to accounts 163 and 184, are cleared to O&M expense accounts. For ratemaking purposes, O&M payroll would be understated if payroll amounts charged to accounts 152, 186, 188 and 242 were not allocated to O&M.

I disagree with the Company's proposed approach (that added $1,530,947 to its test year payroll O&M expenses). I also disagree with the Company's statement that "O&M payroll would be understated if payroll amounts charged to accounts 152, 186, 188 and 242 were not allocated to O&M." The fact is that payroll amounts charged to "Other Accounts" 152, 186, 188 and 242 are *not* allocated to O&M under KPSC, FERC and USOA reporting requirements, and it would be wrong to assume for ratemaking purposes that 100% of the payroll amounts in these "Other Accounts" are allocable to O&M expense.

Q. BASED ON THE PREVIOUSLY DISCUSSED FINDINGS AND CONCLUSIONS,

[9] It should be noted that this statement is incorrect. The Company did not allocate a *portion* of the payroll amounts originally charged to accounts 152, 186, 188 and 242 to O&M expense. Rather, it allocated *100%* of the payroll amounts originally charged to accounts 152, 186, 188 and 242 to O&M expense.

WHAT ARE YOUR RECOMMENDATIONS WITH REGARD TO THE ISSUE IN THIS CASE?

A. First, I recommend that KPCo's proposed unadjusted test year payroll O&M expenses of $20,137,863 be reduced to $18,606,916 to reflect the appropriate level of actual test year payroll O&M expenses in accordance with KPSC, FERC and USOA reporting requirements.

Second, I recommend that the Company's proposed payroll O&M ratio of 67.65% be reduced to 62.51%, again, to reflect the appropriate actual test year payroll O&M expense ratio determined in accordance with KPSC, FERC and USOA reporting requirements.

Third, I recommend that all of the Company's proposed pro forma test year expense adjustments that use the Company's proposed payroll O&M ratio of 67.65% be re-calculated based on my recommended test year payroll O&M ratio of 62.51%. As shown on Schedule RJH-10, lines 4 – 15, this would involve the re-calculation of the Company's proposed pro forma adjustments for payroll, employee benefits, savings plan and FICA.

Q. WHAT IS THE IMPACT OF THESE RECOMMENDATIONS ON THE COMPANY'S PROPOSED TEST YEAR OPERATING INCOME?

A. As shown on Schedule RJH-10, my recommendations increase the Company's proposed test year operating income by $984,793.

- <u>Incentive Compensation Expense Adjustment</u>

Q. ARE KPCo EMPLOYEES ELIGIBLE FOR INCENTIVE COMPENSATION PLANS?

A. Yes. KPCo's employees are eligible for three incentive compensation plans: (1) the Incentive Compensation Plan (which is separated into several functional areas such as generation, energy delivery, general services), (2) the Safety Focus Plan, and (3) the Long Term Incentive Plan ("LTIP").

Q. ARE THE AWARDS PAID OUT UNDER THESE INCENTIVE COMPENSATION PLANS ENTIRELY OR PARTIALLY A FUNCTION OF THE ACHIEVEMENT OF CORPORATE FINANCIAL PERFORMANCE GOALS?

A. Yes, 100% of the LTIP is based on corporate financial performance in the form of AEP's Earnings Per Share and Total Shareholder Return and 25% of the Incentive Compensation Plan is based on corporate financial performance in the form of AEP's Earnings Per Share.

Q. HAS THIS COMMISSION PREVIOUSLY DISALLOWED FOR RATEMAKING PURPOSES INCENTIVE COMPENSATION THAT IS A FUNCTION OF CORPORATE FINANCIAL PERFORMANCE GOALS?

A. Yes. In Union Light Heat & Power Company's ("ULH&P") most recent base rate case, Case No. 2005-00042, the Commission disallowed 100% of that utility's LTIP incentive compensation that was entirely based on Total Shareholder Return performance. The Commission also disallowed portions of ULH&P's AIP incentive compensation program to the extent that the AIP program was based on corporate financial performance goals. In the three ULH&P base rate cases[10] prior to the most recent Case No. 2005-00042, the Commission disallowed 100% of ULH&P's incentive compensation expenses based on its finding, among other things, that the corporate performance goals in ULH&P's incentive compensation plan placed more weight on the interest of shareholders than customers. In addition, while the AG in Kentucky American Water Company's ("KAWC") most recent rate case, Case No. 2004-00103, recommended the disallowance of 60% of KAWC's incentive compensation (representing the portion of KAWC's incentive compensation program that was a function of the achievement of corporate financial performance goals), the Commission went further and disallowed 100% of KAWC's incentive compensation expenses.

Q. DO YOU AGREE WITH THE COMMISSION'S RATEMAKING POLICY THAT INCENTIVE COMPENSATION EXPENSES THAT ARE A FUNCTION OF CORPORATE FINANCIAL PERFORMANCE GOALS SHOULD BE CHARGED TO THE SHAREHOLDERS RATHER THAN THE RATEPAYERS?

A. Yes. Stockholders are the primary beneficiaries of the achievement of corporate financial performance goals such as Total Stockholder Return, Earnings Per Share, or corporate Net Income. To the extent that a utility's incentive compensation expenses are a function of the achievement of these corporate financial performance goals, the stockholder, as the primary beneficiary, should be made responsible for these expenses.

[10] Case Nos. 2001-092, 92-346 and 91-370.

Q. DO YOU RECOMMEND THAT THE PORTIONS OF KPCo's INCENTIVE COMPENSATION EXPENSES THAT ARE A FUNCTION OF THE ACHIEVEMENT OF CORPORATE FINANCIAL PERFORMANCE GOALS BE CHARGED TO THE STOCKHOLDERS OF AEP?

A. Yes. With regard to the Company's LTIP program, I recommend that 100% of the LTIP expenses included in the test year be moved below-the-line for ratemaking purposes in this case. I am making this recommendation because the stated purpose of the LTIP is to "promote the interests of AEP and its shareholders…"[11] and because the LTIP expenses are solely based on the achievement of AEP's Earnings Per Share and Total Shareholder Return goals. With regard to the Company's Incentive Compensation Plan ("ICP"), I recommend that 25% of the ICP expenses be moved below-the-line. This recommendation is based on the facts that: (i) one of the primary objectives of the ICP is to "Provide an incentive for performance that creates value for AEP's shareholders,"[12] and (ii) 25% of the ICP incentive compensation expenses is based on corporate financial performance goals in the form of AEP's Earnings per Share performance.

Q. WHAT AMOUNT OF INCENTIVE COMPENSATION EXPENSES IS INCLUDED IN THE COMPANY'S TEST YEAR O&M EXPENSES?

A. The Company has provided very confusing information with regard to its test year incentive compensation expenses. In response to AG-1-29, the Company provided information showing that the test year total incentive compensation expenses charged to O&M amount

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[11] Response to AG-1-28, page 28.
[12] Response to AG-1-28, page 3.

to $1,322,814. At the same time, in response to AG-1-30, the Company provided information showing that the test year total incentive compensation expenses charged to O&M amount to $1,765,417. Then, in response to AG-2-9, the Company again changed its position and stated that the corrected test year incentive compensation expenses charged to O&M amount to $1,921,573. Finally, in its response to AG-2-10, the Company stated:

> To clarify any confusion, please refer to pages 2 and 3 of this response to see the total incentive compensation booked for Kentucky Power Company (KPC). The pages show incentive compensation booked per year between those booked directly by KPC and those billed to KPC from AEPSC. It is then broken down between O&M and Non-O&M.

Page 2 of the response to AG-2-10 shows that the total test year incentive compensation expenses charged to KPCo's O&M expense amount to $3,348,646. Schedule RJH-11 (lines 1-3) shows the breakdown of this expense amount by incentive compensation plan and as separated between direct KPCo charges and AEPSC-allocated charges to KPCo.

Q. BASED ON YOUR PREVIOUSLY DISCUSSED RECOMMENDATIONS REGARDING THE INCENTIVE COMPENSATION DISALLOWANCE PERCENTAGES, WHAT IS THE AMOUNT OF THE TOTAL TEST YEAR INCENTIVE COMPENSATION O&M EXPENSE THAT SHOULD BE MOVED BELOW-THE-LINE FOR RATEMAKING PURPOSES IN THIS CASE?

A. As shown on Schedule RJH-11, line 5, I recommend that $980,760 of the Company's test year jurisdictional incentive compensation O&M expense be disallowed for ratemaking purposes in this case.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDED ADJUSTMENT ON THE

COMPANY'S PROPOSED TEST YEAR OPERATING INCOME?

A. As shown on Schedule RJH-11, lines 7-9, my recommendation increases the Company's proposed test year operating income by $596,758.

- **Net Merger Savings True-Up Adjustment**

Q. WHAT IS THE COMPANY'S PROPOSED POSITION IN THIS CASE WITH REGARD TO THE BASE RATE TREATMENT OF THE NET MERGER SAVINGS ESTABLISHED IN CASE NO. 99-149?

A. As shown on Section V, WP S-4, page 9 and as stated on page 31 of the testimony of Company witness Wagner, "In accordance with the Stipulation and Settlement Agreement dated May 24, 1999 in Case No. 99-149, page 4 and in accordance with Attachment A of that order, the fifth year [net merger savings] amount of $7,385,000 is added back as an expense to allow the Net Merger Credit to continue. Also, the actual test year merger credit realized by the retail customers in the amount of $4,018,275 was also added back."

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED BASE RATE TREATMENT OF THIS ISSUE?

A. I disagree with part of the Company's proposed rate treatment. The Company's proposal to add back to test year expense the Year 5 net merger savings of $7,385,000 and, at the same time, increase the test year revenues with the actual test year merger credit realized by the retail ratepayers in the amount of $4,018,275, leaves $3,366,725[13] for stockholder net merger savings sharing in the Company's base rates. As shown in the table below, this proposed net merger savings distribution is inconsistent with the stipulated net merger savings distribution for Year 5 contained in Attachment A of the Order in Case No. 99-149:

	Attachment A of Order In Case No. 99-149	KPCo Proposal In Current Case
Year 5 Net Merger Savings	$7,385,000	$7,385,000
Year 5 Customer Sharing	$4,037,000 (55%)	$4,018,275 (54.4%)
Year 5 Stockholder Sharing	$3,348,000 (45%)	$3,366,725 (45.6%)

The Company argues that only $4,018,275 worth of ratepayer net merger savings should be recognized for ratemaking purposes in this case because that amount happened to be actually credited to the ratepayers in the test year through the Net Merger Credit. This argument is wrong. The above table shows that this proposed approach would inappropriately over-allocate (45.6% vs. 45%) the Year 5 net merger savings to the stockholders while under-allocating (54.4% vs. 55%) the Year 5 net merger savings to the ratepayers. In summary, as approved by the Commission in its Order in Case No. 99-149, the Year 5 net merger savings (while not actually known and measurable) are assumed to be $7,385,000 and this amount should be shared between ratepayers and shareholders at amounts of $4,037,000 (55%) and $3,348,000 (45%), respectively, just as is shown in Attachment A of the Order in Case No. 99-149.

For the previously described reasons, the Company's proposed revenue add-back amount of $4,018,275 on Section V, WP S-4, page 9, line 1 should be trued-up to $4,037,000. Schedule RJH-12 shows that this recommended true-up adjustment increases the

[13] $7,385,000 - $4,018,275 = $3,366,725.

Company's proposed test year operating income by $11,394.

Q. HAS THE COMMISSION PREVIOUSLY APPROVED A SIMILAR RATEPAYER SHARING TRUE-UP ADJUSTMENT?

A. Yes. In the recent Louisville Gas & Electric Company ("LG&E") and Kentucky Utilities Company ("KU") base rate proceedings, Case Nos. 2003-00433 and 2003-00434, both LG&E and KU proposed (and the KPSC approved) adjustments to true-up actual test year Value Delivery Team ratepayer sharing amounts to the amounts that were approved by the Commission in its December 3, 2001 Order in Case No. 2001-169.[14]

- **<u>Storm Damage Expense Adjustment</u>**

Q. PLEASE EXPLAIN THE RECOMMENDED OPERATING INCOME ADJUSTMENT FOR STORM DAMAGE EXPENSES, SHOWN ON SCHEDULE RJH-13.

A. KPCo has proposed to normalize the actual test year storm damage expenses based on the inflation-adjusted average storm damage expense for the last 3 years. As shown in the first column of Schedule RJH-13, this proposed normalized expense level amounts to $2,116,867. I believe it is more appropriate to use a longer period than three years to calculate a normalized storm damage expense level. Any abnormally high or low expenses booked in a three-year normalization period may unduly influence the normalized average

[14] For example, for LG&E: see Rives Exhibit 1, Schedule 1.21 and Valery Scott's direct testimony page 9, lines 4-8, in Case No. 2003-00433.

expense level for that short period of time. Such abnormalities would be smoothed out in a longer normalization period such as, for example, a ten-year period. This approach would also be consistent with this Commission's policy to normalize test year storm damage expenses using a 10-year historic average with an inflation factor based on the CPI-U.[15]

In response to data request KPSC-2-16e, the Company has calculated that the normalized storm damage expense levels based on the inflation-adjusted average expenses during the most recent nine-year[16] period amounts to $1,729,357 using the Handy Whitman Contract Labor inflation factor and $1,796,350 using the CPI-U inflation factor. Consistent with the Commission's prior storm damage expense normalization methodology, I recommend that the CPI-U inflation-adjusted normalized storm damage expense level of $1,796,350 be used for ratemaking purposes in this case.

As shown on Schedule RJH-13, my recommendation increases the Company's proposed test year jurisdictional operating income by $193,073.

- **<u>Vehicle Fuel Cost Adjustment</u>**

Q. PLEASE EXPLAIN THE RECOMMENDED OPERATING INCOME ADJUSTMENT FOR VEHICLE FUEL COSTS, SHOWN ON SCHEDULE RJH-14.

A. This recommended operating income adjustment of $29,016 has been reflected by me to

[15] See discovery question KPSC-3-8c.
[16] In its response to AG-2-15, KPCo states that historic storm damage expense information is only available for the last 9 years.

correct for an error made by the Company in the calculation of its proposed vehicle fuel cost adjustment. This recommended error correction reduces the test year operating income and, in turn, increases the Company's revenue requirement.

- **RTO Formation Cost Adjustment**

Q. PLEASE EXPLAIN THE RECOMMENDED OPERATING INCOME ADJUSTMENT ASSOCIATED WITH RTO FORMATION COSTS, SHOWN ON SCHEDULE RJH-15.

A. As conceded by KPCo in its response to AG-1-68f, the Company's proposed RTO formation cost adjustment of $99,393 should be corrected to a reduced cost amount of $60,450. This cost decrease has the effect of increasing the Company's proposed jurisdictional test year operating income by $23,364.

- **Big Sandy Maintenance Expense Adjustment**

Q. PLEASE EXPLAIN THE RECOMMENDED OPERATING INCOME ADJUSTMENT FOR BIG SANDY MAINTENANCE EXPENSES, SHOWN ON SCHEDULE RJH-16.

A. Since the Big Sandy plant maintenance occurs in a three-year cycle, KPCo has proposed to normalize the actual test year Big Sandy maintenance expenses based on the inflation-adjusted average annual maintenance expense for the last 3 years. As shown in the first column of Schedule RJH-16, this proposed normalized expense level amounts to

$13,710,014. For the same reasons as discussed in my earlier testimony concerning normalized storm damage expenses, I believe it is more appropriate to use a longer period than three years to calculate a normalized maintenance expense level. In response to data request KPSC-2-19, the Company has calculated that the normalized annual Big Sandy maintenance expense level based on the inflation-adjusted average maintenance expense during the most recent nine-year period amounts to $12,756,185. I recommend that this normalized Big Sandy maintenance expense level be used for ratemaking purposes in this case as it is calculated based on a longer historic period that covers three consecutive three-year maintenance cycles.

As shown on Schedule RJH-16, my recommendation increases the Company's proposed test year jurisdictional operating income by $572,246.

- **Year-End Customer Revenue Annualization Adjustment**

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED TEST YEAR-END CUSTOMER REVENUE ANNUALIZATION ADJUSTMENT.

A. In order to "match" the test year revenues with its proposed use of a June 30, 2005 test year-end rate base and capitalization, the Company has restated its test year revenues based on the annualization of the revenues associated with the test year-end number of customers. The Company calculated the resulting gross revenue adjustment of $195,124 based on a comparison of the actual June 30, 2005 test year-end number of customers to the corresponding actual 12-month average test year number of customers. Next, the Company offset this proposed gross revenue adjustment with an associated expense increase of $142,148 based on a proposed Operating Expense Ratio of 72.85%.[17] As shown on Exhibit DMR-1, page 2, the Operating Expense Ratio of 72.85% represents the ratio of total pro forma adjusted test year O&M expenses exclusive of labor expenses to total pro forma adjusted test year operating revenues. Thus, as shown in the first column of Schedule RJH-17, the Company's proposed test year-end customer revenue annualization adjustment increases the test year net operating revenues by a net amount of $52,976.

Q. DO YOU RECOMMEND THAT ADJUSTMENTS BE MADE TO THE COMPANY'S PROPOSED NET REVENUE ADJUSTMENT?

A. Yes. First, in accordance with well-established KPSC ratemaking policy, the gross revenue annualization amount should be based on a comparison of the actual June 30, 2005 test year-end number of customers to the corresponding actual 13-month average test year number of customers, not the 12-month average test year number of customers. However, after repeated requests[18] to re-calculate its proposed customer revenue annualization adjustment based on the 13-month average test year number of customers, the Company refused to make these calculations. Since not enough information is available to me to make these calculations myself, I recommend that the Commission order the Company to make these calculations.

Second, the Operating Expense Ratio used in determining the associated expense

[17] $195,124 x 72.85% = $142,148.
[18] AG-1-54 and AG-2-18.

adjustment should be the ratio of (a) total pro forma adjusted test year O&M expenses, exclusive of fuel costs, labor expenses, employee pension and benefit expenses and regulatory expenses, as compared to (b) total pro forma adjusted test year operating revenues, exclusive of fuel revenues. As calculated in footnote (3) of Schedule RJH-17, this produces a recommended Operating Expense Ratio of 57.54%. As shown in the third column of Schedule RJH-17, the use of this Operating Expense Ratio results in a recommended associated expense increase adjustment of $112,274.

Q. PLEASE EXPLAIN THE REASONS FOR YOUR RECOMMENDED OPERATING EXPENSE RATIO.

A. Any changes in the Company's fuel costs as the result of revenue growth from the test year-end customer adjustment are trued up and recovered in the Company's separate fuel adjustment clause rate recovery mechanism. Therefore, the offsetting test year fuel revenues and fuel costs should be removed from the adjusted test year operating revenues and the adjusted test year O&M expenses in the determination of the appropriate Operating Expense Ratio. Otherwise, the fuel expenses associated with the test year-end customer growth adjustment will be recovered twice, once in the base rates and, again, in the fuel adjustment clause.

Also, in several recent Kentucky utility base rate proceedings, the Commission has established the ratemaking policy that, in the determining the appropriate Operating Expense Ratio for similar year-end customer revenue annualization adjustments, the total test year O&M expenses should be exclusive of labor, employee pension and benefit, and regulatory expenses.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDED ADJUSTMENT ON THE COMPANY'S PROPOSED TEST YEAR OPERATING INCOME?

A. As shown on Schedule RJH-17, lines 3 – 5, my recommended adjustment increases the Company's proposed test year jurisdictional operating income by $18,177. This recommended test year operating income adjustment should eventually also reflect the impact of a Commission-ordered re-calculation of this customer annualization adjustment based on the test year's 13-month average level of customers.

- **<u>AEP Pool Capacity Cost Adjustment</u>**

Q. PLEASE DESCRIBE YOUR UNDERSTANDING OF THE COMPANY'S PROPOSAL TO ADJUST ITS TEST YEAR AEP POOL CAPACITY COSTS.

A. KPCo is a member of the FERC-approved AEP Interconnection Agreement together with its sister companies, Appalachian Power Company (APCo), Columbus Southern Power Company CSP), Indiana Michigan Power Company (I&M), and Ohio Power Company (OPCo). Although each operating company owns its own specific generating facilities, the AEP system is designed, built and operated on an integrated system basis. KPCo is a deficit member of the Interconnection Agreement, which means that the Company pays a capacity deficit payment (AEP Pool capacity charge) to the surplus members every month. In this case, KPCo has proposed pro forma adjustments to the Company's actual test year AEP Pool capacity charge to reflect several events that have already taken place or will take place shortly after the test year.

The first event is the addition of 830 MW of generation capability to the CSP generating fleet. This event was finalized on September 28, 2005 and the impact of this event on KPCo's AEP Pool capacity charge actually started in that month, September 2005.[19] The Company claims that this event increases its actual test year AEP Pool capacity charge by approximately $5.6 million.

The second event is the addition of 481 MW of generating capability to APCo's generating fleet. The closing date of APCo's purchase of this additional capacity is expected to occur in early December 2005, at which time this event would start impacting KPCo's AEP Pool capacity charge.[20] The Company claims that this event increases its actual test year AEP Pool capacity charge by approximately $5.6 million.

The third event is the addition of 289 MW of load to CSP's system. As explained in the response to AG-1-60, on November 9, 2005, the Public Utility Commission of Ohio issued an order in Case 05-765-EL-UNC approving the transfer of Monongahela Power Company's service territory to CSP. The transfer will become effective on January 1, 2006, and CSP will assume the obligation to provide electric service to Monongahela's customers. Monongahela's service territory equates to a load of 289 MW. The Company claims that this event decreases its actual test year AEP Pool capacity charge by approximately

[19] Response to AG-1-58.
[20] Response to AG-1-59.

$276,000.

The fourth event concerns the retirement of 250 MW of generating capability from CSP's generating fleet. CSP plans to retire Conesville Units 1 and 2 by January 1, 2006, following review and approval by PJM by that time.[21] The Company claims that this event decreases its actual test year AEP Pool capacity charge by approximately $1.5 million.

The fifth and final event concerns the estimated impact on KPC's actual test year AEP Pool capacity cost of the annualization of load changes during and after the test year of all operating members of the AEP System Pool. The Company has estimated that this event increases its actual test year AEP Pool capacity charges by approximately $2.3 million. In its response to AG-1-62, the Company confirms that this proposed adjustment "reflects anticipated load changes for all members of the AEP-System East Zone, if applicable."

In summary, as shown on Section V, WP S-4, page 30, the Company has proposed to increase its actual test year AEP Pool capacity charges by a jurisdictional amount of almost $9 million to reflect these five events.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED ADJUSTMENT?

A. Based on the previously described information, it is my opinion that the Company's proposed adjustments for the first 4 events are sufficiently known and measurable to warrant rate recognition in this case. However, I recommend that the Commission reject

[21] Response to AG-1-61.

the Company's proposal to increase KPCo's AEP Pool charges by an estimated amount of approximately $2.3 million to reflect the annualization of load changes during and after the test year of all operating members of the AEP System Pool. I believe that this particular adjustment does not represent a known and measurable event that can be accurately quantified. In this regard, I note that my Schedule RJH-32 lists some examples of other post-test year events, which have the effect of *reducing* the Company's future revenue requirement. The Company has not reflected these events in its filing because it believes that these events "contain too much uncertainty to allow them to be used to modify the test year actual expenses."[22] I don't believe that the estimated KPCo cost impact of the load change annualization for all AEP System Pool members can be considered any more certain than the estimated cost and revenue impacts of the post-test year events listed on Schedule RJH-32.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON THE COMPANY'S PROPOSED TEST YEAR OPERATING INCOME?

A. As shown on Schedule RJH-18, my recommendation increases the Company's proposed test year jurisdictional operating income by $1,390,521.

- <u>PJM NTS and PTP Transmission Service Revenue Adjustments</u>

Q. PLEASE DESCRIBE YOUR UNDERSTANDING OF THE COMPANY'S PROPOSAL TO ADJUST ITS TEST YEAR PJM POINT-TO-POINT ("PTP") AND

[22] Responses to KPSC-2-105 and 2-106.

NETWORK TRANSMISSION SERVICE ("NTS") REVENUES.

A. The reasons for the Company's proposed revenue adjustments are summarized as follows on page 5 of Company witness Bethel:

> The NTS and PTP revenues, distributed to KPCo from those received by the AEP East Zone Companies for transmission services provided pursuant to PJM's FERC-approved Open Access Transmission Tariff (OATT) charges to non-affiliated parties, act as credits to reduce the cost of service for KPCo customers. On October 1, 2004, the AEP East Tranmission System was integrated into the PJM RTO. This change, and the action of the FERC in Docket No. EL04-135-000 *et al* to eliminate charges for through and out (T&O) transmission service between PJM and the MidWest ISO (MISO), means that effective April 1, 2006 the AEP Companies, including KPCo, will experience a large reduction in PTP transmission revenues. The elimination of T&O charges between PJM and MISO actually occurred on December 1, 2004, but the FERC simultaneously implemented a temporary load-based lost revenue recovery mechanism known as Seams Elimination Cost Allocation (SECA) charges. The SECA charges will end as of April 1, 2006, causing KPCo's revenues from PTP transmission service to be reduced compared to those received during the Test Year.

To reflect these anticipated PJM revenue changes for ratemaking purposes in this case, the Company projected its annualized post-April 1, 2006 PTP and NTS revenues and then compared these projected revenues to the actual test year PTP and NTS revenues. A review of the forecasting methodologies used to make these annualized post-April 1, 2006 PTP and NTS revenue projections, described on pages 6 – 9 of Mr. Bethel's testimony, indicates that the Company's projections incorporate a large number of estimates and assumptions.

Based on these projections, the Company has proposed to reduce its actual test year PJM PTP revenues in this case by $9,723,371 and to increase its actual test year PJM NTS revenues by $1,660,768. As summarized on Schedule RJH-19, the net effect of these two proposed PJM revenue adjustments is a pro forma test year net revenue reduction of

$8,062,603.

Q. HAS AEP TAKEN ACTIONS TO MITIGATE THE LOSS OF THE PREVIOUSLY DESCRIBED T&O AND SECA REVENUES?

A. Yes. These actions are described as follows on pages 9 and 10 of Mr. Bethel's testimony:

> AEP has filed an appeal of the FERC decision to eliminate T&O transmission charges, however that appeal is presently being held in abeyance, pending the outcome of the SECA/Regional Rate Design proceeding. AEP also filed a protest of a January 2005 filing by certain PJM transmission owners proposing the continuation of zonal License Plate rates in PJM until at least February 2008. The FERC found merit in AEP's arguments, and opened a new complaint proceeding, Docket No. EL05-121-000, wherein PJM parties may file, by September 30, 2005, proposals to change the PJM transmission rate design. AEP noticed the FERC on September 1, 2005 that the AEP Companies will propose a change in the PJM transmission rate design that will provide compensation for use of AEP transmission by non-zone entities. If AEP is successful in obtaining post-SECA revenues under such a regional rate proposal, the incremental revenues would act to reduce AEP zonal costs in the future.

Q. HAS THE COMPANY PROVIDED AN ESTIMATE OF THE POST-SECA REVENUES IT WOULD REALIZE IF AEP IS SUCCESSFUL IN HAVING ITS PROPOSED CHANGE IN THE PJM TRANSMISSION RATE DESIGN APPROVED?

A. Yes. In its response to AG-1-83b, the Company estimated that, "If AEP's proposal is approved, transmission customers in the AEP Zone could benefit from a net reduction in TCOS of up to approximately $125 million per year." In a subsequent response to AG-2-28, the Company clarified that, based on the annual TCOS reduction of $125 million, KPCo's annual PJM PTP and NTS revenues would increase by approximately $9.3 million.

Q. BASED ON THE FOREGOING FINDINGS, WHAT IS YOUR RECOMMENDATION REGARDING THIS ISSUE?

A. I recommend that the Company's proposed test year net revenue adjustment of $8,062,603 for PJM PTP and NTS revenues be rejected by the Commission. I am making this recommendation because I do not believe that the Company's proposed net revenue adjustment is truly known and measurable or reliably representative of post-SECA revenue conditions during the rate effective period of this case. While it is true that the SECA revenues are scheduled to expire effective April 1, 2006, it does not automatically follow that, therefore, the Company's projected PTP and NTS revenue adjustments are known and measurable. The adjustments are based on annualized post-SECA projections that include many estimates and assumptions that cannot be verified at this time. In addition, the post-SECA revenue loss may be completely offset if AEP's pending PJM rate design proposal in FERC Docket No. EL05-121-000 is approved.

Q. WHAT IS THE IMPACT OF THIS RECOMMENDATION ON THE COMPANY'S PROPOSED TEST YEAR OPERATING INCOME?

A. As shown on Schedule RJH-19, my recommendation increases the Company's proposed test year jurisdictional operating income by $4,837,130.

- **Net PJM Revenue/Expense Normalization Adjustments**

Q. PLEASE EXPLAIN THE NET PJM REVENUE AND EXPENSE

NORMALIZATION ADJUSTMENTS THAT ARE SHOWN ON SCHEDULE RJH-20.

A. Since KPCo joined PJM in October 2004, the Company has started booking a number of PJM-related revenues and expenses, including Financial Transmission Right (FTR) revenues and Implicit Congestion, Operating Reserve, Synchronous Condensing Service, Reactive Supply Service, and Blackstart Service costs. As these PJM revenues and costs are included in the test year for only nine months or less, the Company has proposed an adjustment in this case to annualize these test year revenues and costs. The annualized revenue and expense levels for the PJM cost items shown on lines 3 through 6 on Schedule RJH-20 were calculated by the Company simply by annualizing the actual costs that were included in the test year. The Company did not use a similar annualization approach for the test year Implicit Congestion costs and FTR revenues shown on lines 1 and 2 of Schedule RJH-20.

Q. HOW DID THE COMPANY ANNUALIZE THE TEST YEAR IMPLICIT CONGESTION COSTS AND FTR REVENUES?

A. In its response to AG-1-64, the Company presented information showing how it annualized the actual test year Implicit Congestion costs and FTR revenues. A review of the information on AG-1-64, page 3 indicates that the Company did not really annualize the test year implicit costs and FTR revenues. Instead, with regard to FTR revenues, the Company took the 2006 FTR revenues that were forecasted for AEP and were allocated to

KPCo for 2006 on a monthly basis,[23] and then reduced these forecasted 2006 FTR revenues by 19.28% effective June 2006 to reflect the estimated FTR revenue impact from the anticipated operation of the new Wyoming – Jackson Ferry 765 kV transmission line in June 2006. Similarly, with regard to Implicit Congestion costs, the Company took the projected 2006 Implicit Congestion costs for AEP that were allocated to KPCo for 2006 on a monthly basis, and then reduced these forecasted 2006 Implicit Congestion costs by 29.66% effective June 2006 to reflect the estimated Implicit Congestion cost impact from the anticipated operation of the new Wyoming – Jackson Ferry 765 kV transmission line in June 2006.

Q. DO YOU RECOMMEND THAT THE TEST YEAR IMPLICIT CONGESTION COSTS AND FTR REVENUES BE ANNUALIZED BASED ON THE PREVIOUSLY DISCUSSED ANNUALIZATION APPROACH PROPOSED BY KPCo?

A. No. I believe that the many projection elements incorporated in the Company's proposed annualization approach disqualify the projected annualized end result from being known and measurable.

Q. WHAT METHOD DO YOU RECOMMEND TO ANNUALIZE THE TEST YEAR IMPLICIT CONGESTION COSTS AND FTR REVENUES?

A. When the Company prepared this case, 12 months of actual Implicit Congestion costs and FTR revenues were not available. Such data are available now. I believe that the most reasonable way to annualize the test year Implicit Congestion costs and FTR revenues is to

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[23] Bradish direct testimony page 9, lines 14 – 17.

replace the 9 months worth of actual test year costs and revenues with the actual Implicit Congestion costs and FTR revenues for the most recent 12-month period available at this time.

In fact, I recommend this annualization approach not only for the Implicit Congestion costs and FTR revenues, but also for the Operating Reserve, Synchronous Condensing Service, Reactive Supply Service, and Blackstart Service costs.

Q. WHAT IS THE IMPACT OF USING THIS RECOMMENDED ANNUALIZATION APPROACH ON THE COMPANY'S PROPOSED TEST YEAR OPERATING INCOME?

A. In its response to AG-2-25, the Company provided the actual costs and revenues for the aforementioned PJM items during the 12-month period ended November 30, 2005. As shown on Schedule RJH-20, this actual data produces $1,414,663 more in net PJM revenues than under the Company's proposed annualization approach. This, in turn, increases the Company's proposed test year jurisdictional operating income by $848,722.

Q. MR. BRADISH IS PROPOSING THAT A TRACKING MECHANISM BE IMPLEMENTED FOR THE RECOVERY OF FUTURE NET FTR REVENUES AND IMPLICIT CONGESTION COSTS. DO YOU AGREE WITH THIS PROPOSAL?

A. No. While counsel will address the legal issues relating to the establishment of a tracker, I will address the accounting impact of trackers and why this tracker should not be allowed.

Traditional ratemaking involves the establishment of a base rate that allows the utility an *opportunity* to recover its cost of service and to earn a fair rate of return but does not guarantee either because some expenses and revenues will rise and others will fall while the base rate remains the same. Both the risk and reward of the efficient operation of the company are on the utility when the cost of service is recovered through base rates. Trackers are formula rates that set up the elements of expense or revenue to be collected/credited under the rate. The tracker may result in a credit or charge based on how the included expenses and revenues actually materialize. The purpose of a tracker is to guarantee cost recovery.

From an accounting perspective, the impact of a tracker established in the context of general rate case, where the base rates are set on traditional principles of ratemaking, is to declare that the general rates established in the case cannot in and of themselves be fair, just and reasonable because the expenses and revenues covered by the tracker cannot be accommodated within the traditional ratemaking expectation that some expenses and revenues will rise and others will fall, but the *opportunity* to earn will continue to be present until new rates are sought. Outside of (i) trackers agreed to by all parties to allow the parties to give and/or receive the benefits of settlements, and (ii) trackers allowed or required by the state's regulatory scheme, my experience has been that trackers are generally utilized only when the covered costs or revenues represent a very significant portion of the utility's total operating costs or operating revenues – i.e., are "material" - and exhibit extreme volatility and unpredictability. These are the properties that underlie the most commonly utilized trackers, fuel adjustment clauses and gas recovery clauses. Rate recovery through a tracking mechanism should continue to be allowed only when very specific requirements of materiality and volatility can be met.

While there may be some merit to Mr. Bradish's argument that the FTR revenues and Implicit Congestion costs exhibit volatility from month to month, I believe that the net FTR revenues and Implicit Congestion costs fail to meet the "materiality" requirement. As shown on Schedule RJH-20, lines 1 – 2, the combination of the annual Implicit Congestion and FTR revenues under the Company's proposed position amounts to a net revenue number of approximately \$3 million.[24] This is only .9% of the test year's total Kentucky jurisdictional revenues of approximately \$350 million. Under the AG's recommended position, the combination of the annual Implicit Congestion and FTR revenues amounts to a net revenue number of approximately \$5.7 million. This is only 1.6% of the test year's total Kentucky jurisdictional revenues of \$350 million. I don't believe that these percentages can be considered material enough to justify the implementation of the proposed tracking mechanism. I also note that if the Commission were to allow the Company's tracking mechanism proposal, this would represent a novelty in that it would, for the first time, introduce a tracker in an area (transmission) where previously no trackers have been allowed.

[24] The proposed tracking mechanism is for the combined, net effect of the Implicit Congestion costs and FTR revenues.

- **PJM Administrative Cost Adjustment**

Q. PLEASE EXPLAIN THE RECOMMENDED OPERATING INCOME ADJUSTMENT FOR PJM ADMINISTRATIVE COSTS, SHOWN ON SCHEDULE RJH-21.

A. As shown in the first column of Schedule RJH-21, and as confirmed in its response to AG-1-71b, the Company has proposed to normalized its PJM administrative costs in this case by annualizing the actual PJM administrative costs that were recorded during the last 9 months of the test year and then applying an estimated cost increase factor of 19.5% to the annualized cost. While I agree with the Company's proposal to annualize the 9 months worth of administrative costs in the test year, I recommend that the Commission at this time reject the Company's proposal to increase this annualized cost level by 19.5%.

As confirmed in the Company's response to AG-1-71, the assumed 19.5% PJM administrative cost increase is based on a new "stated rate" filed with FERC by PJM on July 1, 2005. As of today, this PJM-requested rate increase has not been approved by FERC. Specifically, in its response to AG-1-71e, the Company stated in this regard:

> The stated rate has not been approved. The FERC issued a deficiency letter on August 31, 2005 that required PJM to respond within 60 days. PJM filed a partial response on October 28, 2005 along with a request for a 30-day extension for the remainder of their response. The Company cannot project when FERC will rule on this matter.

In its response to KPSC-3-13, the Company provided updated information by stating that PJM revised its proposed stated rate downwards in a supplemental November 30, 2005 filing and is currently involved in a settlement proceeding with the next settlement meeting set for January 12, 2006. Based on these responses, I find that the proposed estimated PJM administrative cost increase of 19.5% does not represent a known and measurable cost change at this time.

As shown on Schedule RJH-21, my recommendation to remove this proposed cost increase increases the Company's proposed test year jurisdictional operating income by $345,437.

- **Public/Community Relations Expense Adjustments**

Q. PLEASE EXPLAIN THE RECOMMENDED OPERATING INCOME ADJUSTMENT FOR PUBLIC/COMMUNITY RELATIONS EXPENSES, SHOWN ON SCHEDULE RJH-22.

A. As shown on Schedule RJH-22, lines 1-3, the Company's proposed above-the-line O&M expenses include a total of $436,419 for expenses related to public/community relations activities. Of this expense total, $126,696 is associated with public/community relations expenses charged to KPCo by AEPSC and the remaining expense amount of $309,723 represents other public/community relations expenses booked by KPCo in the test year. As indicated in the Company's responses to AG-1-74a(2) and AG-2-14c, these expenses are for public/community relations activities such as tasks associated with involving the Company in the community; supporting media tours and open houses; staging events including tours and open houses; meeting with civic officials; work time contributed to support community activities and organizations; participating in local civic organizations; coordination of employee volunteer programs; performing operation feed activities; and administering visitor centers. These activities have nothing to do with the provision of safe, adequate and reliable electric service. Rather, they involve activities that have as their primary purpose the creation of goodwill for the Company and enhance its image as a good corporate citizen. For these reasons, I do not believe that these expenses should be charged to the Company's captive ratepayers. They should properly be assigned to the Company's stockholders.

As shown on Schedule RJH-22, lines 3 – 5, my recommendation to remove this expense of $436,419 from the test year increases the Company's proposed test year operating income by $265,546.

- **Expense Adjustments For Miscellaneous AEPSC Charges to KPCo**

Q. PLEASE EXPLAIN THE OPERATING INCOME ADJUSTMENT FOR MISCELLANEOUS AEPSC CHARGES TO KPCo.

A. The response to KPSC-2-98E indicates that the Company's test year expenses include $43,233 for Legislative Affairs expenses and $45,963 for Public Policy Issue expenses that were charged to KPCo by AEPSC. Legislative Affairs expenses are essentially lobbying expenses that should not be charged to the ratepayers and should be moved below-the-line for ratemaking purposes consistent with Commission ratemaking policy. I also do not see why ratepayers should pay for Public Policy Issue expenses incurred by AEPSC and allocated to KPCo. From their description, these expenses would appear to be for activities that have nothing to do with the provisions of safe, adequate and reliable electric service for the direct benefit of KPCo's ratepayers. I therefore recommend that these Public Policy

Issue expenses also be treated below-the-line for ratemaking purposes in this case.

In addition, in its response to data request AG-1-74, the Company conceded that the test year includes $1,412 for AEPSC charges to KPCo that should be removed for ratemaking purposes. I have reflected this expense adjustment on Schedule RJH-23, line 3.

As shown on Schedule AG-1-74, my recommended expense adjustments have the effect of increasing the Company's proposed test year operating income by $55,132.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING THIS ISSUE?

A. Yes. The response to KPSC-2-98E also indicates that the test year includes approximately $115,000 for Public/Community Relations expense charges from AEPSC to KPCo. I have assumed that these AEPSC charges are included in the $126,696 Public/Community Relations expense charges from AEPSC to KPCo identified in the response to AG-1-74 that were already removed from the test year on my Schedule RJH-22, line 1. If this is not the case, then these Public/Community Relations expenses of $115,000 should also be removed from test year expense.

- **EEI Dues Adjustment**

Q. PLEASE EXPLAIN HOW THE COMPANY HAS TREATED ITS TEST YEAR EDISON ELECTRIC INSTITUTE ("EEI") DUES.

A. As shown in the first column of Schedule RJH-24, the total test year EEI dues amount to

$75,838, of which the Company has treated $23,325 below-the-line. Thus, the Company has reflected net EEI dues of $52,513 for ratemaking purposes in this case.

Q. DO YOU RECOMMEND THAT AN ADJUSTMENT BE MADE TO THE COMPANY'S PROPOSED ABOVE-THE-LINE EEI DUES OF $52,513?

A. Yes. I recommend that of the total test year EEI dues of $75,838, an amount of $36,410 be treated below-the-line. This latter amount is 48.01% of the total test year EEI dues. The 48.01% represents the portion of EEI activities associated with legislative advocacy, regulatory advocacy, public relations, and an estimated 50%[25] of the advertising activities that are described in the Company's responses to AG-1-79c and KPSC-3-41a. The exact make-up of the 48.01% is shown in footnote (2) of Schedule RJH-24. I recommend that this 48.01% portion of the Company's EEI dues be disallowed for ratemaking purposes because it represents EEI activities associated with lobbying, goodwill and image building, and institutional/promotional advertising.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDED ADJUSTMENT ON THE COMPANY'S PROPOSED TEST YEAR OPERATING INCOME?

A. As shown on Schedule RJH-24, lines 3 – 5, my recommended adjustment increases the Company's proposed test year operating income by $7,962.

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[25] In its response to KPSC-3-41a, the Company was unable to identify the portions of the EEI advertising associated with institutional and promotional activities that are listed in the response to AG-1-79c, page 5 of 8. Due to the unavailability of this information, I have assumed that half of the EEI advertising is related to institutional and promotional activities.

- **Lobbying Expense Adjustment**

Q. WHAT IS THE COMPANY'S PROPOSED POSITION IN THIS CASE WITH REGARD TO LOBBYING EXPENSES?

A. As indicated in the response to KPSC-1-33, KPSCo's lobbying activities are the responsibility of Gregory Pauley, the Company's governmental/environmental affairs manager, whose principal function is lobbying at the local and state level. The Company in this case has proposed to remove as lobbying expenses 16.3% of Mr. Pauley's $112,900 salary, or a total amount of $18,400.[26]

Q. DO YOU AGREE WITH THIS PROPOSED LOBBYING EXPENSE ADJUSTMENT?

A. No. First, I disagree with the Company's proposal to only remove the lobbying expense portion of Mr. Pauley's annual salary. Rather, I recommend that the appropriate lobbying expense portion of Mr. Pauley's *total compensation* be removed for ratemaking purposes in this case. As shown in the Company's response to AG-1-77b, Mr. Pauley's total test year compensation - including base salary, incentive compensation, FICA, and all employee benefits such as pension, medical insurance, life insurance, etc. – amounts to $173,991.

Second, I believe that the Company's proposal to classify only 16.3% of Mr. Pauley's annual activities as lobbying-related activities falls far short of what the appropriate

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[26] The Company also moved below-the-line $13,193 for Mr. Pauley's out-of-pocket lobbying expenses and $16,672 for lobbying expenses allocated to KPCo by AEP.

percentage would be on a normalized ongoing basis. When the Company was asked in AG-1-77c why the Company only considered 16.3% of Mr. Pauley's time to be associated with lobbying activities given that his principal function is lobbying at the local and state level, the Company stated that "During the test year, the Kentucky General Assembly only met for 30 days." I believe it is inappropriate to base the estimated normalized lobbying portion of Mr. Pauley's annual activities on what the number of Kentucky General Assembly meeting days happen to be in the test year. For this reason, and given the fact that the Company itself has confirmed that Mr. Pauley's *principal function* is lobbying at the local and state level, I recommend that 75% be used in this case as a representative lobbying portion of Mr. Pauley's annual activities on a normalized ongoing basis.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDED LOBBYING EXPENSE ADJUSTMENT ON THE COMPANY'S PROPOSED TEST YEAR OPERATING INCOME?

A. As shown on Schedule RJH-25, my recommended adjustment increases the Company's proposed test year operating income by $68,205.

- **Expense Adjustments For Award Banquets, Social Events, Prizes and Gifts**

Q. PLEASE EXPLAIN THE RECOMMENDED OPERATING INCOME ADJUSTMENT FOR AWARD BANQUETS, SOCIAL EVENTS, PRIZES AND GIFTS, SHOWN ON SCHEDULE RJH-26.

A. As confirmed in its response to AG-1-75, the test year above-the-line operating expenses include $58,871 worth of expenses related to award banquets, social events, prizes and gifts. These expenses have been removed by me to reflect KPSC ratemaking policy and because they have nothing to do with the provision of safe, adequate and reliable electric service.

As shown on Schedule RJH-26, my recommendation increases the Company's proposed test year operating income by $35,821.

- **Miscellaneous Expense Adjustments**

Q. PLEASE EXPLAIN THE MISCELLANEOUS EXPENSE ADJUSTMENTS YOU SHOW ON SCHEDULE RJH-27.

A. The miscellaneous expense adjustments shown on Schedule RJH-27, lines 1 – 5, concerning donations, non-utility property taxes, sponsorships and contributions, institutional advertising, and certain regulatory commission expenses represent non-contested expense adjustments the Company has conceded should be removed for ratemaking purposes in this case. The Company's concessions concerning these expense adjustments are contained in the data responses referenced in footnotes (1) through (5) of Schedule RJH-27. The miscellaneous expense adjustment for the removal of spousal expenses on line 6 is to reflect Commission policy to treat such expenses below-the-line for ratemaking purposes.

As shown on Schedule RJH-27, line 9, my miscellaneous expense adjustments have the effect of increasing the Company's proposed test year operating income by $20,258.

- **Correction For KPCo's Proposed Depreciation Expense Adjustment**

Q. PLEASE EXPLAIN THE DEPRECIATION EXPENSE ADJUSTMENT SHOWN ON SCHEDULE RJH-28.

A. As explained in the response to AG-2-2(d), the Company made an error in the calculation of its proposed depreciation expense adjustment in this case. On Schedule RJH-28, I show that the correction for this error increases the Company's proposed depreciation expense adjustment by $38,860 and decreases the Company's proposed test year operating income by $23,645.

- **Annualized Depreciation Expense Adjustment**

Q. PLEASE EXPLAIN THE ANNUALIZED DEPRECIATION EXPENSE ADJUSTMENT SHOWN ON SCHEDULE RJH-29.

A. This adjustment reflects my adoption of the depreciation expense recommendations contained in the testimony of Michael Majoros, the AG's expert depreciation witness. As shown on Schedule RJH-29, Mr. Majoros' depreciation recommendations reduce the Company's proposed test year annualized depreciation expenses by $11,049,739 which, in turn, increases the Company's proposed test year jurisdictional operating income by $6,656,146.

As shown on Schedule RJH-29, lines 10 and 11, the AG's recommended annualized depreciation expense adjustment also impact the Company's proposed depreciation reserve and accumulated deferred income tax balances in rate base.

- **Miscellaneous Service Charge Revenue Adjustment**

Q. PLEASE EXPLAIN THE RECOMMENDED OPERATING INCOME ADJUSTMENT FOR MISCELLANEOUS SERVICE CHARGE REVENUES, SHOWN ON SCHEDULE RJH-30.

A. This adjustment reflects my adoption of the miscellaneous service charge recommendations contained in the testimony of AG witness David Brown-Kinloch. As shown on Schedule RJH-30, Mr. Brown-Kinloch's recommendations reduce the Company's proposed test year miscellaneous service charge revenues by $384,085 which, in turn, decreases the Company's proposed test year jurisdictional operating income by $233,702.

- **AFUDC Offset Adjustment**

Q. PLEASE EXPLAIN THE RECOMMENDED OPERATING INCOME ADJUSTMENT FOR THE AFUDC OFFSET, SHOWN ON SCHEDULE RJH-31.

A. As shown in the first column of Schedule RJH-31, consistent with its proposal to include Construction Work in Progress ("CWIP") in its capitalization and rate base, the Company has proposed to include in the test year above-the-line operating income the annualized

AFUDC booked on the test year CWIP balance that is subject to AFUDC accrual. The AFUDC accrual rate used by the Company is equal to its proposed overall rate of return of 7.89% in this case. While I recommend the same AFUDC offset adjustment as proposed by KPCo, my adjustment uses the AG's recommended overall rate of return of 6.81% as the AFUDC accrual rate. Schedule RJH-31 shows that this difference reduces the Company's proposed test year operating income by $170,773.

- **Employee Discounts**

Q. DOES THE COMPANY PROVIDE DISCOUNTED ELECTRIC SERVICE TO ITS EMPLOYEES?

A. Yes. As stated on page 12 of 103 of Exhibit EKW-5, "Regular employees who have been in the Company's employ for 6 months or more may, at the discretion of the Company, receive a reduction in their residence electric bills for the premises occupied by the employee."

Q. IS THERE A POTENTIAL ISSUE IN THIS CASE WITH REGARD TO THESE EMPLOYEE DISCOUNTS?

A. Yes. Employee discounts granted during the test year have reduced the test year operating revenues. If, for ratemaking purposes, the Company does not make a pro forma adjustment to increase the test year revenues for the amount of these employee discounts, this test year operating revenue reduction results in a revenue requirement in this case. In a prior KPCo rate case, Case No. 9061, the Commission accepted my recommended adjustment to remove the revenue requirement in that case caused by these employee discounts. On page 28 of its

Order[27] in that case, the Commission issued the following ruling regarding this issue:

> Kentucky Power offered no evidence that its employee discounts is considered in its wage and benefits negotiations with its union employees or that it was considered in determining non-union wages and salaries. Although Kentucky Power and its employees may regard discounted electric service as an employee benefit, the record herein provides no evidence to convince the Commission that ratepayers should bear the cost of service discounts granted employees. Therefore, the Commission has increased Kentucky Power's jurisdicational operating revenues by $59,656 to eliminate the effect of employee discounts.

At this time, I do not know whether the test year includes a revenue requirement associated with any test year revenue reductions due to the employee discounts. However, to the extent that the test year does include such a revenue requirement, this revenue requirement should be removed by making a pro forma adjustment to increase the test year operating revenues for the actual employee discounts booked during the test year.

Q. WHAT ARE YOUR SPECIFIC RECOMMENDATIONS REGARDING THIS POTENTIAL ISSUE?

A. First, I recommend that the Company provide information showing (i) by what dollar amount the actual test year operating revenues have been reduced due to the booking of employee discounts; and (ii) whether the Company has eliminated these revenue reductions for ratemaking purposes in this case. In addition, if this information indicates that the test year includes a revenue requirement associated with the Company's test year employee discounts, I recommend that this revenue requirement be eliminated for ratemaking purposes in this case in a similar fashion and for the same reasons as per the above-referenced Commission ruling in Case No. 9061.

[27] PSC Order dated December 4, 1984 *In the Matter of: General Adjustment in Electric Rates of Kentucky Power Company, Case No. 9061*

Q. MR. HENKES, DOES THIS CONCLUDE YOUR DIRECT TESTIMONY IN THIS CASE?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY
BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

General Adjustment In Electric Rates Of Kentucky Power Company	)))	Case No. 2005-00341

AFFIDAVIT

Comes the Affiant, Robert J. Henkes, and being duly sworn states as follows: The prepared Direct Testimony, together with supporting schedules, exhibits, and/or appendices attached thereto constitute the direct testimony of Affiant in the above styled case. Affiant further states that to the best of his information and belief, all statements made and matters contained therein are true and correct. Further Affiant saith not.

STATE OF CONNECTICUT
COUNTY OF Fairfield

Subscribed and sworn to before me by Robert J. Henkes this the 3rd day of ~~December~~ January, ~~2005~~ 2006.

MY COMMISSION EXPIRES: ____________

MARIA RIGAKOS
NOTARY PUBLIC
My Commission Expires January 31, 2008

Maria Rigakos
Notary Public, State at Large

Test Period Ended 6/30/05
Case No. 2005-00341

Sch. RJH-1

KENTUCKY POWER COMPANY
REVENUE REQUIREMENT

	KPC (1)	Adjustment	AG	
1. Adjusted Capitalization	$ 853,082,950	$ (7,322,778)	$ 845,760,172	Sch. RJH-3
2. Rate of Return	7.89%		6.81%	Sch. RJH-2
3. Operating Income Requirement	67,308,245	(9,722,428)	57,585,817	
4. Pro Forma Operating Income	28,406,655	20,018,492	48,425,147	Sch. RJH-7
5. Operating Income Deficiency	38,901,590	(29,740,920)	9,160,670	
6. Gross Revenue Conversion Factor	1.6656		1.6479	(2)
7. Revenue Deficiency	$ 64,796,239	$ (49,700,407)	$ 15,095,832	

(1) Section V, Schedule 2

(2)

		KPC		AG
Operating Revenues		100.00		100.00
Less: Uncollectible Accounts Expense		(0.47)		(0.47)
		99.53		99.53
Less: State Income Taxes	@ 7.20%	(7.17)	@ 6.20%	(6.17)
		92.36		93.36
Less: Federal Income Taxes @ 35%		(32.33)		(32.68)
Operating Income Percentage		60.04		60.68
Gross Revenue Conversion Factor		1.6656		1.6479

KENTUCKY POWER COMPANY
RATE OF RETURN

KPC PROPOSED:

	Capitalization	Ratios	Cost Rates	Weighted Cost Rates
	(1)	(1)	(1)	(1)
Long Term Debt	$ 482,392,123	56.55%	5.70%	3.22%
Short Term Debt	3,340,763	0.39%	3.34%	0.01%
A/R Financing	30,052,250	3.52%	2.99%	0.11%
Common Equity	337,297,815	39.54%	11.50%	4.55%
Total	$ 853,082,951	100.00%		7.89%

AG RECOMMENDED:

	Capitalization	Ratios	Cost Rates	Weighted Cost Rates
	[Sch. RJH-3]		(2)	
Long Term Debt	$ 479,249,392	56.66%	5.70%	3.23%
Short Term Debt	1,293,426	0.15%	3.34%	0.01%
A/R Financing	30,054,116	3.55%	2.99%	0.11%
Common Equity	335,163,238	39.63%	8.75%	3.47%
Total	$ 845,760,172	100.00%		6.81%

(1) Section V, WP S-2, page 1

(2) Testimony of Dr. J. Randall Woolridge

KENTUCKY POWER COMPANY
RATE BASE

	KPC (1)	Adjustment	AG	
1. Electric Plant in Service	$ 1,336,938,136	$ (5,484,600)	$ 1,331,453,536	Sch. RJH-5
2. Depreciation Reserve	(432,998,450)	10,939,242 (2)	(422,059,208)	
3. Net Electric Plant in Service	903,939,686	5,454,642	909,394,328	
4. Plant Held for Future Use	83,282		83,282	
5. Prepayments	4,739,146	139,353	4,878,499	Sch. RJH-6, L6
6. Materials and Supplies	20,044,715	(3,800,980)	16,243,735	Sch. RJH-6, L3
7. Cash Working Capital	49,058,717		49,058,717	
8. Construction Work In Progress	19,159,718		19,159,718	
9. Customer Advances	(56,784)		(56,784)	
10. Customer Deposits	(10,541,285)		(10,541,285)	
11. Accum. Deferred Income Taxes	(127,983,435)	(4,283,096) (3)	(132,266,531)	
12. TOTAL NET RATE BASE	$ 858,443,760	$ (2,490,082)	$ 855,953,678	

(1) Section V, Schedules 4 and 7
(2) Schedule RJH-29, line 10
(3) Schedule RJH-29, line 11

KENTUCKY POWER COMPANY
RELIABILITY ADJUSTMENT

	KPC	Adjustment	AG
RATE BASE IMPACT:	(1)		
1. Year 1 Average Investment	$ 1,800,000		$ -
2. Year 2 Cumulative Avg. Investment	5,485,000		-
3. Year 3 Cumulative Avg. Investment	9,335,000		-
4. Three-Year Average	$ 5,540,000	$ (5,540,000)	$ -
5. Jurisdictional Allocation Factor		0.990	
6. Jurisdictional Rate Base Adjustment		$ (5,484,600)	
CAPITALIZATION IMPACT:	$ 5,540,000	$ (5,540,000)	$ -
OPERATING INCOME IMPACT:			
7. Year 1 O&M Expenditure	$ 5,750,000		$ -
8. Year 2 O&M Expenditure	6,120,000		-
9. Year 3 O&M Expenditure	3,500,000		-
10. Three-Year Average	6,123,333		-
11. Jurisdictional Allocation Factor	0.992		0.992
12. Jurisdictional O&M Expense Adjustment	$ 6,074,346	$ (6,074,346)	$ -
13. Composite After-Tax Income Rate		0.608465 (2)	
14. Impact on Operating Income		$ 3,696,027	

(1) Section V, WP S-4, page 29

(2) Composite of SIT of 6.39% and FIT of 35% = 39.1535%. After-tax income rate is 1 - 39.1535% = 60.8465%

Test Period Ended 6/30/05
Case No. 2005-00341

KENTUCKY POWER COMPANY
ADJUSTED CAPITALIZATION

KPC PROPOSED:	Per Books Balance	Big Sandy Coal Stock Adj.	Equity Pension Adj.	Reliability Capital Adj.	FRECO A/C 124 Property	Carrs Site	Non-Utility Property	Sub-Total	KY Jurisdiction	Reapportioned KY Jurisdiction
	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	[@ 99%]	(1)
Long Term Debt	487,716,122			3,181,718	(2,638,456)	(3,892,927)	(572,237)	483,794,220	478,956,278	482,392,123
Short Term Debt	-	3,592,837		196,622	(163,050)	(240,573)	(35,363)	3,350,473	3,316,968	3,340,763
A/R Financing	30,139,598							30,139,598	29,838,202	30,052,250
Common Equity	331,354,481		9,588,250	2,161,660	(1,792,568)	(2,644,856)	(388,778)	338,278,189	334,895,407	337,297,815
	849,210,201	3,592,837	9,588,250	5,540,000	(4,594,074)	(6,778,356)	(996,378)	855,562,480	847,006,855	853,082,950
JDTC	6,137,470							6,137,470	6,076,095	-
Total	855,347,671	3,592,837	9,588,250	5,540,000	(4,594,074)	(6,778,356)	(996,378)	861,699,950	853,082,950	853,082,950

AG RECOMMENDED:	Per Books Balance	Big Sandy Coal Stock and Prepayment Adjustments	Equity Pension Adj.	Reliability Capital Adj.	FRECO A/C 124 Property	Carrs Site	Non-Utility Property	Sub-Total	KY Jurisdiction	Reapportioned KY Jurisdiction
		[Sch RJH-6]		[Sch. RJH-5]					[@ 99%]	
Long Term Debt	487,716,122			-	(2,638,456)	(3,892,927)	(572,237)	480,612,502	475,806,377	479,249,392
Short Term Debt	-	1,736,091		-	(163,050)	(240,573)	(35,363)	1,297,105	1,284,134	1,293,426
A/R Financing	30,139,598							30,139,598	29,838,202	30,054,116
Common Equity	331,354,481		9,588,250	-	(1,792,568)	(2,644,856)	(388,778)	336,116,529	332,755,364	335,163,238
	849,210,201	1,736,091	9,588,250	-	(4,594,074)	(6,778,356)	(996,378)	848,165,734	839,684,076	845,760,172
JDTC	6,137,470							6,137,470	6,076,095	-
Total	855,347,671	1,736,091	9,588,250	-	(4,594,074)	(6,778,356)	(996,378)	854,303,204	845,760,172	845,760,172

(1) Section V, Schedule 3

KENTUCKY POWER COMPANY
MATERIALS AND SUPPLIES AND PREPAYMENTS

	AG	
MATERIALS AND SUPPLIES:		
1. Test Year Per Books M&S Balance:		
a. 13-month Average Test Year Balance	$ 14,510,165	(1)
b. KPSC Jurisdictional Allocator	0.987	(2)
c. Jurisdictional Per Books Average M&S Balance	14,321,533	
2. a. Big Sandy Coal Stock Adjustment:	1,949,495	Sch. RJH-6A
b. KPSC Jurisdictional Allocator	0.986	(3)
c. Jurisdictional Coal Stock Adjustment	1,922,202	
3. Total Recommended Jurisdictional M&S Balance	$ 16,243,735	
PREPAYMENTS:		
4. Test Year Per Books Prepayment Balance:		
a. 13-Month Average Test Year Balance	$ 1,016,099	(1)
b. Remove: KPSC Assessments (13-mos avg.)	(213,404)	(1)
c. Adjusted 13-Month Average Test Year Balance	802,695	
d. KPSC Jurisdictional Allocator	0.990	(2)
e. Jurisdictional Per Books Prepayment Balance	794,668	
5. Prepaid Pension Funding (KPSC Jurisdictional)	4,083,831	(4)
6. Total Recommended Jurisdictional Prepayments	$ 4,878,499	
CAPITALIZATION IMPACT:		
7. Big Sandy Coal Stock Adjustment [L2a]	$ 1,949,495	
8. KPSC Assessment Prepayment Removal [L4b]	(213,404)	
9. Total Capitalization Adjustment	$ 1,736,091	

(1) Derived from Section IV, page 14 of 16

(2) Section V, Schedule 15

(3) Section V, WP S-4, page 28

(4) Section V, WP S-4, page 40

KENTUCKY POWER COMPANY
BIG SANDY COAL STOCK ADJUSTMENT

	KPC (1)	Adjustment	AG	
1. Coal Days Supply on Hand	35		35	
2. Daily Burn Rate	8,000		7,048	(2)
3. Average $/Ton	$ 49.32		$ 49.32	
4. Pro Forma Coal Stock Balance [L1xL2xL3]	$ 13,809,600		$ 12,166,258	
5. Actual Test Year-end Coal Stock Balance	10,216,763		10,216,763	
6. Coal Stock Balance Adjustment	$ 3,592,837	$ (1,643,342)	$ 1,949,495	

(1) Section V, WP S-4, page 28

(2) Actual average burn rate for 26-month period September 2003 - October 2005 (derived from response to AG-117b2)

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Sch. RJH-7

KENTUCKY POWER COMPANY
PRO FORMA OPERATING INCOME

1. Pro Forma Jurisdictional Opating Income Proposed by KPC	$ 28,406,655	(1)
AG-Recommended Operating Income Adjustments:		
2. State Income Tax Adjustment (6.39% vs. 7.20%)	(98,263)	Sch. RJH-8
3. Reliability O&M Expense Adjustment	3,696,027	Sch. RJH-5, L14
4. Interest Synchronization Adjustment	(52,820)	Sch. RJH-9
5. O&M Expense Ratio Adjustment	984,793	Sch. RJH-10
6. Incentive Compensation Expense Adjustment	596,758	Sch. RJH-11
7. Net Merger Savings True-Up Adjustment	11,394	Sch. RJH-12
8. Storm Damage Expense Adjustment	193,073	Sch. RJH-13
9. Vehicle Fuel Cost Adjustment	(29,016)	Sch. RJH-14
10. RTO Formation Cost Adjustment	23,364	Sch. RJH-15
11. Big Sandy Maintenance Expense Adjustment	572,246	Sch. RJH-16
12. Year-End Customer Revenue Annualization Adjustment	18,177	Sch. RJH-17
13. AEP Pool Capacity Cost Adjustment	1,390,521	Sch. RJH-18
14. PJM NTS and PTP Transmission Service Revenue Adjs.	4,837,130	Sch. RJH-19
15. Net PJM Revenue/Expense Normalization Adjustments	848,722	Sch. RJH-20
16. PJM Administrative Cost Adjustment	345,437	Sch. RJH-21
17. Public/Community Relations Expense Adjustments	265,546	Sch. RJH-22
18. Expense Adjustment for Miscellaneous AEPSC Charges to KPCo	55,132	Sch. RJH-23
19. EEI Dues Adjustment	7,962	Sch. RJH-24
20. Lobbying Expense Adjustment	68,205	Sch. RJH-25
21. Exp. Adj. for Award Banquets, Social Events, Prizes and Gifts	35,821	Sch. RJH-26
22. Miscellaneous Expense Adjustments	20,258	Sch. RJH-27
23. Correction for KPCo's Proposed Annualized Depreciation Exp. Adj.	(23,645)	Sch. RJH-28
24. Pro Forma Annualized Depreciation Expense Adjustment	6,656,146	Sch. RJH-29, L9
25. Miscellaneous Service Charge Adjustment	(233,702)	Sch. RJH-30
26. AFUDC Offset Adjustment	(170,773)	Sch. RJH-31
27. AG-Recommended Pro Forma Jurisdictional Operating Income	$ 48,425,147	

KENTUCKY POWER COMPANY
STATE INCOME TAX ADJUSTMENT

	KPC	Adjustment	AG	
TEST YEAR JURISDICATIONAL PER BOOKS:	[SIT @ 7.20%] (1)		[SIT @ 6.39%]	
1. State Income Taxes	$ 1,030,001		$ 914,504	(2)
2. Current Federal Income Taxes	4,668,094		4,708,518	(2)
3. Total Current Income Taxes	$ 5,698,095	$ (75,073)	$ 5,623,022	
PRO FORMA INCOME TAX ADJUSTMENTS:				
4. State Income Taxes	$ (2,378,229)		$ (2,111,557)	(3)
5. Current Federal Income Taxes	(10,733,225)		(10,826,561)	(3)
6. Total Current Income Taxes	$ (13,111,454)	$ 173,336	$ (12,938,118)	
7. Total Income Tax Adjustment		$ 98,263		

(1) Section V, Schedule 4, lines 7 and 8
(2) Response to AG-2-5
(3) Response to AG-2-4

KENTUCKY POWER COMPANY
INTEREST SYNCHRONIZATION ADJUSTMENT

	KPC (1)	Adjustment	AG	
1. Capitalization	$ 853,082,950		$ 845,760,172	Sch. RJH-2
2. Weighted Cost of LT and ST Debt	3.23%		3.24%	Sch. RJH-2
3. Weighted Cost of A/R Financing			0.11%	Sch. RJH-2
4. Total Weighted Cost of Debt	3.23%		3.34%	
5. Pro Forma Annualized Interest [L1 x L4]	27,607,932		28,259,034	
6. Interest per Books Net of ABFUDC (retail)	28,829,564		29,615,570	(2)
7. Pro Forma Interest Expense Adjustment	$ (1,221,632)	$ (134,904)	$ (1,356,536)	
8. Composite ncome Tax Rate		39.1535% (3)		
9. Impact on Operating Income		$ (52,820)		

(1) Section V, WP S-4, page 20
(2) Response to AG-1-19
(3) Based on state income tax rate of 6.39% and federal income tax rate of 35%

Test Period Ended 6/30/05
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Sch. RJH-10

KENTUCKY POWER COMPANY
OPERATION AND MAINTENANCE EXPENSE RATIO ADJUSTMENT

	KPC		Adjustment	AG	
1. Test Year Per Books Payroll Costs	$ 29,767,000			$ 29,767,000	
2. O&M Expense Ratio	67.65%			62.51%	(2)
3. Test Year Per Books Payroll O&M Exp.	$ 20,137,863	(1)	$ (1,530,947)	$ 18,606,916	(2)
4. Pro Forma Payroll Cost Adjustment	$ 1,348,275			$ 1,348,275	
5. O&M Expense Ratio	67.65%			62.51%	(2)
6. Pro Forma Payroll O&M Exp. Adjustment	$ 912,108	(3)	$ (69,301)	$ 842,807	
7. Pro Forma Employee Benefit Cost Adj.	$ 480,383			$ 480,383	
8. O&M Expense Ratio	67.65%			62.51%	(2)
9. Pro Forma Empl. Benefit O&M Exp. Adj.	$ 324,979	(4)	$ (24,692)	$ 300,287	
10. Pro Forma Savings Plan Cost Adj.	$ 59,513			$ 59,513	
11. O&M Expense Ratio	67.65%			62.51%	(2)
12. Pro Forma Savings Plan O&M Exp. Adj.	$ 40,261	(5)	$ (3,059)	$ 37,202	
13. Pro Forma FICA Cost Adjustment	$ 100,922			$ 100,922	
14. O&M Expense Ratio	67.65%			62.51%	(2)
15. Pro Forma FICA O&M Exp. Adjustment	$ 68,274	(6)	$ (5,187)	$ 63,086	
16. Total O&M Expense Adjustment			$ (1,633,186)		
17. Jurisdicational Allocation Factor			0.991		
18. Jurisdictional O&M Expense Adjustment			(1,618,488)		
19. Composite After-Tax Income Rate			0.608465 (7)		
20. Impact on Operating Income			$ 984,793		

(1) Section V, WP S-7, pages 3 and 4 of 5.

(2) Responses to KPSC-1-23c, page 17 of 18 AG-1-26b, page 4 of 4.

(3) Section V, WP S-4, page 3

(4) Section V, WP S-4, page 4

(5) Section V, WP S-4, page 6

(6) Section V, WP S-4, page 5

(7) Composite of SIT of 6.39% and FIT of 35% = 39.1535%. After-tax income rate is 1 - 39.1535% = 60.8465%

KENTUCKY POWER COMPANY
INCENTIVE COMPENSATION EXPENSE ADJUSTMENT

		Total Test year Incentive Compensation Charged to KPC's O&M Expense						
		Commerc. Operation	Gene-ration	Energy Delivery	General Services	Safety Focus	LTIP	Total
1. For KPC Employees	(1)	-	518,057	658,163	168,199	244,323	57,360	1,646,102
2. Charged to KPC By AEPSC	(1)	154,480	326,968	330,933	630,446	24,221	235,496	1,702,544
3. Total		154,480	845,025	989,096	798,645	268,544	292,856	3,348,646
4. % Based on AEP Earnings Per Share and Total Stockholder Return	(2)	25%	25%	25%	25%	0%	100%	
5. Incentive Comp. to be Charged to Stock-holder [L3 x L4]		38,620	211,256	247,274	199,661	-	292,856	989,668
6. Jurisdictional Allocation Factor								0.991
7. Jurisdictional O&M Expense Removal								980,760
8. Composite After-Tax Income Rate	(3)							0.608465
9. Impact on Operating Income								$ 596,758

(1) Response to AG-2-10, page 2 of 3

(2) Response to AG-2-7. Assumed no corporate performance measurement criteria for Safety Focus ICP

(3) Composite of SIT of 6.39% and FIT of 35% = 39.1535%. After-tax income rate is 1 - 39.1535% = 60.8465%

KENTUCKY POWER COMPANY
NET MERGER SAVINGS TRUE-UP ADJUSTMENT

	KPC (1)	Adjustment	AG	
1. Ratepayer's Actual Test Year Merger Revenue Credit	$ 4,018,275		$ 4,018,275	
2. True-Up to PSC-Approved Ratepayer's Merger Revenue Credit for Year 5 per Attachment A of PSC Order in Case No. 99-149	-	18,725	18,725	
3. Adjusted Ratepayer Merger Revenue Credit	$ 4,018,275	$ 18,725	$ 4,037,000	(2)
4. Composite After-Tax Income Rate		0.608465 (3)		
5. Impact on Operating Income		$ 11,394		

(1) Section V, WP S-4, page 9, line 1

(2) Ratepayer Year 5 Merger Revenue Credit per Atttachment A of the PSC Order in Case No. 99-149

(3) Composite of SIT of 6.39% and FIT of 35% = 39.1535%. After-tax income rate is 1 - 39.1535% = 60.8465%

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Sch. RJH-13

KENTUCKY POWER COMPANY
STORM DAMAGE EXPENSE ADJUSTMENT

	KPC (1)	Adjustment	AG	
1. Normalized Storm Damage Expenses:				
a. Based on 3-Year Average (2003-2005)	$ 2,116,867			
b. Based on 9-Year Average (1997-2005)			$ 1,796,350	(2)
2. Actual Test Year Storm Damage Expense	576,808		576,808	
3. Storm Damage Expense Adjustment	$ 1,540,059	$ (320,517)	$ 1,219,542	
4. Jurisdictional Allocation Factor		0.99		
5. Composite After-Tax Income Rate		0.608465 (3)		
6. Impact on Operating Income		$ 193,073		

(1) Section V, WP S-4, page 16

(2) Response to KPSC-2-16e, page 6 of 6.

(3) Composite of SIT of 6.39% and FIT of 35% = 39.1535%. After-tax income rate is 1 - 39.1535% = 60.8465%

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Sch. RJH-14

KENTUCKY POWER COMPANY
VEHICLE FUEL COST ADJUSTMENT

	KPC (1)	Adjustment	AG	
1. Vehicle Fuel Cost O&M Expense Adjustment	$ 134,799	$ 48,267	$ 183,066	(2)
2. Jurisdictional Allocation Factor		0.988		
3. Composite After-Tax Income Rate		0.608465 (3)		
4. Impact on Operating Income		$ (29,016)		

(1) Section V, WP S-4, page 31

(2) Response to KPSC-2-18, page 3

(3) Composite of SIT of 6.39% and FIT of 35% = 39.1535%. After-tax income rate is 1 - 39.1535% = 60.8465%

KENTUCKY POWER COMPANY
RTO FORMATION COST ADJUSTMENT

	KPC (1)	Adjustment	AG	
1. RTO Formation Amortization Cost Adjustment	$ 99,393	$ (38,943)	$ 60,450	(2)
2. Jurisdictional Allocation Factor		0.986		
3. Composite After-Tax Income Rate		0.608465 (3)		
4. Impact on Operating Income		$ 23,364		

(1) Section V, WP S-4, page 36

(2) Response to AG-1-68, page 4

(3) Composite of SIT of 6.39% and FIT of 35% = 39.1535%. After-tax income rate is 1 - 39.1535% = 60.8465%

KENTUCKY POWER COMPANY
BIG SANDY MAINTENANCE EXPENSE ADJUSTMENT

	KPC (1)	Adjustment	AG	
1. Normalized Maintenance Expenses:				
a. Based on 3-Year Average (2003-2005)	$13,710,014			
b. Based on 9-Year Average (1997-2005)			$ 12,756,185	(2)
2. Actual Test Year Maintenance Expense	12,392,698		12,392,698	
3. Storm Damage Expense Adjustment	$ 1,317,316	$ (953,829)	$ 363,487	
4. Jurisdictional Allocation Factor		0.986		
5. Composite After-Tax Income Rate		0.608465 (3)		
6. Impact on Operating Income		$ 572,246		

(1) Section V, WP S-4, page 38

(2) Response to KPSC-2-19

(3) Composite of SIT of 6.39% and FIT of 35% = 39.1535%. After-tax income rate is 1 - 39.1535% = 60.8465%

KENTUCKY POWER COMPANY
YEAR-END CUSTOMER REVENUE ANNUALIZATION ADJUSTMENT

	KPC (1)	Adjustment	AG
1. Revenue Annualization Adj. for Year-End Cust.:	$ 195,124		$ 195,124
2. Associated Operating Expense Adjustment	142,148	(29,874)	112,274 (2)
3. Net Operating Revenue Adjustment	$ 52,976	$ 29,874	$ 82,850
4. Composite After-Tax Income Rate		0.608465 (3)	
5. Impact on Operating Income		$ 18,177	

(1) Section V, WP S-4, page 24

(2) Pro forma adjusted test year operating revenues	$ 337,148,564	DMR-1, page 2
Less: fuel revenues	(111,984,770)	AG-1-53
Operating revenues net of fuel revenues	$ 225,163,794	
Pro forma adusted test year O&M expenses	$ 266,838,943	DMR-1, page 2
Less: fuel costs	(111,984,770)	AG-1-53
O&M expenses net of fuel costs	154,854,173	
Less: adjusted labor expense	(21,231,952)	DMR-1, page 2
adjusted test year employee pension and benefit exp.	(3,893,293)	AG-1-52
adjusted test year regulatory commission expense	(173,778)	(30,211 + 143,567)
Adjusted test year net O&M expenses	$ 129,555,150	
Operating Ratio : $129,555,150 / $225,163,794 =	57.54%	

(3) Composite of SIT of 6.39% and FIT of 35% = 39.1535%. After-tax income rate is 1 - 39.1535% = 60.8465%

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KENTUCKY POWER COMPANY
AEP POOL CAPACITY COST ADJUSTMENT

	KPC (1)	Adjustment	AG
1. AEP Pool Capacity Cost Adjustment	$ 9,120,390	$ (2,317,742)	$ 6,802,648 (2)
2. Jurisdictional Allocation Factor		0.986	
3. Composite After-Tax Income Rate		0.608465 (3)	
4. Impact on Operating Income		$ 1,390,521	

(1) Section V, WP S-4, page 30

(2) Excludes estimated cost adjustment for annualized load changes.

(3) Composite of SIT of 6.39% and FIT of 35% = 39.1535%. After-tax income rate is 1 - 39.1535% = 60.8465%

KENTUCKY POWER COMPANY
PJM NTS AND PTP TRANSMISSION SERVICE REVENUE ADJUSTMENTS

	KPC (1)	Adjustment	AG
1. Normalization of PJM PTP Transmission Revenues	$(9,723,371)	$ 9,723,371	$ -
2. Normalization of PJM NTS Revenues	1,660,768	$(1,660,768)	-
3. Net PJM PTP and NTS Revenue Adjustments	$(8,062,603)	$ 8,062,603	$ -
4. Jurisdictional Allocation Factor		0.986	
5. Composite After-Tax Income Rate		0.608465 (2)	
6. Impact on Operating Income		$ 4,837,130	

(1) Section V, WP S-4, pages 33 and 39

(2) Composite of SIT of 6.39% and FIT of 35% = 39.1535%. After-tax income rate is 1 - 39.1535% = 60.8465%

KENTUCKY POWER COMPANY
NET PJM (REVENUES)/EXPENSES ANNUALIZATION ADJUSTMENTS

	KPC (1)	Adjustment	AG (2)
1. Annualized/Normalized PJM Implicit Congestion Costs	$ 4,958,940	$ 6,933,087	$ 11,892,027
2. Annualized/Normalized PJM FTR Revenues	(7,961,292)	(9,619,647)	(17,580,939)
3. Annualized PJM Operating Reserve Costs	1,495,680	1,243,413	2,739,093
4. Annualized PJM Net Synchr. Condensing Costs	444,600	(2,144)	442,456
5. Annualized PJM Net Reactive Supply Costs	394,728	34,348	429,076
6. Annualized Net Blackstart Costs	12,732	(3,720)	9,012
7. Total Annualized Net PJM (Revenues)/Costs	$ (654,612)	$(1,414,663)	$ (2,069,275)
8. Jurisdictional Allocation Factor		0.986	
9. Composite After-Tax Income Rate		0.608465 (3)	
10. Impact on Operating Income		$ 848,722	

(1) RWB Exhibits 2, 3, 4 and Section V, WP S-4, page 32, column (4).

(2) Response to AG-2-25. Represents actual results for most recent 12-month period ended 11/30/05.

(3) Composite of SIT of 6.39% and FIT of 35% = 39.1535%. After-tax income rate is 1 - 39.1535% = 60.8465%

KENTUCKY POWER COMPANY
PJM ADMINISTRATIVE COST ADJUSTMENT

	KPC (1)	Adjustment	AG
1. Actual Test Year PJM Admin Costs (9 months)	$ 2,215,551		$ 2,215,551
2. Annualization of Test Year PJM Admin Costs [Line 1 x 12/9]	2,954,068		2,954,068
3. Assumed PJM Admin Cost Increase Factor	1.195		-
4. Pro Forma Normalized PJM Admin Costs [L1 x L2]	$ 3,529,848	$ (575,780)	$ 2,954,068
5. Jurisdictional Allocation Factor		0.986	
6. Composite After-Tax Income Rate		0.608465 (2)	
7. Impact on Operating Income		$ 345,437	

(1) Section V, WP S-4, page 41 and response to AG-1-71(b)

(2) Composite of SIT of 6.39% and FIT of 35% = 39.1535%. After-tax income rate is 1 - 39.1535% = 60.8465%

KENTUCKY POWER COMPANY
PUBLIC/COMMUNITY RELATIONS EXPENSE ADJUSTMENTS

1.	Remove Public Relations and Community Relations O&M Expenses Charged to KPCo from AEPSC	$(126,696)	(1)
2.	Remove Other Public Relations and Community Relations O&M Expenses Booked by KPCo	(309,723)	(2)
3.	Total Expense Removal From Test Year O&M Expense	(436,419)	
4.	Composite After-Tax Income Rate	0.608465	(3)
5.	Impact on Operating Income	$ 265,546	

(1) Response to AG-1-74

(2) Responses to AG-1-47 and AG-2-14

(3) Composite of SIT of 6.39% and FIT of 35% = 39.1535%. After-tax income rate is 1 - 39.1535% = 60.8465%

KENTUCKY POWER COMPANY
EXPENSE ADJUSTMENT FOR MISCELLANEOUS AEPSC CHARGES TO KPCo

AEPSC Charges to KPCo:

1. Legislative Affairs Expenses	$	43,233	(1)
2. Public Policy Issues Expenses		45,963	(1)
3. Miscellaneous Additional AEPSC Charges		1,412	(2)
4. Total Expense Removal		90,608	
5. Composite After-Tax Income Rate		0.608465	(3)
6. Impact on Operating Income	$	55,132	

(1) Derived from response to KPSC-2-98E

(2) Responses to AG-1-74a(5) - $111 and AG-1-74b: $179; Response to KPSC-3-4-c&d: $830 and $292

(3) Composite of SIT of 6.39% and FIT of 35% = 39.1535%. After-tax income rate is 1 - 39.1535% = 60.8465%

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Sch. RJH-24

KENTUCKY POWER COMPANY
EEI DUES ADJUSTMENT

	KPC (1)	Adjustment	AG	
1. Test Year Total EEI Membership Dues	$75,838		$75,838	
2. Test Year EEI Dues Charged Below-The-Line	23,325		36,410	(2)
3. Test Year EEI Dues Charged to O&M	$52,513	$ (13,085)	$39,428	
4. Composite After-Tax Income Rate		0.608465 (3)		
5. Impact on Operating Income		$ 7,962		

(1) Response to AG-1-79a, page 2 of 8.
(2) 48.01% x $75,838 = $36,410.

Legislative advocacy (AG-1-79b, page 3 of 8)	23.40%
Regulatory advocacy (AG-1-79b, page 3 of 8)	15.84%
Public relations (AG-1-79b, page 3 of 8)	7.83%
Advertising (AG-1-79b, page 3 of 8: 1.88% x 1/2)	0.94%
	48.01%

(3) Composite of SIT of 6.39% and FIT of 35% = 39.1535%. After-tax income rate is 1 - 39.1535% = 60.8465%

Test Period Ended 6/30/05
Case No. 2005-00341

Sch. RJH-25

KENTUCKY POWER COMPANY
LOBBYING EXPENSE ADJUSTMENT

1. Mr. Pauley's Test Year Total Compensation	$	173,991	(1)
2. Percent Allocable to Lobbying Activities		75%	
3. Test Year Expense to be Removed as Lobbying Expense		130,493	
4. Pauley Compensation Removed from Test Year Expense by KPC as Lobbying Expense		18,400	(2)
5. Additional Lobbying Expenses to be Removed from Test Year Expense	$	112,093	
6. Composite After-Tax Income Rate		0.608465	(3)
7. Impact on Operating Income	$	68,205	

(1) Response to AG-1-77b

(2) Response to KPSC-1-33

(3) Composite of SIT of 6.39% and FIT of 35% = 39.1535%. After-tax income rate is 1 - 39.1535% = 60.8465%

KENTUCKY POWER COMPANY
EXPENSE ADJUSTMENT FOR AWARD BANQUETS, SOCIAL EVENTS, PRIZES AND GIFTS

1. Test Year Expenses Related to Award Banquets Social Events, Prizes and Gifts	$ 58,871	(1)
2. Composite After-Tax Income Rate	0.608465	(2)
7. Impact on Operating Income	$ 35,821	

(1) Response to AG-1-75

(2) Composite of SIT of 6.39% and FIT of 35% = 39.1535%. After-tax income rate is 1 - 39.1535% = 60.8465%

Test Period Ended 6/30/05
Case No. 2005-00341

Sch. RJH-27

KENTUCKY POWER COMPANY
MISCELLANEOUS EXPENSE ADJUSTMENTS

1.	Remove Donation Expenses	$	2,346	(1)
2.	Remove Non-Utility Property Taxes		9,880	(2)
3.	Remove Sponsorship and Contribution Expenses		13,282	(3)
4.	Remove Additional Institutional Advertising Expenses		4,930	(4)
5.	Remove Certain Regulatory Commission Expenses		1,750	(5)
6.	Remove Spousal Expenses		1,105	(6)
7.	Total Miscellaneous Expense Removal		33,293	
8.	Composite After-Tax Income Rate		0.608465	(7)
9.	Impact on Operating Income	$	20,258	

(1) Responses to KPSC-1-32 and 2-100
(2) Responses to KPSC-1-37 and 2-101
(3) Response to AG-1-46
(4) Response to PSC-1-30, page 2.
(5) Response to AG-2-13
(6) Response to AG-1-75
(7) Composite of SIT of 6.39% and FIT of 35% = 39.1535%. After-tax income rate is 1 - 39.1535% = 60.8465%

Test Period Ended 6/30/05
Case No. 2005-00341

Sch. RJH-28

KENTUCKY POWER COMPANY
CORRECTION FOR KPCo's PROPOSED DEPRECIATION EXPENSE ADJUSTMENT

	KPC (1)	Adjustment	Corrected KPC (2)
1. KPC's Proposed Pro Forma Annualized Depreciation Expenses	$ 44,603,968		$ 44,603,968
2. Test Year Per Books Depreciation Expenses	40,912,138	$ (39,253)	$ 40,872,885
3. Depreciation Expense Adjustment	3,691,830	$ 39,253	3,731,083
4. Jurisdictional Allocation Factor	0.990		0.990
5. Jurisdictional Depreciation Expense Adj.	$ 3,654,912	38,860	$ 3,693,772
6. Composite After-Tax Income Rate		0.608465 (3)	
7. Impact on Operating Income		$ (23,645)	

(1) Section V, WP S-4, page 8, column (6), line 5

(2) Response to AG-2-2(d)

(3) Composite of SIT of 6.39% and FIT of 35% = 39.1535%. After-tax income rate is 1 - 39.1535% = 60.8465%

Test Period Ended 6/30/05
Case No. 2005-00341

Sch. RJH-29

KENTUCKY POWER COMPANY
ANNUALIZED DEPRECIATION EXPENSE ADJUSTMENT

OPERATING INCOME IMPACT:	KPC (1)	Adjustment	AG (2)
1. Production Steam	$ 16,391,668	$ (1,974,346)	$ 14,417,322
2. Transmission	10,443,768	(3,506,948)	6,936,820
3. Distribution	16,198,088	(5,562,530)	10,635,558
4. General Plant	1,570,444	(5,915)	1,564,529
5. Total Annualized Depreciation Expense	$ 44,603,968	$ (11,049,739)	$ 33,554,229
6. Jurisdictional Allocation Factor		0.990	
7. Jurisdictional Depreciation Expense Adj.		(10,939,242)	
8. Composite After-Tax Income Rate		0.608465 (3)	
9. Impact on Operating Income		$ 6,656,146	

RATE BASE IMPACT:	
10. Jurisdictional Depreciation Reserve Reduction [L7]	$ (10,939,242)
11. Accumulated Deferred Income Tax Increase [L10 x 39.1535%]	4,283,096

(1) Section V, WP S-4, page 8, column (5)

(2) Testimony of Michael M. Majoros

(3) Composite of SIT of 6.39% and FIT of 35% = 39.1535%. After-tax income rate is 1 - 39.1535% = 60.8465%

Test Period Ended 6/30/05
Case No. 2005-00341

Sch. RJH-30

KENTUCKY POWER COMPANY
MISCELLANEOUS SERVICE CHARGE REVENUE ADJUSTMENT

	KPC (1)	Adjustment	AG (2)
1. Pro Forma Annualized Misc. Service Charge Revenues	$620,799	$ (384,085)	$236,714
2. Test Year Miscellaneous Service Charge Revenues	164,826		164,826
3. Miscellaneous Service Charge Revenue Adjustment	$455,973	(384,085)	$ 71,888
4. Composite After-Tax Income Rate		0.608465 (3)	
5. Impact on Operating Income		$ (233,702)	

(1) Section V, WP S-4, page 21
(2) Testimony of David Brown-Kinloch
(3) Composite of SIT of 6.39% and FIT of 35% = 39.1535%. After-tax income rate is 1 - 39.1535% = 60.8465%

Test Period Ended 6/30/05
Case No. 2005-00341

Sch. RJH-31

KENTUCKY POWER COMPANY
AFUDC OFFSET ADJUSTMENT

	KPC (1)	Adjustment	AG	
1. CWIP Subject to AFUDC	$ 15,798,401		$ 15,798,401	
2. Overall Rate of Return	7.89%		6.81%	Sch. RJH-2
3. Pro Forma Annualized Test Year AFUDC	1,246,494	(170,818)	1,075,676	
4. DFIT on ABFUDC	184,674	(45)	184,629	(2)
5. Net Operating Income Impact	$ 1,061,820	$ (170,773)	$ 891,047	

(1) Section V, WP S-4, page 19
(2) $1,075,676 x 49.04% [(6.81% - 3.47%) / 6.981%] x 35%

KENTUCKY POWER COMPANY
EXAMPLES OF POST TEST YEAR CHANGES NOT REFLECTED BY KPC

	KPC-Proposed Test Year Annualized	2006	2007	2008
	(1)	(2)	(2)	(2)
1. Pension Costs	$ 1,505,873	$ 1,077,519	$ 1,137,590	$ 747,046
2. Change from Test Year		(428,354)	(368,283)	(758,827)
3. O&M Expense Ratio		67.65%	67.65%	67.65%
4. Jurisdictional Allocator		0.991	0.991	0.991
5. Jurisdictional O&M Exp. Impact [L3xL4xL5]		$ (287,173)	$ (246,901)	$ (508,726)

	KPC-Proposed Test Year Annualized	2006	2007	2008
	(1)	(3)	(3)	(3)
6. OPEB Costs	$ 2,204,014	$ 2,062,204	$ 1,918,830	$ 1,782,872
7. Change from Test Year		(141,810)	(285,184)	(421,142)
8. O&M Expense Ratio		67.65%	67.65%	67.65%
9. Jurisdictional Allocator		0.991	0.991	0.991
10. Jurisdictional O&M Exp. Impact [L3xL4xL5]		$ (95,071)	$ (191,191)	$ (282,338)

	KPC-Proposed Test Year Annualized	2006	2007	2008
	(4)	(5)	(5)	(5)
11. Customer Growth Revenue Annualization	$ 195,124	$ 1,226,355	$ 3,675,928	$ 4,990,764
12. Change from Test Year		1,031,231	3,480,804	4,795,640
13. Operating Exp. Change @ Ratio of 57.54% (6)		593,370	2,002,855	2,759,411
14. Net Revenue Change [L12-L13]		$ 437,861	$ 1,477,949	$ 2,036,229

(1) Section V, WP S-4, page 4, lines 10 and 16
(2) Response to KPSC-1-50, p. 49
(3) Response to KPSC-1-51, pp. 51, 52 and 53
(4) Exhibit DMR-1, page 1
(5) Section II, Application Exhibit A, page 348 of 352
(6) Schedule RJH-, footnote (3)

APPENDIX I

PRIOR REGULATORY EXPERIENCE OF ROBERT J. HENKES

* = Testimonies prepared and submitted

ARKANSAS

Southwestern Bell Telephone Company Divestiture Base Rate Proceeding*	Docket 83-045-U	09/1983

DELAWARE

Delmarva Power and Light Company Electric Fuel Clause Proceeding	Docket 41-79	04/1980
Delmarva Power and Light Company Electric Fuel Clause Proceeding	Docket 80-39	02/1981
Delmarva Power and Light Company Sale of Power Station Generation	Complaint Docket 279-80	04/1981
Delmarva Power and Light Company Electric Base Rate Proceeding	Docket 81-12	06/1981
Delmarva Power and Light Company Gas Base Rate Proceeding*	Docket 81-13	08/1981
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 82-45	04/1983
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 83-26	04/1984
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 84-30	04/1985
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 85-26	03/1986
Delmarva Power and Light Company Report of DP&L Operating Earnings*	Docket 86-24	07/1986
Delmarva Power and Light Company Electric Base Rate Proceeding*	Docket 86-24	12/1986 01/1987
Delmarva Power and Light Company	Docket 85-26	10/1986

Report Re. PROMOD and Its Use in Fuel Clause Proceedings*		
Diamond State Telephone Company Base Rate Proceeding*	Docket 86-20	04/1987
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 87-33	06/1988
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 90-35F	05/1991
Delmarva Power and Light Company Electric Base Rate Proceeding*	Docket 91-20	10/1991
Delmarva Power and Light Company Gas Base Rate Proceeding*	Docket 91-24	04/1992
Artesian Water Company Water Base Rate Proceeding*	Docket 97-66	07/1997
Artesian Water Company Water Base Rate Proceeding*	Docket 97-340	02/1998
United Water Delaware Water Base Rate Proceeding*	Docket 98-98	08/1998
Delmarva Power and Light Company Revenue Requirement and Stranded Cost Reviews	Not Docketed	12/1998
Artesian Water Company Water Base Rate Proceeding*	Docket 99-197 (Direct Test.)	09/1999
Artesian Water Company Water Base Rate Proceeding*	Docket 99-197 (Supplement. Test)	10/1999
Tidewater Utilities/ Public Water Co. Water Base Rate Proceedings*	Docket No. 99-466	03/2000
Delmarva Power & Light Company Competitive Services Margin Sharing Proceeding*	Docket No. 00-314	03/2001
Artesian Water Company Water Base Rate Proceeding*	Docket No. 00-649	04/2001

Chesapeake Gas Company Gas Base Rate Proceeding*	Docket No. 01-307	12/2001
Tidewater Utilities Water Base Rate Proceeding*	Docket No. 02-28	07/2002
Artesian Water Company Water Base Rate Proceeding*	Docket No. 02-109	09/2002
Delmarva Power & Light Company Electric Cost of Service Proceeding	Docket No. 02-231	03/2003
Delmarva Power & Light Company Gas Base Rate Proceeding*	Docket No. 03-127	08/2003
Artesian Water Company Water Base Rate Proceeding*	Docket No. 04-42	08/2004

DISTRICT OF COLUMBIA

District of Columbia Natural Gas Co. Gas Base Rate Proceeding*	Formal Case 870	05/1988
District of Columbia Natural Gas Co. Gas Base Rate Proceeding*	Formal Case 890	02/1990
District of Columbia Natural Gas Co. Waiver of Certain GS Provisions	Formal Case 898	08/1990
Chesapeake and Potomac Telephone Co. Base Rate Proceeding*	Formal Case 850	07/1991
Chesapeake and Potomac Telephone Co. Base Rate Proceeding*	Formal Case 926	10/1993
Bell Atlantic - District of Columbia SPF Surcharge Proceeding	Formal Case 926	06/19/94
Bell Atlantic - District of Columbia Price Cap Plan and Earnings Review	Formal Case 814 IV	07/1995

GEORGIA

Southern Bell Telephone Company	Docket 3465-U	08/1984

Base Rate Proceeding		
Southern Bell Telephone Company Base Rate Proceeding	Docket 3518-U	08/1985
Georgia Power Company Electric Base Rate and Nuclear Power Plant Phase-In Proceeding*	Docket 3673-U	08/1987
Georgia Power Company Electric Base Rate and Nuclear Power Plant Phase-In Proceeding*	Docket 3840-U	08/1989
Southern Bell Telephone Company Base Rate Proceeding	Docket 3905-U	08/1990
Southern Bell Telephone Company Implementation, Administration and Mechanics of Universal Service Fund*	Docket 3921-U	10/1990
Atlanta Gas Light Company Gas Base Rate Proceeding*	Docket 4177-U	08/1992
Southern Bell Telephone Company Report on Cash Working Capital*	Docket 3905-U	03/1993
Atlanta Gas Light Company Gas Base Rate Proceeding*	Docket No. 4451-U	08/1993
Atlanta Gas Light Company Gas Base Rate Proceeding	Docket No. 5116-U	08/1994
Georgia Independent Telephone Companies Earnings Review and Show Cause Proceedings	Various Dockets	1994
Georgia Power Company Earnings Review - Report to GPSC*	Non-Docketed	09/1995
Georgia Alltel Telecommunication Companies Earnings and Rate Reviews	Docket No. 6746-U	07/1996
Frontier Communications of Georgia Earnings and Rate Review	Docket No. 4997-U	07/1996
Georgia Power Company Electric Base Rate / Accounting Order Proceeding	Docket No. 9355-U	12/1998

Savannah Electric Power Company Electric Base Rate Case/Alternative Rate Plan*	Docket No. 14618-U	03/2002
Georgia Power Company Electric Base Rate / Alternative Rate Plan Proceeding*	Docket No. 18300-U	12/2004
Savannah Electric Power Company Electric Base Rate Case/Alternative Rate Plan*	Docket No. 19758-U	03/2005

FERC

Philadelphia Electric/Conowingo Power Electric Base Rate Proceeding*	Docket ER 80-557/558	07/1981

KENTUCKY

Kentucky Power Company Electric Base Rate Proceeding*	Case 8429	04/1982
Kentucky Power Company Electric Base Rate Proceeding*	Case 8734	06/1983
Kentucky Power Company Electric Base Rate Proceeding*	Case 9061	09/1984
South Central Bell Telephone Company Base Rate Proceeding*	Case 9160	01/1985
Kentucky-American Water Company Base Rate Proceeding*	Case 97-034	06/1997
Delta Natural Gas Company Base Rate Proceeding*	Case 97-066	07/1997
Kentucky Utilities and LG&E Company Environmental Surcharge Proceeding	97-SC-1091-DG	01/1999
Delta Natural Gas Company Experimental Alternative Regulation Plan*	Case No. 99-046	07/1999
Delta Natural Gas Company Base Rate Proceeding*	Case No. 99-176	09/1999

Louisville Gas & Electric Company Gas Base Rate Proceeding*	Case No. 2000-080	06/2000
Kentucky-American Water Company Base Rate Proceeding*	Case No. 2000-120	07/2000
Jackson Energy Cooperative Corporation Electric Base Rate Proceeding*	Case No. 2000-373	02/2001
Kentucky-American Water Company Base Rate Rehearing*	Case No. 2000-120	02/2001
Kentucky-American Water Company Rehearing Opposition Testimony*	Case No. 2000-120	03/2001
Union Light Heat and Power Company Gas Base Rate Proceeding*	Case No. 2001-092	09/2001
Louisville Gas & Electric Company and Kentucky Utilities Company Deferred Debits Accounting Order	Case No. 2001-169	10/2001
Fleming-Mason Energy Cooperative Electric Base Rate Proceeding	Case No. 2001-244	05/2002
Northern Kentucky Water District Water District Base Rate Proceeding	Case No. 2003-0224	02/2004
Louisville Gas & Electric Company Electric Base Rate Proceeding*	Case No. 2003-0433	03/2004
Louisville Gas & Electric Company Gas Base Rate Proceeding*	Case No. 2003-0433	03/2004
Delta Natural Gas Company Base Rate Proceeding*	Case No. 2004-00067	07/2004
Union Light Heat and Power Company Gas Base Rate Proceeding*	Case No. 2005-00042	06/2005
Big Sandy Rural Electric Cooperative Electric Base Rate Proceeding	Case No. 2005-00125	08/2005
Louisville Gas & Electric Company Value Delivery Surcredit Mechanism*	Case No. 2005-00352	12/2005

Kentucky Utilities Company Value Delivery Surcredit Mechanism*	Case No. 2005-00351	12/2005

MAINE

Continental Telephone Company of Maine Base Rate Proceeding	Docket 90-040	12/1990
Central Maine Power Company Electric Base Rate Proceeding	Docket 90-076	03/1991
New England Telephone Corporation - Maine Chapter 120 Earnings Review	Docket 94-254	12/1994

MARYLAND

Potomac Electric Power Company Electric Base Rate Proceeding*	Case 7384	01/1980
Delmarva Power and Light Company Electric Base Rate Proceeding*	Case 7427	08/1980
Chesapeake and Potomac Telephone Company Western Electric and License Contract	Case 7467	10/1980
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7467	10/1980
Washington Gas Light Company Gas Base Rate Proceeding	Case 7466	11/1980
Delmarva Power and Light Company Electric Base Rate Proceeding*	Case 7570	10/1981
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7591	12/1981
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7661	11/1982
Chesapeake and Potomac Telephone Company Computer Inquiry II*	Case 7661	12/1982
Chesapeake and Potomac Telephone Company	Case 7735	10/1983

Divestiture Base Rate Proceeding*		
AT&T Communications of Maryland Base Rate Proceeding	Case 7788	1984
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7851	03/1985
Potomac Electric Power Company Electric Base Rate Proceeding	Case 7878	1985
Delmarva Power and Light Company Electric Base Rate Proceeding	Case 7829	1985

NEW HAMPSHIRE

Granite State Electric Company Electric Base Rate Proceeding	Docket DR 77-63	1977

NEW JERSEY

Elizabethtown Water Company Water Base Rate Proceeding	Docket 757-769	07/1975
Jersey Central Power and Light Company Electric Base Rate Proceeding	Docket 759-899	09/1975
Middlesex Water Company Water Base Rate Proceeding	Docket 761-37	01/1976
Jersey Central Power and Light Company Electric Base Rate Proceeding	Docket 769-965	09/1976
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings	Docket 761-8	10/1976
Atlantic City Electric Company Electric Base Rate Proceeding*	Docket 772-113	04/1977
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket 7711-1107	05/1978
Public Service Electric and Gas Company Raw Materials Adjustment Clause	Docket 794-310	04/1979

Rockland Electric Company Electric Base Rate Proceeding*	Docket 795-413	09/1979
New Jersey Bell Telephone Company Base Rate Proceeding	Docket 802-135	02/1980
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 8011-836	02/1981
Rockland Electric Company Electric Base Rate Proceeding*	Docket 811-6	05/1981
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 8110-883	02/1982
Public Service Electric and Gas Company Electric Fuel Clause Proceeding*	Docket 812-76	08/1982
Public Service Electric and Gas Company Raw Materials Adjustment Clause	Docket 812-76	08/1982
New Jersey Bell Telephone Company Base Rate Proceeding	Docket 8211-1030	11/1982
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 829-777	12/1982
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket 837-620	10/1983
New Jersey Bell Telephone Company Base Rate Proceeding	Docket 8311-954	11/1983
AT&T Communications of New Jersey Base Rate Proceeding*	Docket 8311-1035	02/1984
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 849-1014	11/1984
AT&T Communications of New Jersey Base Rate Proceeding*	Docket 8311-1064	05/1985
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket ER8512-1163	05/1986

Public Service Electric and Gas Company Electric Fuel Clause Proceeding*	Docket ER8512-1163	07/1986
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket ER8609-973	12/1986
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket ER8710-1189	01/1988
Public Service Electric and Gas Company Electric Fuel Clause Proceeding*	Docket ER8512-1163	02/1988
United Telephone of New Jersey Base Rate Proceeding	Docket TR8810-1187	08/1989
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket ER9009-10695	09/1990
United Telephone of New Jersey Base Rate Proceeding	Docket TR9007-0726J	02/1991
Elizabethtown Gas Company Gas Base Rate Proceeding*	Docket GR9012-1391J	05/1991
Rockland Electric Company Electric Fuel Clause Proceeding	Docket ER9109145J	11/1991
Jersey Central Power and Light Company Electric Fuel Clause Proceeding	Docket ER91121765J	03/1992
New Jersey Natural Gas Company Gas Base Rate Proceeding*	Docket GR9108-1393J	03/1992
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket ER91111698J	07/1992
Rockland Electric Company Electric Fuel Clause Proceeding	Docket ER92090900J	12/1992
Middlesex Water Company Water Base Rate Proceeding*	Docket WR92090885J	01/1993
Elizabethtown Water Company Water Base Rate Proceeding*	Docket WR92070774J	02/1993
Public Service Electric and Gas Company	Docket ER91111698J	03/1993

Electric Fuel Clause Proceeding		
New Jersey Natural Gas Company Gas Base Rate Proceeding*	Docket GR93040114	08/1993
Atlantic City Electric Company Electric Fuel Clause Proceeding	Docket ER94020033	07/1994
Borough of Butler Electric Utility Various Electric Fuel Clause Proceedings	Docket ER94020025	1994
Elizabethtown Water Company Water Base Rate Proceeding	Non-Docketed	11/1994
Public Service Electric and Gas Company Electric Fuel Clause Proceeding	Docket ER 94070293	11/1994
Rockland Electric Company Electric Fuel Clause Proceeding and Purchased Power Contract By-Out	Docket Nos. 940200045 and ER 9409036	12/1994
Jersey Central Power & Light Company Electric Fuel Clause Proceeding	Docket ER94120577	05/1995
Elizabethtown Water Company Purchased Water Adjustment Clause Proceeding*	Docket WR95010010	05/1995
Middlesex Water Company Purchased Water Adjustment Clause Proceeding	Docket WR94020067	05/1995
New Jersey American Water Company* Base Rate Proceeding	Docket WR95040165	01/1996
Rockland Electric Company Electric Fuel Clause Proceeding	Docket ER95090425	01/1996
United Water of New Jersey Base Rate Proceeding*	Docket WR95070303	01/1996
Elizabethtown Water Company Base Rate Proceeding*	Docket WR95110557	03/1996
New Jersey Water and Sewer Adjustment Clauses Rulemaking Proceeding*	Non-Docketed	03/1996
United Water Vernon Sewage Company	Docket WR96030204	07/1996

Base Rate Proceeding*		
United Water Great Gorge Company Base Rate Proceeding*	Docket WR96030205	07/1996
South Jersey Gas Company Base Rate Proceeding	Docket GR960100932	08/1996
Middlesex Water Company Purchased Water Adjustment Clause Proceeding*	Docket WR96040307	08/1996
Atlantic City Electric Company Fuel Adjustment Clause Proceeding*	Docket No.ER96030257	08/1996
Public Service Electric & Gas Company and Atlantic City Electric Company Investigation into the continuing outage of the Salem Nuclear Generating Station*	Docket Nos. ES96039158 & ES96030159	10/1996
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket No.EC96110784	01/1997
Consumers New Jersey Water Company Base Rate Proceeding*	Docket No.WR96100768	03/1997
Atlantic City Electric Company Fuel Adjustment Clause Proceeding*	Docket No.ER97020105	08/1997
Public Service Electric & Gas Company Electric Restructuring Proceedings*	Docket Nos. EX912058Y, EO97070461, EO97070462, EO97070463	11/1997
Atlantic City Electric Company Limited Issue Rate Proceeding*	Docket No.ER97080562	12/1997
Rockland Electric Company Limited Issue Rate Proceeding	Docket No.ER97080567	12/1997
South Jersey Gas Company Limited Issue Rate Proceeding	Docket No.GR97050349	12/1997
New Jersey American Water Company Limited Issue Rate Proceeding	Docket No.WR97070538	12/1997
Elizabethtown Water Company and Mount Holly Water Company	Docket Nos. WR97040288, WR97040289	12/1997

Limited Issue Rate Proceedings

United Water of New Jersey, United Water Toms River and United Water Lambertville Limited Issue Rate Proceedings	Docket Nos.WR9700540, WR97070541, WR97070539	12/1997
Public Service Electric & Gas Company Electric Restructuring Proceedings*	Docket Nos. EX912058Y, EO97070461, EO97070462, EO97070463	01/1998
Consumers New Jersey Water Company Base Rate Proceeding*	Docket No. WR97080615	01/1998
New Jersey-American Water Company Base Rate Proceeding*	Docket No.WR98010015	07/1998
Consumers New Jersey Water Company Merger Proceeding	Docket No.WM98080706	12/1998
Atlantic City Electric Company Fuel Adjustment Clause Proceeding*	Docket No.ER98090789	02/1999
Middlesex Water Company Base Rate Proceeding*	Docket No.WR98090795	03/1999
Mount Holly Water Company Base Rate Proceeding - Phase I*	Docket No. WR99010032	07/1999
Mount Holly Water Company Base Rate Proceeding - Phase II*	Docket No. WR99010032	09/1999
New Jersey American Water Company Acquisitions of Water Systems	Docket Nos. WM9910018	09/1999
	WM9910019	09/1999
Mount Holly Water Company Merger with Homestead Water Utility	Docket No. WM99020091	10/1999
Applied Wastewater Management, Inc. Merger with Homestead Treatment Utility	Docket No.WM99020090	10/1999
Environmental Disposal Corporation (Sewer) Base Rate Proceeding*	Docket No.WR99040249	02/2000
Elizabethtown Gas Company		
Gas Cost Adjustment Clause Proceeding	Docket No.GR99070509	03/2000
DSM Adjustment Clause Proceeding	Docket No. GR99070510	03/2000

New Jersey American Water Company Gain on Sale of Land	Docket No. WM99090677	04/2000
Jersey Central Power & Light Company NUG Contract Buydown	Docket No. EM99120958	04/2000
Shore Water Company Base Rate Proceeding	Docket No. WR99090678	05/2000
Shorelands Water Company Water Diversion Rights Acquisition	Docket No. WO00030183	05/2000
Mount Holly and Elizabethtown Water Companies Computer and Billing Services Contracts	Docket Nos. WO99040259 WO9904260	06/2000 06/2000
United Water Resources, Inc. Merger with Suez-Lyonnaise	Docket No. WM99110853	06/2000
E'Town Corporation Merger with Thames, Ltd.	Docket No. WM99120923	08/2000
Consumers Water Company Water Base Rate Proceeding*	Docket No. WR00030174	09/2000
Atlantic City Electric Company Buydown of Purchased Power Contract	Docket No. EE00060388	09/2000
Applied Wastewater Management, Inc. Authorization for Accounting Changes	Docket No. WR00010055	10/2000
Elizabethtown Gas Company		
Gas Cost Adjustment Clause Proceeding	Docket No. GR00070470	10/2000
DSM Adjustment Clause Proceeding	Docket No. GR00070471	10/2000
Trenton Water Works Water Base Rate Proceeding*	Docket No. WR00020096	10/2000
Middlesex Water Company Water Base Rate Proceeding*	Docket No. WR00060362	11/2000
New Jersey American Water Company Land Sale - Ocean City	Docket No. WM00060389	11/2000
Pineland Water Company Water Base Rate Proceeding*	Docket No. WR00070454	12/2000

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