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JAN 9 2006

PUBLIC SERVICE
COMMISSION

Via Hand Delivery

January 9, 2006

Beth A. O'Donnell, Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602

Re: Case No. 2005-00341

Dear Ms. O'Donnell:

Please find enclosed the original and twelve (12) copies each of the Direct Testimony and Exhibits of Lane Kollen, Stephen J. Baron and Richard A. Baudino filed on behalf of the Kentucky Industrial Utility Customers, Inc. in the above-referenced matter. By copy of this letter, all parties listed on the Certificate of Service have been served.

Please place this document of file.

Very Truly Yours,

David F. Boehm, Esq.
Michael L. Kurtz, Esq.
BOEHM, KURTZ & LOWRY

MLKkew
Attachment
cc: Certificate of Service

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing was served by mailing a true and correct copy, by first-class postage prepaid mail, and electronic mail, (when available) to all parties on the 9th day of January, 2005.

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

JAN 9 2006

PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

DIRECT TESTIMONY

AND EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

JANUARY 2006

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

GENERAL ADJUSTMENTS IN	)	
ELECTRIC RAATES OF	)	**CASE NO.**
KENTUCKY POWER COMPANY	)	**2005-00341**

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

DIRECT TESTIMONY OF LANE KOLLEN

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Lane Kollen. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a utility rate and planning consultant holding the position of Vice President and Principal with the firm of Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I earned a Bachelor of Business Administration in Accounting degree from the University of Toledo. I also earned a Master of Business Administration degree from the University of Toledo. I am a Certified Public Accountant, with a practice license, and a Certified Management Accountant.

I have been an active participant in the utility industry for more than twenty-five years, both as an employee and as a consultant. Since 1986, I have been a consultant with Kennedy and Associates, providing services to state government agencies and large consumers of utility services in the ratemaking, financial, tax, accounting, and management areas. From 1983 to 1986, I was a consultant with Energy Management Associates, providing services to investor and consumer owned utility companies. From 1976 to 1983, I was employed by The Toledo Edison Company in a series of positions encompassing accounting, tax, financial, and planning functions.

I have appeared as an expert witness on accounting, finance, ratemaking, and planning issues before regulatory commissions and courts at the federal and state levels on more than one hundred occasions. I have developed and presented papers at industry conferences on ratemaking, accounting, and tax issues.

I have testified before the Kentucky Public Service Commission on numerous occasions, including the most recent Kentucky Power Company ("KPC" or "Company") Environmental Cost Recovery ("ECR") proceeding, Case No. 2005-00068; other Company ECR proceedings, Case Nos. 1996-00489, 2000-00107 and 2002-00169; the three most recent Louisville Gas and Electric Company ("LG&E") and two most recent Kentucky Utilities Company ("KU") base rate proceedings; numerous LG&E and KU ECR and fuel adjustment clause ("FAC") proceedings; and other proceedings involving Big Rivers Electric Corporation and East Kentucky Power Cooperative, Inc. My qualifications and regulatory appearances are further detailed in my Exhibit___(LK-1).

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Kentucky Industrial Utility Customers, Inc. ("KIUC"), a group a large users taking electric and gas service on the Kentucky Power Company system.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the Company's request for a new Net Congestion Recovery ("NCR") rider, to address the Company's requests to modify the existing System Sales Clause ("SSC") and Environmental Cost Recovery ("ECR") riders, and to address numerous revenue requirement issues that affect the amount of the Company's requested base rate increase.

Q. Please summarize your testimony.

A. I recommend that the Commission accept and implement the Company's proposed Net Congestion Recovery Rider. However, I recommend that the Commission modify the Company's proposed NCR rider to include off-system sales margins and eliminate the SSC as a separate tariff. This new NCR rider will track and allow the Company recovery of the net changes in the actual financial transmission rights ("FTR") and auction revenue rights ("ARR") revenues, implicit congestion costs and off-system sales margins compared to the amounts included in base rates. Including off-system sales margins in the NCR rider in addition to the revenues and costs proposed by the Company will ensure that these uncertain revenues and costs all are provided ratemaking recovery in a comprehensive and consistent manner, thus equitably balancing the interests of the Company and its ratepayers.

I recommend that the Commission accept the Company's proposal to roll-in the test year ECR revenue requirement to base rates and to reflect a credit in the ECR for the roll-in revenue requirement. However, I recommend that the Commission modify the Company's computation of the ECR credit to reflect a percentage of revenues credit on a jurisdictional basis, consistent with the Commission precedent on such roll-ins. The Company's proposed fixed dollar credit methodology significantly understates the effect of the roll-in the ECR because it fails to reflect sales growth subsequent to the test year and understates the jurisdictional amount of ECR costs recovered through base rates. I also recommend that the Commission reject the Company's proposal to modify the existing ECR to eliminate the effects of the §199 deduction on federal and state income tax expense. The Commission recently decided this issue in Case No. 2005-00068. The Company advances no new arguments that require the Commission to revisit this issue.

In addition, I recommend that the Commission reduce the Company's claimed net increase of $64.796 million (after the ECR revenue credit) by at least $38.872 million for the issues listed and amounts quantified on the following table. I address each of these issues on the following table, except for the return on common equity, which Mr. Baudino addresses, and the transmission revenue credits and PJM net congestion costs, which Mr. Baron addresses. I also quantify the effects of each issue on the revenue requirement.

KENTUCKY POWER COMPANY REVENUE REQUIREMENT
SUMMARY OF KIUC RECOMMENDATIONS
REVENUE REQUIREMENT EFFECTS
($ MILLION)

Capitalization Issues	
Reduction to Reflect 13 Month Avg M&S Inventory	(73)
Remove KPCO Reliability Capital Adjustment	(597)
Recognize Additional Pension Funding in 2005	(660)
Remove Prior Deferral of RTO Formation Costs	(129)
Operating Income Issues	
Correct Error in Off-System Sales Margin Roll-In	(2,035)
Increase Off-System Sales Margins to 2006 Projection	(5,102)
Remove Amortization of Deferred RTO Formation Costs	(160)
Remove KPCO Reliability O&M Expense Adjustment	(6,103)
Reduce Pension Expense to 2006 Amount	(288)
Reduce OPEB Expense to 2006 Amount	(96)
Revise Depreciation Expense for Changes in Proposed Depreciation Rates	(6,760)
Reduce KPCO Storm Damage Adjustment Based on 10 Year Average	(386)
Increase PJM Transmission Revenue Credits	(399)
Reduce PJM Net Congestion Costs	(2,121)
Remove KPCO Big Sandy Plant Maintenance Expense Adjustment	(1,305)
Remove KPCO §199 Deduction Tax Savings Included in Filing	414
Correct Error in Tax Expense Due to Interest Synchronization	(74)
Remove OH and WV Taxes from Gross Revenue Conversion Factor	(135)
Revise Kentucky State Income Tax Rate to 6.0%	(675)
Include Corrected §199 Deduction Tax Savings	(548)
Rate of Return Issues	
Reflect Return on Equity of 9.350%	(11,639)
Total KIUC Adjustments to KPCO Request	(38,872)

II. TARIFF RIDER ISSUES

<u>Proposed Net Congestion Recovery Tariff Should Be Accepted, but Modified to Include Off-System Sales Margins</u>

Q. Please describe the Company's proposal for a Net Congestion Recovery Rider.

A. The Company proposes a Net Congestion Recovery Rider to recover the incremental net costs or to refund the incremental net revenues associated with PJM financial transmission right revenues and PJM implicit congestion costs in excess of the net revenues or costs included in base rates.[1] The Company proposes that the incremental net congestion revenues or costs be determined annually for the twelve months ending September 30 each year with a rate effective period of January 1 through December 31 of the following year. A true-up adjustment for the actual preceding calendar year will be recovered or refunded over the rate effective period of February 1 through December 31 of the following year. The Company proposes no sharing of the net congestion revenues or costs. The entirety of the net cost will be either recovered from or the net revenues refunded to ratepayers.

---

[1] The Company proposes that Auction Revenue Rights revenues be included in the NCR Rider commencing in June 2007 when AEP is first allocated these rights.

Q. Please describe the Company's proposal for the existing System Sales Clause Rider.

A. The Company proposes to continue the SSC, but to reset the off-system sales margin in base rates at $24.855 million (see Section V Workpaper S-4 page 26). The Company proposes no change in the 50%/50% sharing of margins above costs and in excess of the amount of the margins included in base rates.

Q. Should the Commission accept the Company's proposal for a Net Congestion Recovery Rider?

A. Yes. I recommend that the Commission accept the Company's proposal, subject to several modifications. The first modification is to include off-system sales margins in the NCR. This will require the termination of the SSC Rider effective with the expense month at the date of the roll-in because it no longer will be necessary. The SSC over or under-recovery at the date of the last SSC billings should be transferred to the true-up balance of the NCR Rider.

The second modification is to change the amounts rolled-in to base rates for FTR and ARR revenues, congestion costs, and system sales margins to reflect the amounts allowed by the Commission in the base revenue requirement, and for which KIUC proposes amounts different than those proposed by the Company.

Q. Why should the Commission integrate off-system sales margins in the Net Congestion Recovery Rider?

A. First, off-system sales margins are subject to significant volatility. Volatility is the primary argument advanced by the Company in support of the NCR Rider for FTR revenues and implicit congestion costs. The PJM hourly and day ahead market prices that AEP receives for off system sales cannot be accurately predicted. These PJM market prices fluctuate with natural gas prices, emission allowance prices, and for other reasons. Nor can the volume of off-system sales be accurately forecasted. Volume depends on native load use, weather, generation forced outages, and other reasons. Because of volatility and its significance to revenue requirements, off-system sales margins are ideally suited for a rider.

Second, including off-system sales margins in the NCR and the elimination of the existing SSC Rider will promote administrative efficiency through a single annual filing for FTR and ARR revenues, off-system sales margins, and implicit congestion costs in the manner proposed by the Company for the NCR Rider.

Third, grouping these revenues and costs together ensures that they will be treated consistently and equitably for ratemaking purposes, with 100% of the net revenues and costs recovered or refunded to ratepayers, rather than 100% of some revenues and costs and 50% of other revenues refunded to ratepayers.

Fourth, the use of a single annual factor, subject to true-up, in the manner proposed by the Company for the NCR Rider, will eliminate the monthly volatility of the existing SSC Rider.

Finally, when this Commission approved the Company's transfer of its transmission system to PJM, one of the most significant benefits claimed by AEP was increased margins from off-system sales into the PJM market. That promise can best be realized through inclusion of the off-system sales margins in the new rider.

Q. Should the Commission continue the 50%/50% sharing of incremental off-system sales margins regardless of whether those margins are included in the proposed Net Congestion Recovery Rider or retained in the SSC?

A. No. The Commission should discontinue the 50%/50% sharing regardless of its determination on the continuation of the existing SSC Rider as a separate tariff. Under any scenario, 100% of the margins should go to ratepayers.

First, there is no rationale to continue the 50%/50% sharing given the Company's participation in PJM and the ability to sell all excess available energy on an economic basis into the pool. If ratepayers are required to pay 100% of the costs to supply the off-system sales, which they are even under the SSC Rider,[2] then they should receive 100% of the margins in excess of those costs, not only 50%.

Second, there is no rationale or need to pay a commission or incentive for the Company to engage in off-system sales. The entirety of the fixed costs, salaries and other costs incurred to engage in such off-system sales by the AEP Service Corporation, as the sales agent for the AEP Companies, is paid by the AEP System Companies according to their respective Member Load Ratio (MLR) shares. The Company's MLR share of its off-system sales agent's costs is included in the base revenue requirement. The entirety of the incremental costs of the off-system sales also is paid by the AEP System Companies. The Company's MLR share of these incremental costs is included in either the base revenue requirement or the System Sales Clause Rider. Given that there already is 100% cost recovery of the costs incurred by the Company for the services of its sales

[3] 100% of the fuel, variable O&M, including explicit congestion costs, and environmental costs incurred to supply the off-system sale are recovered through the SSC. Only the revenues in excess of these costs (the margins) are shared 50%/50%.

agent, it makes no sense to require ratepayers also to pay the Company a commission or incentive for the same services of the same agent.

In addition, the payment of an incentive to AEP shareholders by Kentucky ratepayers will not increase the margins on AEP's off system sales. Kentucky Power Company comprises only 7.5% of the AEP System load as measured by its MLR. Given the Company's relatively small size, an incentive paid by Kentucky ratepayers will not cause AEP to realize greater off-system sales or margins.

Third, the Commission is under no obligation to perpetuate the existing 50%/50% sharing of incremental off-system sales margins over the amount included in base rates. The SSC, with it 50%/50% sharing, was an experimental rider implemented in an earlier era. The SSC originally was the result of a settlement of Case No. 9061 subsequent to the issuance of an initial order that was strongly contested in that proceeding. The SSC was continued indefinitely beyond its initial experimental period in Case No. 91-066 as the result of another settlement in that proceeding. In neither the settlements nor the Commission Orders approving those settlements did the Commission establish the sanctity of or even the necessity for a 50%/50% sharing outside the specific context of those settlement agreements.

In addition, the 50%/50% sharing was adopted in an earlier era, prior to the extensive changes in the wholesale power market occasioned by the 1992 EPA Act and the FERC's actions to transform the wholesale power market through the issuance and implementation of Orders 888, 889, 2000, and others, including its efforts to promote the formation of RTOs. The existence of the PJM hourly and day ahead market provides AEP a readily available outlet for all of its excess generation. While the PJM market makes it far easier for utilities to sell all of their excess generation, that market liquidity comes at a cost. The cost consists of all of the PJM fees and administrative charges to operate the market. While I do not object to AEP recovering 100% of the PJM fees and administrative costs, a balanced ratemaking approach should give ratepayers 100% of the off-setting benefits in the form of off-system sales margins. As such, no incentive or subsidy from Kentucky ratepayers is needed or appropriate for AEP to maximize its off-system sales margins.

Fourth, the elimination of the 50%/50% sharing is consistent with the Company's own proposal to recover 100% of its net congestion costs through the Net Congestion Recovery Rider. The elimination of the 50%/50% sharing also is consistent with all the Company's other tariff Riders, which include the Company's FAC and ECR Riders. These other tariff Riders all provide the Company 100% recovery of its net costs. None of those Riders require the Company to share in either costs or revenues. Thus, it is inconsistent and inequitable to refund only 50% of the off-system sales revenues in excess of the costs to make those sales through either the Net Congestion Recovery Rider or the existing System Sales Clause Rider.

Fifth, the Company's proposal to perpetuate the 50%/50% sharing is inconsistent with a recent proposal made by AEP Appalachian Power Company pending before the West Virginia Public Service Commission. In that proposal, AEP Appalachian Power Company proposed an Expanded Net Energy Cost ("ENEC") recovery clause, which includes, among other revenues and costs, off-system sales revenues, net of costs to supply, and FTR revenues net of congestion costs. These are the same types of revenues and costs allocated to all AEP System companies on the basis of their respective member load ratios. However, unlike the Company in this proceeding, AEP Appalachian Power Company proposes that ratepayers be provided 100% of the off-system sales margins with no sharing. I have attached a copy of the AEP Appalachian Power Company testimony describing its proposal in the West Virginia proceeding as my Exhibit___(LK-2).

There is no reason why Kentucky ratepayers should be required to relinquish and transfer 50% of the off-system sales margins to the Company, while West Virginia ratepayers retain 100% of their MLR share of those same AEP System margins. Kentucky should not get second class treatment compared to West Virginia.

Sixth, as I subsequently discuss in more detail, AEP recently filed an Application with the FERC to change the allocation of off-system sales margins between the AEP East and West Companies, which will result in a greater allocation to the AEP East Companies, including Kentucky Power Company. The Company is not entitled and should not be allowed to retain 50% of these increased margins simply as the result of a reallocation between the AEP East and West Companies. These increased margins will not result from any increased AEP System sales. 100% of the actual increased allocation of off-system sales margins should be captured in the Net Congestion Recovery Rider or, alternatively, in the System Sales Clause Rider if it is continued.

<u>Commission Should Modify Company's Proposal to Credit ECR For Environmental Costs Included in Base Rates and Reject Company's Proposal to Eliminate §199 Deduction</u>

Q. Please describe the Company's proposals to modify the ECR.

A. The Company proposes to roll-in to base rates the test year ECR revenue requirement. The Company proposes a fixed ECR credit equivalent to the test year ECR revenue requirement rolled-in to base rates of $28.107 million on a total Company basis (Exhibit EKW-12 and Wagner Direct at 55). The Company proposes to apply this dollar amount as a credit against the total Company ECR revenue requirement, before application of the jurisdictional percentage. The Company also proposes to reverse the Commission's decision in Case No. 2005-0068 by eliminating the §199 deduction from the ECR gross revenue conversion factor.

Q. Does the Company's proposal to credit a fixed dollar amount against the ECR revenue requirement to reflect the roll-in to base rates correctly quantify the effect of the roll-in on the jurisdictional ECR revenue requirement?

A. No. The Company's proposal is inconsistent with Commission precedent for such roll-ins, will understate the amount of the ECR recovery through base rates, will overstate the jurisdictional ECR recovery percentage of revenues factor, and will result in excessive ECR recovery from ratepayers.

As a foundational matter, the Company's proposal is inconsistent with Commission precedent for such roll-ins, which properly measures the effect of the ECR roll-in to base rates as a percentage of revenues. The Commission then credits the roll-in percentage of revenues against the jurisdictional ECR percentage of revenues, which was computed as the jurisdictional ECR revenue requirement amount divided by total jurisdictional revenue excluding ECR revenues. The Commission employed this methodology in prior LG&E and KU ECR roll-ins to base rates. This methodology was first employed by the Commission in LG&E Case No. 2002-00193 and was adopted for KU in Case No. 2003-00068.

The Commission's established methodology properly accounts for the increased recovery of ECR roll-in amounts due to sales growth and properly integrates the jurisdictional recovery through base rates with the jurisdictional allocation of the ECR revenue requirement. In contrast to the Commission's established methodology, the Company's proposal fails to reflect the recovery the Company will receive through the roll-in to base rates, which will continue to increase as base revenues increase due to sales growth. Instead, the Company's proposal reflects only the fixed test year revenue requirement based on the costs that were rolled-in. Consequently, the Company's proposal will result in excessive recovery of its environmental costs if it is not modified.

Under the Commission's established ECR roll-in methodology, the credit to the ECR is intended to reflect the amount of ECR revenues achieved through base rates, not the costs included at the time of the roll-in. As revenues increase due to sales growth, the Company's recovery also increases. Under the Company's proposal, this increased ECR recovery, achieved as the result of sales growth, will not be captured and applied to reduce the ECR revenue requirement. Consequently, it is essential that the ECR roll-in amount be quantified as a percentage of the revenues at the time of the roll-in and that the credit in the ECR be a reduction to the percentage of revenues, not a dollar reduction to the ECR costs.

In addition, the Company's proposal will improperly increase the jurisdictional allocation of the ECR costs and the amount of the ECR recovery, to the harm of ratepayers. The Company's proposal credits the test year total Company dollar amount of the roll-in against the total Company ECR revenue requirement. The dollar amount of the credit then is reduced by the ECR jurisdictional percentage, which substantially understates the amount of ECR recovery through base rates by diminishing the value of the credit. The Commission should reject the Company's proposal and utilize the ECR roll-in methodology previously established for LG&E and KU.

Q. Have you quantified the amount of the harm that will result from the Company's proposal to use a fixed dollar amount credit against the total Company ECR revenue requirement before jurisdictional allocation?

A. Yes, although the actual harm will depend on the monthly ECR jurisdictional factors.

For the test year, the annual harm will be approximately $6.7 million, computed as the total Company amount of the roll-in to base rates of $28.107 million multiplied by the difference between the base rate jurisdictional factor of approximately 99% compared to an average ECR jurisdictional factor of approximately 65%.

Q. **Doesn't the fact that the SSC will be allocated a lesser amount of the ECR costs cure the jurisdictional problem with the Company's ECR proposal that you identified?**

A. No. If the SSC, with its 50%/50% sharing, is continued, the excessive ECR recovery under the Company's proposed methodology due to the jurisdictional allocation problem will be eliminated only partially through an increase in the SSC refunds. Indeed, there will be increased margins in the SSC Rider due to a reduction in the amount of the ECR revenue requirement allocated to off-system sales. However, ratepayers will receive only 50% of those increased margins under the SSC as presently configured.

Q. **The Company's ECR presently uses a formula based dollar credit for the base period revenue requirement ("BRR"), which dates to Case No. 1996-00489, but does not reflect any prior ECR roll-in to base rates. Is your recommendation to**

modify the BRR component to reflect a percentage credit in the same manner as the Commission uses for LG&E and KU?

A. Yes. I have attached a copy of the relevant pages from the October 2004 KU ECR filing as my Exhibit___(LK-3) which shows the base period jurisdictional environmental surcharge factor ("BESF") as a percentage credit to the current period jurisdictional environmental factor ("CESF"), also computed as a percentage of retail revenues.

Q. What is the basis for the Company's proposal to eliminate the §199 deduction from the ECR Rider?

A. The Company argues that the income tax expense effect of the §199 deduction is fixed and is fully reflected in the test year base revenue requirement. Thus, there should be no allocation of the §199 deduction to the ECR revenue requirement.

Q. Is the Company's argument correct?

A. No. The Company's argument reflects a fundamental error in the application of the tax law for ratemaking purposes, an error which it first advanced in Case No. 2005-00068 and which it apparently has determined to relitigate in this proceeding. The Commission rejected the Company's arguments in Case No. 2005-00068 and it should reject them again in this proceeding.

Effective January 1, 2005, §199 of the Internal Revenue Code provides for a 3% deduction against taxable income for qualified domestic production activities, i.e., the production component of the Company's taxable income. As I described in my testimony in Case No. 2005-00068, the only taxable income in setting rates is that which results from the income tax gross-up on the equity return on capitalization (base rates) or rate base (ECR).

The §199 deduction is a direct function of the production taxable income reflected in the revenue requirement, whether it is the base revenue requirement or the ECR revenue requirement. If there is an increase in the ECR rate base and the related revenue requirement, then there inherently is an increase in the taxable income and the §199 deduction.

The Commission correctly determined in three separate ECR proceedings involving LG&E, KU, and the Company that the appropriate methodology to capture the effect of the §199 deduction was to reflect it as a reduction to the income tax rate used to compute the ECR gross revenue conversion factor.

Q. Should the Commission eliminate the §199 deduction from the ECR Rider?

A. No. First, as noted previously, the Commission already has decided this issue in three separate ECR proceedings involving LG&E, KU, and the Company. The issue is decided and there is no reason or basis to revisit it in this proceeding. The amount of the §199 deduction is not fixed. It is inherently an incremental computation and the §199 deduction will change as the ECR rate base and the weighted equity return on the ECR rate base changes.

Second, if the §199 deduction is removed from the total Company ECR revenue requirement, then the total ECR revenue requirement will be overstated and the amount it is overstated will continue to increase over time as the §199 deduction rate and the Company's return on ECR rate base increase. The Company's proposed credit also will be overstated, but the dollar amount of the credit will not continue to increase over time as the §199 deduction rate and the Company's return on ECR rate base increase. There will be a growing mismatch as the ECR revenue requirement increases compared to the fixed dollar amount of the credit rolled-in to base rates. Consequently, the §199 deduction must stay in the ECR surcharge computation to avoid harm to ratepayers.

III. REVENUE REQUIREMENT - CAPITALIZATION ISSUES

<u>Non-Fuel M&S Inventory Should Be Quantified Using 13 Month Average</u>

Q. Please describe the Company's proposal for non-fuel inventory included in rate base and capitalization.

A. The Company proposes the use of the June 30, 2005 balance of non-fuel M&S inventory in rate base and capitalization. However, it proposes an adjustment to increase fuel inventory in rate base and capitalization based on its target number of days inventory. The Company made this latter adjustment by increasing short term debt included in capitalization, and thus, the total capitalization, upon which the Company earns a return.

Q. Is the use of the June 30, 2005 amount of non-fuel M&S inventory appropriate for ratemaking purposes?

A. No. It overstates the rate base and capitalization for the test year. Non-fuel M&S inventory fluctuates throughout the year. The June 30, 2005 amount of $16.720 million (total Company) overstates the Company's average investment of $14.510 million (total Company) during the test year. The average investment, using a 13 month average, is more representative of the actual investment than the June 30, 2005 amount and both rate base and capitalization should be reduced accordingly. The reduction to rate base and capitalization should be $2.210 million (total Company). I have relied on the computation of the 13 month average confirmed by the Company in response to AG 1-13.

Q. Have you reflected this adjustment for non-fuel M&S inventory in your recommended total capitalization and revenue requirement?

A. Yes. I have reflected the revenue requirement effects of this adjustment on the table in the Summary section of my testimony. The computations of the effect on the revenue requirement are detailed in Section II on my Exhibit___(LK-4). I reduced short term debt for the amount of this adjustment. The use of short term debt for this adjustment is consistent with the Company's use of short term debt to increase the capitalization for its proposed adjustment to increase fuel inventory.

Commission Should Reject Company's Proposal to Change Its Vegetation Management Program and Significantly Increase Costs to Ratepayers

Q. Please describe the Company's proposal to increase its vegetation management program costs.

A. The Company proposes to greatly expand its vegetation management program, moving from its present performance based program to a cycle based program. The proposed expansion of the vegetation management program applies to its entire service territory, although the Commission's Focused Management Audit, ostensibly the catalyst for the Company's proposal, addressed only the Company's Hazard County service territory.

The Company's proposal does not include any increased costs related to potential revisions to the NERC standards in the aftermath of the widespread August 14, 2003 Northeast blackout, which would apply to transmission circuits operating at 200 kV and above along with critical transmission lines of lower voltage as determined by the applicable Regional Reliability Council.

To move to a cycle based program, the Company proposes post test year increases in rate base and capitalization and in operating expenses. However, it plans to move to the cycle based program only if the Commission authorizes its requested rate recovery. It proposes an increase to rate base and capitalization of $5.540 million (total Company), which is based on a projected 3 year average of capital expenditures subsequent to the test year. It does not propose a reduction to this amount for either accumulated depreciation or accumulated deferred income taxes. It proposes an increase to O&M

expense of $6.123 million (total Company) and $6.074 million (jurisdictional), which is based on a projected 3 year average of increased O&M expense subsequent to the test year. These post test year increases in capitalization and O&M expenses are detailed in Section V Workpaper S-4 page 29.

Q. Has the Company performed any studies to demonstrate that the proposed expansion in its vegetation management program to a cycle based approach is cost-effective and superior to the present performance based approach?

A. No. The Company has not performed any such studies. Such studies are essential for the Commission to make an informed decision and yet all the Company has provided are increased cost estimates based on expanded activities and vague assurances that "once fully established and consistently maintained, Kentucky Power expects continuing maintenance dollars to be reduced," according to its response to KIUC 2-17.

In KIUC 2-20, the Company was specifically asked to "provide a copy of all studies, analyses, and correspondence that addresses the economics and/or cost-effectiveness of the performance based versus cyclic vegetation management approach relied on by the Company to determine that a cyclic approach is superior and should be adopted." In its response to this request, the Company failed to provide any studies that address the "economic" or "cost-effectiveness" of its proposed program. Instead it provided a five year projection of the costs to implement its proposed program. It also provided two PowerPoint slides comparing different vegetation management approaches for AEP Appalachian Power Company, which included projections of the costs for that Company to implement a cycle-based vegetation management program.

If indeed the proposed expanded vegetation management program will reduce outages, presumably there will be at least three related effects that should be considered in an economic analysis in addition to the cost to implement the program. First, there should be a reduction in O&M expense. Second, there should be a reduction in both recurring annual transmission and distribution plant investment and removal costs due to longer line and equipment life. Third, there should be increased revenues due to increased usage which otherwise would have been foregone during outages.

The Company apparently considered none of these factors based on its responses to discovery, including those previously cited and KIUC 2-22 and AG 1-9, all of which are important not only from an economic or cost-effectiveness perspective, but also from a ratemaking perspective. From a ratemaking perspective, all these factors would serve to reduce or eliminate the incremental costs proposed by the Company.

In short, the failure of the Company to consider the economics or cost-effectiveness of its proposed expansion of the vegetation management program is sufficient grounds to reject the proposal. The Commission should not blindly agree to use ratepayer money to fund an unjustified expansion on the basis of vague assurances of future benefits.

Q. Given that the Company has failed to provide any economic rationale for its request, has it provided a sufficient reliability rationale that justifies this significant increase in spending on vegetation management?

A. No. The Company has failed in this respect as well to justify the proposed expansion of the vegetation management program. First, it fails to make the case that the present level of reliability is unacceptable. Contrary to the assertions of AEP witness Mr. Phillips, tree-related customer complaints have not been increasing. In 2000, there were 11 complaints; in 2001, 5 complaints; in 2002, 14 complaints; in 2003, 11 complaints; in 2004, 24 complaints; and in 2005 (through October), 3 complaints, according to the Company's response to KIUC 2-23. In addition, the Company has not demonstrated that the tree-related outage reliability indices, SAIFI, CAIDI, and SAIDI, excluding major events, are unacceptable or outside industry norms.

Second, the Company offers the Commission no target improvements in reliability, but rather only vague assurances of reductions in tree-related outages in response to the Commission's Focused Management Audit. For example, the Company has not provided the Commission with target absolute or percentage improvements in the basic reliability metrics. The Company requests an increase in vegetation management program costs that doubles its O&M expense, but fails to describe or quantify the target improvements in CAIDI, SAIFI, SAIDI and customer complaints. Will each $1 million result in a 1% improvement in these metrics or a 10% improvement? If the cost doubles, will there be an elimination of all tree-related outages? Only with such target improvements in the reliability metrics, can the Commission answer the question: Is the cost justified by the improvement in the metrics?

Unfortunately, the paucity of information provided by the Company leaves the Commission in a singularly uninformed position. The Commission has been offered no specific reliability improvements as measured by any of the standard reliability metrics and has no basis to assess the reasonableness of the Company's proposed costs against the potential reliability improvements.

In exchange for the vague assurances or reliability improvements, the Company requests that the Commission provide it with certain and specific recovery of tens of millions of dollars in ratepayer funds over the next several years and continuing even beyond that in the absence of any O&M expense reductions or revenue increases. Such a proposition is unreasonable and should be rejected.

Third, the Company offers no guarantees of improved reliability as measured by the standard metrics. Even projections of improvements quantified in absolute or percentage terms are meaningless in the absence of meaningful performance requirements.

Fourth, to the extent there are specific circuits that require attention, then those circuits should be factored in to the present performance based approach, thus expanding the list of priority projects.

Q. **Has the Company provided any assurance that it will actually incur the projected costs if they are included in the revenue requirement?**

A. No. Once again, the Company offers no assurance in this area either. Including these amounts in the revenue requirement simply increases the revenue requirement; it provides no assurance to the Commission or ratepayers either that the costs will be incurred or that, if incurred, the costs actually will be incremental to the specific reliability program costs otherwise included in the Company's test year O&M expense and revenue requirement. The Commission cannot cure this deficiency simply by mandating that such amounts actually be incurred each year subsequent to the Commission's Order in this proceeding. There must be some assurance that the amounts indeed are and will continue to be incremental to some test year baseline rather than supplanting test year expense levels.

Q. Are there other reasons the Commission should reject the Company's request for post test year increases to capitalization and expenses for the proposed expanded vegetation management program?

A. Yes. First and perhaps, fundamentally, the Company's request for a post test year increase to capitalization violates basic test year ratemaking principles by including amounts in plant that have not yet been expended while ignoring reductions in existing test year rate base that certainly will occur due to post test year increases in accumulated depreciation and accumulated deferred income taxes. The concept of a test year ensures that the revenue requirement is determined on a comprehensive basis, not a selective basis that serves to increase the revenue requirement.

Second, the Company's adjustment to increase capitalization violates the basic ratemaking process in Kentucky. Normally, the Company incurs the cost and the

Commission includes it in capitalization after it is incurred. In this case, the Company requests that the Commission effectively reach beyond the rate effective date some 36 months because it uses a 3 year projection. This is equivalent to reaching some 46 months beyond the end of the test year. The Company offers no rationale as to why the Commission should violate the basic ratemaking process.

Third, the Company's computation fails to consider the accumulated depreciation and accumulated deferred income taxes that would be created during the projected period associated with the additional plant investment.

Q. Have you quantified the effect of eliminating the Company's proposed increase to capitalization for these post test year reliability expenditures on the revenue requirement?

A. Yes. The effect is to reduce the Company's revenue requirement by $0.597 million. The computations are detailed in Section III on my Exhibit___(LK-4). I reduced all capitalization components proportionately for the amount of this adjustment. I address the quantification of the expense increase in the Revenue Requirement – Operating Income Issues section of my testimony.

Q. As an alternative to the Company's proposal to expand its vegetation management program and recover the costs in this proceeding, could the Commission initiate a collaborative process to assess the effectiveness of the Company's existing program system-wide and develop cost-effective enhancements that will achieve specified target reliability improvements?

A. Yes. Such an approach would be far superior to the Company's vague proposal to simply spend more money on vegetation management. In that manner, all interested parties can participate and the Commission can ensure that if additional recovery is authorized, the amounts will be spent on cost-effective programs with tangible and quantifiable benefits.

<u>**Commission Should Correct Company's Proposed Adjustment for Minimum Pension Funding to Reflect Actual Contributions to Pension Fund Already in Capitalization**</u>

Q. Please describe the Company's proposed adjustment to increase common equity for the amount of the minimum pension funding liability.

A. The Company proposes an adjustment to increase common equity by $9.588 million (total Company), the amount of the minimum pension funding liability reflected in the per books common equity at June 30, 2005. This has the effect of increasing both the common equity and total capitalization on which the Company earns a rate of return.

Q. Is the Company's proposed adjustment correct?

A. No. Although the adjustment to common equity is correct, the Company's adjustment is incomplete because it fails to reflect additional pension contributions the Company made to partially eliminate the minimum pension funding liability prior to June 30, 2005. These additional pension contributions already are reflected in the Company's June 30, 2005 total capitalization. The minimum pension funding liability reflected in the Company's per books common equity and which formed the basis for the Company's adjustment was based on pension funding levels as of January 1, 2004, not as of June 30, 2005. Consequently, it is necessary to reduce all capitalization proportionately by the amount of the additional pension funding to avoid the double counting the Company's actual additional pension contributions in both the Company's adjustment to increase common equity and the June 30, 2005 per books capitalization.

The Company made additional contributions in March 2005 and June 2005 totaling $6.092 million (total Company) (see Section V WP S-4 page 40). These contributions had the effect of increasing the Company's capitalization as of June 30, 2005. However, they will not change the Company's per books minimum pension funding liability reflected in common equity until a new actuarial computation is made by the Company's pension actuaries for 2006 or possibly 2007 using pension funding levels as of January 1, 2005 or 2006.

Q. How have you reflected this adjustment in your recommended capitalization and revenue requirement?

A. The revenue requirement is reduced by $0.660 million. I have reflected the revenue requirement effects of this adjustment on the table in the Summary section of my testimony. The computations are detailed in Section IV on my Exhibit___(LK-4). I reduced all capitalization components proportionately for the amount of this adjustment.

Commission Should Reject Company's Request for Retroactive Recovery of RTO Formation Costs and Reduce Common Equity for Amount of Deferrals

Q. Please describe the Company's request for recovery of RTO formation costs.

A. The Company requests that the Commission include deferred RTO formation costs in capitalization and an amortization of the deferred costs in operating income. These costs were incurred by AEP in conjunction with the Alliance, MISO, and PJM RTOs and then allocated to the AEP System Companies on the basis of their respective MLRs. The amounts included in the Company's request also include deferred carrying costs on the deferred RTO formation costs.

The Company's share of the unamortized deferred AEP RTO formation costs at June 30, 2005 was $1.124 million (total Company), according to its response to AG 1-67(c). In addition to Mr. Bethel's testimony on the RTO formation costs, the Company has provided further details on the costs and history of these costs in response to AG 1-67, 1-68, and 1-185 and KIUC 2-33.

Q. Did the Company seek or obtain authorization from the Commission to defer these RTO formation costs for accounting or ratemaking purposes?

A. No. These costs were incurred by AEP and then allocated to the AEP System Companies on the basis of their Member Load Ratios. The Company never sought nor obtained authorization from the Commission either to defer these costs as a regulatory asset or provide ratemaking recovery of these deferred costs prior to this proceeding.

Q. The Company relies upon the authorization of the FERC to defer the RTO formation costs for accounting purposes in support of its request for ratemaking recovery. Is that relevant?

A. No. Although the FERC authorized deferral for accounting purposes, it specifically refused to provide AEP assurance of future ratemaking recovery in response to AEP's request for such assurance. In Docket No. AC04-101-000, the FERC stated "Your proposed accounting treatment is approved. This approval is for accounting purposes only and is not determinative for ratemaking purposes." This statement was footnoted with the following proviso: "If rate recovery of all or part of the deferred costs is later disallowed, the disallowed costs should be charged to Account 426.5, Other Deductions, at the time of the disallowance." I have attached a copy of this letter order as my Exhibit___(LK-5).

Initially, the FERC refused even to allow AEP to defer the costs as a regulatory asset. Pursuant to a subsequent AEP request, the FERC authorized the transfer of the deferred amounts to a regulatory asset account, but it would not provide assurance of ratemaking recovery. Even so, the FERC's ratemaking authority and ability to authorize recovery of such deferred costs extends only to wholesale ratemaking. The Company's request in this proceeding does not result from a cost incurred pursuant to a wholesale rate. The

FERC's authority does not extend to retail ratemaking regardless of whether the Company's costs are booked in accordance with the FERC Uniform System of Accounts.

Q. Should the Commission authorize the RTO formation costs in capitalization and the related amortization expense?

A. No. First, the Commission is under no obligation to allow these costs in capitalization or to allow an amortization expense in operating income. These costs were deferred pursuant to a FERC accounting order, in which the FERC specifically declined to ensure ratemaking recovery in response to AEP's request for it to do so. Further, and even if the FERC had authorized ratemaking recovery, the FERC's authority for ratemaking purposes does not extend to retail ratemaking unless there is a federal rate. The allocation of AEP RTO formation costs to the Company is simply an accounting exercise, not a ratemaking directive.

Second, the recovery of these costs would constitute impermissible retroactive ratemaking. These costs were incurred by AEP and allocated to Kentucky Power Company while the Company was under a rate freeze pursuant to the merger agreement approved by the Commission in Case No. 99-149. Absent the accounting deferral, these costs would have been expensed when incurred by the Company because the Company had not sought nor received authorization from the Commission to defer them and could not have recovered them in rates during the moratorium regardless of the FERC accounting order.

In its Order approving the merger, the Commission found that "Absent a force majeure, KPCO will not file a petition, which, if approved, would have the effect, directly or indirectly, or authorizing a general increase in basic rates and charges that would be effective prior to January 1, 2003 or three years from the effective date of the merger, whichever is later (the "rate moratorium)." (Order at 3). The Company's deferral of these costs constitutes an indirect increase in base rates, albeit delayed, and circumvented the Commission's Order and the Company's settlement agreement in the merger proceeding. As such, granting the Company's request for ratemaking recovery of these start-up costs incurred during the rate moratorium and without Commission authorization to defer as a regulatory asset would constitute impermissible retroactive ratemaking. The Company's request should be rejected.

Q. If the Company had not deferred these costs and expensed them when incurred, what effect would that have had on the Company's capitalization in this proceeding?

A. In the absence of deferral of these costs, the Company would have expensed the jurisdictional portion. Consequently, the Company's requested common equity would have been lower due to the resultant lower earnings prior to June 30, 2005.

Q. Have you quantified the effect of the Company's request on capitalization and the revenue requirement?

A. Yes. I have quantified the effect of removing the deferred costs from capitalization as a reduction in the revenue requirement of $0.129 million. I removed the after tax effects of the deferred costs from common equity. The computations are detailed in Section V on my Exhibit___(LK-4).

IV. REVENUE REQUIREMENT – OPERATING INCOME ISSUES

Commission Should Correct Company Error Understating Amount of System Sales Clause Margins Rolled-In to Base Rates

Q. Please describe how the Company rolled-in the System Sales Clause Rider revenues and expenses to base revenue requirement.

A. In the first step, the Company included the total test year jurisdictional portion of off-system sales revenues as a reduction to O&M expense. It made no proforma adjustments to test year O&M expense. In this manner, the entirety of the actual test year jurisdictional off-system sales margins were used to reduce the base revenue requirement.

However, in a second and erroneous step, the Company increased the test year O&M expense for the portion of the ECR costs allocated to off-system sales but which were not reflected in the SSC for the months of July 2004 through October 2004. This second step incorrectly increased O&M expense by $2.052 million (total Company) and $2.026 million (jurisdictional).

Q. Why does this second step constitute an error?

A. It constitutes an error because the total ECR costs for the test year already were included in the per books capitalization and expense amounts. The test year per books capitalization and expense amounts had not been reduced in any manner for the portion of the ECR costs allocated to off-system sales that were not included as a reduction in the SSC margins for the months of July 2004 through October 2004. Consequently, nothing should have been added to the O&M expense.

Q. Is the second step appropriate to make in the computation of the "baseline" off-system sales margins rolled-in and included in base rates?

A. Yes. It is appropriate to make this adjustment to quantify the new "baseline" for the off-system sales margins in the NCR or SSC, if it is continued, but it is not appropriate to include the adjustment as an increase to expense for revenue requirement purposes. The Company's per books O&M expense and capitalization (rate base) already included all O&M, including all ECR costs. However, the quantification of the margins rolled-in to base rates for use as the new baseline margin in the NCR requires an allocation of the per books amounts to off-system sales. The best measure for that allocation is to use the test year actual off-system sales margin amounts as quantified in the SSC filings and to adjust them for the portion of the ECR costs allocated to off-system sales in July through

October 2004, but not reflected in the SSC filings for those months. Consequently, the Company's quantification of the test year off-system sales margins for the new "baseline" is correct, but it is incorrect to extrapolate this quantification to create an artificial expense and double-up the amount of the ECR costs allocated to off-system sales for July through October 2004 that were already included in per books capitalization and expense.

Commission Should Quantify Off-System Sales Margins Rolled-In to Base Rates at Going Forward Amount Consistent with Company's Proposal on PJM Revenues and Costs

Q. **Except for the error previously described, the Company used the actual test year off-system sales margins to reduce the base revenue requirement. Is that appropriate?**

A. No. It may have been appropriate if the Company had adhered strictly to the test year for its revenues, expenses, rate base and capitalization, but it did not. Instead, the Company utilized normalized and projected amounts for PJM revenues and costs and included certain other post test year costs, including costs for changes in its vegetation management program, changes in postage expenses, and changes in its projected income tax expense. The objective of such adjustments is to reflect the going forward amounts of these revenues and costs in the rate effective period. The off-system sales margins should be considered in the same manner as a matter of consistency and equity.

Q. Has the Company provided a projection of off-system sales margins for 2006 in response to discovery?

A. Yes. The Company provided a projection of its off-system sales margins for 2006 of $30.0 million (total Company) in response to KIUC 1-38. I have attached a copy of the Company's summary results of this quantification with the confidential monthly amounts redacted and my handwritten total as my Exhibit___(LK-6). The Company's counsel agreed that KIUC could utilize the 2006 annual total in its testimony. By comparison, the test year off-system sales margin included by the Company in the base revenue requirement was only $24.855 million.

Q. Should the Commission use the Company's projection of off-system sales margins for 2006 in setting the base revenue requirement?

A. Yes. The Commission should increase the off-system sales margins included in the base revenue requirement by $5.145 million (total Company) to $30.0 million (total Company). This is the Company's own projection and is consistent with the Company's use of 2006 amounts for PJM revenues and expenses and the use of numerous other post-test year adjustments to reflect going forward levels of revenues and expenses. The use of the Company's 2006 off-system sales margin projection also is consistent with the Company's proposal for the NCR Rider, which would be effective contemporaneous with the change in base rates in this proceeding. It also would be consistent with my recommendation to include off-system sales margins in the NCR Rider, which would be effective with the change in base rates in this proceeding. In that manner, the off-system sales margins and PJM revenues and costs all would be quantified for the same time period and would be recovered or refunded in a consistent manner.

The Commission also should use the Company's projected 2006 amount as the new "baseline" for the SSC going forward if it reflects this amount in the base revenue requirement.

Q. Why would the Company oppose the use of its own projection of off-system sales margins for 2006 in lieu of the test year levels?

A. If the additional margins are not reflected in the base revenue requirement and instead are captured in the SSC, the Company will retain 50% of the increased margins due to the operation of the SSC Rider in addition to any rate increase from this proceeding.

This illustrates why it is important for the Commission to use the 2006 projection in the base revenue requirement, rather than using the actual test year amount and adjusting the "baseline" for the NCR on that basis.

Q. Will the failure to use the Company's projection of off-system sales margins in the base revenue requirement have an ongoing effect beyond 2006?

A. It will if the 50%/50% sharing is continued. In that circumstance, the Company will retain $2.5 million each year, based on the 2006 projections, until base rates are reset and the off-system sales margins once again rolled-in to base rates. Thus, if the 50%/50% sharing is continued, it is imperative that the Commission use the Company's 2006 projection because the harm from the failure to do so will continue each year.

<u>Commission Should Revise Upward Amount of Off-System Sales Margins Rolled-In to Base Rates For FERC Reallocation of Margins Between AEP East and West Companies</u>

Q. Please describe the AEP request pending before the FERC to reallocate the off-system sales margin between the East and West Companies and the effect this will have on the Company.

A. AEP recently filed an Application with the FERC in Docket No. ER06-141-000, Re An Amendment to the System Integration Agreement Schedule D Service Schedule, that will result in a reallocation of the AEP System off-system sales margins between the AEP East and West Companies. Schedule D governs the allocation of "Trading and Marketing Realizations," i.e., net revenues or margins from off-system sales. AEP requested an effective date for the Amendment of January 1, 2006. I have attached a copy of the AEP Application as my Exhibit___(LK-7).

The effect of AEP's proposed reallocation will be to allocate an increased amount of the AEP System off-system sales margins to the East Companies based on the direct assignment methodology, i.e., the margins will be allocated to the East or West Companies depending on which supplied the sales. AEP witness J. Craig Baker summarized the reason for the proposed reallocation in an affidavit filed with the Application as follows: "For the historic 12-month period analyzed, the change from the current allocation methodology to the proposed direct assignment allocation methodology is to be expected since the East Zone Companies, at present, provide a greater portion of the total AEP Trading and Marketing Realizations than their current allocation."

In its filing with the FERC, AEP quantified the effect for the 12 months ending June 30, 2005 as an increase in margins to the East Companies of $59.574 million ($445.379 million less $395.805 million) and an increase in margins to Kentucky Power Company of $3.603 million ($33.302 million less $29.699 million) (Exhibit I to FERC Application page 1 of 2). The allocation among the East Companies is on MLR in accordance with the AEP Interconnection Agreement. I have attached a copy of Mr. Baker's affidavit and Exhibit I as my Exhibit___(LK-8).

Q. Should the Commission reflect this increase in off-system sales margins in the base revenue requirement?

A. Yes. First, AEP has proposed that the change be effective January 1, 2006, which means that it will be in effect when rates are set in this proceeding. Second, the increase in off-system sales margins allocated to the Company is known and measurable because it is based on the actual twelve months ended June 30, 2005, which is coincident with the Company's test year in this proceeding. Third, the increased off-system sales margins are not the result of any marketing or sales effort on the part of AEP or the Company, but rather arise simply because of a reallocation. As such, there is no rationale for sharing of these margins through the SSC. Including the margins in base rates ensures that ratepayers receive 100% of the off-system sales margins allocated to the Company.

Fourth, recognition of this change is consistent with the Company's proposed annualization of the PJM revenues and costs and its proposed recognition of the effect of the FERC rate increase on its transmission revenues.

If my proposal to include 100% of off-system sales margins in the new NCR Rider is adopted, then by definition there will be a complete reflection of these increased margins in rates. There would be less need to forecast this volatile number because of the dollar for dollar true up. Nevertheless, inclusion of the 2006 margins and the affect of the new AEP East/West allocation is beneficial as it will lower the initial base rates and provide the benefit of these increased margins to ratepayers on a more timely basis.

<u>Commission Should Revise Interest Income on Temporary Cash Investments If It Allows Company to Revise Costs of Long Term Debt, Short Term Debt, and AR Financing</u>

Q. Please describe how the Company included interest income on temporary cash investments in the revenue requirement.

A. The Company included interest on temporary cash investments in revenues (see Section V WP S-4 page 18). The Company included the actual test year amount and did not reflect increases in interest rates that have occurred since the test year. (Wagner Direct at 34). Short term interest rates have risen significantly since the beginning of the test year.

Q. If the Commission allows the Company to update its costs of financing, including long term debt, short term debt, and accounts receivables financing, should it also require an update to the interest income amount?

A. Yes. Either all or none of the interest rates should be updated. My concern is simply that the interest income reflected in revenues not be overlooked in such an update because it is not specifically reflected in the cost of capital computation. In the event of an update, the Commission should annualize the interest income included in revenues using the most recent interest rates.

<u>Commission Should Reject Amortization of RTO Formation Costs</u>

Q. Please describe the Company's request for an amortization expense to recover its deferred RTO formation costs.

A. The Company requests an amortization expense of $0.161 million (total Company) and $0.159 million (jurisdictional). The Company computed this amount on a levelized basis using an annuity formula over a 10 year amortization period and its requested after tax rate of return in this proceeding. Although this is the amount included in the Company's requested revenue requirement, the Company acknowledged an error in its computation and revised the amount downward to $0.123 million (total Company) or $0.121 million (jurisdictional) in response to AG 1-68(f).

Q. Should the Commission authorize this amortization expense?

A. No. The Commission should reject the request for the amortization expense for the same reasons that I discussed in conjunction with its request to include these costs in capitalization. In addition, the Company's expense amount, even the corrected amount, is overstated because it includes a rate of return on the deferred costs as a component of the annuity computation. Given that the deferred amount already is included in the Company's proposed capitalization, specifically in common equity, no additional rate of return is justified. However, if the Commission allows the amortization expense, including the return, then it still should adopt my recommendation to remove the deferred costs from capitalization.

<u>Commission Should Remove Company's Request for Increased O&M Expense Due to Expanded Vegetation Management Program</u>

Q. In conjunction with your previous discussion regarding the Company's proposed expanded vegetation management program, have you also reduced the Company's revenue requirement for its requested increase in O&M expense?

A. Yes. This adjustment reduces the Company's revenue requirement by $6.103 million, which I have reflected in the table in the Summary section of my testimony. I computed the revenue requirement effect by multiplying the Company's requested increase in O&M expense by a gross revenue conversion factor that includes only the uncollectible accounts factor.

<u>Commission Should Revise Company's Pension Expense to Reflect Going-Forward Cost</u>

Q. Please describe the pension expense included by the Company in its revenue requirement.

A. The Company included the pension expense quantified by its actuaries, Towers Perrin, for the calendar year 2005. The Company increased the actual test year pension expense through a proforma adjustment detailed in its filing on Section V Workpaper S-4 page 4. The Company also included an increase to rate base for additional pension fund contributions in March and June 2005, which I discussed previously in the Revenue Requirement - Capitalization Issues section of my testimony.

Q. Is the amount included by the Company for pension expense appropriate?

A. No. The Commission should use the Company's projection for 2006 prepared by Towers Perrin and also included in the 2005 pension actuarial report provided in response to Staff 1-50. The projection for 2006 is lower than the amount for 2005 and reflects the fact that the Company planned to fully fund its accumulated benefit obligation by the end of 2005, according to the assumptions stated in the actuarial report. Thus, the use of the 2006 projection is consistent with the additional 2005 contributions reflected in the Company's total capitalization, which I discussed previously.

Q. What is the effect on the revenue requirement of using the Company's 2006 actuarial projection rather than the 2005 amount?

A. The 2006 projection from the Towers Perrin actuarial report reflects a reduction in SFAS 87 pension costs in 2006 compared to 2005 of $0.428 million (total Company).

This total Company amount must be multiplied by the 67.65% O&M percentage (from Section V Workpaper S-4 page 4), then multiplied by the 99.1% jurisdictional percentage (from Section V Workpaper S-4 page 4), and then grossed-up for the uncollectible accounts expense factor.

Q. In response to Staff 2-105, the Company argues that the 2006 pension cost amount is not appropriate for ratemaking purposes. Do you agree?

A. No. First, the 2006 projection was prepared by Towers Perrin, the Company's actuaries, on the same basis as the 2005 amount proposed by the Company, and included in the same actuarial report. This is an independently prepared projection relied on by AEP and the Company for other purposes and the cost of the services provided by Towers Perrin is included in the Company's revenue requirement. Although the Company attempts to disparage the value of the projections, it retained Towers Perrin to prepare the projections and Towers Perrin did not disclaim their validity or usefulness.

Second, the 2006 projection explicitly reflects the additional pension contributions that the Company believes the Commission should consider in this proceeding as an addition to rate base while the 2005 amount does not. This is a relevant consideration because earnings on these contributions reduce the pension expense for 2006 compared to 2005 and in subsequent years.

Third, the reasonableness of the 2006 projection can be demonstrated by multiplying the unfunded accumulated benefit obligation, which the Company and Towers Perrin assumed would be fully funded by the end of 2005, by the assumed return on the pension fund assets and then using this amount as a credit against the 2005 expense. The Company's proposed adjustment to rate base for the additional funding is $4.084 million (see Section V Schedule 4 page 5) times 8.75% (see response to Staff 1-50 page 7) equals $0.357 million. This computation essentially affirms the reasonableness of the $0.428 million reduction reflected in the actuarial report, adjusted to reflect the O&M expense and jurisdictional allocations.

<u>Commission Should Revise Company's OPEB Expense to Reflect Going-Forward Cost</u>

Q. Please describe the OPEB expense included by the Company in its revenue requirement.

A. The Company included the OPEB expense quantified by its actuaries, Towers Perrin, for the calendar year 2005. The Company reduced the actual test year OPEB expense through a proforma adjustment detailed in its filing on Section V Workpaper S-4 page 4.

The net reduction was due to the new Medicare Part D subsidy for the prescription drug benefit.

Q. Is the amount included by the Company for pension expense appropriate?

A. No. The Commission should use the Company's projection for 2006 prepared by Towers Perrin and included in the 2005 pension actuarial report provided in response to Staff 1-51 for the same reasons that it should use the pension cost projection for 2006. The projection for 2006, after reduction for the Medicare Part D subsidy, is lower than the amount for 2005, after reduction for the Medicare Part D subsidy, by $0.142 million (total Company).

Q. Have you quantified the revenue requirement effect of your OPEB expense recommendation?

A. Yes. The revenue requirement should be reduced by $0.095 million, computed as the reduction in OPEB expense in 2006 compared to 2005 of $0.142 million multiplied by the Company's 67.65% O&M expense percentage (Section V Workpaper S-4 page 4), multiplied by the 99.1% jurisdictional percentage (Section V Workpaper S-4 page 4), and then grossed-up for the uncollectible accounts expense factor.

<u>Commission Should Reduce Company's Proposed Depreciation Rates to Remove Big Sandy Plant Demolition Costs from Steam Production Plant Net Negative Salvage Rate</u>

Q. Please generally describe the Company's request for depreciation expense and the changes proposed by the Company.

A. AEP performed a depreciation study on behalf of the Company to develop new depreciation rates for use in this proceeding. These new depreciation rates result in an increase in depreciation expense compared to the present rates. In general, the new depreciation rates reflect proposed increases in interim retirement rates and net negative salvage rates, both of which result in increases in depreciation rates compared to the present rates, all else equal. In addition, the Company included demolition costs in the net negative salvage rates for the Big Sandy plant. The Company provided a copy of its depreciation study with its filing and provided the workpapers for the study in response to AG 1-105.

Q. Please describe the Company's request for demolition costs included in the proposed net negative salvage for the Big Sandy steam production plant.

A. The Company proposes that the Big Sandy depreciation rates include net negative salvage for demolition costs at current price levels for dismantling the plant (see JEH-1 page 9 and electronic workpapers). The demolition cost estimate is based on a "conceptual demolition cost estimate" of $32.0 million prepared by Brandenburg Industrial Service Company specifically for this proceeding. The Company's request increases depreciation expense by $1.409 million (jurisdictional), computed as the $1.423 million total Company amount multiplied by the 99.0% jurisdictional allocation factor and increases the Company's proposed steam production plant depreciation rate to 3.57% from 3.26%.

Q. Should the Commission include this estimated demolition cost in the Big Sandy steam production plant depreciation rates?

A. No. First, AEP has not determined that it will demolish the facility. In addition, the Company is not aware of any legal requirement that it do so, according to its response to KIUC 1-63. As such, the demolition of the facility is merely an assumption and an exercise in speculation without any foundational support. In fact, in response to AG 1-173, the Company acknowledged that "No alternatives were studied."

Second, this demolition estimate was prepared solely for this proceeding in an attempt to increase the Big Sandy steam production plant depreciation rates. AEP has never prepared a demolition cost estimate for any other retired units prior to or subsequent to their retirement, including the retirements of the Conesville 1 and 2 units reflected in the Company's proposed MLR (see responses to KIUC 1-44 for Conesville 1 and 2 units and KIUC 1-45 for all other units already retired).

Third, AEP is unable to quantify actual net negative salvage costs for any other retired units, according to its response to KIUC 1-45. Consequently, there is nothing in the record to assess the validity of the approach or the cost estimate for the Big Sandy demolition.

Fourth, there is no certainty regarding the retirement date of Big Sandy 1. I discuss this in a subsequent section of my testimony.

Fifth, if the Company actually retires and demolishes the Big Sandy plant or actually presents a plan and timetable to do so, the Commission can reconsider the issue at that time. Depreciation is a closed-loop and it is continually adjusted to reflect the most recent estimates to prevent harm either to the Company or its ratepayers.

<u>Commission Should Reduce Company's Proposed Steam Production Plant Depreciation Rates to Correct Excessive Interim Retirement Rate</u>

Q. **Please describe how the Company determined the interim retirement rates for steam production plant (Big Sandy).**

A. The Company used 30 years of actual historical data to quantify projected interim retirement rates for all steam production plant accounts. For account 312, it then added additional projected interim retirements in 2007 and 2009. The additional 2007 and 2009 retirements are due to the projected replacement of the SCR catalysts. The Company did not adjust the historical data to remove abnormal interim retirements related to the installation of pollution control retrofits.

Q. **Should the Commission utilize the interim retirement rates proposed by the Company for account 312?**

A. No. The Company's methodology doubles up the abnormal and nonrecurring interim retirements on a going forward basis, thus understating the average remaining average service life and overstating the depreciation rate. The retirement rates are overstated because they effectively included abnormal interim retirements both in the retirement rate based on the historical data and used in the projection of retirements and then again in the specific additional abnormal interim retirements included in 2007 and 2009. I have attached a copy of the Company's detailed interim retirement workpapers with the entire historical database and the Company's projections for steam production plant as my Exhibit___(LK-9). The Company's actual interim retirement activity for account 312 for the most recent 5 years and the Company's projections for 5 years demonstrate the effect that abnormal interim retirements can have on the both the historic retirement rate and on projected retirements ($ million).

Actual Account 312 Interim Retirements

2000	0.704
2001	0.357
2002	0.561
2003	15.171
2004	2.293

Projected Account 312 Interim Retirements

2005	4.868
2006	4.868
2007	6.498
2008	4.843
2009	11.362

Arguably, all abnormal retirements should be excluded from the historical data and thus, from the projected retirements to determine a normal retirement rate. The abnormal retirements due to the pollution control retrofits are not recurring and should not influence the projected retirements or the interim retirement rates reflected in the depreciation rates. However, if the Commission includes the historical abnormal retirements experience in the projected interim retirements, then the additional specific projected interim retirements for 2007 and 2009 should be removed to avoid double counting abnormal experience.

Q. What is your recommendation on the interim retirements for steam production plant in account 312?

A. I recommend that the Commission simply use the historic interim retirement rates, despite the abnormal retirements in the historical data. Under no circumstances should the Commission use the projected specific additional and abnormal interim retirements.

Q. Have you quantified the effect of your recommendation to simply use the historical interim retirement rate and to exclude the Company's specific projected additional interim retirements for account 312?

A. Yes. The effect is to reduce the Company's depreciation expense by $0.273 million (jurisidictional). The computations are detailed on my Exhibit___(LK-10).

Q. Is there another problem with the Company's use of historical data in the development of the interim retirement rates?

A. Yes. The Company used only 30 years of the 35 years of interim retirement history available. This had the effect of understating the remaining average service life and overstating the depreciation rate. The Commission should use the entirety of the steam production plant retirement history.

Q. Have you quantified the effect of your recommendation to simply use the entirety of the historical interim retirement data for steam production plant?

A. Yes. The effect is to reduce the Company's depreciation expense by $0.909 million (jurisdictional). The computations are detailed on my Exhibit___(LK-11).

<u>Commission Should Reduce Company's Proposed Depreciation Rates to Correct Improper Allocation of Net Negative Salvage Rate to Plant Accounts</u>

Q. Please describe how the Company determined the net negative salvage rates for each plant account.

A. The Company determined the net negative salvage rate on a functional plant basis (steam production, transmission, distribution, and general) using 15 years of historic data for the years 1990-2004. It then used "judgment" to allocate the net functional negative salvage rate to plant accounts based on unknown criteria, despite discovery requests (KIUC 1-58 and Staff 1-83) seeking those criteria, but which it still failed to provide. This allocation to plant accounts mathematically results in the same net negative salvage rate as a percentage of retirement dollars on an aggregate functional basis.

Q. If it results in the same net negative salvage rate in the aggregate on a functional basis, does it make a difference how the net negative salvage is allocated to the plant accounts?

A. Yes. Although the allocation appears neutral on a functional basis as a percentage of retirement dollars, the net negative salvage rates are actually included in the depreciation rates, which are applied to gross plant by plant account. These net negative salvage rates are not applied to retirements. Consequently, when these net negative salvage rates are included in the depreciation rates and applied to gross plant by plant account, the results are no longer neutral on a functional basis and indeed result in a substantial increase in the depreciation expense included in the revenue requirement. The result of the

Company's methodology is to substantially and improperly increase the depreciation rates and depreciation expense to recover excessive amounts of net negative salvage costs compared to historical experience, even before consideration of the additional problem with net negative salvage that I subsequently discuss.

Q. What is your recommendation regarding the allocation of the net negative salvage to plant accounts?

A. There is only one reasonable approach. That is to use the net negative salvage rate developed on a functional basis for all plant accounts within each of those functions rather than attempting to allocate the experience to plant accounts on the basis of some unknown "judgment." The data are not collected or maintained at the plant account level. The Company should not be allowed to manipulate the functional result through some unknown manner of "judgment" that has the effect of improperly increasing the proposed depreciation rates and depreciation expense.

Q. Have you quantified the effect of your recommendation to simply use the net negative salvage rate for all plant accounts within the function?

A. Yes. The effect is to reduce the Company's depreciation expense by $1.352 million (jurisdictional). The computations are detailed on my Exhibit___(LK-12).

Commission Should Reduce Company's Proposed Depreciation Rates to Correct Excessive Net Negative Salvage Rate Due to Use of Limited History of Salvage and Removal Data

Q. Do you agree with the Company's use of only 15 years of salvage and removal data, despite the availability of more than 30 years of such data?

A. No. The Company's methodology had the effect of overstating the net negative salvage or understating any net positive salvage and thus, overstating the proposed depreciation rates and depreciation expense. The Company utilized only the most recent 15 years of data because it resulted in increased depreciation rates. There is nothing inherently correct about limiting the data to only the most recent. To the contrary, it can and indeed did, in this case, result in biased and excessive net negative salvage rates.

Q. Have you quantified the effect of your recommendation to use all net negative salvage data rather than only the most recent 15 years?

A. Yes. The effect is to reduce the Company's depreciation expense by $2.694 million (jurisdictional). The computations are detailed on my Exhibit___(LK-13).

<u>Commission Should Reduce Company's Steam Production Plant Proposed Depreciation Rates to Reflect Deferred Retirement of Big Sandy 1</u>

Q. What retirement date has the Company assumed for Big Sandy 1 in its depreciation study?

A. The Company has assumed a retirement date of 2015 in its depreciation study. Its only support for this date is that it used the 2015 date in its most recent IRP filing with the Commission.

Q. Has the Company performed any studies to evaluate the possibility and economics continued operation, the possibility and economics of life extension, or the types or costs of replacement capacity?

A. No. In KIUC 2-1 and 2-2, the Company was asked to provide copies of all documents that address the actual retirement of Big Sandy 1, the timing of its retirement, and all documents related to potential life extension. In response to KIUC 2-1, the Company stated that "The Company is unaware of any specific studies, analyses, correspondence or other documents that specifically address the retirement of Big Sandy 1."

In response to KIUC 2-2, the Company referred to its response to AG 1-141. In response to AG 1-141, Wagner claimed that "Neither Kentucky Power nor the AEP Service Corp. has undertaken any unit life extension studies involving Big Sandy U1, Big Sandy U2 or Rockport. Expecting operating life extends to 60 years or more based on the economic operation of the individual units. Individual component repair or replacement projects are considered on an as needed basis." The Company plans to continue to operate Big Sandy 1 as long as it is economic to do so. In short, there are no definitive plans to retire Big Sandy 1 in 2015 and depreciation rates based on that assumption necessarily are excessive.

Further, there is every indication that AEP plans to continue to operate Big Sandy 1 beyond 2015. In fact, the latest AEP generation planning study indicates that AEP plans to install FGD and SCR retrofits on Big Sandy 1 in 2011 (see confidential response to KIUC 1-42 p. 17). This study is in rather stark contrast to the following assumption in the Company's depreciation study (page 2 of 443) explaining the use of a 2015 retirement date for Big Sandy 1: "There are currently no plans to install FGD equipment on Unit 1. Due to environmental constraints, the current plans are to retire Unit 1 in year 2015." Clearly, the assumption relied on in the depreciation study is incorrect and should be rejected.

Q. Should the Commission use a retirement date later than 2015 for Big Sandy 1?

A. Yes. I recommend that the Commission use a retirement date of 2020, which reflects an additional 5 years of service.

Q. Have you quantified the effect of your recommendation to use a retirement date of 2020 for Big Sandy 1?

A. Yes. The effect is to reduce the Company's depreciation expense by $0.091 million (jurisdictional). The computations are detailed on my Exhibit___(LK-14).

Commission Should Correct Acknowledged Error in Company's Computation of Interest Synchronization Adjustment

Q. Has the Company acknowledged an error in its computation of the interest synchronization adjustment to tax expense?

A. Yes. In response to AG 1-19, the Company acknowledges that it failed to reflect the accounts receivables financing interest deduction in the state and federal income tax expense. The Company provided a revised quantification of the interest synchronization adjustment in response to AG 1-19, which resulted in a reduction of $0.045 million in income tax expense (jurisdictional). The revenue requirement effect of this error is $0.073 million, computed as the reduction in income tax expense multiplied by the gross revenue conversion factor ("GRCF").

<u>Commission Should Reject Company's Request to Include Ohio and West Virginia Taxes in Gross Conversion Factor</u>

Q. Please describe the Company's request to include Ohio and West Virginia taxes in the gross revenue conversion factor.

A. The Company included apportioned Ohio franchise and West Virginia income taxes in the computation of the GRCF, as detailed on Section V Workpaper S-2 page 2. The inclusion of these taxes increased the Company's proposed GRCF and the Company's revenue requirement because the Company multiplied its proposed operating income deficiency by the GRCF to determine the revenue deficiency.

Q. Should the Commission include the Ohio franchise and West Virginia income taxes in the GRCF?

A. No. This is simply incorrect and totally inappropriate. Fundamentally, the Ohio franchise and West Virginia income taxes will decrease as the result of a Kentucky retail rate increase because both taxes are based on apportioned income, at least in part. If total Company income increases, which it will with the Kentucky rate increase, then the Ohio and West Virginia portion of the Company's income necessarily will decrease. The Company confirmed this fact in response to KIUC 2-5, wherein it stated: "All other factors remaining equal, the Ohio franchise tax should decrease after any Kentucky rate increase due to the lower apportionment caused by the increased revenues and income."

Q. Have you quantified the effect of removing the Ohio and West Virginia income taxes from the GRCF?

A. Yes. The effect is to reduce the Company's proposed revenue requirement by $0.135 million. The GRCF computations are detailed on my Exhibit___(LK-15) and the GRCF carried forward to Section VI on my Exhibit___(LK-3) to quantify the revenue requirement effect.

<u>Commission Should Reflect Reduction in Kentucky Corporate Income Tax Rate to 6.0%</u>

Q. Has the Company reflected the reduction in the Kentucky state income tax rate to 7.0% effective January 1, 2005?

A. Yes. However, it has not reflected the reduction from 7.0% to 6.0% scheduled to go into effect on January 1, 2007. Consequently, under its proposal, the Company will recover an excessive amount for state income taxes after December 2006 that it will simply retain for the benefit of its shareholder.

Q. How does the Company's proposal to retain the benefit of the January 1, 2007 Kentucky state income tax rate reduction for the benefit of its shareholder compare to its proposal to reflect the phase-out of the Ohio franchise tax in its proposed GRCF?

A. Although the Company proposes to retain the benefit of the reduction in the Kentucky state income tax rate, it proposes to provide the benefit of the phase-out of the Ohio franchise tax to ratepayers in the revenue requirement. The Company's proposes to reflect an average of the phase-out rates for 5 years starting with January 1, 2007, the same date the Kentucky state income tax rate will be reduced to 6.0%.

Q. The Company argues in response to discovery that it did not reflect the reduction

in the Kentucky state income tax rate to 6.0% because of the uncertainties associated with the new requirement to file a consolidated return. Is this a valid argument?

A. No. First, the Kentucky Commission has always used separate standalone tax computation and the Company's income tax expense at the 7.0% rate reflects a separate standalone tax expense computation. Thus, this argument should be dismissed as irrelevant. Second, if the income tax expense can be computed at a 7.0% rate, then it can be computed at the 6.0% rate, notwithstanding the uncertainties that would apply to both rates, even assuming the uncertainties were relevant.

Q. How do you propose that the Commission reflect the 6.0% Kentucky state income tax rate?

A. I recommend that the Commission use a 6.0% rate given that the rates from this proceeding will be in effect no more than 7 months in 2006. This also is consistent with the Company's approach of averaging the projected Ohio franchise tax rates over the five years commencing January 1, 2007. Alternatively, the Commission could increase the rate slightly by applying a weighting factor to the 7.0% rate for the 7 months in 2006 compared to 53 months at 6.0% for a five year total, although this would be a variation on the Company's Ohio franchise tax phase-out methodology.

Q. Have you quantified the effect of using the 6.0% Kentucky state income tax rate?

A. Yes. The effect is to reduce the Company's proposed revenue requirement by $0.675 million. The GRCF computations are detailed on my Exhibit___(LK-15) and the GRCF carried forward to Section VII on my Exhibit___(LK-3) to quantify the revenue requirement effect.

Commission Should Reflect §199 Deduction Based on Taxable Income for Ratemaking Purposes

Q. The Company claims that it has "reflected 100% of the annual effect of the Section 199 deduction in the calculation of the State and Federal income tax liability" (Wagner Direct at 16). Is that correct?

A. It is correct only for historic accounting purposes, but it is not correct for ratemaking purposes. The Company simply used the per books amount for the January 1 through

June 30, 2005 period and doubled it to quantify a 12 month effect.[3] The Company provided further detail of the per books computation in response to KIUC 2-43, which was based on 2004 tax accruals.

As I previously discussed, the §199 deduction is a function of domestic manufacturing activity (production) taxable income and taxable income arises in a ratemaking context from the income taxes on the equity return. Thus, the §199 deduction can be computed directly as a reduction to the federal and state income tax rates used in the GRCF and applied to the production portion of capitalization. This is the same approach employed by the Commission in the LG&E, KU, and Company ECR proceedings, except that in a base rate proceeding, the capitalization or rate base must be allocated between production and non-production.

Q. Have you quantified the effect of the §199 deduction?

A. Yes. The effect is to reduce the Company's revenue requirement by $0.548 million, which is $0.134 million more than the revenue requirement effect of the Company's per books amount. The GRCF computations are detailed on my Exhibit___(LK-16) and the

[3] The §199 deduction was effective January 1, 2005 and the test year per books amounts included only six months. This can be seen on the workpapers underlying Schedule 10 which were provided in response to KIUC 1-15 on CD.

GRCF carried forward to Section VIII on my Exhibit___(LK-3) to quantify the revenue requirement effect.. The §199 deduction is applied only to production taxable income. As such, it is necessary to allocate capitalization between production and non-production, which I have done based on rate base. The allocation of capitalization based on a computation of production and non-production rate base is detailed on my Exhibit___(LK-17). The computations in Section VIII on my Exhibit___(LK-3) reflect both a production grossed-up rate of return, which reflects the §199 deduction and is applied to the production portion of capitalization, and a non-production grossed-up rate of return, which reflects no §199 deduction and is applied to the non-production portion of capitalization to determine the revenue requirement effect.

Commission Should Use Ten Year Average to Quantify Storm Damage Expense

Q. Please describe the Company's request for storm damage expense.

A. The Company used a 3 year average of storm damage expense of $1.525 million (jurisdictional), computed using the 12 months ending June 30, 2003 amount of $2.949 million, the June 30, 2004 amount of $2.751 million, and the June 30, 2005 amount of $0.577 million. The Company used a constant dollar index to inflate the 12 months ending June 30, 2003 amount before it computed the 3 year average.

Q. Is the use of a 3 year average consistent with the Commission's historical practice?

A. No. The Commission historically uses a 10 year average. The use of a 10 year average has the advantage of reducing the impact of unusual storm damage costs in specific years.

Q. What is the effect of using a 10 year average in lieu of the 3 year average proposed by the Company?

A. In response to Staff 2-16(e), the Company provided a 9 year average amount in response to the Staff's request for a 10 year average. The result was a reduction in O&M expense of $0.384 million (jurisdictional), computed as $1.525 million requested less the $1.141 million 9 year average.

<u>Commission Should Reject Company's Proposed Big Sandy Plant Maintenance Normalization Adjustment</u>

Q. Please describe the Company's proposed Big Sandy plant maintenance expense normalization adjustment.

A. The Company proposes a Big Sandy Plant maintenance expense normalization adjustment of $1.317 million (total Co) and $1.299 (jurisdictional) (Section V WP S-3 page 38) based on a 3 year average.

Q. Should the Commission adopt this proposed adjustment?

A. No. First, there is nothing to indicate that the test year is abnormal or requires normalization other than the fact that the use of a 3 year average results in an increase in the revenue requirement. The only support offered for this adjustment is that "Because KPCo has one generating plant and plant maintenance is performed on a cycle basis, an adjustment to the test year is required to reflect a normal level of plant maintenance in the Company's test year cost of service." (Wagner at 40). This adjustment does not inherently reflect a normal level of plant maintenance; it only reflects the mathematical average of 3 years of maintenance expense, one year of which included nonrecurring charges due to a 16 week outage to install the Unit 2 SCR (response to AG 1-70 page 3).

Second, the test year already appears to be normal based on the weeks of outage for the 3 historic years and the weeks of outages projected for 2005 – 2007, according to the Company's response to AG 1-70 page 3. The test year reflected 2 weeks of Unit 1 outage and 4 weeks for Unit 2. Actual for 2004 was 2 weeks Unit 1 outage and 4 weeks Unit 2 outage. Projections for 2005 are 2 weeks for Unit 1 and 0 weeks for Unit 2. Projections for 2006 and for 2007 are 2 weeks for Unit 1 and 2 weeks for Unit 2 and projections for 2008 are 3 weeks for Unit 1 and 8 weeks for Unit 2. This results in a five year average of 2.2 weeks for Unit 1 and 3.2 weeks for Unit 2 or fewer outage weeks on average than already reflected in the test year.

Third, the Company's approach may constitute impermissible retroactive ratemaking instead of "normalization" because the average includes the 2002 SCR outage.

V. REVENUE REQUIREMENT – RATE OF RETURN ISSUES

Company's Proposed Return on Common Equity Results in Excessive Revenue Requirement

Q. Have you quantified the effect of Mr. Baudino's recommendation for a 9.35% return on common equity?

A. Yes. The KIUC recommendation reduces the revenue requirement by $11.639 million. Each 1.0% change in the return on common equity is equivalent to $5.413 million in the revenue requirement. The Company requests an 11.50% return on common equity, or 19.15% grossed-up using the Company's proposed gross revenue conversion factor of 1.6656. The KIUC recommendation is 15.24% grossed-up using the gross revenue conversion factor 1.6301 (weighted average of production reflecting §199 deduction GRCF and non-production GRCF) that I recommend and previously discussed in the Revenue Requirement – Operating Income section of my testimony.

Q. Does this complete your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA
JANUARY 2006