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PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF:

ADJUSTMENT OF RATES OF	)	
KENTUCKY POWER COMPANY	)	Case No. 2009-00459

KENTUCKY POWER COMPANY
REBUTTAL TESTIMONY

May 14, 2010

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENT OF ELECTRIC)
RATES OF KENTUCKY POWER COMPANY) Case No. 2009-00459

KENTUCKY POWER COMPANY
REBUTTAL TESTIMONY OF TIMOTHY C MOSHER

May 14, 2010

REBUTTAL TESTIMONY OF
TIMOTHY C. MOSHER
ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2009-00459

TABLE OF CONTENTS

**REBUTTAL DIRECT TESTIMONY OF
TIMOTHY C. MOSHER
ON BEHALF OF
KENTUCKY POWER COMPANY,
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY
CASE NO. 2009-00459**

I. Introduction

Q: PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A: My name is Timothy C. Mosher. My position is President and Chief Operating Officer, Kentucky Power Company (Kentucky Power, KPCo or Company). My business address is 101 A Enterprise Drive, Frankfort, Kentucky 40601.

II. Background

Q: PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A: I received a Bachelor in Electrical Engineering degree from the University of Detroit in 1969 and an MBA from the University of Akron in 1974. In 1981 I attended an AEP Management Program at the University of Michigan. I also attended the Executive Program at the Darden Graduate School of Business Administration at the University of Virginia in 1995.

III. Purpose of Testimony

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: The purpose of my testimony is to respond to matters regarding the Company's Home Energy Assistance Program (HEAP), offered in the testimony of by Mr.

Roger McCann, filed in this case on behalf of the Community Action of Kentucky.

Q: **DO YOU AGREE WITH MR. McCANN'S CONCLUSION AT PAGE 6 OF HIS PREFILED TESTIMONY THAT KENTUCKY POWER COMPANY MUST INCREASE THE PER METER CHARGE FOR THE HOME ENERGY ASSISTANCE PROGRAM (HEAP)?**

A: No. The problems presented by the inability of some Kentucky Power ratepayers to meet their energy bills are larger than the resources the Company and the Commission reasonably can commit to them and are more fairly and efficiently addressed through broadly-based social programs. Kentucky Power is willing to work with the Commission and its staff to address these broader society-wide issues. Kentucky Power expects to continue collecting its $0.10 per month on each residential bill going forward; however, the Company has no intention to increase the amount unless ordered to by the Public Service Commission.

Q: **DO YOU AGREE WITH MR. MCCANN'S RECOMMENDATION AT PAGE 6 OF HIS TESTIMONY THAT KENTUCKY POWER COMPANY SHOULD MAKE SHAREHOLDER CONTRIBUTIONS TO THE COMPANY'S HEAP PROGRAM?**

A: No. As part of its February 6, 2006, Settlement Agreement with the Attorney General, Kentucky Industrial Utility Customers, Inc., Kentucky Association for Community Action, Inc. and Kentucky Cable Telecommunications Association in

In the Matter of: General Adjustment in Electric Rates of Kentucky Power Company, Case No. 2005-00341 ("2005 Rate Case"), Kentucky Power agreed to match for two years the funding provided by the $0.10 per month line item on residential bills used to fund the Home Energy Assistance Program. Settlement Agreement, 2005 Rate Case at ¶ 8. The Company intended its two-year contribution to "jump-start" the program, and also as a means of helping the community action agencies administering the program defray their start-up costs. At the time of its commitment, Kentucky Power was one of the few, if not the only, electric utility in the Commonwealth making such contributions. The Company has collected and matched the following total dollars in each of the years since that settlement:

Collected		Matched
April '06 - March '07:	$166,129.40	$166,129.40
April '07 - March '08:	$173,237.18	$173,237.18
April '08 - March '09:	$173,041.66	7,224.74*
April '09 - March '10:	$172,482.87	$0.00

* Per regulatory, due to phase in of the rates, April 2006 only had a 1/2 month contribution made by the company. Additional contribution of 1/2 April 2008 rates made in June 2009.

Kentucky Power appreciates and respects the commendation contained in the Commission's March 14, 2006, Order approving the Settlement Agreement in its 2005 Rate Case. Nevertheless, the Company was candid in the agreement concerning the extent of the obligation it was undertaking: "The Company shall have no further obligation following the two (2) year contribution period." Settlement Agreement, 2005 Rate Case at ¶ 8.

Kentucky Power regularly contributes to the communities in its service territory. For example, during the past four calendar years, Kentucky Power contributed to Ashland Community College, Challenger Learning Center, Foundation for the Tri-State, Hazard Community & Technical College, Kentucky River Area, Paramount Arts Center, Pikeville College, Leadership Kentucky Foundation, Ashland Summer Motion, KCTCS Foundation, Big Sandy College Education Foundation, Kentucky Chamber of Commerce, Boys & Girls Club, Kentucky Educational Television, and the Highlands Foundation. The cost of these contributions is borne solely by Kentucky Power's shareholder, American Electric Power Company, Inc. *See South Central Telephone Company v. Public Service Commission, 702 S.W. 2d 447, 452 (Ky. App. 1985).* Further, the funds available in any year for contributions are limited. Thus, an increase in contributions to one recipient typically means a reduction or elimination of contributions to other recipients. Kentucky Power's home energy assistance program matching contributions were in addition to its regular contributions and thus were for a limited period. In addition, to the extent such considerations are relevant, the Company notes that the rate of return on equity imputed in the Settlement Agreement by the Commission was 10.5%: "Therefore, the Commission finds that the weighted average cost of capital for the Kentucky Power component of the current period revenue requirement should be determined using…a rate of return on equity of 10.5 percent as stated in the Settlement Agreement" Order, 2005 Rate Case at ¶14. For the three calendar years ended since the Commission's March 14, 2006 Order, the Company has yet to earn the imputed rate of return on equity:

Twelve Month Period Ending	KPCo's Rate of Return on Equity
December 31, 2006	9.73%
December 31, 2007	8.67%
December 31, 2008	6.14%
December 31, 2009	5.75%
Average	7.5%

With that low of a rate of return on equity, sufficient cash flows are not produced to fund higher levels of contributions.

Q: **DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?**

A. Yes.

AFFIDAVIT

Timothy C. Mosher, upon being first duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

T. C. Mosher
Timothy C. Mosher

Commonwealth of Kentucky	)	
	)	Case No. 2009-00459
County of Franklin	)	

Sworn to before me and subscribed in my presence by Timothy C. Mosher, this the 12th day of May, 2010.

Judy K Rasquist
Notary Public

My Commission Expires: January 23, 2013

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENT OF ELECTRIC)
RATES OF KENTUCKY POWER COMPANY) Case No. 2009-00459

KENTUCKY POWER COMPANY
REBUTTAL TESTIMONY OF WILLIAM E AVERA

May 14, 2010

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF THE ELECTRIC RATES, TERMS, AND CONDITIONS OF KENTUCKY POWER COMPANY	)))	CASE NO. 2009-00459

REBUTTAL TESTIMONY

OF

WILLIAM E. AVERA

on behalf of

KENTUCKY POWER COMPANY

REBUTTAL TESTIMONY OF WILLIAM E. AVERA

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. William E. Avera, 3907 Red River, Austin, Texas, 78751.

Q. Did you previously provide direct testimony in this proceeding?

A. Yes, I did.

Q. What is the purpose of your rebuttal testimony?

A. My testimony addresses the testimony of Richard A. Baudino, submitted on behalf of the Kentucky Industrial Utility Consumers, concerning a fair rate of return on common equity ("ROE") for the jurisdictional electric utility operations of Kentucky Power Company ("KPCo" or "the Company"). In addition, I also demonstrate that his criticisms of my applications and conclusions should be rejected by the Public Service Commission of the Commonwealth of Kentucky ("KPSC" or "the Commission").

II. Summary and Conclusions

Q. Please summarize the principal conclusions of your rebuttal testimony.

A. Mr. Baudino's recommendations are flawed and should be rejected. With respect to his analyses:

- *Because of flaws in the screening criteria and data used by Mr. Baudino, his proxy group should be rejected;*
- *Because electric utilities have significantly altered their dividend policies in recent years, Mr. Baudino's reliance on dividend growth rates to apply the discounted cash flow ("DCF") model imparts a downward bias to his results;*
- *Because Mr. Baudino's screening criteria eliminated growth rates at the upper end of the range while retaining numerous illogical estimates at the low end, his DCF cost of equity estimates are biased downward. Correcting this bias results in a DCF estimate for Mr. Baudino's proxy group of 10.7 percent based on earnings growth rates and an average DCF cost of equity 10.6 percent;*

- *Contrary to Mr. Baudino's unsupported allegations, the expected earnings approach is consistent with the opportunity cost principle advanced in his own testimony;*
- *Applying the expected earnings approach to Mr. Baudino's proxy group results in an average ROE of 10.8 percent and demonstrates that his recommendation fails to meet accepted regulatory and economic standards;*
- *Mr. Baudino ignored the results of his application of the Capital Asset Pricing Model ("CAPM") and so should the KPSC;*
- *Mr. Baudino's failure to consider the impact of flotation costs contradicts the findings of the financial literature and the economic requirements underlying a fair rate of return on equity;*

My rebuttal testimony also demonstrates that Mr. Baudino's criticisms of my alternative applications and conclusions should be rejected.

III. PROXY GROUP REVENUE TEST IS UNSUPPORTED

Q. Do you agree with Mr. Baudino that the source of a utility's revenues is a valid criterion in selecting a proxy group for KPCo?

A. No. Mr. Baudino selected proxy companies with at least 50 percent of their revenues from electric operations;[1] however, he failed to demonstrate how this arbitrary criterion translates into differences in the investment risks perceived by investors. Any comparison of objective indicators demonstrates that the investment risks for the firms in my proxy groups are relatively homogeneous and comparable to KPCo.

Q. Did Mr. Baudino demonstrate a nexus between his 50 percent revenue criterion and objective measures of investment risk?

A. No. Under the regulatory standards established by *Bluefield*[2] and *Hope*,[3] the salient criterion in establishing a meaningful proxy group to estimate

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[1] Baudino Direct at 15.
[2] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n,* 262 U.S. 679 (1923).

investors' required return is *relative risk*, not the source of the revenue stream. Mr. Baudino presented no evidence to demonstrate a relationship between the 50 percent revenue criterion that he employed and the views of real-world investors in the capital markets.

Moreover, the comfort that Mr. Baudino takes in limiting his proxy groups is misplaced. Due to differences in business segment definition and reporting among utilities, it is often difficult for investors to accurately apportion financial measures, such as total revenues, between utility segments (*e.g.*, electric and natural gas) or regulated and non-regulated sources. In fact, other regulators have rebuffed these notions, with the Federal Energy Regulatory Commission ("FERC") rejecting attempts to restrict a proxy group to companies based on sources of revenues. As FERC recently concluded:

> This is inconsistent with Commission precedent in which we have rejected proposals to restrict proxy groups based on narrow company attributes.[4]

Similarly, FERC has specifically rejected arguments a utility "should be excluded from the proxy group given the risk factors associated with its unregulated, non-utility business operations."[5]

Q. Do objective criteria confirm the conclusion that Mr. Baudino's arbitrary revenue test does not reflect comparable risk in the minds of investors?

A. Yes. Credit ratings are perhaps the most objective guide to utilities' overall investment risks and they are widely cited in the investment community and

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[3] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).
[4] *Pepco Holdings, Inc.*, 124 FERC ¶ 61,176 at P 118 (2008).
[5] *Bangor Hydro-Elec. Co.*, 117 FERC ¶ 61,129 at PP 19, 26 (2006).

referenced by investors. While the credit rating agencies are primarily focused on the risk of default associated with the firm's debt securities, credit ratings and the risks of common stock are closely related. As noted in *Regulatory Finance: Utilities' Cost of Capital*:

> Concrete evidence supporting the relationship between bond ratings and the quality of a security is abundant. ... The strong association between bond ratings and equity risk premiums is well documented in a study by Brigham and Shome (1982).[6]

Indeed, Mr. Baudino apparently agrees. He reviewed the bond ratings of the companies in his alternative proxy group (p. 16) and testified (p. 12) that bond ratings are based on "detailed analyses of factors that contribute to the risks of a particular investment" and "quantify the total risk of a company."

All of the utilities followed by Value Line identified as having electric revenues less than Mr. Baudino's 50 percent cutoff have bond ratings equal to or stronger than the criterion used to establish his proxy group.[7]

Q. What do you conclude from this review of independent, objective risk factors used by the investment community?

A. Considering that credit ratings provide one of the most widely accepted benchmarks for investment risks, a comparison of this objective indicator demonstrates that the range of risks for the companies eliminated under the arbitrary revenue criterion proposed by Mr. Baudino are either less risky than or comparable to those of the other firms in my Utility Proxy Group. Contrary to the assertions of Mr. Baudino,[8] comparisons of this objective, published indicator that incorporates consideration of a broad spectrum of

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[6] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utility Reports* (1994) at 81.
[7] Response to KPCo 1-11.
[8] Response to KPCo 1-9.

risks confirms that there is no link between the 50 percent electric revenue test he applied to define his proxy group and the risk perceptions of investors. In other words, there is no basis to distinguish between the risks that investors associate with the companies that Mr. Baudino would eliminate under his revenue criterion and those included in his proxy group.

Q. **Are there inconsistencies and errors associated with the revenue test proposed by Mr. Baudino?**

A. Yes. While Mr. Baudino screened all electric and combination electric and gas utilities followed by Value Line, his revenue test was based solely on electric revenues and ignored the revenue impact of gas utility operations. For example, despite the fact that SCANA Corporation reported in its 2009 Form 10-K report that electric and gas utility operations contributed 73 percent of consolidated revenues, Mr. Baudino would exclude this firm under his revenue test. Similarly, while Mr. Baudino's source reports that CenterPoint Energy, Inc.'s electric utility operations contributed only 19 percent of total revenues, the electric and gas utility segments posted 2009 revenues equal to 65.1 percent of the total consolidated revenues. Meanwhile, Wisconsin Energy Corporation reported in its 2009 Form 10-K Report (p. 109) that its regulated utility segment accounted for approximately 99.7 percent of total revenues. Considering the similarities in the regulatory and business environments for regulated electric and gas utility operations, the failure of Mr. Baudino to incorporate gas utility revenues in implementing his test is inappropriate.

The arbitrary nature of the 50 percent revenue criterion proposed by Mr. Baudino is further illustrated by the lack of any independent, objective findings to support his imposed threshold. Apart from the absence of any evidence to link revenues with investors' risk perceptions, Mr. Baudino granted that there is no underlying basis for his arbitrary test.[9]

Q. Are there other problems associated with the data used by Mr. Baudino to screen his proxy group?

A. Yes. Mr. Baudino applied his screen based on bond ratings reported by AUS Utility Reports. However, these reflect senior debt ratings, not the corporate, or issuer, credit rating for the utility as a whole. Because equity investors are focused on the overall investment risks of the firm, and not those attributable to a specific debt issue, the appropriate indicia is the corporate credit rating.

For example, while Mr. Baudino included UniSource Energy Corporation ("UniSource") in his proxy group based on a reported S&P bond rating of "BBB+", the corporate credit rating corresponding to UniSource is "BB+".[10] This rating falls below the ladder of investment grade ratings and places UniSource in the same category as speculative, or "junk" investments. As S&P informed investors, UniSource's finances and risks reflect "the continuing effect of a series of losses and near bankruptcy two decades ago."[11] Similarly, prior to requesting that S&P withdraw its ratings in December 2009,[12] Central Vermont Public Service Corporation, which was included in Mr. Baudino's proxy group, was also assigned a corporate

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[9] As indicated in response to data request KPCo 1-9 (b), "Mr. Baudino did not prepare any studies or documentation for the 50% regulated electric revenue criterion." Mr. Baudino granted in response to KPCo 1-9 (c) that he had no analyses, studies, or publications to support his position that the percent of revenues from electric utility operations is related to investors' risk perceptions.

[10] Standard & Poor's Corporation, "Tucson Electric Power Co.," *RatingsDirect* (Dec. 22, 2009). S&P's ratings, including those relied on by Mr. Baudino, reflect its assessment of UniSource's primary subsidiary.

[11] *Id.*

[12] Standard & Poor's Corporation, "Research Update: Central Vermont Public Service Corp. Ratings Withdrawn At The Company's Request," *RatingsDirect* (Dec. 10, 2009).

credit rating of "BB+". These junk bond ratings do not reflect comparable risks to KPCo and the financial and operating challenges that typically accompany a speculative grade rating skew the data used to estimate the cost of equity and seriously compromise the resulting DCF estimates.

Q. **Are there other manifestations of this problem reflected in the testimony of Mr. Baudino?**

A. Yes. As noted above, due to differences in business segment definition and reporting between utilities, it is often impossible to accurately apportion financial measures, such as total revenues, between utility and non-utility sources based on the financial information available to investors. Consider the example of Dominion Resources, Inc. (Dominion), which Mr. Baudino excluded from his sample group based on the contention that only 43 percent of Dominion's revenues were from electric utility sources. This 43 percent figure used to apply Mr. Baudino's electric revenue criterion is unrelated to the actual percentage of regulated revenues for Dominion, which classifies its operations into three primary segments – Dominion Virginia Power, Dominion Energy, and Dominion Generation.

Dominion Virginia Power includes regulated electric distribution and transmission, as well as nonregulated retail energy marketing operations. Similarly, Dominion Energy includes the regulated natural gas distribution business, as well as tariff-based natural gas pipeline and natural gas storage businesses subject to varying degrees of rate regulation, LNG import and storage activities, and petroleum exploration and production. Meanwhile, Dominion Generation includes the generation operations for both the electric utility and merchant power generation operations. As a result, even ignoring the fact that there is no clear link between the source of a utility's revenues and investors' risk perceptions, it is not possible to accurately apply Mr. Baudino's criterion.

IV. NO BASIS TO DISREGARD NON-UTILITY PROXY GROUP

Q. Does Mr. Baudino raise any meaningful criticisms regarding the use of your Non-Utility Proxy Group?

A. No. Mr. Baudino presented no meaningful evidence to rebut the results for my Non-Utility Proxy Group; rather, he simply noted (p. 34) that utilities "have protected markets ... enjoy full recovery of prudently incurred costs, and may increase their rates to cover increases in costs." Based on this, Mr. Baudino summarily concluded, "Obviously, the non-utility companies have higher overall risk structures."

In fact, however, investors are quite aware that utilities are <u>not</u> guaranteed recovery of prudent costs and that there are many instances in which utilities are unable to increase rates to fully recoup reasonable and necessary costs, resulting in an inability to earn the allowed rate of return on invested capital. The simple observation that a firm operates in non-utility businesses says nothing at all about the overall investment risks perceived by investors, which is the very basis for a fair rate of return. For example, consider (1) an electric utility such as UniSource with frozen rates, a debt-to-capital ratio of 73 percent, and a junk bond credit rating, versus (2) Wal-Mart Stores, Inc. ("Wal-Mart"), which faces competition on numerous fronts. Despite its lack of a regulated monopoly, with a double-A bond rating, the highest Value Line Safety Rank, and a beta of 0.60, the investment community would undoubtedly regard Wal-Mart as a less risky alternative to the utility included in Mr. Baudino's proxy group.

Q. Is there any basis to ignore required returns for non-utility companies?

A. No. The implication that an estimate of the required return for firms in the competitive sector of the economy is not useful in determining the appropriate return to be allowed for rate-setting purposes is wrong. In fact, returns in the competitive sector of the economy form the very underpinning for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets. The Supreme Court has recognized that it is the degree of risk, not the nature of the business, which is relevant in evaluating an allowed ROE for a utility.[13]

Consistent with this view, Mr. Baudino noted (pp. 10-11) that the notion of "opportunity cost" underlies the Supreme Court's economic standards, and that:

> One measures the opportunity cost of an investment equal to what one would have obtained in the next best alternative. ... That alternative could have been another utility stock, a utility bond, a mutual fund, a money market fund, or any other number of investment vehicles. (emphasis added)

As Mr. Baudino correctly observed (p. 11), "The key determinant in deciding whether to invest, however, is based on comparative levels of risk," and he concluded, "[T]he task for the rate of return analyst is to estimate a return that is equal to the return being offered by other risk-comparable firms." In other words, Mr. Baudino recognized that investors gauge their required returns from utilities against those available from non-utility firms of comparable risk. My reference to a comparable-risk Non-Utility Proxy Group is entirely consistent with the guidance of the Supreme Court and the principles outlined in Mr. Baudino's own testimony.

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[13] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

Q. Did Mr. Baudino present any objective evidence to support his contention that your Non-Utility Proxy Group is riskier than KPCo or your proxy group of electric utilities?

A. No. Apart from sweeping generalizations about the risk differences between regulated and non-regulated companies, Mr. Baudino provided no support whatsoever for his contention. In fact, the objective risk measures specifically cited by Mr. Baudino as being relevant indicia of overall investment risks contradict his assertions. As noted earlier, Mr. Baudino testified that bond ratings reflect a detailed and comprehensive analysis of the key factors contributing to a firm's overall investment risk, concluding (p. 12), "Bond ratings are tools that investors use to assess the risk comparability of firms." Contradicting Mr. Baudino's unsupported assertion (p. 34) that the companies in my Non-Utility Proxy Group "have higher overall risk structures," my direct testimony noted that the average corporate credit rating for the Non-Utility Proxy Group of "A+" is higher than the "BBB" average for the Utility Proxy Group and KPCo. In fact, the review of objective indicators of investment risk presented in my direct testimony (Table WEA-1), which consider the impact of competition and market share, demonstrated that, if anything, the Non-Utility Proxy Group could be considered less risky in the minds of investors than the common stocks of the proxy group of electric utilities.

V. DCF RESULTS FAIL TO REFLECT INVESTORS' EXPECTATIONS

Q. Do you agree with Mr. Baudino (p. 36) that you "erred" by ignoring Value Line's DPS growth projections in your application of the DCF model?

A. No. As I explained in my direct testimony, specific trends in dividend policies for utilities and evidence from the investment community fully support my conclusion that earnings growth projections are likely to provide a superior guide to investors' expectations. Indeed, while Mr. Baudino suggests (p. 37) that dividends per share ("DPS") growth "must be considered," his own review of this information confirms my decision to exclude it. As shown on Mr. Baudino's Exhibit__(RAB-7), the DPS growth rates for the firms in my Utility Proxy Group ranged from –5.5 percent to 25.0 percent. Even after excluding "aberrant or negative growth rates,"[14] Value Line's DPS growth rates for the firms in my Utility Proxy Group result in an average DCF cost of equity estimate of 9.06 percent, which falls far below even Mr. Baudino's downward biased 10.10 percent ROE recommendation.

Moreover, I disagree with Mr. Baudino's assertion (p. 36) that because Value Line's projected DPS growth rates "are widely available to investors," they can "reasonably be assumed to influence their expectation with respect to growth." Value Line publishes a wide variety of financial information, including growth rates in revenues and cash flows -- simply because a statistic is included in Value Line's report does not mean that investors would rely on it in determining their growth expectations. Indeed,

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[14] Mr. Baudino failed to exclude growth rates of zero or 1.0 percent, despite the concerns noted on page 21 of his testimony.

Value Line makes a number of five and ten-year historical growth rates available to investors, including historical growth in DPS, which Mr. Baudino nevertheless rejected as inconsistent with investors' expectations.[15]

Q. Do Mr. Baudino's projected DPS growth rates exhibit similar problems?

A. Yes. As shown on page 1 of Mr. Baudino's Exhibit__(RAB-4), DPS growth rates for four of the firms in his reference group were equal to 1.0 percent or less, and his average dividend growth rate of 4.36 percent was over 160 basis points below the growth rate indicated from his review of analysts' earnings growth projections. This mirrors the trend towards a more conservative payout ratio for electric utilities and the need to conserve financial resources to provide a hedge against heightened uncertainties. However, while utilities have significantly altered their dividend policies in response to more accentuated business risks in the industry, this is not necessarily indicative of investors' long-term growth expectations. In fact, as discussed in my direct testimony, growth in earnings is far more likely to provide a meaningful guideline to investors' expected growth rate.

Q. Do you agree that the screening criteria Mr. Baudino applied resulted in a reasonable growth estimate?

A. No. While I certainly agree that it is appropriate to evaluate the reasonableness of inputs to the DCF model, I take issue with the specific criteria applied by Mr. Baudino. After a review of the individual growth rates for the companies in his reference group, Mr. Baudino speculated (p. 21) that no growth rate of 10 percent or above is reasonable. Mr. Baudino's

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[15] Baudino Direct at 19.

"Method 3" results omitted all double-digit growth rates, as well as those below 1 percent.

But the growth expectations relevant to the DCF model are those of investors, not his personal assessment, and he presented no evidence to support his claim that the growth expectations that investors build into current stock prices could never equal 10 percent or above. Moreover, while I agree with Mr. Baudino that growth rates below 1 percent cannot be considered reasonable, his criterion retains numerous other low-end growth estimates that produce illogical cost of equity estimates. For example, in his "Method 3" analysis, Mr. Baudino excluded the 10.0 percent Value Line DPS growth rate for UniSource while retaining Value Line's 2.5 percent projected DPS growth rate for OGE Energy, Inc. ("OGE").[16] But adding OGE's 4.04 percent dividend yield (Exhibit__(RAB-3), p. 2) to the 2.5 percent growth rate from Value Line results in an implied cost of equity of 6.54 percent, which is not significantly above the yield on triple-B public utility bonds and falls far below a meaningful estimate of investors' required return for an electric utility. In other words, while Mr. Baudino was quick to discard growth estimates at the upper end of his range as being "excessive," he retained other low-end growth rates that are not supported by economic logic.

Q. **Have other regulators approved DCF estimates based on growth rates that exceed single digits?**

A. Yes. For example, in 2002 the FERC approved an ROE zone of reasonableness of 9.21 percent to 15.96 percent for the utility participants in the Midwest Independent Transmission System Operator, Inc., with the high-

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[16] Baudino Direct at Exhibit__(RAB-4), p. 1.

end of the DCF range being based on a growth rate of 11.00 percent.[17] Similarly, in 2009 FERC approved an ROE based on DCF cost of equity estimates for a proxy group of fifteen companies that incorporated twelve individual growth rates ranging from 8.0 percent to 11.5 percent.[18] These authorized DCF results contradict Mr. Baudino's conclusion that double-digit growth rates are *per se* illogical.

Q. **What then is a more reasonable application of Mr. Baudino's DCF analysis?**

A. As shown on Exhibit WEA-10, revising Mr. Baudino's DCF method to exclude growth rates of 1.00 percent or less, along with the 17.0 percent growth rate for UniSource, results in an average DCF cost of equity of approximately 10.6 percent, or 10.7 percent if Mr. Baudino's DPS growth rates are excluded.

Q. **Is there a downward bias inherent in Mr. Baudino's internal, "br" growth rates?**

A. Yes. The sustainable growth rate is calculated by the formula, g = br+sv, where "b" is the expected retention ratio, "r" is the expected earned return on equity, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate. Mr. Baudino based his calculations of the internal, "br+sv" retention growth rate on data from Value Line, which reports end-of-period results.[19] If the rate of return, or "r" component of the "br+sv" growth rate, is based on end-of-year book

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[17] *Midwest Independent Transmission System Operator, Inc.*, 99 FERC ¶ 63,011 at Appendix A (2002).

[18] *Pioneer Transmission, LLC*, 126 FERC ¶ 61,281 (2009).

[19] While Mr. Baudino calculated sustainable, "br" growth rates for the firms in his proxy group, his DCF analysis ignored these data.

values, such as those reported by Value Line, it will understate actual returns because of growth in common equity over the year. This downward bias has been recognized by regulators[20] and is illustrated in the example below.

Consider a hypothetical firm that begins the year with a net book value of common equity of $100. During the year the firm earns $15 and pays out $5 in dividends, with the ending net book value being $110. Using the year-end book value of $110 to calculate the rate of return produces an "r" of 13.6 percent. As the FERC has recognized, however, this year-end return "must be adjusted by the growth in common equity for the period to derive an average yearly return."[21] In the example below, this can be accomplished by using the average net book value over the year ($105) to compute the rate of return, which results in a value for "r" of 14.3 percent. Use of the average rate of return over the year is consistent with the theory of this approach to estimating investors' growth expectations, and as illustrated below, it can have a significant impact on the calculated retention growth rate:

Beginning Net Book Value	$100
Earnings	15
Dividends	5
Retained Earnings	10
Ending Net Book Value	$110

"b x r" Growth	End-of Year	Average
Earnings	$ 15	$ 15
Book Value	$110	$105
"r"	13.6%	14.3%
"b"	66.7%	66.7%
"b x r" Growth	**9.1%**	**9.5%**

[20] See, *e.g.*, *Southern California Edison Company*, Opinion No. 445, 92 FERC ¶ 61,070 (2000).
[21] *Id.*

Because Mr. Baudino did not adjust to account for this reality in his analysis, the "internal" growth rates that he calculated are downward-biased.

Q. Are there other considerations that produce a downward bias in Mr. Baudino's calculation of internal, "br" growth?

A. Yes. Mr. Baudino ignored the impact of additional issuances of common stock in his analysis of the sustainable growth rate. Under DCF theory, the "sv" factor is a component designed to capture the impact on growth of issuing new common stock at a price above, or below, book value. As noted by Myron J. Gordon in his 1974 study:

> When a new issue is sold at a price per share P = E, the equity of the new shareholders in the firm is equal to the funds they contribute, and the equity of the existing shareholders is not changed. However, if P > E, part of the funds raised accrues to the existing shareholders. Specifically...[v] is the fraction of the funds raised by the sale of stock that increases the book value of the existing shareholders' common equity. Also, "v" is the fraction of earnings and dividends generated by the new funds that accrues to the existing shareholders.[22]

In other words, the "sv" factor recognizes that when new stock is sold at a price above (below) book value, existing shareholders experience equity accretion (dilution). In the case of equity accretion, the increment of proceeds above book value (P > E in Professor Gordon's example) leads to higher growth because it increases the book value of the existing shareholders' equity. In short, the "sv" component is entirely consistent with DCF theory, and the fact that Mr. Baudino failed to consider the incremental

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[22] Gordon, Myron J., "The Cost of Capital to a Public Utility," MSU Public Utilities Studies (1974), at 31–32.

impact on growth results in another downward bias to his "internal" growth rates.

VI. EXPECTED EARNINGS METHOD IS AN ACCEPTED APPROACH

Q. **Is there any basis for Mr. Baudino's contention that the expected earnings is not a valid ROE benchmark?**

A. No. My expected earnings approach is predicated on the comparable earnings test, which developed as a direct result of the Supreme Court decisions in *Bluefield* and *Hope*. From my understanding as a regulatory economist, not as a legal interpretation, these cases required that a utility be allowed an opportunity to earn the same return as companies of comparable risk. That is, the cases recognized that a utility must compete with other companies (including non-utilities) for capital.

Q. **What economic premise underlies the expected earnings approach?**

A. The simple, but powerful concept underlying the expected earnings approach is that investors compare each investment alternative with the next best opportunity. As Mr. Baudino recognized (p. 10), economists refer to the returns that an investor must forgo by not being invested in the next best alternative as "opportunity costs".

Q. **What are the implications of setting an allowed ROE below the returns available from other investments of comparable risk?**

A. If the utility is unable to offer a return similar to that available from other opportunities of comparable risk, investors will become unwilling to supply the capital on reasonable terms. For existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their opportunity cost of capital. In this situation the government is effectively taking the value of investors' capital without adequate compensation.

Q. How is the comparison of opportunity costs typically implemented?

A. The traditional comparable earnings test identifies a group of companies that are believed to be comparable in risk to the utility. The actual earnings of those companies on the book value of their investment are then compared to the allowed return of the utility. While the traditional comparable earnings test is implemented using historical data taken from the accounting records, it is also common to use projections of returns on book investment, such as those published by recognized investment advisory publications (*e.g.*, Value Line). Because these returns on book value equity are analogous to the allowed return on a utility's rate base, this measure of opportunity costs results in a direct, "apples to apples" comparison.

Q. Is the traditional comparable earnings method an accepted approach to evaluating a fair rate of return on equity?

A. Yes. In fact, a textbook prepared for the Society of Utility and Regulatory Analysts labels the comparable earnings approach the "granddaddy of cost of equity methods," and notes that the comparable earning approach is based on the opportunity cost concept and consistent with both sound regulatory economics and the legal standards set forth in the landmark *Bluefield* and *Hope* cases.[23] It has been widely referenced in regulatory decision-making.[24]

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[23] Parcell, David C., *The Cost of Capital—a Practitioner's Guide* (1997).

[24] For example, the comparable earnings approach was identified as a favored method in determining the allowed ROE for 24 of the agencies surveyed in NARUC's compilation of regulatory policy. "Utility Regulatory Policy in the U.S. and Canada, 1995-1996," National Association of Regulatory Utility Commissioners (December 1996). In my experience, while a few Commissions have explicitly rejected comparable earnings, most regard it as a useful tool.

Q. **Do you agree with Mr. Baudino (p. 39) that it is necessary to examine a "market-based model" in evaluating investors' opportunity costs?**

A. No. While I agree that market-based models are important tools in estimating investors' required rate of return, this in no way invalidates the usefulness of the expected earnings approach. In fact, this is one of its advantages.

It is a very simple, conceptual principal that when evaluating two investment of comparable risk, investors will choose the alternative with the higher expected return. If KPCO is only allowed the opportunity to earn Mr. Baudino's recommended 10.1 percent on the book value of its equity investment, while the comparable-risk utilities in my proxy group are expected to earn an average of 11.3 percent,[25] the implications are clear – KPCo's investors will be denied the ability to earn their opportunity cost.

Moreover, regulators do not set the returns that investors earn in the capital markets – they can only establish the allowed return on the value of a utility's investment, as reflected on its accounting records. As a result, the expected earnings approach provides a direct guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. This opportunity cost test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a benchmark for investors' opportunity costs that is independent of fluctuating stock prices,

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[25] Avera Direct at Exhibit WEA-8.

market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

Q. **What ROE is implied if the expected earnings approach is applied to the companies in Mr. Baudino's proxy group?**

A. As shown on Exhibit WEA-11, the expected earnings approach implied an average cost of equity for the utilities in Mr. Baudino's proxy group of 10.8 percent.[26] While the reliability of Mr. Baudino's results are compromised because of the flaws associated with his proxy group, this provides another indication that his recommendation of 10.1 percent is simply too low to meet accepted regulatory standards.

VII. CAPM RESULTS SHOULD BE IGNORED

Q. **Did Mr. Baudino rely on his CAPM results in arriving at his recommendation in this case?**

A. No. As Mr. Baudino noted,[27] his ROE recommendation was based solely on cost of equity estimates implied by his application of the DCF model and ignored his CAPM results entirely.

Q. **Is there good reason to entirely disregard the results of Mr. Baudino's CAPM analyses?**

A. Yes. As discussed in my direct testimony,[28] applying the CAPM is complicated by the impact of the recent capital market turmoil and recession on investors' risk perceptions and required returns. The CAPM cost of

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[26] As shown there, I eliminated one low-end outlier of 6.7 percent. Given current yields available to investors on triple-B public utility bonds, this value provides no meaningful guidance as to a fair ROE for KPCo.

[27] Baudino Direct at 2:21—3:2.

[28] Avera Direct at 43-44.

common equity estimate is calibrated from investors' required risk premium between Treasury bonds and common stocks. In response to heightened uncertainties, investors sought a safe haven in U.S. government bonds and this "flight to safety" pushed Treasury yields significantly lower while yield spreads for corporate debt widened. This distortion not only impacts the absolute level of the CAPM cost of equity estimate, but it affects estimated risk premiums. Economic logic would suggest that investors' required risk premium for common stocks over Treasury bonds has also increased. This is simply not the time for the Commission to give much weight to the CAPM, irrespective of methodology. As the Staff of the Florida Public Service Commission recently concluded:

> [R]ecognizing the impact the Federal Government's unprecedented intervention in the capital markets has had on the yields on long-term Treasury bonds, staff believes models that relate the investor-required return on equity to the yield on government securities, such as the CAPM approach, produce less reliable estimates of the ROE at this time.[29]

I agree with Mr. Baudino's decision to give no weight to his CAPM results. While his application of this approach contains serious methodological flaws, I have chosen not to address these issues because Mr. Baudino does not rely on this method to support his recommended ROE.

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[29] *Staff Recommendation for Docket No. 080677-E1 - Petition for increase in rates by Florida Power & Light Company*, at p. 280 (Dec. 23, 2009).

VIII. NO BASIS TO IGNORE FLOTATION COSTS

Q. Please respond to the argument that there is no basis to consider the impact of flotation costs in establishing KPCo's ROE.

A. The need for a flotation cost adjustment to compensate for past equity issues has been recognized in the financial literature. In a *Public Utilities Fortnightly* article, for example, Brigham, Aberwald, and Gapenski demonstrated that even if no further stock issues are contemplated, a flotation cost adjustment in all future years is required to keep shareholders whole, and that the flotation cost adjustment must consider total equity, including retained earnings.[30] Similarly, *Regulatory Finance: Utilities' Cost of Capital* contains the following discussion:

> Another controversy is whether the underpricing allowance should still be applied when the utility is not contemplating an imminent common stock issue. Some argue that flotation costs are real and should be recognized in calculating the fair rate of return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument implies that the company has already been compensated for these costs and/or the initial contributed capital was obtained freely, devoid of any flotation costs, which is an unlikely assumption, and certainly not applicable to most utilities. ... The flotation cost adjustment cannot be strictly forward-looking unless all past flotation costs associated with past issues have been recovered. (p. 175)

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[30] Brigham, E.F., Aberwald, D.A., and Gapenski, L.C., "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly,* May, 2, 1985.

Q. Can you provide a simple numerical example illustrating why a flotation cost adjustment is necessary to account for past flotation costs?

A. Yes. The following example demonstrates that investors will not have the opportunity to earn their required rate of return (*i.e.*, dividend yield plus expected growth) unless an allowance for past flotation costs is included in the allowed rate of return on equity. Assume a utility sells $10 worth of common stock at the beginning of year 1. If the utility incurs flotation costs of $0.48 (5 percent of the net proceeds), then only $9.52 is available to invest in rate base. Assume that common shareholders' required rate of return is 11.5 percent, the expected dividend in year 1 is $0.50 (*i.e.*, a dividend yield of 5 percent), and that growth is expected to be 6.5 percent annually. As developed below, if the allowed rate of return on common equity is only equal to the utility's 11.5 percent "bare bones" cost of equity, common stockholders will not earn their required rate of return on their $10 investment, since growth will really only be 6.25 percent, instead of 6.5 percent:

Year	Common Stock	Retained Earnings	Total Equity	Market Price	M/B Ratio	Allowed ROE	Earnings Per Share	Dividends Per Share	Payout Ratio
1	$ 9.52	$ -	$ 9.52	$10.00	1.050	11.50%	$ 1.09	$ 0.50	45.7%
2	$ 9.52	$ 0.59	$10.11	$10.62	1.050	11.50%	$ 1.16	$ 0.53	45.7%
3	$ 9.52	$ 0.63	$10.75	$11.29	1.050	11.50%	$ 1.24	$ 0.56	45.7%
Growth			**6.25%**	**6.25%**			**6.25%**	**6.25%**	

The reason that investors never really earn 11.5 percent on their investment in the above example is that the $0.48 in flotation costs initially incurred to raise the common stock is not treated like debt issuance costs (*i.e.*, amortized into interest expense and therefore increasing the embedded cost of debt), nor is it included as an asset in rate base.

Q. Can you illustrate how the flotation cost adjustment allows investors to be fully compensated for the impact of past issuance costs?

A. Yes. As discussed in my direct testimony, one method for calculating the flotation cost adjustment is to multiply the dividend yield by a flotation cost percentage. Thus, with a 5 percent dividend yield and a 5 percent flotation cost percentage, the flotation cost adjustment in the above example would be approximately 25 basis points. As shown below, by allowing a rate of return on common equity of 11.75 percent (an 11.5 percent cost of equity plus a 25 basis point flotation cost adjustment), investors earn their 11.5 percent required rate of return, since actual growth is now equal to 6.5 percent:

Year	Common Stock	Retained Earnings	Total Equity	Market Price	M/B Ratio	Allowed ROE	Earnings Per Share	Dividends Per Share	Payout Ratio
1	$ 9.52	$ -	$ 9.52	$10.00	1.050	11.75%	$ 1.12	$ 0.50	44.7%
2	$ 9.52	$ 0.62	$10.14	$10.65	1.050	11.75%	$ 1.19	$ 0.53	44.7%
3	$ 9.52	$ 0.66	$10.80	$11.34	1.050	11.75%	$ 1.27	$ 0.57	44.7%
Growth			**6.50%**	**6.50%**			**6.50%**	**6.50%**	

The only way for investors to be fully compensated for issuance costs is to include an ongoing adjustment to account for past flotation costs when setting the return on common equity. This is the case regardless of whether or not the utility is expected to issue additional shares of common stock in the future.

Q. Please respond to Mr. Baudino's only criticism of your flotation cost adjustment.

A. Mr. Baudino wrongly contends (p. 40) that flotation costs should be ignored because they "are already accounted for in current stock prices." *Regulatory Finance: Utilities' Cost of Capital* explained that Mr. Baudino's double counting argument is wrong:

> A third controversy centers around the argument that the omission of flotation cost is justified on the grounds that, in an efficient market, the stock price already reflects any accretion or dilution resulting from new issuances of securities and that a flotation cost adjustment results in a double counting effect. The simple fact of the matter is that whatever stock price is set by the market, the company issuing stock will always net an amount less than the stock price due to the presence of intermediation and flotation costs. As a result, the company must earn slightly more on its reduced rate base in order to produce a return equal to that required by shareholders.[31]

Similarly, the need to consider past flotation costs has been recognized in the financial literature, including sources that Mr. Baudino relied on in his testimony. Specifically, Ibbotson Associates concluded that:

> Although the cost of capital estimation techniques set forth later in this book are applicable to rate setting, certain adjustments may be necessary. One such adjustment is for flotation costs (amounts that must be paid to underwriters by the issuer to attract and retain capital).[32]

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

A. Yes.

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[31] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports, Inc.* (1994) at 174.

[32] Ibbotson Associates, *Stocks, Bonds, Bills, and Inflation, Valuation Edition, 2006 Yearbook*, at 35.

AFFIDAVIT

William E. Avera, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

William E. Avera

William E. Avera

State of Texas)
) ss
County of Travis)

Subscribed and sworn to before me, a Notary Public, by William E. Avera this 11th day of May 2010.

Notary Public

My Commission Expires 1/10/2011

ADRIEN MCKENZIE
Notary Public
STATE OF TEXAS
My Comm Exp. Jan. 10, 2011

BAUDINO DCF ANALYSIS

REVISED GROWTH RATE SCREEN

	Value Line Dividend Gr.	Value Line Earnings Gr.	Zack's Earning Gr.	First Call Earning Gr.	Average of Earnings Gr.	Average of All Gr. Rates
Method 1:						
Dividend Yield	4.36%	4.87%	4.82%	4.82%	4.84%	4.72%
Growth Rate	5.80%	5.42%	5.80%	6.00%	5.74%	5.76%
Expected Div. Yield	4.49%	5.00%	4.96%	4.96%	4.97%	4.85%
DCF Return on Equity	**10.29%**	**10.42%**	**10.76%**	**10.96%**	**10.71%**	**10.61%**
Midpoint of Results						**10.62%**

EXPECTED EARNINGS APPROACH

BAUDINO PROXY GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	American Electric Power Co.	10.0%	1.0293	10.3%
2	Avista Corporation	8.5%	1.0232	8.7%
3	Central Vermont Public Serv. Corp.	6.5%	1.0342	6.7%
4	Cleco Corporation	11.0%	1.0318	11.3%
5	Empire District Electric Co.	10.0%	1.0208	10.2%
6	Entergy Corporation	12.5%	1.0318	12.9%
7	Northeast Utilities	9.0%	1.0274	9.2%
8	OGE Energy Corp.	12.0%	1.0428	12.5%
9	PG&E Corporation	12.0%	1.0422	12.5%
10	Pinnacle West Capital Corp.	9.0%	1.0243	9.2%
11	TECO Energy, Inc.	12.5%	1.0272	12.8%
12	UIL Holdings Corporation	10.5%	1.0186	10.7%
13	UniSource Energy Corporation	11.0%	1.0468	11.5%
14	Westar Energy, Inc.	8.5%	1.0280	8.7%
	Average (d)			**10.8%**

(a) 3-5 year projections from The Value Line Investment Survey (Aug. 28, Sep. 25, & Nov. 6, 2009).
(b) Adjustment to convert year-end "r" to an average rate of return.
(c) (a) x (b).
(d) Excludes highlighted figures.

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENT OF ELECTRIC)
RATES OF KENTUCKY POWER COMPANY) Case No. 2009-00459

KENTUCKY POWER COMPANY
REBUTTAL TESTIMONY OF JEFFREY B. BARTSCH

May 14, 2010

REBUTTAL TESTIMONY OF
JEFFREY B. BARTSCH, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION.

A. My name is Jeffrey B. Bartsch. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am the Director of Tax Accounting and Regulatory Support for American Electric Power Service Corporation (AEPSC), a wholly owned subsidiary of American Electric Power Company, Inc. (AEP), the parent company of Kentucky Power Company (KPCo).

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I earned a Bachelor of Business Administration Degree in Accounting from Ohio University in 1979. I am a Certified Public Accountant and have been licensed in Ohio since 1981. I am also a member of the American Institute of Certified Public Accountants. I was first employed by Arthur Andersen & Co. in 1979 in the Audit section where I was assigned to various clients, including those in the electric utility industry. In 1985, I accepted a position with the Tax Department at AEPSC. Since that time I have held various positions until June 2000 when I was promoted to my current position.

Q. WHAT ARE YOUR RESPONSIBILITIES?

A. As Director of Tax Accounting and Regulatory Support, my responsibilities include oversight of the recording of the tax accounting entries and records of AEP and its subsidiaries, including KPCo. I am also responsible for coordinating the development of Federal tax data to be provided by the AEPSC Tax Department in regulatory proceedings. I have attended numerous tax, accounting and regulatory seminars throughout my professional career.

Q. **HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY PROCEEDING?**

A. Yes. I have filed testimony with the Public Utilities Commission of Ohio on behalf of Columbus Southern Power Company and Ohio Power Company; with the Michigan Public Service Commission on behalf of Indiana Michigan Power Company; with the Public Service Commission of West Virginia on behalf of Appalachian Power Company and Wheeling Power Company; with the Indiana Utility Regulatory Commission on behalf of Indiana Michigan Power Company; with the Public Service Commission of Kentucky on behalf of Kentucky Power Company; with the Virginia State Corporation Commission on behalf of Appalachian Power Company; and with the Federal Energy Regulatory Commission (FERC) in a transmission rate case for the eastern AEP Operating Companies. I have also filed testimony with the Public Utility Commission of Texas on behalf of AEP Texas Central Company, Southwestern Electric Power Company and AEP Texas North Company. Like KPCo these companies are all AEP operating companies.

Q. **WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

A. The purpose of my testimony in this proceeding is to address the Direct Testimony of Mr. Lane Kollen with regards to the IRC Section 199 Manufacturing Deduction, also know as the Production Activities Deduction.

Q. DID THE COMPANY INCLUDE A SECTION 199 DEDUCTION IN THE CALCULATION OF FEDERAL INCOME TAX EXPENSE IN THIS PROCEEDING?

A. No. Based on the Federal income tax returns filed from 2007 thru 2008, the Company has not been entitled to this special deduction. In addition, it appears that the Company will not be entitled to this deduction on the 2009 Federal income tax return due to a Federal tax loss.

Q. MR. KOLLEN STATES ON PAGE 37 HIS TESTIMONY THAT "THE COMMISSION HISTORICALLY HAS COMPUTED THE COMPANY'S INCOME TAX EXPENSE FOR RATEMAKING PURPOSES AS IF IT WERE A STAND-ALONE ENTITY" AND AS A RESULT, THE RATEPAYERS SHOULD RECEIVE "THE BENEFIT OF ALL DEDUCTIONS FOR WHICH IT WOULD BE ELIGIBLE AS A STAND-ALONE ENTITY". DO YOU AGREE WITH THESE COMMENTS?

A. Yes. The Company's income tax expense for ratemaking purposes should be calculated on a separate return or stand-alone basis. In other words, the income tax calculations should not be dependant on the activities of the other companies that are included in the AEP Consolidated Federal income tax return.

Q. MR. KOLLEN CLAIMS THAT THE COMPANY WAS NOT ABLE TO CLAIM THE SECTION 199 DEDUCTIONS IN THE PAST DUE AS A RESULT OF ITS INCLUSION AS A MEMBER OF THE AEP AFFILIATE GROUP. DO YOU AGREE WITH THIS ASSERTION?

A. Mr. Kollen is correct in that any Section 199 deduction that could have been claimed by Kentucky Power may in fact be limited based on its inclusion in the AEP Consolidated Federal income tax return. However, Exhibit JBB-1 shows that even on a stand-alone basis, Kentucky Power Company could have only claimed a Section 199 deduction in 2006 in the amount of $206,583 and could not have claimed a deduction in 2005, 2007 or 2008. In addition, the Company would not be entitled to a deduction in 2009 due to its stand-alone Federal tax loss.

Q. HOW DOES MR. KOLLEN PROPOSE TO CALCULATE THE SECTION 199 MANUFACTURING DEDUCTION FOR PURPOSES OF THIS PROCEEDING?

A. Mr. Kollen bases his calculation of the Section 199 deduction on the Revenue Requirement (-ie- Return) on Common Equity as shown in Section VI of page 2 of his Exhibit LK-15. This amount represents the theoretical Pre-Tax Book Income that the Company would earn in this rate proceeding assuming all of the KIUC adjustments are accepted by the Commission. He then applies a Production Factor (based on a Percent of Production Assets to Total Assets) to the total company return amount in order to calculate the Production Activities Income that should be applied to the Production Activities Deduction percent. The result of this calculation represents his Section 199 deduction.

Q. DO YOU AGREE WITH THIS APPROACH?

A. No. In the first place, the Section 199 deduction is determined on an annual basis based on facts and circumstances and is more closely aligned with taxable income.

Mr. Kollen's calculation assumes that the book return on production activities will approximate the Qualified Production Activities Income (QPAI) which would be used in calculating the Section 199 manufacturing deduction. As indicated on Exhibit JBB-2 the two will not be the same and in fact are quite different.

Q. PLEASE EXPLAIN WHY THESE AMOUNTS WOULD BE DIFFERENT.

A. The primary reason for the difference between book income and QPAI is that QPAI is derived from taxable income associated with generation related activities only. Thus, by using book income, Mr. Kollen is excluding the impact of all book/tax temporary differences in his computation of the Section 199 deduction.

Q. HOW DO YOU RESPOND TO MR. KOLLEN'S CLAIM THAT ANY RATE INCREASE RESULTING FROM THIS CASE WILL INCREASE THE COMPANY'S TAXABLE INCOME, WHICH WILL IN TURN INCREASE THE LIKELIHOOD OF THE COMPANY BEING ABLE TO USE THE SECTION 199 DEDUCTION?

A. While one would assume that an increase in revenues would increase the QPAI on which the Section 199 deduction is calculated, it is nothing more than an assumption. It is important to note that any change in the Section 199 deduction would be dependant on more than the amount of the revenue increase that impacts generation activities. As indicated earlier in my testimony and on Exhibit JBB-2, there is no direct link between book income and QPAI due to the differences in the reporting of revenues and expenses for book and tax purposes.

Q. WHAT IS THE COMPANY'S POSITION ON THE AMOUNT OF THE

SECTION 199 DEDUCTION THAT SHOULD BE INCLUDED IN THE TAX CALCULATION FOR THIS RATE PROCEEDING?

A. The Section 199 deduction for this rate case should be based on historical information and realistic expectations. The deduction should not be based on some theoretical calculation that does not bear any resemblance to reality. It would not be proper to include in rates a tax benefit that cannot realistically be expected to be realized. For purposes this proceeding, I would recommend using a Section 199 deduction amount based on the historical stand-alone deductions that could have actually been claimed on the Company's stand-alone Federal income tax returns.

For this case, I believe that a Section 199 deduction of no more than $620,000 be included in the calculation of income tax expense. This deduction amount would result in a decrease to the Company's requested revenues by $399,000. Exhibit JBB-3 shows how this amount was determined based on the most recent 3 years of historical tax return information.

Q. **DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?**

A. Yes. In conclusion, I would recommend that the Company's revenue requirement be reduced by $399,000 for the Section 199 deduction rather than the $1,362,000 as recommended by KIUC Witness Kollen. It is more reasonable to estimate this deduction based on historical results of tax operations rather than to use a theoretical calculation based on book amounts that cannot possibly be obtained.

AFFIDAVIT

Jeffrey B. Bartsch, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true

Jeffrey B. Bartsch

Jeffrey B. Bartsch

State of Ohio)
) ss
County of Franklin)

Subscribed and sworn to before me, a Notary Public, by Jeffrey B. Bartsch this 11th day of May, 2010.

Pauline A Lutz

Notary Public

My Commission Expires ______

PAULINE A LUTZ
NOTARY PUBLIC
STATE OF OHIO
MY COMM. EXP. 9-12-11

Exhibit JBB-1

Kentucky Power
Stand-Alone §199 Deduction

		2005	2006	2007	2008
1	Domestic Production Gross Receipts	852,995,718	740,947,246	616,038,125	688,653,583
2	Allocable Cost of Goods Sold	818,622,334	672,394,297	508,176,022	683,279,907
3	Directly Allocable Deductions, Expenses, or Losses	41,643,928	52,424,256	100,567,894	8,830,760
4	Indirectly Allocable Deductions, Expenses, or Losses	9,797,178	9,242,596	9,620,284	10,124,326
5	Add lines 2 Through 4	870,063,440	734,061,149	618,364,200	702,234,993
6	Qualified Production Activities Income (Loss)	(17,067,722)	6,886,097	(2,326,075)	(13,581,410)
7	Federal Taxable Income Limitation - Form 1040 - Line 30	11,852,070	34,659,105	26,773,624	1,377,727
8	Enter Smaller of line 6 or Line 7	(17,067,722)	6,886,097	(2,326,075)	(13,581,410)
9	Domestic Production Activities %	3.00%	3.00%	6.00%	6.00%
10	Preliminary Domestic Production Activities Deduction	-	206,583	-	-
11	Form W-2 Wages	32,421,805	2,575,769	11,561,463	13,130,297
12	Wage Limitation Percentage	50.00%	50.00%	50.00%	50.00%
13	Form W-2 Wage Limitation	16,210,903	1,287,885	5,780,732	6,565,149
14	Enter the Smaller of Line 10 or Line 13	-	206,583	-	-
15	Domestic Production Activities Deduction	-	206,583	-	-

KENTUCKY POWER COMPANY
SUMMARY RECONCILIATION OF
BOOK INCOME TO TAXABLE INCOME

KENTUCKY POWER COMPANY --- TOTAL COMPANY

	2005	2006	2007	2008
Pre-Tax Book Income <Loss>	32,945,318	53,689,665	48,456,408	32,426,866
State Income Tax Expense	1,196,688	1,646,562	1,132,195	1,649,820
Book Income Before Federal Income Tax Expense	31,748,630	52,043,103	47,324,213	30,777,046
Schedule M Adjustments	(19,896,560)	(17,383,998)	(20,550,589)	(29,538,347)
Federal Taxable Income <Loss>	11,852,070	34,659,105	26,773,624	1,238,699

KENTUCKY POWER COMPANY --- GENERATION

	2005	2006	2007	2008
Pre-Tax Book Income <Loss>	(505,885)	21,284,042	11,581,462	(14,182,907)
State Income Tax Expense	(2,537,882)	670,055	119,525	486,987
Book Income Before Federal Income Tax Expense	2,031,997	20,613,987	11,461,937	(14,669,894)
Schedule M Adjustments	(14,409,660)	(14,709,381)	(9,619,626)	(1,625,984)
Federal Taxable Income <Loss>	(12,377,663)	5,904,606	1,842,311	(16,295,878)
Qualified Production Activities Income (QPAI)	(17,067,722)	6,886,097	(2,326,075)	(13,581,410)
Difference Between QPAI and Book Income	(16,561,837)	(14,397,945)	(13,907,537)	601,497
Difference Between QPAI and Taxable Income	(4,690,059)	981,491	(4,168,386)	2,714,468

Exhibit JBB-3

Kentucky Power
Stand-Alone §199 Deduction
Qualified Production Activities Income <Loss>
Calculated on Recent Historical Amounts

	2006	2007	2008	3 Year High Amount
Qualified Production Activities Income <Loss>	6,886,097	(2,326,075)	(13,581,410)	6,886,097
Domestic Production Activities %				9.00%
Domestic Production Activities Deduction				620,000
Effective State and Federal Income Tax Rate				39.05%
Increase <Decrease> Income Tax Expense				(242,000)
Gross Revenue Conversion Factor				1.6476
Increase <Decrease> Revenue Requirement				(399,000)

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENT OF ELECTRIC)
RATES OF KENTUCKY POWER COMPANY) Case No. 2009-00459

KENTUCKY POWER COMPANY
REBUTTAL TESTIMONY OF DENNIS W BETHEL

May 14, 2010

REBUTTAL TESTIMONY OF
DENNIS W. BETHEL
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2009-00459

TABLE OF CONTENTS

REBUTTAL TESTIMONY OF
DENNIS W. BETHEL
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q: PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A: My name is Dennis W. Bethel. My position is Managing Director, Regulated Tariffs for American Electric Power Service Corporation.

II. PURPOSE OF TESTIMONY

Q: DID YOU SUBMIT DIRECT TESTIMONY IN THIS PROCEEDING?

A: Yes.

Q: WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A: The purpose of my Rebuttal Testimony is to respond to the recommendations contained in the direct testimony of the KIUC's witness Stephen J. Baron regarding the transmission adjustment tariff, Tariff TA (TTA).

Q: DO YOU AGREE WITH THE RECOMENDATIONS OF KIUC WITNESS BARON CONCERNING THE TTA?

A: No I do not. Witness Baron recommends that the TTA, which would track the PJM open access transmission tariff (OATT) costs, be rejected, nevertheless, he recommends the PJM OATT revenue requirement be used in calculating Kentucky Power Company's (KPCo) base rate revenue requirement. As Company Witness Roush testifies, if KPCo's retail rates are set to reflect a transmission cost of service based on its MLR share of the AEP System charges under the PJM OATT, KPCo currently would collect less revenue from retail customers than its embedded cost to own and operate its Kentucky transmission plant, giving credit for third party transmission revenues. KPCo has proposed base rates including its net embedded transmission cost, and a tracker, the TTA, as a way to flow through to customers the difference between the OATT and KPCo's embedded costs. While the OATT is currently lower than KPCo's embedded costs, the OATT changes each year pursuant to FERC-approved rates that are updated annually. In FERC Docket ER08-1329-000 the company instituted a formula rate that updates the transmission cost service for the AEP Zone each year. In addition, the charges billed to KPCo include charges for PJM regional transmission expansion projects, which are increasing at a rapid pace. AEP has no control over those costs which are also updated annually. KPCo's base rates are not updated annually, instead they are set in proceedings such as this one where a historical test period, with limited adjustments, forms the basis for cost of service. Therefore, implementing the PJM OATT revenue requirement in this case without implementing the TTA would not allow KPCo a reasonable opportunity to recover its cost of providing service to its Kentucky retail customers.

Q: **DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?**

A: Yes.

AFFIDAVIT

Dennis W Bethel, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true

Dennis W. Bethel

Dennis W Bethel

State of Ohio)
) ss
County of Franklin)

Subscribed and sworn to before me, a Notary Public, by Dennis W Bethel this 13th day of May 2010

Ellen A. McAninch

Notary Public

My Commission Expires May 11th, 2011

NOTARIAL SEAL
STATE OF OHIO

ELLEN A MCANINCH
NOTARY PUBLIC
STATE OF OHIO
Comm. Expires
May 11, 2011
Recorded in
Franklin County

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENT OF ELECTRIC)
RATES OF KENTUCKY POWER COMPANY) Case No. 2009-00459

KENTUCKY POWER COMPANY
REBUTTAL TESTIMONY OF ANDREW R. CARLIN

May 14, 2010

REBUTTAL TESTIMONY OF
ANDREW R. CARLIN, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2009-00459

TABLE OF CONTENTS

REBUTTAL TESTIMONY OF ANDREW R. CARLIN, ON BEHALF OF KENTUCKY POWER COMPANY BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is ANDREW R. CARLIN. I am employed as Director Compensation & Executive Benefits for American Electric Power Service Corporation (AEPSC). My business address is American Electric Power, 1 Riverside Plaza, Columbus, Ohio 43215.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. I offer testimony rebutting the recommendations of the Kentucky Industrial Utility Customers, Inc, (KIUC) witness Lane Kollen with regard to his testimony relating to Kentucky Power Company (KPCo or the Company) and AEPSC's long-term incentive compensation plan (LTIP). In addition, due the inability of witness David A. Jolley to attend the hearing, I am adopting Mr. Jolley's direct testimony as my own.

III. TESTIMONY SUMMARY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. Mr. Kollen would disallow all of the Company's long-term incentive compensation because he contends that it incentivizes financial performance that only benefits shareholders, not ratepayers yet he does not challenge the reasonableness of this compensation from a market competitive perspective. This position is misplaced because it fails to take into account that:

1. Providing a portion of compensation as incentive is essential in business today and considered to be good industry practice as well as necessary to provide a market competitive total compensation package.

2. Providing an incentive for improved earnings performance benefits customers by supporting the overall financial health of the Company which has a positive impact on financial costs.

IV. RECOMMENDATIONS FOR ADJUSTMENTS TO LTIP EXPENSES

Q. ON WHAT BASIS DOES MR. KOLLEN MAKE HIS RECOMMENDATION REGARDING LONG-TERM INCENTIVE COMPENSATION?

A. He contends that the performance measures used in the long-term incentive program are based on achieving financial goals that only benefit shareholders and should not be paid by ratepayers.

Q. DO YOU AGREE WITH THIS ADJUSTMENT?

A. No, I do not. Mr. Kollen simply suggests that this plan is calculated on a basis he disagrees with. He does not contend that the plan results in excessive compensation for senior managers, or that the Company and AEPSC could attract high quality senior managers if this aspect of their compensation were eliminated.

Q. WHY IS THAT FACT SIGNIFICANT?

A. It suggests to me that Mr. Kollen is primarily criticizing the design of AEP's compensation program, and not the reasonableness of the compensation. The consequence is that he recommends the disallowance of costs that are actually reasonable and necessary cost of doing business today.

Q. PLEASE EXPLAIN FURTHER.

A. I can do that by using an example. AEP's comprehensive compensation package is specifically designed to be market competitive. In other words, it pays employees the going market rate for their services. Assume that instead of offering an incentive component, AEP were to replace the targeted level of that compensation with a fixed salary. The "improper" incentive compensation identified by Mr. Kollen would be eliminated, and the requested level of compensation would still be reasonable. This suggests that his criticism relates to the method of compensation, not the reasonableness of the amount.

V. LONG-TERM INCENTIVE COMPENSATION PLAN DESIGN

Q. PLEASE DESCRIBE THE PHILOSOPHY BEHIND THE DESIGN OF AEP'S LONG-TERM INCENTIVE COMPENSATION PLAN.

A. Long-term incentives are a key component of the overall total compensation program for senior managers. The three elements of the total compensation package (base salary, annual and long-term incentives) motivate and align manager's efforts with performance measures that balance the Company's financial, reliability, customer service and shareholder performance objectives. The primary purpose of AEP's long-term incentive program is to motivate senior managers to maximize shareholder value by linking a portion of their compensation directly to shareholder return and to take a longer, more strategic view of the business. Since companies of AEP's size and complexity offer similar programs, AEP would not be able to attract and retain the highly qualified professionals needed to effectively manage its utility service without providing a market competitive compensation package, of which AEP's Long-Term Incentive Compensation is a substantial component.

Having compensation tied to performance factors is in the best interest of both customers and shareholders. Utility ratepayers benefit from efficient and effective operations, strong leadership and satisfactory results for shareholders. The Company cannot exist without shareholders. If shareholders are satisfied with the financial performance of the Company and are willing to provide additional investments, ratepayers also benefit. Consideration of the full range of factors, facts and circumstances, and most particularly the fact that manager's salaries are not market competitive without long-term incentive compensation, supports the treatment of long-term incentive pay as reasonable and necessary expenses of utility service.

VI. CONCLUSION

Q. WOULD YOU PLEASE SUMMARIZE YOUR TESTIMONY.

A. AEP'S compensation levels and program design are necessary, reasonable, and market competitive and ensure that AEP and KPCO are able to attract, retain, and motivate the workforce required to provide reliable, cost effective electric service to its customers.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

AFFIDAVIT

Andrew R Carlin, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true

Andrew R. Carlin
Andrew R Carlin

State of Ohio)
) ss
County of Franklin)

Subscribed and sworn to before me, a Notary Public, by Andrew R Carlin this 12th day of May 2010

Terry Jo Smith
Notary Public

My Commission Expires 02-28-12

NOTARY PUBLIC STATE OF OHIO

Terry Jo Smith
Notary Public-State of Ohio
My Commission Expires
February 28 2012

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENT OF ELECTRIC)
RATES OF KENTUCKY POWER COMPANY) Case No. 2009-00459

KENTUCKY POWER COMPANY
REBUTTAL TESTIMONY OF THOMAS M MYERS

May 14, 2010

PRE-FILED REBUTTAL TESTIMONY OF
THOMAS M. MYERS, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2009-00459

TABLE OF CONTENTS

REBUTTAL TESTIMONY OF THOMAS M. MYERS, ON BEHALF OF KENTUCKY POWER COMPANY BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. Introduction

Q: PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A: My name is Thomas M. Myers. My position is Vice President – Commercial & Financial Analysis for American Electric Power Service Corporation (AEPSC), a wholly owned subsidiary of American Electric Power, Inc (AEP). AEPSC supplies engineering, financing, accounting and similar planning and advisory services to AEP's eleven electric operating companies, including Kentucky Power Company ("Kentucky Power, KPCo or Company"). My business address is 155 West Nationwide Boulevard, Columbus, Ohio 43215.

Q. DID YOU SUBMIT DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes

II. Purpose of Testimony

Q: WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my rebuttal testimony is to respond to the issues raised in the testimony of KIUC witness Lane Kollen regarding the Company's proposed modifications to the treatment of OSS margins under the system sales clause. In particular, I will respond to Mr. Kollen's assertions regarding the differences between the existing system sales clause and the Company's proposed modifications, and the merit of some of the Company's specific rationale for the proposed changes to the system sales clause.

III. Proposed Changes in System Sales Clause

Q: **BASED ON MR. KOLLEN'S TESTIMONY, DOES HE REASONABLY PORTRAY THE ISSUES THAT PROMPTED KPCO TO PROPOSE MODIFICATIONS TO THE TREATMENT OF OSS MARGINS UNDER THE SYSTEM SALES CLAUSE?**

A: No, he does not. On page 10 of Mr. Kollen's testimony, he describes the Company's proposed changes to the system sales clause as being "arbitrary", "extremely aggressive", "lacking any logical or other support", and "arbitrarily serving to increase the Company's claimed revenue requirement". Mr. Kollen's characterization of the Company's proposal and its motivations could not be further from the truth.

I address in my direct testimony the reasons a modified system sales clause sharing mechanism for OSS margins makes sense – how it provides a balance of risk and reward, along with appropriate incentives. The Company's proposal is grounded in the principle that an equitable allocation of OSS margins and the management of the related risks are best accomplished by aligning the interests of the customer and the Company. Applying these principles to the treatment of OSS margins resulted in the Company's OSS margin sharing proposal. Figure 1, shown below, illustrates how aligning the interest of both customers and the Company benefits both parties.

FIGURE 1: Aligning the Interests of Company and Customer

Common Goal ———	—▷ OSS Margin Maximization	Proposed Implementation
Because OSS margins are shared 50/50, both customers and the Company directly benefit from increased margins.	Customers: Customers want the largest OSS margins possible because it will directly lead to lower rates. Shareholders: Shareholders want the largest OSS margins possible because it will benefit total earnings	The Company's proposed 50/50 sharing achieves this goal of an equitable sharing of OSS margins.

Q: **HOW DO YOU RESPOND TO MR. KOLLEN'S SPECIFIC CHARGE THAT THE COMPANY'S PROPOSAL IS "ARBITRARY AND LACKING ANY LOGICAL OR OTHER SUPPORT"?**

A: The Company's proposed changes were motivated by several weaknesses in the current treatment of OSS margins under the existing system sales clause, weaknesses that I pointed out in my Direct Testimony. As I described above, the existing treatment of OSS margins was looked at in light of the following principle:

> *The alignment of interests between the Company and the customer, through an equitable sharing of OSS margins and a balanced management of risk, is the best way to encourage the optimization of OSS margins over time.*

The long term interests of customers in regard to OSS margins is to see margins optimized to the greatest extent possible in a way that does not risk the financial integrity of the Company.

To briefly summarize from my direct testimony, the weaknesses of the current system sales clause treatment of OSS margins can be broadly grouped into the following two categories:

1) The existing system sales clause can cause the financial strength of the Company to be put at risk by requiring the Company to absorb negative margins over the same time period in which the customer continues to receive positive OSS margin credits.
2) The existing system sales clause does not reflect the nature of the wholesale market and the many ways in which the Company has contributed to the optimization of margins.

Q: DOES MR. KOLLEN DISCUSS THE RISK OF FINANCIAL HARM TO THE COMPANY CONTAINED IN THE CURRENT SYSTEM SALES CLAUSE?

A: Yes, Mr. Kollen does touch on this topic but only to assert that no such risk exists. He makes the unsupported assertion that the risks associated with optimizing OSS margins exist "independently of the retail ratemaking mechanisms." Contrary to Mr. Kollen's claim, there are significant risks that can result directly from the retail ratemaking mechanism used to distribute OSS margins. The risk of financial harm to the Company in the current system sales clause can be clearly seen in the test year treatment of OSS margins under the existing system sales clause:

TABLE 1

TEST YEAR OSS MARGIN RESULTS - TOTALS & ALLOCATIONS

Customer OSS Credit - Embedded	Actual OSS Margins in Test Year	Actual OSS Margins Retained by the Customer	% of Actual OSS Margins Retained by the Customer	Actual OSS Margins Retained by the Company	% of Actual OSS Margins Retained by the Company
24 million	16 million	18.4 million	115%	-2.4 million	-15%

Such an outcome, on its face, is not a sustainable long-term strategy for the continued optimization of OSS margins. To say nothing of the fairness issue raised by such a margin allocation, outcomes such as experienced in the test year - where the Company receives a negative margin allocation while the customers receive a significant positive OSS margin credit - clearly undermines the financial strength of the Company. Undermining the financial strength of the Company is not in the best interest of the Company or its customers.

Q. DO MR. KOLLEN'S PROPOSALS FOR THE SYSTEM SALES CLAUSE EXHIBIT THE SAME RISK ILLUSTRATED IN TABLE 1?

A. Yes they do. In fact, Mr. Kollen's proposals would magnify that risk, and he defends it by seeming to suggest that forcing this increased level of risk onto the Company somehow benefits the customer. Mr. Kollen, on page 9 of his testimony, proposes two different ways to calculate the OSS margin credit that he proposes be used within the existing system sales clause. One of his recommendations was to base the 'threshold' amount on the Company's 2010 OSS margin forecast of $26 million. The other method Mr. Kollen proposes is for the Commission to calculate the 'threshold' amount by taking the 5 year average of KPCo's OSS margins, amounting to roughly $38 million. A simple example demonstrates the additional risk he is proposing to impose on the Company.

TABLE 2

ALLOCATIONS BASED ON MR. KOLLEN'S PROPOSED THRESHOLD AND UPDATED 2010 FORECAST

Customer OSS Credit - Embedded	Actual OSS Margins in Test Year	Actual OSS Margins Retained by the Customer	% of Actual OSS Margins Retained by the Customer	Actual OSS Margins Retained by the Company	% of Actual OSS Margins Retained by the Company
38 million	18 million	24 million	133%	-6 million	-33%

Table 1 and 2 illustrate that regardless of the sharing allocation, the greater the amount of the OSS margins that are embedded in base rates as a fixed credit, the greater the risk to the financial health of the Company – to the detriment of both shareholder and customer.

Q: **WHAT ARE THE CHARACTERISTICS OF OSS MARGINS THAT NEED TO BE RECOGNIZED?**

A: There are three main attributes of OSS margins that need to be acknowledged and accounted for in whatever the retail ratemaking mechanism is through which they flow. Not incorporating them into the OSS retail ratemaking mechanism will likely result in a mechanism that won't achieve the expected outcome and will likely lead to undesirable results. Those three attributes of OSS margins are:

1) Volatility
2) Materiality
3) Control

Q: **DO YOU AGREE WITH MR. KOLLEN'S DISCUSSION OF THE SOURCES OF OSS MARGINS AND THE WAYS IN WHICH IT IS OPTIMIZED?**

A: I agree that Mr. Kollen, on page 53 and 54, has identified one piece of how OSS margins are created, namely from the sale of excess energy from the Company's generating resources, but his statement is incomplete. Selling surplus energy requires a complex skill set and is much more complicated in today's volatile wholesale power markets. But the Company engages in a host of activity and leverages many different skills and resources in order to produce OSS margins. As I describe in my testimony, AEPSC creates OSS margins through the wholesale power markets in a variety of ways. AEPSC utilizes trading instruments such as swaps and options, is active in physical as well as financial markets, and actively follows the developments in other commodity markets that can influence the price of electricity. Commercial Operations also participates in competitive energy auctions outside of AEP's service territory in PJM and in the Midwest Independent Transmission System Operator (MISO) markets. I provide a more comprehensive description of the Company's full range of OSS optimization activities throughout pages 11-28 of my direct testimony. By severely limiting his description of OSS margin optimization activity, Mr. Kollen obscures the significant level of expertise and work necessary to pursue and effective OSS operation.

IV. Comparison of Existing System Sales Clause vs. Company's Proposal

Q: DOES MR. KOLLEN DESCRIBE HOW THE CURRENT SYSTEM SALES CLAUSE AND THE COMPANY'S PROPOSAL FUNCTION?

A: Yes he does. On page 51, Mr. Kollen does provide a brief description of the current system sales clause, lines 3-7, and the Company's proposal, lines 8-11. However, these descriptions are incomplete. These incomplete descriptions lead to a misunderstanding of the differences between them and results in an incomplete analysis and therefore leads to flawed recommendations. The most significant omission concerning the existing system sales clause is when Mr. Kollen describes the sharing that happens above the current threshold level of $24.855 but does not describe how sharing is calculated when margins fail to reach $24.855 million. The other significant omission Mr. Kollen makes is in regard to the Company's proposed modifications to the system sales clause. That is, under the Company's proposal the customers do not have to 'share' in any margin shortfalls, but continue to have unlimited sharing on positive margins.

Q: PLEASE PROVIDE AN EXAMPLE OF THE CONFUSION RESULTING FROM MR. KOLLEN'S INCOMPLETE DISTINCTION BETWEEN THE EXISTING SYSTEM SALES CLAUSE AND THE COMPANY'S PROPOSAL.

A: On page 51, and throughout his testimony, Mr. Kollen uses the term 'threshold' to refer to the OSS margin credit that is included in base rates for both the existing system sales clause and for the Company's proposal. Using the same term to describe both credits obscures that fact that the two credits operate in distinctly different ways. The OSS margin credit which is included in the base rates under the current system sales clause is most accurately understood as a 'Projected' credit. The OSS margin credit as described in the Company's proposal is most accurately understood as a 'Guaranteed' credit. The distinction is far from semantics.

Under the current system sales clause, the projected credit could be less than the projected credit based on the test year OSS margins. Again, the test year results for OSS margin allocation demonstrate this result.

TABLE 3

TEST YEAR OSS MARGIN RESULTS - TOTALS & ALLOCATIONS

Customer OSS Credit - Embedded	Actual OSS Margins in Test Year	Actual OSS Margins Retained by the Customer	% of Actual OSS Margins Retained by the Customer	Actual OSS Margins Retained by the Company	% of Actual OSS Margins Retained by the Company
24 million	16 million	18.4 million	115%	-2.4 million	-15%

The 'Guaranteed' credit as contained in the Company's proposal represents the minimum amount of OSS credit the customers will receive. Unlike the projected credit in the current system sales clause, customers will never receive less than the OSS margin credit embedded in base rates.

V. Company's Adjustment to Test Year OSS Margins

Q: WHAT IS YOUR GENERAL RESPONSE TO MR. KOLLEN'S DISCUSSION OF THE ADJUSTMENTS THE COMPANY MADE TO THE TEST YEAR OSS MARGINS?

A: Mr. Kollen, on page 8 of his testimony, speculates that the Company treats OSS margins, based on his review of the Company's test year adjustments; as if it assumes that the test year margins are static, stable and expected to remain constant. The Company's view of the volatility of OSS margins is actually the mirror opposite of what Mr. Kollen has assumed. For example, the term 'volatility' appears 28 times in my direct testimony and exhibits. In fact, Mr. Kollen, on pages 51-52, quotes five of the reasons I provide in my testimony in support of the Company's proposal…and 4 out of 5 of those quotes center around volatility and/or risk of OSS margins.

In an effort to recognize common ground when it presents itself, Mr. Kollen on page 8, line 18, states '[h]owever, the OSS margins are not static.' Unfortunately, Mr. Kollen's proposals for the treatment of OSS margins do not incorporate or address this fundamental characteristic.

Q: DO YOU AGREE WITH MR. KOLLEN'S COMPARISON OF THE COMPANY'S ADJUSTMENTS 2&3 TO THE WIND PPA AND BIG SANDY UPRATE?

A: No I do not. Mr. Kollen's comparison of the Company's adjustment to test year margins based on the expiration of the CP&L sale (adjustments 2&3), with the OSS impact of the Big Sandy uprate and the wind PPA is simply not accurate. As explained in the testimony of Dave Roush, the Company's adjustments resulting from the expiration of the CP&L sale are clearly known and measurable. The impact of the Big Sandy uprate and the wind PPA on OSS margins cannot be accurately predicted.

While the proposed wind PPA would likely have an overall positive impact on OSS margins, the amount of that impact is uncertain. A simple "1 for 1" relationship between the additional wind MWhs and total OSS margins is not an accurate assumption. There are many variables that will ultimately determine to what degree the wind contract will impact KPCO's OSS margins. For example, renewable energy resources such as the wind energy purchase power agreement are dedicated resources. The energy output from these resources is assigned to a specific AEP operating Company. As energy is received from the supplier, it displaces energy that would otherwise be used to serve the Company's native load requirement. This displaced energy may potentially be used to increase energy exchanges to other AEP companies or to increase OSS levels for the Company. In the case of any increased energy exchanges to other AEP companies, such affiliate energy exchanges are governed by the AEP East Pooling Agreement and would not be subject to the sharing provisions of either the existing or proposed system sales clause.

KPCO's OSS margins are influenced by many factors, with the additional MWhs resulting from the wind contract being just one of the variables. A 1 MWh increase from the wind contract does not translate into a 1 MWh increase in KPCO OSS margins.

The discussion concerning the potential impacts on OSS margins resulting from the wind PPA applies equally to the Big Sandy uprate. The resulting impact on OSS margins resulting from any additional energy available as a result of the Big Sandy uprate is uncertain at best and subject to the many variables described above.

Q. PLEASE DESCRIBE SOME OF THE OTHER FACTORS THAT CAUSE UNCERTAINTY REGARDING THE IMPACT OF THE WIND CONTRACT ON KPCO'S TOTAL OSS MARGINS.

A. There are periods of time when we are a net purchaser across the AEP East companies to meet internal load obligations. During these periods, the wind contract will not benefit OSS margins, but will instead offset third-party purchase for internal load. It is difficult to forecast when these conditions will occur as several factors impact our energy position. These include such factors as internal load and generation output.

Q. IS THE CONCLUSION THAT MR. KOLLEN DRAWS FROM THE COMPANIES ADJUSTMENTS TO TEST YEAR OSS MARGINS AND ITS TREATMENT OF THE BIG SANDY UPRATE AND WIND PPA VALID?

A. No it is not. On page 8, lines 12-14 of his testimony, Mr. Kollen states, "the dichotomy in the Company's proposed treatment of these multiple events illustrates the inequities of the Company's selective post-test year adjustments." Mr. Kollen's conclusion is flawed in two respects. First, as described previously, the Big Sandy uprate and wind PPA are distinctly different from the expiration of the sale to CP&L, which properly resulted in the Company's adjustment 2&3. Second and more significantly, under the Company's OSS margin sharing proposal if in the future OSS margins exceed the adjusted test year amount, whether it results from the Big Sandy uprate and wind PPA or not, the benefit to the customer is not diminished.

VI. Analysis of Company's Supporting Analysis

Q. PLEASE RESPOND TO MR. KOLLEN'S TESTIMONY REGARDING HIS ANALYSIS OF THE REASONS PROVIDED BY THE COMPANY IN SUPPORT OF ITS MODIFIED SYSTEM SALES CLAUSE PROPOSAL.

A. Mr. Kollen, on pages 51 and 52, cites five of the reasons I provided in my direct testimony in support of the Company's proposed modifications to the system sales clause. After a brief recap, he then summarily dismisses them by claiming that even if these reasons are valid, they would be equally supportive of the existing system sales clause. Mr. Kollen's conclusions are deeply flawed and should not be relied on by the Commission in its analysis of the Company's proposal. Mr. Kollen again overlooks the distinctions between the existing system sales clause and the Company's proposal, as discussed previously, and fails to consider the weaknesses in the existing system sales clause. He adopts a very short-term time horizon in evaluating the risks inherent in the wholesale electricity markets and an inequitable allocation of OSS margins.

The following table builds on various parts of my rebuttal testimony up to this point. Thus, I will limit myself to a brief point, counter-point presentation of some of the areas I believe Mr. Kollen's analysis is incomplete and/or incorrect. The 'Point, Counter-Point' Analysis is as follows:

"The Company cites the following reasons in support of proposed modifications"

- REASON #1 The Company's proposal provides an increased level of certainty for customers.

  Mr. Kollen's Assertion: The rate certainty proposed by the Company does not benefit customers but rather harms them.

  Company's Rebuttal: The rate certainty under the Company's proposal means that the customer will never receive a total OSS credit lower than the amount embedded in base rates. Currently, customers can, and did in the test year, receive a smaller rate credit than the threshold amount currently in rates. The amount of embedded OSS margin credit represents a 'Guaranteed' amount instead of a 'Projected' amount.

- REASON #2 The Company's proposal provides the company a reasonable benefit for embedding a guaranteed OSS credit in base rates.

  Mr. Kollen's Assertion: The Company does not have any risk in embedding 50% of test year margins as a base credit for customers and would have virtually no risk in embedding a much larger base credit.

Company's Rebuttal: The amount of OSS credit put in base rates represents a very real risk to the company based on the relative size of the credit to total operating income and based on the volatility of OSS margins. Simply projecting the results shown in Table 1 and Table 2 forward over a few years demonstrates the potential harm to the company's financial health. Ignoring this risk could clearly harm both the company and the customer.

- REASON #3 The Company's proposal provides the company a prudent incentive for optimizing OSS margins.

Mr. Kollen's Assertion: The Company acts to optimize OSS margins regardless of changes for retail ratemaking services. Thus, no incentive is needed.

Company's Rebuttal: The Company is not proposing that an incentive is needed to further increase the OSS margins. The company is asking for an equitable sharing in recognition of the way OSS margins are currently being optimized. As explained in the company's response to KIUC 1-48, the cumulative effect of the commission decisions across the company's various jurisdictions on OSS margin sharing could lead to scaled back activities.

- REASON #4 Helps to mitigate the significant and volatile risks

Mr. Kollen's Assertion: The Company is not exposed to significant and volatile risks, and regardless, the risks are independent of the retail ratemaking mechanism.

Company's Rebuttal: My direct testimony goes into great detail concerning the risks that must be managed to successfully optimize OSS margins. By denying the clear risks, Mr. Kollen ignores the significant contribution of the Company in optimizing OSS margins.

- REASON #5 Provides better balance of risk and reward

  Mr. Kollen's Assertion: The Company's proposed sharing mechanism would result in the most generous sharing arrangement for shareholders out of all of the company's jurisdictions.

  Company's Rebuttal: During the test year, the current system sales clause resulted in among the worst sharing outcomes across the jurisdictions.

VII. CONCLUSION

Q: WOULD YOU PLEASE SUMMARIZE YOUR TESTIMONY?

A: Yes. The existing system sales clause has several weaknesses – described in more detail in my direct testimony and in summary form in my rebuttal testimony. Mr. Kollen's characterization of the Company's proposed modifications to the system sales clause as "arbitrary" and "lacking any logical or other support" is simply not correct. As described in my direct testimony and my rebuttal, the Company's proposal is grounded in the principle that an equitable allocation of OSS margins and the management of the related risks are best accomplished by aligning the interests of the customer and the Company. The Company's proposal, in recognition of the weaknesses in the existing system sales clause and based on the alignment of interests between Company and customer, provides an equitable balance of risk and reward.

As the recent economic downturn has shown that although Commercial Operations' Trading & Marketing group actively manages the risk associated with the wholesale power market, there are still many factors that are beyond the control of the utility. The proposed modification helps to better shield KPCo's customers and the Company against the volatility of OSS margins, and provides a better balance between risks and rewards of the wholesale power markets. Mr. Kollen's testimony fails to recognize that the way in which OSS margins are treated within the retail rate making mechanism can have a significant impact on the financial health of the Company – a fact important to both Company and customer. The absence of this risk in Mr. Kollen's analysis is woven throughout his testimony related to OSS margins. It leads to an incorrect understanding of the differences between the existing system sales clause and the Company's proposed modifications and produces a flawed proposal.

Finally, in relation to the Company's proposed modifications to the system sales clause, Mr. Kollen's makes blanket assertion that none of the reasons explained and described by the Company are valid. Such an assertion cannot be supported in light of my direct testimony and is plainly incorrect. The Company's proposed treatment of OSS margins corrects the weaknesses found in the existing system sales clause and is in the best interests of Company and customer.

Q: **DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL TESTIMONY?**

A: Yes.

AFFIDAVIT

Thomas Myers, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Thomas Myers

State of Ohio)
) ss
County of Franklin)

Subscribed and sworn to before me, a Notary Public, by Thomas Myers this 12th day of May 2010.

Barbara R. Pletcher
Notary Public

My Commission Expires October 1, 2013

BARBARA R. PLETCHER
NOTARY PUBLIC • STATE OF OHIO
Recorded in Franklin County
My commission expires Oct. 1, 2013

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENT OF ELECTRIC)
RATES OF KENTUCKY POWER COMPANY) Case No. 2009-00459

KENTUCKY POWER COMPANY
REBUTTAL TESTIMONY OF EVERETT G PHILLIPS

May 14, 2010

REBUTTAL TESTIMONY
OF
EVERETT G. PHILLIPS
ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2009-00459

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

A. My name is Everett G. Phillips. My business address is 12333 Kevin Avenue, Ashland, Kentucky 41102. I am the Director of Customer and Distribution Operations for the Kentucky Power Company (KPCo).

Q. Are you the same Everett G. Phillips who previously filed direct testimony in this case?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to respond to statements made by Kentucky Industrial Utility Customers, Inc. witness Lane Kollen.

Q. Please summarize Mr. Kollen's position with respect to the Company's Proposed Enhanced Reliability and Service Plan (Plan).

A. Mr. Kollen recommends that the Company's request for an additional $16.374 million in O&M and an increase in capitalization of $9.423 be denied. I will respond to Mr. Kollen's general assertion that the Company has failed to justify its Plan.

Q. Mr. Kollen characterizes the Company's Plan as discretionary. Do you agree?

A. No. Mr. Kollen bases this on the Company's expressed intention to implement this Plan only if rate recovery is granted. He believes that the Company's stated intent is a tacit admission that the Plan is discretionary. To the contrary, the Company believes the Plan is needed in order to allow customers to receive the safe and reliable service they desire. It is unreasonable to expect the Company to incur expenses to provide electric service when those expenses are not reflected in its rates.

Q. Mr. Kollen cites the recent case of the Company's affiliate, Appalachian Power Company (APCo), who declined to request recovery of the costs of a similar plan in its Virginia Case No. PUE 2009-00030. Are the situations of both companies similar enough to make this a valid comparison?

A. No. Since 2004, APCo has had an established mechanism to recover increased vegetation expenses occurring in its Virginia service territory. This mechanism was called the APCo Environmental and Reliability Rider. Despite the established mechanism, APCo understands implementation of a cycle-based integrated vegetation management program will eventually be needed to take its reliability to the next level. However, Case No. PUE 2009-00030 was not the right time to implement such a program. APCo's customers want and deserve reliable service and the APCo is working diligently to meet that expectation.

Q. Has Mr. Kollen provided any guidance to establish the appropriateness of an increase in reliability expenditures?

A. Yes. In his response to Staff question 1-4, Mr. Kollen identified three requirements that must be met in order to establish an increase in reliability spending as appropriate: 1) a need to improve reliability beyond a level that can be achieved under current spending levels, 2) established goals for improving reliability and 3) a plan to achieve these goals at a specified cost. In my direct testimony on pages 12 to 26, I have addressed all three of Mr. Kollen's requirements in regards to the Company's Enhanced Vegetation Initiative.

Q. Summarize your response to Mr. Kollen's first requirement?

A. The Company is suffering from a declining tree-related reliability trend while customers' expectations of reliability are increasing. The Company's ability to maintain vegetation on its system can not be achieved under either the spending levels included in the last rate case or under the spending levels the Company is currently maintaining.

Q. Do you feel the Company has adequately identified the need to improve its vegetation management program?

A. Yes. In my direct testimony, I provided three figures that indicate the need for the Enhanced Vegetation Initiative. Figure 1 on page 4 identifies trees as the cause for over one third of outages during the last four years. Figure 2 on page 12 shows the Company's historical SAIDI trend and it is clear that it is trending upward. Finally, Figure 3 on page 15 shows the Company's IO-13 trend, indicating an increasing number of vegetation-related investigation orders.

Additionally, Figure 1 below contains the Company's tree-related outage count, the tree-related SAIDI and the tree-related SAIFI for 2005 through 2009.

Figure 1: Tree-Related Outage Data

	2009	2008	2007	2006	2005
Tree-Related Outages	3,566	3,315	2,396	3,117	2,635
Tree-Related SAIDI	255.7	248.68	148.98	229.67	183.34
Tree-Related SAIFI	0.9219	1.1255	0.7524	0.9749	0.8537

Q. In addition to the Company's declining reliability trend, in your direct testimony, you indicated that the Company's customers expect an increasing level of reliability. Mr. Kollen believes that the survey response that supports this expectation is inadequate. Do you agree?

A. No. I indicated in my direct testimony that the Company's customers are expecting an increasing level of reliability based on surveys conducted by Market Strategies International (MSI). MSI is the 16th largest market research firm in the United States, has extensive experience conducting surveys of utility customers, and is well respected by market research professionals in the electric utility industry. AEP or AEP Companies have worked with MSI since 1986 to gauge customer satisfaction with residential, commercial, and manage key accounts.

The Company has provided a copy of as well as additional detail regarding the surveys conducted on its behalf by MSI in its responses to AG 1-27 and Staff 2-45. Although he does not believe that the MSI survey question is a proper indicator of customer expectations, Mr. Kollen accepts the MSI survey results regarding customer satisfaction in his testimony on lines 19 and 20 of page 19.

Q. Mr. Kollen's second requirement for reliability expenditures is a specified goal. Has the Company specified a goal for the Enhanced Vegetation Initiative?

A. Yes. In Figure 7 on page 20 of my direct testimony, I provided the forecasted 47% reduction in the number of tree-caused outages to be realized upon completion of the five year implementation period.

Q. Is this a reasonable goal for the Enhanced Vegetation Initiative?

A. Yes. As stated in the Company's response to KIUC 22-26, "To properly evaluate the effectiveness of a vegetation management program, one must look at tree-caused outages and how they affect both reliability indices such as SAIFI and SAIDI as well as customer satisfaction."

This plan is designed to improve the reliability of the Company's distribution system but will also improve quality of service and safety. In the Commission's Field Inspection Report of the Company's Hazard District (Hazard Report), issued on February 22, 2010, the Commission states, "If trees are allowed to grow into the conductor before they are trimmed, then this is creating a hazardous situation for company personnel and possibly the public." As I stated on page 13 of my direct testimony and reiterated in my response to AG 1-36, the intent of a four year cycle-based plan is to maintain vegetation such that over the duration of the cycle, vegetation will not grow into the Company's lines.

Q. The final requirement identified by Mr. Kollen is a specified plan with specified costs. Has the company prepared a plan?

A. Yes. In my direct testimony, I discussed the Company's intention to transition away from its current performance-based vegetation management program to a four year cycle-based vegetation management program over the course of a five year implementation period.

I provided the incremental costs of the plan in Figure 9 on page 23 of my direct testimony. Figure 9 includes a projection of the incremental costs of the Enhanced Vegetation Initiative during the five year transition period as well as two additional years. Figure 10 on page 24 of my testimony graphically presents the annual cost of the program over the first eight years.

Q. **Mr. Kollen stated in his testimony that "It is the Company's obligation to demonstrate that present spend rates are inadequate" and reiterated this point in his response to Staff 1-4. Please address this point.**

A. In Figure 8 on page 22 of my direct testimony, I provided a summary of the Company's historical distribution vegetation management expenditures. This figure clearly indicates the Company's current expenditures are significantly more than the test year expenditures included in the Company's last case. If the Company's present authorized spend rates were adequate, the Company would not be incurring additional costs. In addition, as stated above, it is unreasonable to expect the Company to continue to incur costs that are not reflected in rates.

Q. **Is the cycle-based approach something new to the industry?**

A. No. The cycle-based approach is used throughout the industry and is prevalent in Kentucky. As indicated in my response to KIUC 2-22, the Davies report, on page 11, identifies a four year cycle as the most common tree trimming benchmark. In its vegetation management filing under KPSC Case No. 2006-00494, E.On identified its use of a cycle-based program with the intent to limit its cycle duration to less than five years. Page 104 of the Commission's Ike and Ice Report issued on November 19, 2009, states "Jurisdictional utilities clear their distribution systems on cycles ranging from two to seven years, with the majority reporting a cycle of about four years."

Q. **Has the Commission suggested to the Company that it transition to a cycle-based vegetation management approach?**

A. Yes. In its Hazard Report, the Commission found that "the company should consider using a cycle trim on the entire circuit, and should strive to maintain the same quality of service for each customer on that circuit."

Q. **Do you agree with Mr. Kollen that the cycle-based vegetation management approach has not been proven to improve reliability?**

A. No. In my direct testimony, I indicated the 58% reduction in customer outages achieved by the Company's affiliate, Public Service Company of Oklahoma, since their implementation of a four year cycle-based vegetation management program. In addition, in its response to AG 2-11, the Company provided a copy of the E.On 2008 Annual Reliability Report for its subsidiaries, Kentucky Utilities Company (KU) and Louisville Gas & Electric Company (LG&E). Both KU and LG&E reported a cycle duration of 4.56 years with tree-caused SAIDI values of 0.158 and 0.136, respectively.

Q. **The Company has also included an Enhanced Equipment Inspection and Mitigation Initiative (Initiative) in its Plan, which Mr. Kollen believes is unnecessary. Do you agree?**

A. No. As discussed on page 26 of my direct testimony, this Initiative will improve service by reducing equipment-related outages to the Company's customers. Figure 1 on page 4 of my direct testimony identifies equipment as the cause of approximately one quarter of outages over the last four years. Figure 2 below shows the Company is experiencing an increase in outage quantity, frequency and duration due to cutout[1] failures.

Figure 2: Outage Data due to Cutout Failures

	2009	2008	2007	2006	2005
Outages Due To Cutout Failures	627	671	624	581	497
SAIDI Due To Cutout Failures	25.91	37.55	21.52	26.94	19.96
SAIFI Due To Cutout Failures	0.1559	0.2371	0.1489	0.117	0.1048

Q. Mr. Kollen states that the Commission does not need to provide premature recovery for the costs of the Company's current proposed gridSMART initiative. Do you agree?

A. No. The Company's gridSMART initiative is Phase One of its efforts to incorporate the Federal Standards of the Energy Independence and Security Act of 2007. These efforts align with the Commission's interest in the deployment of these technologies as expressed in Case No. 2008-00408. Given this alignment, recovery of and a return on these costs should be granted.

Q. Does that conclude your rebuttal testimony?

A. Yes, it does.

[1] A cutout fuse is a combination of a fuse and a switch, used in primary overhead feeder lines and taps, to protect step-down transformers from current surges and overloads.

AFFIDAVIT

Everett G Phillips, upon being first duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Everett G. Phillips

Everett G. Phillips

Commonwealth of Kentucky)
) Case No. 2009-00459
County of Pike)

Sworn to before me and subscribed in my presence by Everett G. Phillips, this the 10 day of May, 2010.

Notary Public

My Commission Expires: August 7, 2011

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENT OF ELECTRIC)
RATES OF KENTUCKY POWER COMPANY) Case No. 2009-00459

KENTUCKY POWER COMPANY
REBUTTAL TESTIMONY OF MARC D REITTER

May 14, 2010

REBUTTAL TESTIMONY
OF
MARC D. REITTER
ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY
CASE NO. 2009-00459

Q. WOULD YOU PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION?

A. My name is Marc D. Reitter and my business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by American Electric Power Service Corporation (AEPSC) as Manager of Corporate Finance. AEPSC supplies engineering, financing, accounting and similar planning and advisory services to AEP's eleven electric operating companies, including Kentucky Power Company ("Kentucky Power, KPCo or Company").

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

The purpose of my testimony is to respond to the recommendations made by Kentucky Industrial Utility Customers (KIUC) Witness Lane Kollen on pages 11-13 of his direct testimony incorporating his recommendations concerning the issues in Commission case 2009-00545. I am providing the same rebuttal testimony I filed in the 2009-00545 docket on April 30, 2010, to ensure consistency for the Commission's records.

Q. DOES THE COMPANY INTEND TO ASK FOR ADDITIONAL REVENUE RELATED TO THE IMPUTED DEBT CALCULATION?

A. No. The Company does not intend to ask for additional revenue related to an imputation of debt for the wind farm purchase power agreement (PPA). As I will describe below, only

Standard & Poors (S&P) calculates an imputed debt related to wind farm PPA's and given their methodology on holding company ratings, it is not necessary for KPCo to offset that imputation with additional equity.

Q. **DO ALL OF THE RATING AGENCIES IMPUTE DEBT FOR WIND FARM POWER PURCHASE AGREEMENTS (PPAs)?**

A. No. Generally only S&P will impute debt for a wind farm PPA. There is no imputed debt by either Moody's Investor Service (Moody's) or Fitch Ratings (Fitch).

Q. **PLEASE DESCRIBE HOW MOODY'S AND FITCH TREAT PURCHASE POWER AGREEMENTS (PPAs).**

A. Moody's addressed PPAs in its August 2009 Ratings Methodology update. In that update, Moody's indicated that each particular circumstance may be treated differently by Moody's. However, to the extent there is pass-through capability of the cost of purchasing power under the PPAs to their customers, "Moody's regards these PPA obligations as operating costs with no long-term debt-like attributes." It is reasonable to assume that a Commission approved contract in base rates has pass-through of those costs and would be treated as an operating cost. Many PPAs are also considered leases by the accounting rules, in which case Moody's will impute debt, but that is not the case for this contract.

Fitch addressed PPAs in 2006 and indicated that it occasionally treats an energy contract as debt-equivalent when all of the following three conditions are met:

(1) the contract is material to the company's cash flow

(2) the contract price is significantly above market value

(3) the buyer has a low likelihood of recovering the contract cost through the regulatory process.

This particular renewable energy purchase agreement is not material to KPCo and consequently violates one of Fitch's debt equivalency conditions.

Q. DOES S&P TREAT PPAs DIFFERENTLY?

Yes. S&P does impute debt for PPAs, including wind farms. The S&P analysis starts with the NPV of the capacity payments under the contract. Since wind farms have no capacity payment, S&P uses a proxy for the capacity charge. The proxy capacity charge used by S&P is currently 50% of the forecasted cost of the contract. Then S&P applies a risk factor to the NPV of capacity payments and that risk factor varies between 25% - 50% to determine the debt imputation. Mr. Kollen's assumption of a 30% risk factor is consistent with S&P's methodology.

Q. WHY IS THE COMPANY SAYING THAT IMPUTED DEBT IS NOT NECESSARY FOR THIS WIND FARM GIVEN THE S&P TREATMENT OF THE CONTRACT?

A. S&P takes a family view of ratings of the AEP system, which differs from the company specific methodology of Moody's and Fitch. S&P evaluates the risk profile and financial metrics of the entire system to determine a family credit rating which is then applied to all the utilities. So, while a meaningful contract such as one for a baseload unit could drive an overall capitalization change and perhaps debt imputation by the other rating agencies, it is not necessary for this PPA. Moreover, even a debt imputation for this contract by one rating agency would not have a great enough effect to drive a change in the capitalization and a resulting revenue requirement for KPCo.

Q. **IS MR. KOLLEN CORRECT IN HIS ANALYSIS OF S&P's TREATMENT OF IMPUTED DEBT ASSOCIATED WITH PPAs IN CONFIDENTIAL EXHIBIT LK-10 IN KPSC CASE 2009-00545?**

A. No. There are miscalculations in Mr. Kollen's analysis of the imputed debt treatment by S&P of PPAs. First, he disregarded using a 50% proxy capacity factor for the wind farm PPA, furthermore, Mr. Kollen assumed a 50/50 capital structure for KPCo. Revising his Confidential Exhibit LK-10 in KPSC Case 2009-00545 by applying the S&P 50% proxy capacity factor reduces the NPV of the revenue requirement to $105.7 million and the resulting imputed debt amount to $31.7 million. Then using the equity percentage filed in the case, results in a revenue requirement of $4.6 million.

Q. **WHAT IS YOUR CONCLUSION?**

A. KPCo is not seeking additional revenue based upon the imputed debt, if any, associated with the wind PPA. Moreover, although the modification of KPCo's capital structure in conformity with S&P's methodology would result in an annual revenue requirement of $4.6 million for the Company, it is not necessary for KPCo to make any adjustment to its capital structure as a result of the PPA. The size of the contract, the family approach of ratings used by S&P, and the differing approaches to contracts of this sort by Moody's and Fitch makes it unnecessary for the Company to impute debt for this contract.

AFFIDAVIT

Marc D. Reitter, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Marc D. Reitter

State of Ohio)
)
County of Franklin)

Subscribed and sworn to before me, a Notary Public, by Marc D. Reitter this 13th day of May 2010.

Notary Public

NOTARIAL SEAL STATE OF OHIO

David C. House, Attorney At Law
NOTARY PUBLIC - STATE OF OHIO
My commission has no expiration date
Sec. 147.03 R.C.

My Commission Expires ____________

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENT OF ELECTRIC)
RATES OF KENTUCKY POWER COMPANY) Case No. 2009-00459

KENTUCKY POWER COMPANY
REBUTTAL TESTIMONY OF DAVID M ROUSH

May 14, 2010

REBUTTAL TESTIMONY OF
DAVID M. ROUSH
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2009-00459

TABLE OF CONTENTS

REBUTTAL TESTIMONY OF
DAVID M. ROUSH
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q: PLEASE STATE YOUR NAME AND POSITION.

A: My name is David M. Roush. My position is Manager - Regulated Pricing and Analysis for American Electric Power Service Corporation.

II. PURPOSE OF TESTIMONY

Q: DID YOU SUBMIT DIRECT TESTIMONY IN THIS PROCEEDING?

A: Yes.

Q: WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A: The purpose of my Rebuttal Testimony is to respond to the recommendations contained in the direct testimony of the KIUC's witnesses Stephen J. Baron and Richard A. Baudino, CAK's witness Roger McCann and Walmart's witness Steve W. Chriss regarding KPCo's rate design proposals.

III. REBUTTAL

Q: DO YOU AGREE WITH THE CONCERN EXPRESSED BY CAK WITNESS MCCANN REGARDING THE PROPOSED RESIDENTIAL CUSTOMER CHARGE?

A: No, I do not. The Company's proposed residential customer charge of $8.00 per month is based upon the Company's actual costs. If a lower customer charge were implemented, the residential energy charge would be higher. This would increase the bills of higher usage residential customers. For example, customers that cannot afford high efficiency appliances and weatherization.

Q: **DO YOU AGREE WITH THE CONCERNS EXPRESSED BY KIUC WITNESS BARON AND WALMART WITNESS CHRISS REGARDING THE PROPOSED QUANTITY POWER TARIFF RATE DESIGN?**

A: No, I do not. A full Demand-Energy-Customer (D-E-C) rate that collects demand costs through a demand charge, energy costs through an energy charge and customer costs through a customer charge is a reasonable and generally accepted rate design; but it is not the best approach in all circumstances. A full D-E-C rate is most applicable to a homogeneous class of higher load factor customers. KPCo's Quantity Power Tariff (Q.P.) applies to all KPCo customers having a demand between 1,000 kW and 7,500 kW. These Tariff Q.P. customers have diverse load factors. As such the use of a rate which includes a portion of the demand charge in a first block energy charge is appropriate. KPCo utilizes a similar rate structure in its Medium General Service Tariff (M.G.S.).

As shown by KIUC witness Baron at page 20, the effect of the Company's proposal is that higher load factor customers (above 350 hours-use) would pay a rate that is comparable to a D-E-C rate. In fact, the Company's proposed effective demand charge for primary customers under Tariff Q.P. is $16.48 per kW which is an increase over the current Q.P. primary demand rate of $11.53 per kW and is much closer to full cost than the current demand charge.

Q: DO YOU AGREE WITH KIUC WITNESS BARON STATEMENT ON PAGE 26 OF HIS TESTIMONY THAT THE COMPANY'S PROPOSED TRANSMISSION ADJUSTMENT TARIFF CONTAINS A MISMATCH?

A: No, I do not. The issue that KIUC witness Baron raises is the use of the test year level of transmission revenues included in base rates in the determination of any over/under recovery in the Transmission Adjustment Tariff. This approach is entirely consistent with the methodologies approved for use in both KPCo's Environmental Surcharge and System Sales Clause. Consistent with those Tariffs, the base level of transmission revenues would be reviewed at the time of a base rate proceeding and adjusted if necessary. This same methodology should be employed in the proposed Transmission Adjustment Tariff. Any difference between the actual transmission costs and the base transmission revenues will be reflected in the Transmission Adjustment Tariff.

Q: PLEASE EXPLAIN THE IMPACT THAT THE CHANGE IN THE COMPANY'S RETURN ON EQUITY RECOMMENDED BY KIUC WITNESS BAUDINO WOULD HAVE ON THE COMPANY'S PROPOSED TRANSMISSION ADJUSTMENT TARIFF.

A: The Company's proposed Transmission Adjustment Tariff is based upon a comparison of the charges under PJM's Tariff to the embedded cost of transmission as determined from KPCo's cost-of-service study (and included in KPCo's proposed base rates). To the extent that the Return on Equity changes, the Company's embedded cost of transmission would also change. Since the charges under PJM's tariff would not change, the amount to be included in the

Transmission Tariff would change by the same amount that the Company's embedded cost of transmission changed.

For example, the Company's proposed transmission rate base is approximately $252.5 million. A 165 basis point reduction in ROE, as recommended by KIUC witness Baudino, would reduce the Company's return on rate base by approximately 70 basis points. Multiplying the 70 basis point reduction in the return on rate base by the transmission rate base of $252.5 million would reduce required income by approximately $1.8 million and reduce KPCo's embedded cost of transmission by approximately $2.9 million, after adjusting for taxes. Under this scenario, the Transmission Adjustment Tariff would be a credit of $4.1 million instead of a credit of $7.0 million.

Similarly, any change in other transmission expenses, such as O&M or depreciation expense, would change the embedded cost of transmission and thus also change the amount to be included in the Transmission Adjustment Tariff.

Q: DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A: Yes.

AFFIDAVIT

David M Roush, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true

David M Roush

David M Roush

State of Ohio)
) ss
County of Franklin)

Subscribed and sworn to before me, a Notary Public, by David M Roush
this 12th day of May 2010

Ellen A. McAninch

Notary Public

My Commission Expires May 11, 2011

NOTARIAL SEAL
STATE OF OHIO

ELLEN A. MCANINCH
NOTARY PUBLIC
STATE OF OHIO
Comm. Expires
May 11, 2011
Recorded in
Franklin County

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENT OF ELECTRIC)
RATES OF KENTUCKY POWER COMPANY) Case No. 2009-00459

KENTUCKY POWER COMPANY
REBUTTAL TESTIMONY OF ERROL K WAGNER

May 14, 2010

REBUTTAL TESTIMONY OF
ERROL K. WAGNER
ON BEHALF OF KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2009-00459

TABLE OF CONTENTS

REBUTTAL TESTIMONY OF
ERROL K. WAGNER
ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

Introduction

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Errol K. Wagner and I am the Director of Regulatory Services, Kentucky Power Company ("Kentucky Power, KPCo or Company"). My business address is 101 A Enterprise Drive, Frankfort, Kentucky 40602.

Q. DID YOU SUBMIT DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my testimony is to rebut portions of the direct testimony presented by the KIUC's Witness Lane Kollen and the CAK's Witness Roger McCann.

System Sales Margin Adjustment

Q. DO YOU AGREE WITH WITNESS KOLLEN'S STATEMENT AT PAGE 7, LINE 6, THAT THE COMPANY'S CP&L ANCILLARY SERVICES ADJUSTMENT AND THE CP&L SALES FOR RESALE ADJUSTMENT TO THE TEST YEAR LEVEL OF SYSTEM SALES MARGINS (SECTION V, WORKPAPER S-4, PAGE 26) ARE NOT KNOWN AND MEASURABLE?

A. No. The contract which resulted in KPCo realizing these revenues was terminated at December 31, 2009 along with the ability of KPCo to realize the resulting transmission revenues.

Q. WHAT ARE THE "RESULTING REVENUES" THAT WILL NOT BE REALIZED?

A. The CP&L Ancillary Services revenues were KPCo's MLR share of the ancillary service revenues the AEP System realized for delivering the energy to CP&L from I&M. The CP&L Sales for Resale revenues were KPCo's MLR share of the AEP System's transmission services revenues AEP received resulting from AEP delivering the energy to CP&L from I&M. Because the energy was transmitted over the AEP System's transmission facilities KPCo received its MLR share of these revenues and these revenues were included in the System Sales Clause. When the CP&L contract terminated on December 31, 2009 KPCo ability to receive these revenues in the future also terminated.

Q. ARE YOU SAYING THE CP&L ANCILLARY SERVICE REVENUES AND THE CP&L SALES FOR RESALE ADJUSTMENTS TO THE TEST YEAR LEVEL OF SYSTEM SALES MARGINS IN SECTION V, WORKPAPER S-4, PAGE 26, WHICH TOTAL $452,677, DO NOT RESULT FROM SYSTEM SALES MARGINS?

A. Yes. These revenues are transmission revenues recorded in Account Nos. 4470004 and 4470005. Pursuant to the Company's Tariff S.S.C. paragraph 2 (a), however, they are reflected in the System Sales Clause calculations.

Q. DO YOU AGREE WITH WITNESS KOLLEN'S STATEMENT AT PAGE 7, LINE 8, THAT THE CAPACITY AND ENERGY REMAIN AVAILABLE TO THE AEP POOL FOR OFF SYSTEM SALES?

A. No. During the life of the contract, the 250 MW contracted to CP&L was not available to the AEP Pool for off system sales. The CP&L contract was a contract between I&M and CP&L and the energy and capacity sales were between those two entities. The transmission revenues, at issue in this adjustment, were revenues resulting from the contract between I&M and CP&L - not AEP and CP&L.

Q. NOW THAT THE 250 MWs ARE INCLUDED IN I&M's MEMBER PRIMARY CAPACITY, IS THE CAPACITY AND ENERGY AVAILABLE TO THE AEP POOL FOR OFF SYSTEM SALES?

A. Not necessarily. As Company Witness Myers states in his testimony there are many factors that affect the level of the AEP System's off system sales. For example, the economic down turn, the weather and the price of natural gas all influence the level of off system sales. Just because the AEP System has additional generating capability does not mean the AEP System will realize a higher level of off system sales margins.

AEP Capacity Payments for Termination of I&M Sale to CP&L

Q. DO YOU AGREE WITH MR. KOLLEN'S CONCLUSION BEGINNING ON PAGE 14, LINE 17, THAT THE COMMISSION SHOULD NOT ADOPT THE COMPANY'S CAPACITY ADJUSTMENT ASSOCIATED WITH THE TERMINATION OF THE I&M AND CP&L CONTRACT?

A. No I do not. Just because the Company can not predict with certainty where the energy from the 250 MWs of capacity will be allocated does not mean that the Company can not predict with certainty where the capacity costs associated with the 250 MWs will be allocated. In fact, the FERC-approved AEP Pool Agreement does just that. The FERC-approved agreement requires that the 250 MWs be included in I&M's Member Primary Capacity and be used in the calculations of the members' monthly Pool Capacity credit or charge.

Q. DO YOU AGREE WITH THE STATEMENT THAT THIS ADJUSTMENT IS NOT KNOWN AND MEASURABLE?

A. No. The fact that the contract terminated on December 31, 2009 supports the known element. The AEP Pool Capacity statement calculations support the measurable element.

Proposed Enhanced Reliability Reporting

Q. DOES THE COMPANY AGREE WITH WITNESS KOLLEN'S STATEMENT AT PAGE 27, LINE 17 THAT "IT WILL BE VERY DIFFICULT FOR THE COMMISSION TO ENSURE THAT THE AMOUNTS AUTHORIZED ACTUALLY ARE SPENT FOR THAT PURPOSE BECAUSE IT WILL NOT BE ABLE TO TRACE THE ADDITIONAL RECOVERY ALLOWED TO THE ACTUAL AMOUNTS EXPENDED"?

A. No. The Company currently files an annual report April 1 with the Commission containing information relating to the Company's actual System Average

Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI) and Customer Average Interruption Duration Index (CAIDI) experienced for the preceding year. The Company could easily modify the April 1 annual report to include the circuits where the distribution vegetation management operation and maintenance expense for the prior year was spent, the amount of expense incurred and the type of work performed. Then September 30 of each year the Company could file with the Commission a work plan for the next year's distribution vegetation management. This report could include the circuits where the work is expected to be performed, type of work to be performed and the estimated level of expense to be incurred. This level of detail reporting in the two reports should ensure the Commission that the amount authorized for distribution vegetation management operation and maintenance expense was actually incurred.

Cost of Capital Issue

Q. DO YOU AGREE WITH THE CONCLUSION AT PAGE 38 OF MR. KOLLEN'S TESTIMONY THAT THE COMPANY IMPROPERLY FAILED TO INCLUDE SHORT TERM DEBT IN ITS CAPITAL STRUCTURE?

A. No. The Company has used the same methodology in the calculation of its short term debt since at least Case No. 8734 (Test Year December 31, 1982). In fact, Witness Kollen used this very same methodology in the Company's prior rate proceeding, Case No. 2005-00341 (See Exhibit (LK-4) in that proceeding).

Q. DID WITNESS KOLLEN USE THE 13 MONTH AVERAGE SHORT TERM DEBT BALANCE TO DETERMINE THE SHORT TERM DEBT BALANCE TO BE REFLECTED IN THE TOTAL CAPITALIZATION IN THAT PRIOR PROCEEDING?

A. No he did not.

Q. DID WITNESS KOLLEN ADJUST ANY OTHER CAPITAL COMPONENT IN THIS PROCEEDING DUE TO A RELATIVELY LOW CAPITAL RATIO?

A. No, he did not, even though he recognized on page 42, Line 19 that the common equity ratio of KPCo was "relatively low".

Q. WHAT WOULD THE EFFECT BE ON THE COMPANY'S REVENUE REQUIREMENT OF ADJUSTING THE COMMON EQUITY BALANCE UPWARD?

A. When, as is usual, the cost of the common equity is higher than the costs of the other capitalization components, an increase in the common equity ratio increases the Company's annual revenue requirement.

Q. HOW DID WITNESS KOLLEN ADJUST THE BIG SANDY COAL STOCK IN THE COMPANY'S PRIOR PROCEEDING?

A. Again using Exhibit (LK-4) in the 2005 proceeding, Mr. Kollen accepted the Company's adjustment to increase the short term debt balance by $3.5 million associated with the increase in the Company's coal inventory balance.

Q. DID MR. KOLLEN PROPOSE THE COAL STOCK ADJUSTMENT BE RATABLY ALLOCATED AMONG SHORT TERM DEBT (STD), LONG

TERM DEBT (LTD) AND COMMON EQUITY (CE) IN THE COMPANY'S 2005 PROCEEDING?

A. No he did not.

Q. **WOULD YOU PLEASE EXPLAIN THE COAL INVENTORY AJUSTMENT IN THE 2005 PROCEEDING?**

A. Yes. In that proceeding, the Company's June 30, 2005 coal inventory was 207,146 tons, which was equal to 26 days of coal inventory using a daily burn rate of 8,000 tons. The then-target day's supply was 35 days or 280,000 tons (8,000 tons per day time 35 days). The difference between the target level and the level on hand at June 30, 2005 was 72,854 tons. The resulting increase in the value of the coal pile was $3,593,159 ($49.32 X 72,854).

Q. **IS THE METHODOLOGY FOR CALCULATING THE EFFECT OF THE COAL INVENTORY ADJUSTMENT KIUC IS PROPOSING IN THIS PROCEEDING THE SAME METHODOLOGY IT SPONSORED IN THE 2005 RATE CASE?**

A. No, in this proceeding KIUC's position is to ratably spread the decrease adjustment among STD, LTD and CE. In the Company's 2005 rate case KIUC proposed including the entire increase adjustment in STD only. Mr. Kollen did not provide any explanation or support for the change in his approach in making the coal stock adjustment in the 2005 case vs. the 2009 case.

Q. **WHAT IS THE EFFECT OF THE TWO DIFFERENT INCONSISTENT METHODS?**

A. Because the cost component on STD was the lowest cost of the three components, when the coal stock adjustment was an **increase** adjustment as in Case No. 2005-00341, the revenue requirement was lower than if the increase adjustment was ratably spread among all three elements. When the coal stock adjustment is a **decrease** and the adjustment is spread ratably among all three elements as proposed by Mr. Kollen in the current proceeding, the revenue requirement is again lower than if the entire adjustment was reflected in the STD. By picking and choosing the methodology to make the coal stock adjustment and being inconsistent one can always reduce or increase the required revenue requirement.

Q. WAS THE METHODOLOGY USED BY THE KIUC WTINESS IN THE SELECTION OF THE STD COST THE SAME IN THE 2005 CASE VS THE 2009 CASE?

A. No. Because the Company did not incur any STD interest cost during the test year (twelve months ended June 30, 2005), the Company proposed AEP Money Pool rate of 3.34% and KIUC accepted the methodology. However, in this proceeding, using Exhibit (LK-15), KIUC rejected KPCo's weighted average interest rate of short term borrowings outstanding during the test year of 2.29 % and instead used 1%.

Q. HOW WAS THE 1% RATE CALCULATED FOR THIS PROCEEDING?

A. At pages 43 and 44 Mr. Kollen indicates he obtained the STD rate from the April 6, 2010 *Wall Street Journal*. Mr. Kollen states the rate he used is slightly higher than the one year LIBOR rate on that date.

Q. DOES THIS APPEAR TO BE A REASONABLE APPROACH IN SELECTING A STD RATE FOR RATE MAKING PURPOSES?

A. No it does not. First, methods should not be picked based upon the results they yield. Yet, Mr. Kollen's change in methods (without explanation) appears to be just that. Moreover, it is not reasonable to assume that today's current low short term debt rate will remain in effect for the expected life for the base rates established in this proceeding. If one were to deviate from using the actual STD rates experienced by the Company during the test year, one should at least use a three-year or five-year average LIBOR rate.

Q. WHAT IS THE RESULT OF USING A THREE-YEAR OR FIVE-YEAR AVERAGE LIBOR RATE?

A. Using the one-year LIBOR rates for the three-year and five-year periods ending March 31, 2010 one would calculate an average rate of 2.94% and 3.74% respectively (Source: www.liborated.com/historic_libor_rates.asp).

Q. WHAT WAS THE STD RATE THE COMPANY USED IN THIS PROCEEDING?

A. Section V, Workpaper S-2, Page 1 of 3 demonstrates the Company used a STD rate of 2.29%. This is below both the three-year and five-year average LIBOR rate.

Q. ARE THERE OTHER PROBLEMS WITH WITNESS KOLLEN'S APPROACH OF USING A RATE SLIGHTLY HIGHER THAN THE ONE YEAR LIBOR RATE IN THE APRIL 6, 2010 WALL STREET JOURNAL?

A. Yes. Mr. Kollen's approach ignores the cost incurred by the Company to maintain a line of credit. Section V, Workpaper S-3, Page 2 of 3, line 16 not only includes the actual cost associated with the AEP Money Pool it also includes the actual cost the Company incurred to maintain a line of credit. This is a cost of providing service to its customers and should be included in the calculation of the Company's cost of service.

CAK's Proposed Recommendations

Q. HAS THE COMPANY REVEIWED THE TESTIMONY OF THE COMMUNITY ACTION KENTUCKY, INC. (CAK) WITNESS ROGER McCANN?

A. Yes.

Q. WHAT IS THE COMPANY'S POSITION REGARDING MR. McCANN'S RECOMMENDATION THAT THE PROPOSED RATE INCREASE FOR RESIDENTIAL ELECTRIC CUSTOMERS BE SIGNIFICANTLY DECREASED AND THERE BE A DIFFERENT DISTRIBUTION OF THE PROPOSED INCREASE AMONG ALL THREE RATE CLASSES?

A. First, the Company believes the rates it charges its customers (Residential, Commercial or Industrial) for electric service should be based upon the costs the Company incurs to provide electrical service to its customers. Second, as it relates to a different distribution of the proposed increase among all three rate classes, the Company believes it attempted a reasonable distribution of the proposed increase by reducing the subsidies among the classes by 10%. The Company believes it is important to give all customers a proper price signal so when they are faced with a decision on how to spend there energy dollars they make a rational and logical decision.

Q. **WHAT IS THE COMPANY'S POSITION AS IT RELATES TO THE CAK'S RECOMMENDATION TO EXPAND THE EXISTING DSM PROGRAMS?**

A. This issue is more properly addressed in the DSM process than in this proceeding. The Company's existing DSM programs were established in a DSM proceeding pursuant to KRS 278.285. The Company has worked with its DSM Collaborative, the local Community Action Agencies are active members, to make DSM programs recommendations to the KPSC.

Q. **WHAT IS THE COMPANY'S POSITION AS IT RELATES TO MR. McCANN'S RECOMMENDATION THAT THE COMPANY MUST INCREASE THE PER METER CHARGE FOR THE ENERGY ASSISTANCE PROGRAM DESIGNED TO HELP LOW INCOME HOUSEHOLDS, AND MAKE MATCHING SHAREHOLDER CONTRIBUTIONS TO THE ENERGY ASSISTANCE PROGRAM?**

A. It is the Commission not the Company that establishes the Home Energy Assistance Program (HEAP) charge. Should the Commission increase the current $0.10 per meter per month charge the Company has no issue with that decision. However, the Company disagrees with the recommendation requiring the Company's shareholders to make a matching contribution to the energy assistance program. Requiring the Company to make a matching contribution without reimbursement reduces the Company's ability to earn the Commission's authorized return on equity.

Conclusion

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

AFFIDAVIT

Errol K Wagner, upon being first duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Errol K Wagner

Errol K Wagner

Commonwealth of Kentucky)
) Case No. 2009-00459
County of Franklin)

Sworn to before me and subscribed in my presence by Errol K Wagner, this the 12th day of May, 2010.

Notary Public

My Commission Expires: January 23, 2013

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENT OF ELECTRIC)
RATES OF KENTUCKY POWER COMPANY) Case No. 2009-00459

KENTUCKY POWER COMPANY
REBUTTAL TESTIMONY OF SCOTT C WEAVER

May 14, 2010

REBUTTAL TESTIMONY
OF
SCOTT C. WEAVER
ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2009-00459

TABLE OF CONTENTS

REBUTTAL TESTIMONY OF
SCOTT C. WEAVER
ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION?

A. My name is Scott C. Weaver, and my business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by the American Electric Power Service Corporation (AEPSC) as Managing Director-Resource Planning and Operational Analysis. AEPSC supplies engineering, financing, accounting and similar planning and advisory services to AEP's eleven electric operating companies, including Kentucky Power Company ("Kentucky Power, KPCo or Company").

Q. ARE YOU THE SAME SCOTT C. WEAVER WHO FILED DIRECT TESTIMONY ON BEHALF OF KPCO IN THIS CASE?

A. Yes.

II. PURPOSE

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my testimony is to respond to the recommendations made by Kentucky Industrial Utility Customers (KIUC) Witness Lane Kollen on pages 11-13 of his direct testimony incorporating his recommendations concerning the issues in Commission case 2009-00545. I am providing the same rebuttal testimony I filed in the 2009-00545 docket on April 30, 2010, to ensure consistency for the Commission's records. In that rebuttal I reviewed the testimony filed in this case by Kentucky Industrial Utility Customers (KUIC) Witness Lane Kollen and addressed certain points he has raised regarding the following issues and topic-areas:

- The fact that the life cycle costs associated with the LDWEC REPA are "least-cost" when compared to other supply-side resources;
- the possibility of other (renewable) options availing themselves to the Company in lieu of the wind energy emanating from the LDWEC REPA in the timeframe required, or at a lower cost;
- the prospect of the enactment of either Kentucky or Federal renewable mandates;
- the attendant prospect that any such state Renewable Portfolio Standards (RPS) enacted would be restricted to in-state renewable resources only;
- the "need" for the renewable energy from the Lee Dekalb Wind Energy Center (LDWEC) that is associated with the proposed Kentucky Power Company Renewable Energy Purchase Agreement with FPL Energy Illinois Wind, LLC ("the REPA", or REPA), was based *not* on specific requirements as set forth under the AEP Interconnection Agreement, but rather on the Company's position around the establishment of a renewable energy portfolio;
- the fact that there would be no incremental transmission costs associated with the energy received from the proposed REPA;
- the reality that the forecast of energy pricing utilized in the economic analysis of this wind PPA did proxy a PJM Locational Marginal Price (LMP), and, finally;
- the conclusion that there are incremental <u>benefits</u> associated with the LDWEC REPA, rather than its representation by Mr. Kollen as causing "harm" to KPCo's customers.

Q. **WERE THE EXHIBITS OFFERED TO SUPPORT THIS REBUTTAL TESTIMONY PREPARED BY YOU OR BY SOMEONE UNDER YOUR SUPERVISION?**

A. Yes.

III. OTHER RESOURCE OPTIONS AND COSTS

Q. MR. KOLLEN STATES ON PAGES 6 AND 7 OF HIS TESTIMONY IN THE KPSC 2009-00545 CASE THAT THE COMPANY HAS PROVIDED NO EVIDENCE THAT THE COSTS ASSOCIATED WITH THE LDWEC PPA ARE LEAST-COST. IS THAT A TRUE STATEMENT?

A. No it is not. As described in the very discovery response Mr. Kollen identifies—KIUC 1-17, represented as Exhibit LK-4), the Company set forth Exhibit JFG-3 which clearly represented that the offer that served as the basis for the LDWEC REPA, when compared to other renewable offers received from the same solicitation discussed by Company witness Godfrey in his direct testimony, was indeed the least-cost renewable alternative offered. Further, my direct testimony indicates that under the reasonable assumption that a federal RPS will evolve, the least-cost option to achieve such mandates would be the LDWEC REPA when compared to the cost of acquiring RECs.

Moreover, the company provided information in response to discovery in the Company's rate case proceeding (Case No. 2009-00459), specifically, KIUC 1-15 and KIUC 2-1, that was not mentioned by Mr. Kollen. That response, reproduced here as Exhibit SCW-1R, compares and contrasts the levelized (life cycle) cost of electricity (COE) of the LDWEC REPA *versus* a range of levelized COE for both natural gas combined cycle (NGCC) and natural gas combustion turbine (NGCT) resource options, each represented on a "$ per Mwh" (generated) basis. The resulting Exhibit SCW-1R chart shows that under a high utilization (i.e. high capacity factor) view of either of those natural gas facility options—which of course would tend to reduce the "per Mwh" cost—in all cases the LDWEC REPA levelized life cycle cost would be the least-cost option.

Q. DOES MR. KOLLEN SUGGEST OTHER OPTIONS IN THE EVENT SUCH RENEWABLE STANDARDS ARE ENACTED?

A. Yes he does. Beginning on page 8 of his direct testimony in the KPSC 2009-00545 case, he indicates that the Company has identified "other options" in the form of biomass co-firing at existing KPCo generating units as well as the purchase of renewable energy certificates.

Q. WOULD YOU PLEASE ELABORATE ON THOSE ADDITIONAL OPTIONS?

A. Yes. As also previously indicated in my direct testimony in this case, while the notion of biomass co-firing at existing KPCo units—such as its Big Sandy and Rockport facilities—may be plausible, each has not been considered until the 2015 and 2013 timeframe, respectively, in the Company's indicative planning. This is necessary to afford time for the required pulverizer and boiler testing of various biomass feedstock options, as well as to address feedstock availability/supply issues and options.

As far as renewable energy certificates being utilized as an "option", Mr. Kollen failed to recall that my direct testimony in this case did offer a comparison of the estimated incremental costs associated with the LDWEC REPA versus the projected costs of RECs.[1] As further indicated on page 22 of my direct testimony in the KPSC 2009-00545 case it would:

> "…suggest that these incremental or "net" costs of the LDWEC project are indeed anticipated to be lower than, alternatively, acquiring RECs alone. Plus, possessing the renewable energy offered by the project offers KPCo with the further, non-quantified societal benefit of a more environmentally-friendly generation portfolio."

[1] Exhibit SCW-3, col. "L" versus col. "M" ; from Weaver Direct Testimony in Case No. 2009-00545

Q. **AS IT PERTAINS TO A BIOMASS RENEWABLE OPTION, WHAT ADDITIONAL COST INFORMATION IS NOW AVAILABLE THAT WOULD CONTRAST IT WITH THE COST OF THE LDWEC REPA?**

A. The Company has provided a Supplemental response to Attorney General request 2-3 in the KPSC 2009-00545 case. That Supplemental response—describing cost estimates associated with a proposed biomass development project in Kentucky—is included as part of this rebuttal testimony as Exhibit SCW-2R and further demonstrates the relative benefits of the LDWEC contract.

IV. INCREMENTAL RTO-PJM COSTS

Q. **DOES MR. KOLLEN DRAW AN INCORRECT CONCLUSION BY SUGGESTING THAT THE ECONOMIC EVALUATION OF THE LDWEC PPA SHOULD HAVE CONSIDERED "TRANSMISSION" COSTS? IF SO, WHY?**

A. Yes, his conclusion is in error. AEP or the Company would incur no incremental transmission costs associated with the energy received through the LDWEC REPA. First, under Section 5.3(B) of the REPA, it specifies that the:

> "Seller shall be responsible for all interconnection, electric losses, transmission and ancillary services arrangements and costs required to deliver Purchaser's Contact Capacity Share of the Renewable Energy from the Facility to Purchaser at Point of Delivery. Purchaser shall be responsible for all electric losses, transmission and ancillary services arrangements and costs required to receive Purchaser's Contract Capacity Share if the Renewable Energy at the Point of Delivery and deliver such Energy to points beyond the Point of Delivery"[2]

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[2] "Point of Delivery" being defined under the REPA as "...the electric interconnection point... at which point the quantities of Renewable Energy and Ancillary Services delivered are recorded and measured by the Interconnection Provider's [PJM] revenue meters."

So while Mr. Kollen is essentially correct by stating on page 8 of his testimony in the KPSC 2009-00545 case, that the "contract provides for delivery near the wind farm site and the purchaser is responsible for transmission", he errors in presuming there would be a cost for this transmission within PJM to any such points *beyond* this Point of Delivery. Rather, the energy associated with this transaction received by Kentucky Power at the (PJM) delivery point would be ascribed PJM Network Integration Transmission Service (NITS) status. It should *not* be confused with a "point-to-point" service along a unique source-to-sink transmission path that would be reserved under, and payable through, the PJM-OATT. As a NITS transaction, the energy would flow from the established (LDWEC) generation node at no additional cost to the energy purchaser and transmission owner/customer, Kentucky Power. Therefore, the costs of the LDWEC REPA as represented in my original Exhibit SCW-3—representing a purchase cost for a delivered product (into PJM)—is then effectively inclusive of "transmission costs".

Q. **LIKEWISE, DO YOU AGREE WITH MR. KOLLEN'S CLAIM THAT THE COMPANY'S REPRESENTATION OF LDWEC-RELATED COSTS PROVIDED IN EXHIBIIT SCW-3 DOES NOT INCLUDE THE COSTS OF PJM CONGESTION AND LINE LOSSES?**

A. No I do not. As represented in Exhibit SCW-3, the Company considers certain relative variable costs/(credits), including those that would flow through AEP Pool Energy Settlements. As part of this computation, the Company accounts for the expected revenues its generating sources will receive from PJM in the form of Locational Marginal Price (LMP). In modeling these revenues, the company applies a proxy price that represents

PJM LMP. Since the proxy price emulates PJM's LMP, it considers *all three* LMP components: Energy, Congestion and Line Losses.

V. RENEWABLE RESOURCE MANDATES

Q. ON PAGE 4 OF HIS TESTIMONY IN THE KPSC 2009-00545 CASE, MR. KOLLEN STATES, "THERE IS SIGNIFICANT UNCERTAINTY AS TO WHETHER THERE EVER WILL BE A FEDERAL OR KENTUCY LEGISLATIVE MANDATE TO ACQUIRE SUCH RESOURCES AND THE COMPANY DOES NOT CLAIM OTHERWISE." DO YOU AGREE WITH MR. KOLLEN?

A. No. As reflected on page 11 of my direct testimony in the KPSC 2009-00545 case I indicate mandatory RPS requirements "…are likely to be required at the federal level." I testify that H.R 2454 (Waxman-Markey Bill) that was passed by the U.S. House included a federal renewable energy standard (RES); and that the U.S. Senate's Energy and Natural Resources Committee passed out of that committee S. 1462 (Bingaman Bill) which likewise included an RES, with the latter enjoying bi-partisan support. Such ultimate RPS/RES legislation could be part of either a fully-comprehensive set of "climate change/greenhouse gas" legislation or, potentially, as a unique "carve-out" component of a federal energy bill. It also bears pointing out that 29 other states and the District of Columbia currently have mandated renewable portfolio standards ranging from 10-33 percent of sales. (See Exhibit SCW-3R "(State) Renewable Portfolio Standards", April 2010) [3].

[3] http://www.dsireusa.org/summarymaps/index.cfm?ee=1&RE=1

Moreover, the Commonwealth of Kentucky is actively addressing the prospect of an RPS requirement. In addition to Kentucky H.B. 3 highlighted by Mr. Kollen, H.B. 408 also sets forth the very real prospect for such mandates. Although neither bill has passed, given the on-going support for such legislation from the Commonwealth's executive branch based on Governor Beshear's late-2008 energy plan for the development of diverse and clean energy resources: *"Intelligent Energy Choices for Kentucky's Future*", it is also very plausible to assume that the Commonwealth would join the nearly 30 states across the U.S.—including states contiguous to Kentucky: Illinois, Ohio, and West Virginia—that have adopted such mandated renewable energy standards.

Q. MR. KOLLEN ALSO SUGGESTS THAT THE LDWEC CONTRACT WOULD NOT QUALIFY AS A RENEWABLE RESOURCE UNDER H.B. 3. DO YOU AGREE WITH THAT PROSPECT?

A. No. Ultimately, I believe any such state-specific mandates that could emerge in the Commonwealth of Kentucky would not seek to be prescriptive to Kentucky-sourced renewable energy only. To do so could both greatly limit the opportunity for such clean energy opportunities and potentially severely increase the cost of those opportunities to Kentucky's electricity consumers.

First, Section 6(3) of H.B. 408, which was not cited by Mr. Kollen, provides that "…renewable energy that is generated or purchased by the retail electric supplier from a generational facility that became operational before the effective date of this Act may be used to comply with the renewable portfolio standard requirement for that supplier." I would interpret this as suggesting that transactions such as the LDWEC project would potentially *not* be excluded.

Second, each of the neighboring states to Kentucky that currently have mandated renewable energy standards (Illinois, Ohio and West Virginia) have provisions that *do* allow use of "out-of-state" renewable energy to achieve their respective RES:

- Ohio: S.B. 221 (4928.64 (B)(3)): States that up to one-half must be from in-state (Ohio) renewable resources, while "… the remainder shall be met with resources than can be shown to be deliverable into this state."
- West Virginia: H.B. 103 (S 24-2F-4 (b)(1)): States that such renewable facilities must be located within the geographical boundaries of West Virginia, *or* located outside of West Virginia, but within the service territory of the regional transmission organization that manages the transmission system in any part of this state (i.e. sourced from any of the thirteen interconnected states served by PJM).
- Illinois: Public Act 0-5-0481; S.B. 1592 (Sec 1-75 (c)(3)): States that for the period prior to 6/2011 out-of-state renewable sources are allowed only if insufficient "cost effective" resources are available in-state. After 6/2011, both in-state *and* sources outside of Illinois --but that "adjoin" Illinois-- may be counted in meeting the state renewable standard. If still insufficient "cost effective" resources available, renewable energy "…shall be purchased elsewhere and shall be counted towards compliance."

Third, given this, I find it unlikely that the Commonwealth of Kentucky would pass legislation that could effectively disadvantage its electricity consumers from a "cost-to-comply" perspective through the establishment of such a limitation on the renewable portfolio of its electricity service providers by effectively building a fence around the state. Moreover, although I am not a legal expert, I have been advised by the Company's legal counsel that state legislative action that would place such restrictions on renewable energy sourcing could violate the "commerce clause" from the United States Constitution and its application to interstate commercial transactions. From the perspective of a resource planner, this would be akin to denying the ability of Kentucky coal producers to export their energy product for use in Ohio generating facilities.

Finally, Mr. Kollen fails to acknowledge that any *federal* RPS requirements placed upon retail electricity providers would clearly be met via ubiquitous, nation-wide sourcing of (physical) renewable energy and/or Renewable Energy Certificates (RECs).

Q. WHAT ADDITIONAL INFORMATION COULD YOU OFFER TO SUPPORT THE VIABILITY OF KENTUCKY-BASED RENEWABLE GENERATION RESOURCES TO FULLY ACHIEVE ANY POTENTIAL KENTUCKY RPS?

A. Through discussions with the Company's renewable energy expert witness, Jay Godfrey, he informs me he is aware of <u>no</u> renewable project—be it wind, solar, biomass, incremental hydro, geothermal, or landfill gas—that is currently under advanced development or construction within the Commonwealth, other than the biomass development project previously mentioned in this testimony and referenced as within Exhibit SCW-2R.

VI. <u>RENEWABLE RESOURCE NEED</u>

Q. PLEASE EXPLAIN WHY THE ENERGY ASSOCIATED WITH THE LDWEC PPA IS CRITICAL FOR KENTUCKY POWER'S RESOURCE PORTFOLIO IN SPITE OF MR. KOLLEN'S CONTENTION THAT THE COMPANY HAS NO "NEED" FOR THIS ENERGY.

A. The fact is that Mr. Kollen has ignored the basic thrust of my direct testimony in this case which clearly demonstrates the importance of Kentucky Power positioning itself for the likelihood of a state or federal renewable portfolio standard. As stated in detail, the

Company and its AEP parent take this prospect very seriously and is attempting to position itself to take advantage of pricing for such renewables resources—pricing advantages that will also likely dissipate once such RPS mandates do come to pass—by setting forth a system-wide strategy that established a goal to obtain an incremental 2,000 MW of renewable energy resources by the end of 2011; a prospect that was included in the externally-published AEP *2009 Corporate Sustainability Report*.[4] Although KPCo's initial contribution to the attainment of that goal would be manifested in this LDWEC REPA, all of the other AEP affiliate operating companies with generation have previously entered into comparable REPA transactions such that nearly *one-half* of this goal has currently been met.

I summarize this very issue around "need" beginning on page 18 of my direct testimony in the KPSC 2009-00545 case when I respond to the following question:

> "KPCO'S OVERALL RENEWABLE PLAN WOULD ADD RENEWABLE RESOURCES TO AN ELECTRIC UTILITY OPERATING IN A STATE—KENTUCKY—WHICH CURRENTLY HAS NO RENEWABLE PORTFOLIO STANDARD. WHY THEN IS THE ATTAINMENT OF SUCH RENEWABLE RESOURCE AMOUNTS NECESSARY, AND HOW CAN THAT BE CONSIDERED TO BE IN THE BEST INTERESTS OF THE CUSTOMERS OF KPCO?"

...and my unwavering response from that same testimony is:

> "...the relative cost of electricity inclusive of the LDWEC wind generation under consideration, **is competitive with alternative resources available to KPCo**. Second, with the current federal PTCs for wind development now set to expire at the end of 2012, it would be anticipated that **the costs of wind projects placed into service <u>after</u> that expiration date will significantly increase**. As more fully discussed in the testimony of Company Witness Godfrey, **by acting now to secure wind contracts, KPCo is locking in wind energy at a relatively low cost**. Third, under the very reasonable prospect that a federal renewable energy standard will

[4] Available at http://www.aep.com/citizenship/crreport/docs/CS_Report_2009_web.pdf

> become law—whether included as a component of more comprehensive GHG legislation, or carved-out under separate legislation—**demand for renewable resources including wind energy will undoubtedly increase, further driving up the costs to KPCo's customers over the long-term.**
>
> Therefore, the development of a KPCo plan to add sufficient renewable resources prior to the expiration of the PTCs could serve to **mitigate KPCo's customers' exposure to the cost risks associated with such potential federal renewable energy and/or GHG legislation.** *(emphasis added in bold-face type for purposes of this rebuttal testimony)*

In fact, Mr. Kollen fails to recognize the criticality of the planning issues around renewable resources when he discusses the overall "need" issue. By placing his head in the sand by simply pointing to KPCo's current energy position within the AEP Interconnection Agreement as the suggested basis for such (wind) energy need, he does a disservice to the very constituents he represents by exposing them to significant cost exposures upon the enactment of such renewable standards.

VII. SUMMARY AND CONCLUSION

Q. LASTLY, MR. KOLLEN SUGGESTS THAT THE LDWEC REPA WOULD "HARM" KPCO RATEPAYERS. IS THAT AN ACCURATE STATEMENT?

A. No it is not. Based on the facts set forth in both my direct and rebuttal testimonies, it would suggest just the opposite; that Kentucky Power's customers will benefit by the foresight to be an early-mover in the acquisition of very attractive and competitively-priced, carbon-free renewable resources represented by the LDWEC REPA.

In fact the ratepayer "harm" mentioned by Mr. Kollen that he claims is quantified on Exhibit SCW-3 of my direct testimony is totally unfounded. As I indicate, the LDWEC REPA would have an order of magnitude impact of 0.07 (seven one-hundredths) of a cent per kWh effect on KPCo's costs over the period represented on the exhibit (col J), but that would <u>exclude</u> the consideration of the costs of RECs that could be borne by KPCo customers if required *in lieu of* this LDWEC wind energy. As previously discussed, that comparison clearly demonstrates that eschewing the inclusion of wind energy in the Company's generation portfolio by doing-nothing and effectively becoming a "price-taker" for RECs, would represent the higher-cost option.[5] Finally, under the further notion that available REC markets could potentially be extremely illiquid, particularly in any initial years of an RPS period, it would further suggest that such REC pricing could be very volatile subjecting KPCo's customers to unnecessary price uncertainty.

For these reasons, the Company concludes that the benefits of the wind energy to KPCo customers emanating from the LDWEC REPA clearly outweigh the cost (or "harm" as suggested by Mr. Kollen) and, therefore, affirms its prudence.

Q. **DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?**

A. Yes.

[5] Cf. note 2

AFFIDAVIT

Scott C Weaver, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true

Scott C. Weaver

State of Ohio)
) ss
County of Franklin)

Subscribed and sworn to before me, a Notary Public, by Scott C Weaver this 13th day of May 2010.

Ellen A. McAninch
Notary Public

My Commission Expires May 11th, 2011

NOTARIAL SEAL STATE OF OHIO

ELLEN A. MCANINCH
NOTARY PUBLIC
STATE OF OHIO
Comm. Expires
May 11, 2011
Recorded in
Franklin County

Exhibit SCW-1R
(PUBLIC)

Kentucky Power Company

REQUEST

Refer to page 6 lines 15-19 of Mr. Scott Weaver's Direct Testimony wherein he describes the AEP System review of supply-side resource options and consideration of combined cycle and combustion turbine resources. With respect to the proposed wind power purchased power agreement, please provide a comparison of the annual and life-cycle costs of that proposed contract to the most recent least cost bid from a supplier or AEP's most recent cost projection for combined cycle and/or combustion turbine capacity.

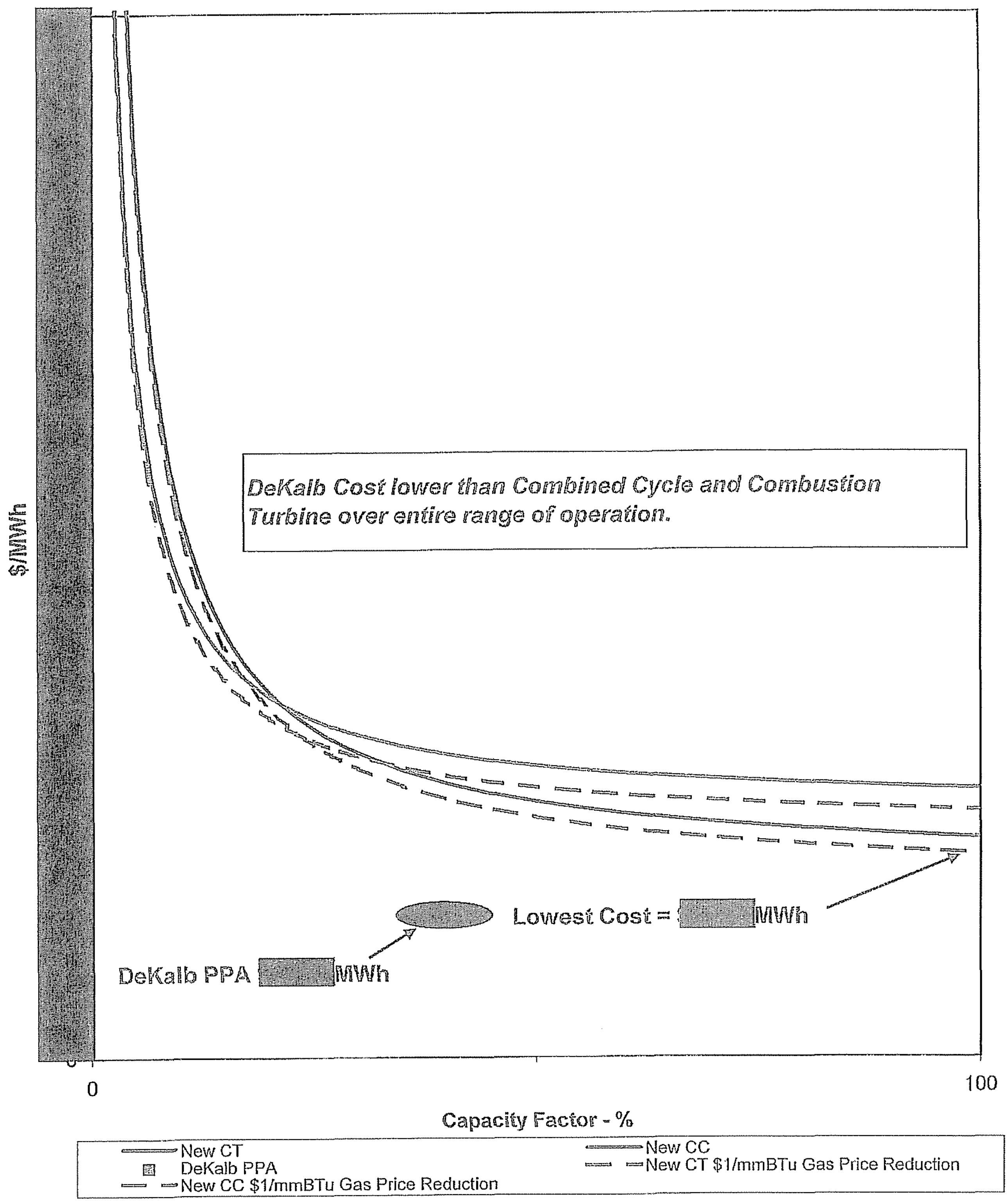
RESPONSE

See pages 2 of 3 for a graphical comparison of life-cycle costs of the proposed contract and recent projections for CT and CC capacity, and page 3 of 3 for key assumptions used in developing the CT and CC life cycle costs. Confidential protection of portions of the attachment is being requested in the form of a Motion for Confidential Treatment.

WITNESS: Scott C Weaver

Exhibit SCW-1R
(PUBLIC)

DeKalb vs. New CT & New CC
2010 - 2030 Levelized All-in Cost



Case No. 2009-00459
Filed May 14, 2010 – Weaver Rebuttal Testimony

Exhibit SCW-1R
(PUBLIC)

KPSC Case No. 2009-00459
KIUC 1st Set of Data Requests
Order
Item No. 15,Public
Page 3 of 3

AEP SYSTEM-EAST ZONE
New Generation Technologies
Key Supply-Side Resource Option Assumptions (a)(b)(c)

Type	Capability (MW) (Unforced Capacity) Std. ISO	Winter	Summer	Installed Cost (d) ($/kW)	Trans. Cost (e) ($/kW)	Full Load Heat Rate (HHV,Btu/kWh)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Emission Rates SO2 (Lb/mmBtu)	NOx (Lb/mmBtu)	CO2 (Lb/mmBtu)
Intermediate											
Combined Cycle (2X1 GE7FA, w/ Duct Firing)	580	598	545	[redacted]					0.0007	0.008	116.0
Peaking											
Combustion Turbine (4X1GE7FA)	627	652	600	[redacted]					0.0007	0.033	116.0

Notes: (a) Installed cost, capability and heat rate numbers have been rounded.
(b) All costs in 2008 dollars.
(c) $/kW costs are based on Unforced Capacity.
(d) Total Plant & Interconnection Cost w/AFUDC
(e) Transmission Cost ($/kW,w/AFUDC).

Kentucky Power Company

REQUEST

Is the company aware that ecoPower Generation, LLC ["ecoPower"] has filed an application with the Kentucky State Board on Electric Generation and Transmission Siting seeking approval for construction of a 50 MW merchant generation plant that would utilize low grade wood and wood waste for fuel? In your response, please consider the company's response to KIUC 1-9.

a. Is the company aware that ecoPower proposes to sell its generation to AEP?

b. If AEP agrees to purchase such generation, will the need for the wind-generated power which is the subject of the instant case decrease or be eliminated?

c. Does the company have any cost projections for the power that would be generated from ecoPower's plant contrasted with the cost for the wind-generated power? If not, will the company agree to supplement its response to this request in the event any such cost projections are made? Please include in your calculations the difference in transmission costs in the ecoPower option as contrasted with transmission costs for the wind-generated power.

d. In the event the cost for power from ecoPower's facility is less expensive than the wind-generated power the company proposes to purchase under the subject contracts, does the company foresee any possibility of cancelling the wind contracts and replacing it with the power from ecoPower? Why or why not? Explain in detail.

e. Can the company negotiate any provisions with the owners of the wind generation farm allowing the company to terminate the wind contracts in the event the price for ecoPower's generation is less expensive than the wind-generated power? Why or Why not? Explain in detail.

f. Would it be more feasible for the PSC to wait for additional information regarding ecoPower's proposals before approving the contracts which are the subject of the instant case?

g. Do AEP, Kentucky Power, or any of its officers, employees or other principals have any affiliation or financial interest of any type or sort with ecoPower?

h. In the event Kentucky Power does not utilize ecoPower's generation output, is it conceivable that other AEP subsidiaries will use it? If so, do Kentucky Power and/or any other AEP subsidiary stand to receive any financial gain of any type or sort, including but not limited to transmission costs and off-system sales, from ecoPower's sale of power to AEP?

RESPONSE

(a) (c). Following the Company's original filed response, a consultant representing the biomass project developer contacted the Company and provided estimated pricing for the proposed biomass project. The developer's preliminary target price for energy, capacity, REC and any future carbon cost reduction value for plant output over a levelized twenty-year term ranges from [redacted]/MWh to [redacted]/MWh. This target price compares to the Lee-DeKalb wind Power Purchase Agreement (PPA) weighted average price of [redacted]/MWh in the initial year, and a levelized twenty-year price of [redacted]/MWh. The Company provided supporting details for the above pricing in its responses to KPCS 1-14 (2009-00545) and KIUC 1-15 (2009-00459), respectively.

The developer's proposed biomass project and the Company's proposed wind-generated PPA each provide a bundled product delivered to the PJM Interconnection. The output from both projects is subject to PJM Locational Marginal Pricing (LMP).

The responses to subparts (b) and (d)-(h) remain unchanged.

WITNESS: Jay F Godfrey

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENT OF ELECTRIC)
RATES OF KENTUCKY POWER COMPANY) Case No. 2009-00459

KENTUCKY POWER COMPANY
REBUTTAL TESTIMONY OF RANIE K WOHNHAS

May 14, 2010

REBUTTAL TESTIMONY OF
RANIE K. WOHNHAS, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2009-00459

TABLE OF CONTENTS

REBUTTAL TESTIMONY OF
RANIE K. WOHNHAS, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q: PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A: My name is Ranie K. Wohnhas. My position is Director, Business Operations Support, Kentucky Power Company (Kentucky Power, KPCo or Company). My business address is 101 A Enterprise Drive, Frankfort, Kentucky 40602.

II. PURPOSE OF TESTIMONY

Q: DID YOU SUBMIT DIRECT TESTIMONY IN THIS PROCEEDING?

A: Yes.

Q: WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A: The purpose of my testimony is to rebut direct testimony by the KIUC's Witness Lane Kollen on the adjustment to the Company's Normalization of Major Storms.

Q: DO YOU AGREE WITH TESTIMONY OF KIUC WITNESS LANE KOLLEN CONCERNING NORMALIZATION OF MAJOR STORMS?

A: I agree with his testimony for the major storms which occurred as of twelve months ending September 30, 2009.

Q: WERE THERE ADDITIONAL MAJOR STORMS THAT OCCURRED PRIOR TO THE FILING OF THIS RATE PROCEEDING?

A: Yes. On December 8, 2010 and December 18, 2010 the Company incurred two major storms.

Q: **WAS THE COST OF THESE TWO MAJOR STORMS REFLECTED IN THIS RATE PROCEEDING?**

A: Yes. In data responses to both the Commission staff and the KIUC the Company updated various schedules and exhibits to reflect the costs of these storms.

Q: **WERE THESE COSTS ACTUAL?**

A: No. At the time of the responses the Company only had an estimate of these costs.

Q: **WHY DID THE COMPANY INCLUDE THESE COSTS IN RESPONSE TO THE DATA REQUESTS?**

A: The storms occurred prior to the scheduled hearing date in this proceeding and the actual costs were expected to be known prior to a scheduled hearing.

Q: **DOES THE COMPANY NOW HAVE THE ACTUAL COSTS FOR THESE TWO DECEMBER STORMS?**

A: Yes. The actual incremental O&M cost for the December 8, 2009 storm is $619,564 versus the estimate of $820,738 for a reduction of $201,174. The actual incremental O&M cost for the December 18, 2009 storm is $12,566,415 versus the estimate of $13,228,090 for a reduction of $661,675. The combined reduction for both storms is $862,849.

Q: **HOW WOULD THESE DECEMBER ACTUAL STORM COSTS EFFECT MR. KOLLEN'S TESTIMONY?**

A: The addition of the December storms would increase the Normalization of Major Storms Adjustment by $4,355,768.

Q: **IS THERE SUPPORT FOR THIS ADJUSTMENT?**

A: Yes. Attached as Exhibit Rebuttal RKW-1, Page 1 of 2 is the original adjustment (Section V, Workpaper S-4, Page 15) corrected for errors which Mr. Kollen agrees to in his testimony and Exhibit Rebuttal RKW-1, Page 2 of 2 is the adjustment to include the actual incremental costs for the two December storms. The difference between page 1 ($11,414,478) and page 2 ($7,058,710) is the $4,355,768.

Q: WHAT IS YOUR CONCLUSION FOR THE NORMALIZATION OF MAJOR STORMS ADJUSTMENT?

A: This adjustment should include the post test year costs for two December major storms since these costs are known and measureable and were incurred prior to hearings set in this proceeding.

Q: DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A: Yes.

AFFIDAVIT

Ranie K. Wohnhas, upon being first duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Ranie K. Wohnhas

Ranie K. Wohnhas

Commonwealth of Kentucky) Case No. 2009-00459

County of Franklin)

Sworn to before me and subscribed in my presence by Ranie K. Wohnhas, this the 12th day of May, 2010.

Judy K Rosquist

Notary Public

My Commission Expires: January 23, 2013