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April 16, 2012

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APR 16 2012
PUBLIC SERVICE
COMMISSION

Jeff R. Derouen
Executive Director
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

RE: Case No. 2011-00401

Dear Mr. Derouen:

Enclosed please find and accept for filing the original and ten copies of rebuttal testimony tendered on behalf of Kentucky Power Company.

Very truly yours,

STITES & HARBISON, PLLC

Mark R. Overstreet

MRO
cc: Counsel of Record
Consultants of Record

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

RECEIVED

APR 16 2012

PUBLIC SERVICE COMMISSION

IN THE MATTER OF

APPLICATION OF KENTUCKY POWER COMPANY	)
FOR APPROVAL OF ITS 2011 ENVIRONMENTAL	)
COMPLIANCE PLAN, FOR APPROVAL OF ITS	)
AMENDED ENVIRONMENTAL COST RECOVERY	) CASE NO. 2011-00401
SURCHARGE TARIFF, AND FOR THE GRANT OF A	)
CERTIFICATE OF PUBLIC CONVENIENCE AND	)
NECESSITY FOR THE CONSTRUCTION AND	)
ACQUISTION OF RELATED FACILITIES	)

REBUTTAL TESTIMONY AND EXHIBITS ON BEHALF OF KENTUCKY POWER COMPANY FOR AVERA, BECKER, BLETZACKER, MCMANUS, WALTON, WEAVER, AND WOHNHAS

April 16, 2012

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF KENTUCKY POWER COMPANY FOR APPROVAL OF ITS 2011 ENVIRONMENTAL COMPLIANCE PLAN, FOR APPROVAL OF ITS AMENDED ENVIRONMENTAL COST RECOVERY SURCHARGE TARRIFF, AND FOR THE GRANT OF A CERTIFICATE OF CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION AND ACQUISITION OF RELATED FACILITIES	)))))))))	CASE NO. 2011-00401

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. IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am the President of FINCAP, Inc., a firm providing financial, economic, and policy consulting services to business and government.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. A description of my background and qualifications, including a resume containing the details of my experience, is attached as Exhibit WEA-1.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS CASE?

A. In connection with a requested surcharge to recover the costs of planned environmental equipment under Section 278.183 of the Kentucky Code, Kentucky Power Company ("KPCO" or "the Company") is requesting a return on equity ("ROE") of 10.5 percent, which is equal to the value established by the Kentucky Public Service Commission ("KPSC") in the Company's most recent rate case, subject to review in the two-year reviews,[1] and that was used in its most recent completed environmental surcharge review.[2]

My purpose is to rebut the testimony of Dr. J. Randall Woolridge, submitted on behalf of the Kentucky Office of Attorney General ("OAG"), and Mr. Stephen G. Hill, on behalf of the Kentucky Industrial Utility Customers, Inc. ("KIUC"),

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[1] Case No. 2009-00459.
[2] Case No. 2010-00020.

concerning the ROE that KPCO should be authorized to earn on its investment recovered through the Environmental Cost Recovery ("ECR') Surcharge tariff.

Q. **PLEASE SUMMARIZE THE PRINCIPAL CONCLUSIONS OF YOUR REBUTTAL TESTIMONY.**

A. Dr. Woolridge's and Mr. Hill's recommendations are flawed and should be rejected. Correcting their analyses resulted in the following cost of equity estimates, which confirm the reasonableness of the 10.5 percent ROE requested by KPCO:

TABLE WEA-1
COST OF EQUITY – WOOLRIDGE AND HILL PROXY GROUPS

	Estimate	Average
Expected Earnings Approach		
Woolridge Proxy Group	10.6%	
Hill Proxy Group	10.6%	
		10.6%
Allowed ROE		
Woolridge Proxy Group	10.4%	
Hill Proxy Group	10.5%	
		10.5%
Revised DCF Analyses		
Woolridge - Historical Growth	10.6%	
Woolridge Projected Growth	9.6%	
Hill - Historical Growth	11.0%	
Hill - Projected EPS Growth	10.6%	
		10.4%
CAPM - Current Bond Yields		
Woolridge Group - Unadjusted	10.4%	
Woolridge Group - Adjusted	11.2%	
Hill Group - Unadjusted	10.6%	
Hill Group - Adjusted	11.6%	
CAPM - Projected Bond Yields		
Woolridge Group - Unadjusted	10.8%	
Woolridge Group - Adjusted	11.5%	
Hill Group - Unadjusted	10.9%	
Hill Group - Adjusted	11.9%	
		11.1%
Average -- All Analyses		10.7%

With respect to their analyses I conclude that:

- *Utilities have significantly altered their dividend policies in recent years and reliance on historical and dividend growth rates to apply the discounted cash flow ("DCF") model imparts a downward bias to the results, as does reference to illogical growth rates;*
- *The calculations underlying the sustainable growth rates used by Dr. Woolridge and Mr. Hill are flawed and incomplete;*
- *The expected earnings approach is entirely consistent with the regulatory and economic principles advanced in the testimony of Dr. Woolridge and Mr. Hill, and represents an "apples to apples" comparison with the allowed ROE;*
- *The recommendations of Dr. Woolridge and Mr. Hill are inadequate to compensate investors in KPCO when evaluated against the results of the expected earnings approach for the proxy utilities;*
- *Contrary to the representations of Dr. Woolridge and Mr. Hill, allowed ROEs also demonstrate that the recommendations of these witnesses are too low to be credible;*
- *The historical applications of the Capital Asset Pricing Model ("CAPM") presented by Dr. Woolridge and Mr. Hill violate the assumptions of this approach and fail to reflect current capital market requirements;*
- *If KPCO* 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, and investors will be denied an opportunity to earn their opportunity cost of capital; and,*
- *The failure of these witnesses 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.*

II. FAILED TO CONSIDER END-RESULT TEST

Q. DR. WOOLRIDGE AND MR. HILL RECOGNIZED THAT THE ALLOWED ROE MUST MEET CERTAIN STANDARDS TO BE CONSIDERED REASONABLE.[3] DO YOU AGREE?

A. Yes. While the details underlying a determination of the cost of equity are all significant to a rate of return analyst, there is one fundamental requirement that any ROE recommendation must satisfy before it can be considered reasonable. Competition for capital is intense, and utilities such as KPCO must be granted the opportunity to earn an ROE comparable to contemporaneous returns available from alternative investments if they are to maintain their financial flexibility and ability to attract capital.

Mr. Hill suggests (p. 9) a simple approach to evaluating the cost of capital, and I agree with this concept. Rather than becoming bogged down in lengthy, pedantic arguments over the merits of one quantitative approach versus another, the Commission can make a determination on the key, threshold question, "Do the ROE recommendations of Dr. Woolridge and Mr. Hill meet the threshold test of reasonableness required by established regulatory and economic standards governing a fair rate of return on equity?" Based on the evidence discussed subsequently, the answer is clearly, "No."

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[3] For example, Dr. Woolridge (p. 19) noted that the ROE must "be commensurate with returns on investments in other enterprises having comparable risks." Mr. Hill (pp. 8-9) cites established legal and regulatory standards, including the opportunity cost principle underlying a fair ROE.

Q. DR. WOOLRIDGE (PP. 6-9) AND MR. HILL (PP. 10-18) DISCUSS THE IMPLICATIONS OF CAPITAL MARKET TRENDS. WHAT OTHER INFERENCES ARE IMPORTANT IN THIS ASSESSMENT ?

A. Considering investors' heightened awareness of the risks associated with the electric power industry, and the implications of ongoing volatility in the markets for long-term capital, supportive regulation remains crucial in preserving KPCO's access to capital. Capital markets recognize that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity, particularly during times of adverse conditions. Moreover, considering the ongoing turmoil faced by investors, sensitivity to market and regulatory uncertainties has increased dramatically.

Q. DOES MR. HILL SPECIFICALLY RECOGNIZE THAT A UTILITY'S ABILITY TO ATTRACT CAPITAL MUST BE CONSIDERED IN ESTABLISHING A FAIR RATE OF RETURN?

A. Yes. Mr. Hill clearly recognized this fundamental standard underlying the regulation of public utilities and a determination of a fair rate of return, and he acknowledged the Supreme Court's *Bluefield* and *Hope* decisions.[4] These decisions established that a regulated utility's authorized returns on capital must be sufficient to assure investors' confidence and that, if the utility is efficient and prudent on a prospective basis, it will have the opportunity to provide returns commensurate with those expected for other investments involving comparable risk.

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[4] Hill Direct Testimony at 8-9.

Q. **DID DR. WOOLRIDGE OR MR. HILL TEST THEIR ROE RECOMMENDATIONS AGAINST THESE FUNDAMENTAL REGULATORY REQUIREMENTS?**

A. No. Expected earned rates of return for other utilities provide one useful benchmark to gauge the reasonableness of the ROE recommendation of Dr. Woolridge and Mr. Hill, but neither witness performed this test. The 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. **DID MR. HILL RECOGNIZE THE ECONOMIC PREMISE UNDERLYING 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. Hill recognized (p. 9), economists refer to the returns that an investor must forgo by not being invested in the next best alternative as "opportunity costs". Mr. Hill went on to explain the logic underlying this approach:

> In a regulated rate-setting context such as this, the cost of equity capital can be most easily understood as the rate of profit that should be allowed for the regulated firm. A firm's profit is the amount of money that remains from its revenues after it has paid all of its costs – operating costs (commodity supply costs, depreciation, equipment maintenance costs, salaries, fees, taxes, retirement obligations), as well as income taxes and interest costs. That dollar amount of profit, divided by the book value of the common equity capital used to finance the firm's regulated assets equals the percentage rate of return on equity. If, for example, the profit earned by a utility is

> $10/year and the firm has $100 of equity capital on its books, the firm's return on equity (ROE), or its profit, is 10%.[5]

But despite the fact that Mr. Hill recognized this standard as the "most easily understood" explanation of "the percentage profit that should be allowed for the regulated firm," he ignored this test in evaluating his recommendation. Similarly, while Dr. Woolridge reported earned returns for the companies in his proxy group,[6] he failed to evaluate their significance.

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. Consistent with Mr. Hill's own example,[7] 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

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[5] Hill Direct Testimony at 9.
[6] Exhibit JRW-4.
[7] Hill Direct Testimony at 9.

the accounting records, it is also common to use projections of returns on book investment, such as those published by The Value Line Investment Survey ("Value Line"), which is a recognized investment advisory publication. 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. **HAVE THE EARNINGS ON BOOK VALUE REFERENCED BY DR. WOOLRIDGE AND MR. HILL BEEN RECOGNIZED AS A VALID ROE BENCHMARK?**

A. Yes. While this method predominated before the DCF model became fashionable with academic experts, I continue to encounter it around the country. Indeed, the Virginia State Corporation Commission ("VSCC") is required by statute (Virginia Code § 56-585.1.A.2.a) to consider the earned returns on book value of electric utilities in its region. In an order issued on July 15, 2010 the VSCC in Docket PUE-2009-00030, the VSCC established the allowed ROE for Appalachian Power Company based solely on the earned returns on book value for a peer group of other electric utilities. Another example is Ms. Terri Carlock, the long-time financial analyst for the Idaho Public Utilities Commission. She has consistently presented evidence on book earnings for decades, and Idaho regulators continue to confirm the relevance of return on book equity evidence. [8]

A textbook prepared for the Society of Utility and Regulatory Analysts labels the comparable earnings approach the "granddaddy of cost of equity

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[8] 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.

methods" and points out that the amount of subjective judgment required to implement this method is "minimal", particularly when compared to the DCF and CAPM methods.[9] Echoing Mr. Hill, the *Practitioner's Guide* notes that the comparable earnings test method is "easily understood" and firmly anchored in the regulatory tradition of the *Bluefield* and *Hope* cases,[10] as well as sound regulatory economics. I have used the comparable earnings approach in my consulting, teaching, and testimony for 35 years, and it has been widely referenced in regulatory decision-making.[11]

Q. DR. WOOLRIDGE (P. 19) AND MR. HILL (P. 9) REFERENCE MARKET DATA. DOES A METHODOLOGY HAVE TO DEPEND ON MARKET DATA TO BE USEFUL IN EVALUATING INVESTORS' OPPORTUNITY COSTS?

A. No. While I agree that market-based models are certainly 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 principle that when evaluating two investments of comparable risk, investors will choose the alternative with the higher expected return. If KPCO is only allowed the opportunity to earn 9.0 percent or 9.2 percent return on the book value of its equity investment, as recommended by Dr. Woolridge and Mr. Hill, while other electric utilities are expected to earn an average

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

[10] *Id.* at 7-3.

[11] For example, a NARUC survey reported that 19 regulatory jurisdictions cited the comparable earnings test as a primary method favored in determining the allowed rate of return. "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.

of 10.5 percent,[12], 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 direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, 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 BY THE EXPECTED EARNINGS FOR THE PROXY GROUPS OF DR. WOOLRIDGE AND MR. HILL?

A. As shown on page 1 of Exhibit WEA-2, reference to expected earnings implied an average cost of equity for the utilities in Dr. Woolridge's proxy group of 10.6 percent. Similarly, page 2 of Exhibit WEA-2 shows that the average expected book return on equity for Mr. Hill's proxy group is also 10.6 percent. These book return estimates are an "apples to apples" comparison to the 9.0 percent and 9.2 percent recommended ROEs of Dr. Woolridge and Mr. Hill, respectively.

Q. WHAT WOULD BE THE EFFECT OF AUTHORIZING A BOOK RETURN THAT IS SO FAR BELOW THE AVERAGE EARNINGS OF THE

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[12] Value Line reports an average expected return on book equity for 2015-17 of 10.5 percent for the electric utility industry. The Value Line Investment Survey at 136 (Feb. 24, 2012).

UTILITIES THAT DR. WOOLRIDGE AND MR. HILL CLAIM ARE COMPARABLE?

A Plain and simple, KPCO will find it difficult to compete for investors' capital and investors would not be earning up to the *Bluefield* standard of comparable earnings:

> A public utility is entitled to such rates as will permit it to earn on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties.[13]

Q. **EXHIBIT JRW-4 TO DR. WOOLRIDGE'S TESTIMONY REPORTS ALLOWED ROES. CAN THIS INFORMATION BE USED TO EVALUATE WHETHER THE RECOMMENDATIONS OF DR. WOOLRIDGE AND MR. HILL ARE SUFFICIENT TO MEET REGULATORY STANDARDS?**

A. Yes. Reference to allowed rates of return for other utilities, such as those cited by Dr. Woolridge, provides one useful guideline that can be used to assess the extent to which the 9.25 percent and 9.0 percent ROE recommendations of Dr. Woolridge and Mr. Hill are comparable and sufficient. As shown on page 1 of Exhibit WEA-3, data from the March 2012 *AUS Monthly Utility Report* (a source relied on by Dr. Woolridge and Mr. Hill) indicates that the average authorized ROE for the firms in Dr. Woolridge's proxy group is 10.42 percent, or 142 basis points higher than his recommendation for KPCO.

With respect to the group of electric utilities that Mr. Hill concluded were most comparable to KPCO's jurisdictional utility operations, as shown on page 2 of Exhibit WEA-3, these firms are presently authorized an average rate of return on

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[13] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n,* 262 U.S. 679 (1923).

equity of 10.55 percent, or 135 basis points more than Mr. Hill's ROE recommendation. It is unreasonable to suppose that investors would be attracted by Dr. Woolridge's or Mr. Hill's recommendations for KPCO, which fall significantly below the allowed returns for other utilities they consider to be comparable.

Q. WHAT DO THESE BENCHMARKS IMPLY WITH RESPECT TO THE ROE RECOMMENDATIONS OF DR. WOOLRIDGE AND MR. HILL?

A. These benchmarks clearly demonstrate that their recommendations are far too low and violate the economic and regulatory standards underlying a fair ROE.

Q. DOES THE FORECASTED PENSION RETURN REFERENCED BY MR. HILL (P. 6-8) SUPPORT HIS ROE RECOMMENDATION?

A. No. The projected equity return reported for the pension fund of KPCO's parent, American Electric Power Company, is not comparable to the 10.5 percent requested ROE for three primary reasons. First, the long-run projected return for equity investments assumed for pension portfolios is generally a geometric mean return indicative of compound returns earned over a long horizon. This is not equivalent to the specific benchmark for investors' forward-looking required rate of return represented by the requested ROE, which is in the nature of an arithmetic mean.[14] As discussed subsequently in my rebuttal testimony, when returns are variable, the geometric mean is always less than the arithmetic mean.

Second, the pension projection applies to equity investments made in the retirement portfolio, which are selected by the pension managers from the many available choices in the equity markets. Pension investments must conform to the requirements of prudence, which includes the "three elements of care, skill, and

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[14] The geometric mean of a series of returns measures the constant rate of return that would yield the same change in the value of an investment over time. The arithmetic mean measures what the expected return would have to be each period to achieve the realized change in value over time.

caution."[15] The requirement for prudence extends to the projections of pension portfolio returns. The projection of pension returns falls under the scrutiny of the U.S. Department of Labor and the U. S. Securities and Exchange Commission, as well as the prudence requirements of the Employee Retirement Income Security Act of 1974 ("ERISA"). In light of this guidance and oversight, the portfolio return projection represents a compound return that the fiduciaries are confident that they can meet or exceed over long periods of time.

Meanwhile, the requested ROE is specific to the risks and circumstances of KPCO's utility operations and a set of comparable risk companies. In order to meet the comparable earnings, financial integrity, and capital attraction standards of *Hope* and *Bluefield* the allowed ROE must be measured by reference to investors' expectations and requirements for comparable risk companies. In contrast, the objective of pension projections is to formulate future expectations for the equity investments in the pension portfolio based on an informed interpretation of historical experience and in light of accepted standards of prudence, and there can be key differences in the data sets and approaches used to derive pension plan projections. As the California Public Utilities Commission concluded, "Pension return assumptions are not comparable to the ROE used in utility ratemaking."[16]

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[15] John Train and Thomas A. Melfe, *Investing and Managing Trusts under the New Prudent Investor Rule* (Harvard Business School Press, Boston, MA, 1999), p. 19. I have taught ethical and professional standards for holders of the Chartered Financial Analyst Designation (CFA) for more than 20 years. This reading has been part of the CFA Curriculum to illustrate prudence and the fiduciary obligations of pension fund managers for a number of years.

[16] *California Public Utilities Commission*, Decision 07-12-049 (Dec. 20, 2007) at 44.

III. DCF RESULTS ARE UNDERSTATED

Q. WHAT ARE THE FUNDAMENTAL PROBLEMS WITH THE DCF ANALYSES CONDUCTED BY DR. WOOLRIDGE (PP. 24-36)?

A. There are three key problems with the DCF analysis presented by Dr. Woolridge that lead to a biased end-result: 1) instead of focusing directly on forward-looking data, Dr. Woolridge incorporates historical results as being indicative of what investors expect; 2) Dr. Woolridge discounts reliance on analysts' growth forecasts for earnings per share ("EPS") as somehow biased, and fails to recognize that it is investors' *perceptions and expectations* that must be considered in applying the DCF model; and, 3) Dr. Woolridge incorrectly included data that results in illogical cost of equity estimates, and wrongly assumed that any resulting bias would be eliminated through averaging or by reference to the median.

Q. DO THE GROWTH RATES REFERENCED BY DR. WOOLRIDGE (P. 27) MIRROR INVESTORS' LONG-TERM EXPECTATIONS IN THE CAPITAL MARKETS?

A. No. There is every indication that his growth rates, and resulting DCF cost of equity estimates, are biased downward and fail to reflect investors' required rate of return. If past trends in earnings, dividends, and book value are to be representative of investors' expectations for the future, then the historical conditions giving rise to these growth rates should be expected to continue. That is clearly not the case for utilities, where structural and industry changes have led to declining growth in dividends, earnings pressure, and, in many cases, significant write-offs. While these conditions serve to depress historical growth measures, they are not representative of long-term expectations for the utility industry or the expectations that investors have incorporated into current market prices.

Q. DR. WOOLRIDGE ARGUES (P. 31) THAT, "THE APPROPRIATE GROWTH RATE IN THE DCF MODEL IS THE DIVIDEND GROWTH RATE." DO YOU AGREE THAT THIS IS WHAT INVESTORS ARE MOST LIKELY TO CONSIDER IN DEVELOPING THEIR LONG-TERM GROWTH EXPECTATIONS?

A. No. While the DCF model is technically concerned with growth in dividend cash flows, implementation of this DCF model is solely concerned with replicating the forward-looking evaluation of real-world investors. In the case of utilities, growth rates in dividends per share ("DPS") are not likely to provide a meaningful guide to investors' current growth expectations. This is because utilities have significantly altered their dividend policies in response to more accentuated business risks in the industry.[17] As a result of this trend towards a more conservative payout ratio, dividend growth in the utility industry has remained largely stagnant as utilities conserve financial resources to provide a hedge against heightened uncertainties. While past conditions for utilities serve to depress DPS growth measures, they are not representative of long-term expectations for the utility industry.

As payout ratios for firms in the utility industry trended downward, investors' focus has increasingly shifted from DPS to earnings as a measure of long-term growth. Future trends in EPS, which provide the source for future dividends and ultimately support share prices, play a pivotal role in determining investors' long-term growth expectations. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community. As

[17] For example, the payout ratio for electric utilities fell from approximately 80 percent historically to on the order of 60 percent. The Value Line Investment Survey (Sep. 15, 1995 at 161, Feb. 24, 2012 at 136).

noted in *Finding Reality in Reported Earnings* published by the Association for Investment Management and Research:

> [E]arnings, presumably, are the basis for the investment benefits that we all seek. "Healthy earnings equal healthy investment benefits" seems a logical equation, but earnings are also a scorecard by which we compare companies, a filter through which we assess management, and a crystal ball in which we try to foretell future performance.[18]

Value Line's near-term projections and its Timeliness Rank, which is the principal investment rating assigned to each individual stock, are also based primarily on various quantitative analyses of earnings. As Value Line explained:

> The future earnings rank accounts for 65% in the determination of relative price change in the future; the other two variables (current earnings rank and current price rank) explain 35%.[19]

The fact that investment advisory services focus primarily on growth in EPS indicates that the investment community regards this as a superior indicator of future long-term growth. Indeed, "A Study of Financial Analysts: Practice and Theory," published in the *Financial Analysts Journal*, reported the results of a survey conducted to determine what analytical techniques investment analysts actually use.[20] Respondents were asked to rank the relative importance of earnings, dividends, cash flow, and book value in analyzing securities. Of the 297 analysts that responded, only 3 ranked dividends first while 276 ranked it last. The article concluded:

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[18] Association for Investment Management and Research, "Finding Reality in Reported Earnings: An Overview" at 1 (Dec. 4, 1996).

[19] The Value Line Investment Survey, *Subscriber's Guide* at 53.

[20] Block, Stanley B., "A Study of Financial Analysts: Practice and Theory", *Financial Analysts Journal* (July/August 1999).

> Earnings and cash flow are considered far more important than book value and dividends.[21]

More recently, the *Financial Analysts Journal* reported the results of a study of the relationship between valuations based on alternative multiples and actual market prices, which concluded, "In all cases studied, earnings dominated operating cash flows and dividends."[22]

Q. **DO THE EPS GROWTH RATE PROJECTIONS OF SECURITY ANALYSTS CONSIDER HISTORICAL TRENDS?**

A. Yes. Professional security analysts study historical trends extensively in developing their projections of future earnings. Hence, to the extent there is any useful information in historical patterns, that information is incorporated into analysts' growth forecasts.

Q. **DID DR. WOOLRIDGE RECOGNIZE THE PITFALLS ASSOCIATED WITH HISTORICAL GROWTH RATES?**

A. Yes. Dr. Woolridge noted that:

> [T]o best estimate the cost of common equity capital using the conventional DCF model, one must look to long-term growth rate expectations.[23]

But as he acknowledged, historical growth rates can differ significantly from the forward-looking growth rate required by the DCF model:

> [O]ne must use historical growth numbers as measures of investors' expectations with caution. In some cases, past growth may not reflect future growth potential. Also, employing a single growth rate number (for example, for five or ten years), is unlikely to accurately

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[21] *Id.* at 88.

[22] Liu, Jing, Nissim, Doron, & Thomas, Jacob, "Is Cash Flow King in Valuations?," *Financial Analysts Journal*, Vol. 63, No. 2 at 56 (March/April 2007).

[23] Woolridge Direct Testimony at 28.

> measure investors' expectations due to the sensitivity of a single growth rate to fluctuations in individual firm performance as well as overall economic fluctuations (i.e., business cycles).[24]

Moreover, to the extent historical trends for utilities are meaningful, they are already captured in projected growth rates, including those published by Value Line, First Call, Zacks, and Reuters, since securities analysts also routinely examine and assess the impact and continued relevance (if any) of historical trends.

Q. IS THE DOWNWARD BIAS IN DR. WOOLRIDGE'S HISTORICAL GROWTH MEASURES SELF EVIDENT?

A. Yes, it is. As shown on page 3 of Exhibit JRW-10, almost one-quarter of the individual historical growth rates reported by Dr. Woolridge for the companies in his proxy group were essentially zero or *negative*, with over one-half of his historical DPS growth rates being 1.0 percent or less. Combining a growth rate of 1.0 percent with Dr. Woolridge's dividend yield of 4.45 percent (Exhibit JRW-10, p. 1) implies a DCF cost of equity of approximately 5.45 percent. This implied cost of equity is not materially different than the yield from triple-B public utility bonds, which averaged 5.13 percent in March 2012.[25] Clearly, the risks associated with an investment in public utility common stocks exceed those of long-term bonds and Dr. Woolridge's DPS growth measures provide no meaningful information regarding the expectations and requirements of investors.

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[24] Woolridge Direct Testimony at 27.

[25] Moody's Investors Service, www.credittrends.com.

Q. DID DR. WOOLRIDGE MAKE ANY EFFORT TO TEST THE REASONABLENESS OF THE INDIVIDUAL GROWTH ESTIMATES HE RELIED ON TO APPLY THE CONSTANT GROWTH DCF MODEL?

A. No. Despite recognizing that caution is warranted in using historical growth rates, Dr. Woolridge simply calculated the average and median of the individual growth rates with no consideration for the reasonableness of the underlying data. In fact, as demonstrated above, many of the cost of equity estimates implied by Dr. Woolridge's DCF application make no economic sense.

Q. DOES REFERENCE TO THE MEDIAN (P. 35) CORRECT FOR ANY UNDERLYING BIAS IN DR. WOOLRIDGE'S HISTORICAL GROWTH RATES?

A. No. The median is simply the observation with an equal number of data values above and below. For odd-numbered samples, the median relies on only a <u>single number</u>, *e.g.*, the fifth number in a nine-number set. Reliance on the median value for a series of illogical values does not correct for the inability of individual cost of equity estimates to pass fundamental tests of economic logic.

Q. HAS DR. WOOLRIDGE RECOGNIZED THE IMPORTANCE OF EVALUATING MODEL INPUTS IN OTHER FORUMS?

A. Yes. As Dr. Woolridge noted in his testimony (Appendix A, p. 1), he is a founder and managing director of *ValuePro*, which is an online valuation service largely based on application of the DCF model. *ValuePro* confirmed the importance of evaluating the reasonableness of inputs to the DCF model:

> Garbage in, Garbage out! Like any other computer program, if the inputs into our Online Valuation Service are garbage, the resulting valuation also will be garbage.[26]

Unlike his approach here, Dr. Woolridge advised investors to use common sense in interpreting the results of valuation models, such as the DCF:

> If a figure comes up for a certain input that is either highly implausible or looks wrong, indeed it may be. If a valuation is way out of line, figure out where the Service may have strayed on a valuation, and correct it.[27]

Given the fact that many of the growth rates relied on by Dr. Woolridge result in illogical cost of equity estimates, it is appropriate to take the same critical viewpoint when evaluating inputs to his DCF model.

Q. WHAT APPROACH SHOULD DR. WOOLRIDGE AND MR. HILL HAVE USED TO EVALUATE LOW-END DCF ESTIMATES?

A. It is a basic economic principle that investors can be induced to hold more risky assets only if they expect to earn a return to compensate them for their risk bearing. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by senior, long-term debt.

S&P reports a corporate credit rating for KPCO of "BBB". As noted earlier, Moody's monthly yields on triple-B bonds averaged approximately 5.1 percent during March 2012. It is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock. Consistent with this principle, DCF results for the Dr. Woolridge's proxy companies must be adjusted to

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[26] http://www.valuepro.net/abtonline/abtonline.shtml.
[27] *Id.*

eliminate estimates that are determined to be extreme low outliers when compared against the yields available to investors from less risky utility bonds.

Q. **HAVE SIMILAR TESTS BEEN APPLIED BY REGULATORS?**

A. Yes. FERC has noted that adjustments are justified where applications of the DCF approach produce illogical results. FERC evaluates DCF results against observable yields on long-term public utility debt and has recognized that it is appropriate to eliminate estimates that do not sufficiently exceed this threshold. In a 2002 opinion establishing its current precedent for determining ROEs for electric utilities, for example, FERC noted:

> An adjustment to this data is appropriate in the case of PG&E's low-end return of 8.42 percent, which is comparable to the average Moody's "A" grade public utility bond yield of 8.06 percent, for October 1999. Because investors cannot be expected to purchase stock if debt, which has less risk than stock, yields essentially the same return, this low-end return cannot be considered reliable in this case.[28]

Similarly, in its August 2006 decision in *Kern River Gas Transmission Company*, FERC noted that:

> [T]he 7.31 and 7.32 percent costs of equity for El Paso and Williams found by the ALJ are only 110 and 122 basis points above that average yield for public utility debt.[29]

The Commission upheld the opinion of Staff and the Administrative Law Judge that cost of equity estimates for these two proxy group companies "were too low to be credible."[30]

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[28] *Southern California Edison Company*, 92 FERC ¶ 61,070 at p. 22 (2000).
[29] *Kern River Gas Transmission Company*, Opinion No. 486, 117 FERC ¶ 61,077 at P 140 & n. 227 (2006).
[30] *Id.*

The practice of eliminating low-end outliers has been affirmed in numerous FERC proceedings,[31] and in its April 15, 2010 decision in *SoCal Edison*, FERC affirmed that, "it is reasonable to exclude any company whose low-end ROE fails to exceed the average bond yield by about 100 basis points or more."[32]

Q. WHAT ELSE SHOULD BE CONSIDERED IN EVALUATING DR. WOOLRIDGE'S LOW-END DCF ESTIMATES?

A. While corporate bond yields have declined substantially as the worst of the financial crisis has abated, it is generally expected that long-term interest rates will rise as the recession ends and the economy returns to a more normal pattern of growth. As shown in Table WEA-2 below, forecasts of IHS Global Insight and the EIA imply an average triple-B bond yield of 6.74 percent over the period 2012-2016:

TABLE WEA-2
IMPLIED BBB BOND YIELD

	2012-16
Projected AA Utility Yield	
IHS Global Insight (a)	5.65%
EIA (b)	5.80%
Average	5.72%
Current BBB - AA Yield Spread (c)	1.02%
Implied Triple-B Utility Yield	**6.74%**

(a) IHS Global Insight, *U.S. Economic Outlook* at 25 (Dec. 2011).
(b) Energy Information Administration, *Annual Energy Outlook 2012, Early Release* (Jan. 23, 2012).
(c) Based on monthly average bond yields for the six-month period Oct. 2011 - Mar. 2012.

[31] *See, e.g., Virginia Electric Power Co.*, 123 FERC ¶ 61,098 at P 64 (2008).
[32] *Southern California Edison Co.*, 131 FERC ¶ 61,020 at P 55 (2010) ("*SoCal Edison*").

The increase in debt yields anticipated by IHS Global Insight and EIA is also supported by the widely-referenced Blue Chip Financial Forecasts, which projects that yields on corporate bonds will climb more than 100 basis points through the period 2013-2017.[33]

Q. HAS DR. WOOLRIDGE ADOPTED THIS EXACT SAME TEST OF LOW-END DCF ESTIMATES IN RECENT TESTIMONY BEFORE FERC?

A. Yes. In testimony filed with FERC on September 30, 2011, Dr. Woolridge applied this test to the results of his DCF analysis.[34] As Dr. Woolridge concluded:

> These data suggest that the prospective yield on utility bonds with a rating similar to the proxy group (A-/BBB+) is in the 5.0% range. Given this figure, and FERC's bond yield plus 100 basis point threshold for the low-end outliers, the elimination [of] the low-end results for Entergy (5.6%) and Great Plains Energy (6.2%) is supported.[35]

Q. IF DR. WOOLRIDGE HAD ELIMINATED LOW-END VALUES, AS HE DID IN HIS RECENT FERC TESTIMONY, WHAT COST OF EQUITY WOULD HAVE RESULTED FROM HIS DCF ANALYSIS BASED ON HISTORICAL GROWTH RATES?

A. As indicated above, Dr. Woolridge's DPS growth measures provide no meaningful information regarding the expectations and requirements of investors and should be entirely ignored. As shown on Exhibit WEA-4, screening Dr. Woolridge's DCF cost of equity estimates based on historical EPS and BVPS growth rates to eliminate illogical, low-end values, as well as high-end outliers, resulted in an implied cost of equity range of 9.6 percent to 12.2 percent, with the midpoint of this range being

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[33] *Blue Chip Financial Forecasts*, Vol. 30, No. 12 (Dec. 1, 2011).
[34] *Testimony of J. Randall Woolridge*, FERC Docket No. EL-66 (2011).
[35] *Id.* at 35-36.

10.9 percent. Similarly, the average cost of equity implied by Dr. Woolridge's corrected historical DCF analysis was 10.6 percent.

Q. YOU ALSO ELIMINATED TWO HIGH-END OUTLIERS ON EXHIBIT WEA-4. IS THERE ANY BASIS TO EXCLUDE A SYMETRICAL NUMBER OF ESTIMATES ON THE LOW AND HIGH END?

A. No. As shown on Exhibit WEA-4, I eliminated two high-end values that exceeded 17 percent because these values were extreme outliers when compared with the balance of the remaining estimates. As discussed above, low-end outliers were evaluated against the observable returns available from long-term bonds. But the fact that there are numerous results that fail this test of reasonableness says nothing about the validity of estimates at the upper end of the range of results, and there is no basis to discard an equal number of values from the top of the range. While a cost of equity estimate of 16.2 percent may exceed expectations for most electric utilities, the remaining low-end estimate of 7.0 percent is assuredly far below investors' required rate of return. Taken together and considered along with the balance of the DCF estimates, these values provide a reasonable basis on which to evaluate investors' required rate of return.

Q. DID YOU ALSO APPLY THIS TEST OF LOGIC TO DR. WOOLRIDGE'S DCF RESULTS BASED ON PROJECTED EPS GROWTH RATES?

A. Yes. As shown on Exhibit WEA-5, combining the projected EPS growth rates referenced by Dr. Woolridge with the dividend yields for his proxy group companies resulted in a number of DCF cost of equity estimates that were below current and expected public utility bond yields. After eliminating these illogical values, the average DCF cost of equity estimates fell in a range of 9.3 percent to 10.2 percent, with a midpoint of 9.8 percent. The average cost of equity implied by Dr.

Woolridge's corrected DCF analysis based on EPS growth projections was 9.6 percent.

Q. **DR. WOOLRIDGE RELIED ON INTERNAL, "BR" GROWTH RATES (EXHIBIT JRW-10, P. 4). SHOULD THE COMMISSION PLACE ANY WEIGHT ON THESE VALUES?**

A. No. Dr. Woolridge's internal growth rates are downward biased because of computational errors and omissions. Dr. Woolridge based his calculations of the internal, "br" retention growth rate on data from Value Line, which reports end-of-period results. If the rate of return, or "r" component of the internal growth rate, is based on end-of-year book 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, which has been recognized by regulators,[36] is illustrated in Table WEA-3 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."[37] 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

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[36] *See, e.g., Southern California Edison Company,* Opinion No. 445 (Jul. 26, 2000), 92 FERC ¶ 61,070.
[37] *Id.*

illustrated below, it can have a significant impact on the calculated retention growth rate:

TABLE WEA-3
BR + SV GROWTH RATE – AVERAGE RATE OF RETURN

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%

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

Q. WHAT OTHER CONSIDERATION LEADS TO A DOWNWARD BIAS IN DR. WOOLRIDGE'S CALCULATION OF INTERNAL, "BR" GROWTH?

A. Dr. Woolridge 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.[38]

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 Dr. Woolridge failed to consider the incremental impact on growth results in another downward bias to his "internal" growth rates, which should be given no weight.

Q. HAS DR. WOOLRIDGE RECOGNIZED THESE ADJUSTMENTS TO THE SUSTAINABLE GROWTH RATE IN TESTIMONY BEFORE OTHER REGULATORS?

A. Yes. In his recent testimony before FERC referenced earlier, Dr. Woolridge incorporated an adjustment to correct for the downward bias attributable to end-of-year book values, and recognized the additional growth from new share issues by incorporating the "sv" component discussed above.[39] Similarly, Mr. Hill noted that, "Investor expectations regarding growth from external sources (sales of stock) must also be considered and examined."[40]

Q. WHAT DO YOU CONCLUDE BASED ON YOUR REVIEW OF DR. WOOLRIDGE'S DCF ANALYSES?

A. Trends in DPS are distorted by fundamental changes in industry financial policies and Dr. Woolridge failed to evaluate the underlying reasonableness of individual

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[38] Gordon, Myron J., "The Cost of Capital to a Public Utility," MSU Public Utilities Studies (1974), at 31–32.
[39] *Testimony of J. Randall Woolridge*, FERC Docket No. EL-66 at Exhibit JRW-8, pp. 3-4 (2011).
[40] Hill Direct Testimony at 26. Mr. Hill incorporated an adjustment for the "sv" factor at Schedule 5, p. 1.

growth rates. In addition, the calculations used to arrive at Dr. Woolridge's internal growth rates are flawed and incomplete. As a result, his DCF cost of equity estimates are biased downward and fail to reflect investors' required rate of return.

Q. DID MR. HILL PROPERLY APPLY THE CONSTANT GROWTH DCF MODEL?

A. No. Mr. Hill began his DCF analysis by correctly stating:

> The DCF model relies on the equivalence of the market price of the stock (P) with the present value of the cash flows investors expect from the stock, and assumes that the discount rate equals the cost of capital.[41]

Nevertheless, his applications of the constant growth DCF model to his proxy group of utilities departed from this fundamental proposition because of his strict reliance on the mathematical DCF theory instead of the realities of investors' actual expectations in financial markets. The use of DCF models to estimate the cost of equity is essentially an attempt to replicate the market pricing mechanism that led to the observed stock price, with investors' required rate of return simply being inferred. In contrast, Mr. Hill's applications of the DCF model reflect a strict interpretation of the academic theory underlying its derivation.

Q. WHAT IS WRONG WITH MR. HILL'S STRICT ADHERENCE TO THE THEORY UNDERLYING THE CONSTANT GROWTH DCF MODEL?

A. Many unrealistic assumptions are required to derive the constant growth form of the DCF model, with Mr. Hill noting some of these infirmities in his testimony:

> The model also assumes that the company whose equity cost is to be measured exists in a steady state environment, *i.e.*, the payout ratio

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[41] Hill Direct Testimony at 22 (emphasis added).

> and the expected return are constant and the earnings, dividends, book value and stock price all grow at the same rate, forever.[42]

Because the assumptions underlying the constant growth DCF model are never met in practice, the constant growth DCF model can, at best, only be considered an abstraction of reality. As such, the DCF model produces estimates that provide one guide to investors' required rate of return, but these results cannot be considered "correct" measures of the cost of equity.. Mr. Hill granted this limitation of the DCF model in his testimony:

> [A]s with all mathematical models of real-world phenomena, the DCF theory does not precisely "track" reality in the shorter term.[43]

Therefore, the only inputs (i.e., cash flows) that matter in implementing the DCF model are those that investors used to value the utility's stock. Any application of the DCF model that does not focus exclusively on investors' actual expectations is a misuse of the DCF model to estimate the cost of equity.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW MR. HILL DISREGARDS THIS PRINCIPLE?

A. Yes. Consider Mr. Hill's discussion of his hypothetical firm in Appendix B to his testimony. He stated that certain actual growth rates can be "unreliable" within DCF theory, and concluded that the proper growth rate to use with the DCF model is the theoretical "sustainable growth rate". But Mr. Hill's contention is wrong. The only correct growth rate to be used in the DCF model is the long-term growth rate investors actually incorporated into the observed stock price, irrespective of whether

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[42] Hill Direct Testimony at 23.
[43] Hill Direct Testimony at 23-24.

Mr. Hill considers it "ridiculous" or inconsistent with "the underlying fundamentals of growth in the DCF model."[44]

The fact is Mr. Hill confused the theory of the DCF model with its application. Professor Myron J. Gordon's complete mathematical DCF model is tautological. In other words, the constant growth DCF model is true by virtue of the strict assumptions made to derive it, and given these assumptions, any number of propositions can be "demonstrated" (Mr. Hill's Appendix B). But to the extent that these assumptions are not met in practice and the DCF model does not "track reality", the theoretical DCF model will not conform to the real world. In turn, cost of equity estimates that are based solely on mathematical identities instead of investors' actual long-term growth expectations will not accurately measure their required rate of return.[45]

Q. ARE MR. HILL'S SUSTAINABLE, BR+SV GROWTH RATES ALSO UNDERSTATED?

A. Yes. Like Dr. Woolridge, Mr. Hill based his calculation of the internal, "br" growth rate on data from Value Line, which reports end-of-period results. As discussed earlier, failing to account for this reality results in downward-biased growth rates and the resulting DCF cost of equity is understated.

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[44] Hill Direct Testimony at Appendix B, p. 4.

[45] In a 2005 case, the New Hampshire Public Service Commission specifically concluded that Mr. Hill's DCF growth analysis, "does not in our view reflect true market conditions." Order No. 24,473, New Hampshire Public Utilities Commission (June 8, 2005).

Q. DOES A MORE REASONABLE DCF APPLICATION BASED ON MR. HILL'S DATA SHOW WHY MR. HILL'S DCF RESULTS ARE UNREASONABLE?

A. Yes. As shown on Exhibit WEA-6, screening Mr. Hill's DCF cost of equity estimates based on historical EPS and BVPS growth rates to eliminate illogical, low-end values, as well as high-end outliers, resulted in an implied cost of equity range of 9.5 percent to 12.5 percent, with the midpoint of this range being 11.0 percent. Similarly, the average cost of equity implied by Mr. Hill's corrected historical DCF analysis was 11.0 percent.

As noted earlier, the projected EPS growth rates of securities analysts are likely to provide a superior guide to investors' expectations than the flawed, theoretical approach adopted by Mr. Hill. Accordingly, I revised his DCF method to incorporate the projected EPS growth rates from IBES and Value Line reported on Schedule 5 to his testimony. As shown on Exhibit WEA-7, this resulted in an average cost of equity of approximately 10.6 percent.

Q IS THERE ANY SUBSTANCE TO MR. HILL'S MODIFIED EARNINGS-PRICE RATIO ANALYSIS (PP. 40-44)?

A. None whatsoever. Mr. Hill's statement that the earnings-price ratio understates the cost of equity when the utility's market-to-book ratio is greater than one, and vice versa,[46] is generally correct. But there is absolutely no theoretical justification for Mr. Hill's averaging the earnings-price ratio with a rate of return on book equity, either current or expected, as he did in his Schedule 10. Nor is such an averaging justified even if the FERC may have sometime in the past utilized the expected rate

[46] Hill Direct Testimony at 40.

of return on book value as a check of reasonableness in establishing an upper bound to investors' required rate of return.[47]

Q. **DOES MR. HILL'S MARKET-TO-BOOK RATIO ("MTB") ANALYSIS (PP. 44-46) PROVIDE ANY NEW INFORMATION AS TO THE RATE OF RETURN REQUIRED BY INVESTORS FROM HIS PROXY GROUP OF UTILITIES?**

A. Absolutely none. As Mr. Hill acknowledged:

> This method is derived algebraically from the DCF model and, therefore, cannot be considered a strictly independent check of that method.[48]

That Mr. Hill's MTB analysis is nothing more than a rehash of his previous DCF analysis is also evident from his exhibits. In particular, there is little difference between Mr. Hill's average cost of equity of 9.55 percent using his DCF method[49] and the 9.35 percent using his MTB method based on Value Line's projections.[50] This similarity is not because the results of two different methods are converging, but because the DCF and MTB methods are essentially the same, only packaged slightly differently. And just as Mr. Hill's DCF analysis is fundamentally flawed because it is tied to tautological DCF theory rather than investors' actual expectations, so too is his MTB analysis since it is derived from the very same theoretical model and uses virtually identical inputs.

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[47] Mr. Hill cited a 1986 FERC decision at p. 41 of his direct testimony.
[48] Hill Direct Testimony at 44.
[49] *Id.* at Schedule 7.
[50] *Id.* at Schedule 11, p. 2.

Q. WHAT IS THE RELEVANCE OF MR. HILL'S AND DR. WOOLRIDGE'S DISCUSSION OF MARKET-TO-BOOK RATIOS?[51]

A. Based on their testimony here and in previous cases, I understand that Mr. Hill and Dr. Woolridge are implying that because current market prices of utility common stocks are greater than their book values, this indicates that investors expect utilities will earn more than their cost of capital. Dr. Woolridge and Mr. Hill are suggesting that regulators, including the KPSC, should lower the authorized ROE, so that the stock price will fall to book value. The KPSC does not regulate utility stock market prices, and as discussed below, there are many leaps between their theoretical reasoning and reality. But if the theory is correct, then Mr. Hill and Dr. Woolridge are asking the KPSC to order a return that would almost certainly lead to a capital loss on the value of KPCO's investment. From an economic perspective, such an action would severely undermine the Company's financial strength and access to capital, and effectively take the value of KPCO's property without compensation.

Q. DR. WOOLRIDGE AND MR. HILL SUGGEST THAT THERE IS A CLEAR LINK BETWEEN MARKET-TO-BOOK RATIOS FOR ELECTRIC UTILITIES AND ALLOWED RATES OF RETURN. IS THIS ACCURATE?

A. No. Underlying Mr. Hill's and Dr. Woolridge's position is the supposition that regulators should set a required rate of return to produce a market-to-book value of approximately 1.0. This is wrong. For example, *New Regulatory Finance* noted that:

> The stock price is set by the market, not by regulators. The M/B ratio is the end result of regulation, and not its starting point. The view that regulation should set an allowed rate of return so as to produce a M/B of 1.0, presumes that investors are irrational. They

[51] Hill Direct Testimony at 40-41; Woolridge Direct Testimony at 14-16.

> commit capital to a utility with a M/B in excess of 1.0, knowing full well that they will be inflicted a capital loss by regulators. This is certainly not a realistic or accurate view of regulation.[52]

With market-to-book ratios for most utilities above 1.0, Mr. Hill and Dr. Woolridge are suggesting that, unless book value grows rapidly, regulators should establish equity returns that will cause share prices to fall. Given the regulatory imperative of preserving a utility's ability to attract capital, this would be a truly nonsensical result.

Q. IS THERE ANY MERIT TO THE CONCERNS OF DR. WOOLRIDGE AND MR. HILL ABOUT A MARKET-TO-BOOK RATIO ABOVE 1.00?

A. No. In fact the majority of stocks currently sell substantially above book value. For example, Value Line reports that over 1,400 of the approximately 1,700 stocks it follows (including utilities and other industries) sell for prices in excess of book value.[53] Moreover, regulators have previously recognized the fallacy of relying on market-to-book ratios in evaluating cost of equity estimates. For example, the Presiding Judge in *Orange & Rockland* concluded, and the FERC affirmed that:

> The presumption that a market-to-book ratio greater than 1.0 will destroy the efficacy of the DCF formula disregards the realities of the market place principally because the market-to-book ratio is rarely equal to 1.0.[54]

The Presiding Judge found that there was no support in FERC precedent for the use of market-to-book ratios to adjust market derived cost of equity estimates based on the DCF model and concluded that such arguments were to be treated as "academic rhetoric" unworthy of consideration.

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[52] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 376 (2006).
[53] www.valueline.com (retrieved Apr. 1, 2012).
[54] *Orange & Rockland Utilities, Inc.*, Initial Decision, 40 FERC ¶ 63,053, 1987 WL 118,352 (F.E.R.C.).

IV. CRITICISMS OF ANALYSTS' GROWTH RATES ARE MISGUIDED

Q. SHOULD THE COMMISSION GIVE ANY CREDENCE TO THE ALLEGATIONS OF DR. WOOLRIDGE AND MR. HILL THAT PROJECTED EPS GROWTH RATES ARE BIASED?

A. No. Dr. Woolridge devoted over ten pages of his testimony to argue the misguided notion that analysts' EPS growth rates are "overly optimistic and upwardly biased."[55] Similarly, Mr. Hill rejects relying solely on earnings forecasts.[56]

Q. PLEASE RESPOND TO THE CRITICISMS OF DR. WOOLRIDGE AND MR. HILL REGARDING RELIANCE ON EPS GROWTH PROJECTIONS IN APPLYING THE DCF MODEL.

A. In applying the DCF model to estimate the cost of equity, the <u>only</u> relevant growth rate is the forward-looking expectations of investors that are captured in current stock prices. Any claim that analysts' estimates are not relied upon by investors is illogical given the reality of a competitive market for investment advice. If financial analysts' forecasts do not add value to investors' decision making, it would be irrational for investors to pay for these estimates. Similarly, those financial analysts who fail to provide credible forecasts will lose out in competitive markets relative to those analysts whose forecasts are favored by investors. The reality that analyst estimates are routinely referenced in the financial media and in investment advisory publications implies that investors use them as a basis for their expectations.

The continued success of investment services such as IBES and Value Line, and the fact that projected growth rates from such sources are widely referenced, provides strong evidence that investors give considerable weight to analysts'

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[55] Woolridge Direct Testimony at B-2.
[56] Hill Direct Testimony at 28.

earnings projections in forming their expectations for future growth. Earnings growth projections of security analysts provide the most frequently referenced guide to investors' views and are widely accepted in applying the DCF model. As explained in *New Regulatory Finance*:

> Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of *g* [growth].[57]

Q. **DOES THE FACT THAT ANALYSTS' EPS PROJECTIONS MAY DEVIATE FROM ACTUAL RESULTS HAMPER THEIR USE IN APPLYING THE DCF MODEL, AS DR. WOOLRIDGE CONTENDS?**[58]

A. No. Investors, just like securities analysts and others in the investment community, do not know how the future will actually turn out. They can only make investment decisions based on their best estimate of what the future holds in the way of long-term growth for a particular stock, and securities prices are constantly adjusting to reflect their assessment of available information. While the projections of securities analysts may be proven optimistic or pessimistic in hindsight, this is irrelevant in assessing the expected growth that investors have incorporated into current stock prices, and any bias in analysts' forecasts – whether pessimistic or optimistic – is irrelevant if investors share analysts' views. As *New Regulatory Finance* concluded, "The accuracy of these forecasts in the sense of whether they turn out to be correct is not an issue here, as long as they reflect widely held expectations."[59] Moreover,

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[57] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 298 (2006).
[58] Woolridge Direct Testimony at Appendix B.
[59] *Id.*

as discussed earlier, there is every indication that expectations for earnings growth are instrumental in investors' evaluation and the fact that analysts' projections deviate from actual results provides no basis to ignore this relationship.

Comparisons between forecasts of future growth expectations and the historical trend in actual earnings are largely irrelevant in evaluating the use of analysts' projections in the DCF model. For example, Dr. Woolridge references a paper he authored that reported that analysts' earnings growth rate estimates are overly optimistic, based on just such a historical comparison.[60] But as noted above, the investment community can only make decisions based on their best estimate of what the future holds in the way of long-term growth for a particular stock, and the fact that projections deviate from actual results says nothing about whether investors rely on analysts' estimates. In using the DCF model to estimate investors' required returns, the purpose is not to prejudge the accuracy or rationality of investors' growth expectations. Instead, to accurately estimate the cost of equity we must base our analyses on the growth expectations investors actually used in determining the price they are willing to pay for common stocks – even if we do not agree with their assumptions. Indeed, despite the findings of his research, Dr. Woolridge reportedly "remains somewhat puzzled that so many continue to put great weight in what [analysts] have to say."[61] As Robert Harris and Felicia Marston noted in their article in *Journal of Applied Finance*:

> ...Analysts' optimism, if any, is not necessarily a problem for the analysis in this paper. If investors share analysts' views, our

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[60] *Id.* at B-8, fn. 11.

[61] Boselovic, Len, "Study Finds Analysts' Forecasts Have Been Too Sunny," *Pittsburgh Post-Gazette* (Mar. 30, 2008).

> procedures will still yield unbiased estimates of required returns and risk premia.[62]

Similarly, there is no logical foundation for criticisms such as those raised by Dr. Woolridge that the purported upward bias of analysts' growth rates limits their usefulness in applying the DCF model. If investors' base their expectations on these growth rates, then they are useful in inferring investors' required returns – even if the analysts' forecasts prove to be wrong in hindsight.[63]

Q. DO THE SELECTED ARTICLES REFERENCED BY DR. WOOLRIDGE IN SUPPORT OF HIS CONTENTION THAT ANALYSTS ARE OVERLY OPTIMISTIC PAINT A COMPLETE PICTURE OF THE FINANCIAL RESEARCH IN THIS AREA?

A. No. In contrast to Dr. Woolridge's assertions, peer-reviewed empirical studies do not uniformly support his contention that analysts' earnings projections are optimistically biased. For example, a study reported in "Analyst Forecasting Errors: Additional Evidence" found no optimistic bias in earnings projections for large firms (market capitalization of $500-$3,000 million), with data for the largest firms (market capitalization > $3,000 million) demonstrating a *pessimistic* bias.[64] Similarly, a 2005 article that examined analyst growth forecasts over the period 1990 through 2001 illustrated that Wall Street's forecasting is not inherently

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[62] Harris, Robert S. and Marston, Felicia C., "The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts," *Journal of Applied Finance* 11 (2001) at 8.

[63] I began my military career in the Navy in the weather office at a Naval Air Station. Using the best methods then available, we provided pilots with weather forecasts for their flight plans. In hindsight we were not very accurate, but I do not recall any pilot ignoring our forecast in planning a mission. In finance, as in weather, no one knows the future. But no one can afford to ignore the best available forecasts.

[64] Brown, Lawrence D., "Analyst Forecasting Errors: Additional Evidence," *Financial Analysts Journal* (November/December 1997).

optimistic. Other research on this topic also concludes that there is no clear support for the contention that analyst forecasts contain upside bias.[65]:

Q DID DR. WOOLRIDGE PROVIDE ANY MEANINGFUL SUPPORT FOR HIS ALLEGATION THAT VALUE LINE FORECASTS ARE "OVERLY OPTIMISTIC"?

A. No. Dr. Woolridge asserted his belief (p. B-11) that Value Line projections have "a decidedly positive bias," based only on his personal belief that Value Line does not report a sufficient number of negative growth rates. But a negative long-term growth rate implies a DCF cost of equity below the firm's dividend yield and is hardly representative of investors' expectations. Dr. Woolridge's personal opinions are irrelevant to a determination of what investors expect and, contrary to his conclusion, Value Line is a well-recognized source in the investment and regulatory communities. For example, *Cost of Capital – A Practitioners' Guide*, published by the Society of Utility and Financial Analysts, noted that:

> [A] number of studies have commented on the relative accuracy of various analysts' forecasts. Brown and Rozeff (1978) found that Value Line was superior to other forecasts. Chatfield, Hein and Moyer (1990, 438) found, further "Value Line to be more accurate than alternative forecasting methods" and that "investors place the greatest weight on the forecasts provided by Value Line".[66]

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[65] Ciccone, Stephen, "Trends in analyst earnings forecast properties," *International Review of Financial Analysis*, 14:2-3 (2005); Abarbanell, Jeffery and Reuven Lehavy, "Biased forecasts or biased earnings? The role of reported earnings in explaining apparent bias and over/under reaction in analysts earnings forecasts," *Journal of Accounting and Economics*, 36: 142 (2003). Similarly, while Dr. Woolridge cites a 2003 *Wall Street Journal* ("WSJ") article,[65] an April 26, 2010 study reported in this publication contradicts his position. The WSJ concluded that analysts' earnings forecasts, "are actually too pessimistic when it comes to predicting company earnings, particularly in the wake of recession." Denning, Liam, "Wall Street's Missed Expectations," *Wall Street Journal* at C8 (Apr. 26, 2010).

[66] Parcell, David C., "The Cost of Capital – A Practitioner's Guide," *Society of Utility and Regulatory Financial Analysts* (1997) at 8-28.

Given the fact that Value Line is perhaps the most widely available source of information on common stocks, the projections of Value Line analysts provide an important guide to investors' expectations.

Moreover, in contrast to Dr. Woolridge's unsupported assertion, the fact that Value Line is not engaged in investment banking or other relationships with the companies that it follows reinforces its impartiality in the minds of investors. Indeed, Value Line was among the providers of "independent research" that benefited from the Global Settlement cited by Dr. Woolridge (p. B-6).[67]

V. CAPM RESULTS SHOULD BE DISREGARDED

Q. WHAT IS THE FUNDAMENTAL PROBLEM ASSOCIATED WITH THE APPROACH THAT DR. WOOLRIDGE AND MR. HILL USED TO APPLY THE CAPM?

A. Like the DCF model, the CAPM is an *ex-ante,* or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using data that reflects the expectations of actual investors in the market. However, the CAPM applications presented by Dr. Woolridge and Mr. Hill were based entirely on *historical* rates of return, not current projections. *Morningstar* recognized the primacy of current expectations:

> The cost of capital is always an expectational or forward-looking concept. While the past performance of an investment and other historical information can be good guides and are often used to estimate the required rate of return on capital, the expectations of

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[67] Tsao, Amy, "The New Era of Indie Research," *Business Week Online Edition* (June 12, 2003).

> future events are the only factors that actually determine cost of capital.[68]

Because they failed to look directly at the returns investors are currently requiring in the capital markets, the 7.5 percent and 7.16-8.32 percent historical CAPM estimates developed by Dr. Woolridge and Mr. Hill fall woefully short of investors' current required rate of return.

Q. DR. WOOLRIDGE (P. 44) CHARACTERIZES HIS RISK PREMIUM AS *EX ANTE*. IS THIS AN ACCURATE ASSESSMENT?

A. No. In order to be considered a forward-looking, *ex ante* estimate of the current market risk premium, the analysis must be predicated on investors' current expectations. Dr. Woolridge did not attempt to develop a market risk premium using current capital market information. Rather, he simply presented the results of various studies and surveys conducted in the past. Certain of these studies may have attempted to infer the equity risk premium using expected data at the time they were developed, but expectations at some point in the past are not equivalent to investors *ex ante* requirements in capital markets today.

Q. IS THERE GOOD REASON TO ENTIRELY DISREGARD THE RESULTS OF HISTORICAL CAPM ANALYSES SUCH AS THOSE PRESENTED BY DR. WOOLRIDGE AND MR. HILL?

A. Yes. 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 common equity estimate is calibrated from investors' required risk premium between Treasury bonds and common stocks. In response to heightened uncertainties, investors have repeatedly sought a safe haven in U.S. government

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[68] Morningstar, *Ibbotson SBBI, 2011 Valuation Yearbook* at 21.

bonds and this "flight to safety" has 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.

Meanwhile, the backward-looking approaches used by Dr. Woolridge and Mr. Hill incorrectly assume that investors' assessment of the relative risk differences, and their required risk premium, between Treasury bonds and common stocks is constant and equal to some historical average. At no time in recent history has the fallacy of this assumption been demonstrated more concretely. This incongruity between investors' current expectations and requirements and historical risk premiums is particularly relevant during periods of heightened uncertainty and rapidly changing capital market conditions, such as those experienced recently.

As a result, there is every indication that the historical CAPM approach fails to fully reflect the risk perceptions of real-world investors in today's capital markets, which would violate the standards underlying a fair rate of return by failing to provide an opportunity to earn a return commensurate with other investments of comparable risk. As the Staff of the Florida Public Service Commission 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.[69]

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

Q. DO ECONOMIC TRENDS, SUCH AS THOSE REFERENCED BY DR. WOOLRIDGE (PP. 4-8) AND MR. HILL (PP. 10-18), FURTHER UNDERMINE THEIR HISTORICAL CAPM ANALYSES?

A. Yes. As Value Line recently recognized, "It has been a turbulent year for the financial markets, to say the least."[70] Investors have faced a myriad of challenges and uncertainties, including the threat of a U.S. government default, political brinkmanship over raising the federal debt ceiling, and S&P's subsequent downgrade of its U.S. sovereign debt rating.[71] The sovereign debt crisis in Europe has also dealt a harsh blow to investor confidence, and concerns over potential exposure to a Euro-zone default continues to undermine confidence in the financial and banking sector.[72] Meanwhile, speculation that the economy remains exposed to a potential "double-dip" persists, with unemployment remaining stubbornly high, lackluster consumer confidence, rising petroleum prices, and continued weakness plaguing the real estate sector.

Investors have had to confront ongoing volatility in share prices and stress in the credit markets,[73] and in response have repeatedly fled to the safety of U.S. Treasury bonds. As Fidelity Investments recently reported to investors:

> It's been quite a year, one of violent mood swings but little overall direction. We seem to be in a time warp where everything happens faster and faster. Everything seems to be correlated. There are very

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[70] The Value Line Investment Survey at 541 (Dec. 9, 2011).

[71] *See, e.g.*, Standard & Poor's Corporation, "Economic Forecast: Still Treading Water," *RatingsDirect* (Aug. 17, 2011).

[72] *See, e.g.*, Standard & Poor's Corporation, "U.S. Risks To The Forecast: Choppy Seas," *RatingsDirect* (Dec. 21, 2011).

[73] *See, e.g.*, Gongloff, Mark, "Stock Rebound Is a Crisis Flashback – Late Surge Recalls Market's Volatility at Peak of Credit Difficulties; Unusual Correlations," *Wall Street Journal* at B1 (Feb. 6, 2010); Lauricella, Tom, "Stocks Nose-Dive Amid Global Fears – Weak Outlook, Government Debt Worries Drive Dow's Biggest Point Drop Since '08," *Wall Street Journal* at A1 (Aug. 5, 2011).

> few places to hide, and even those places don't feel like good options anymore.[74]

While stock prices have trended higher in 2012, market sentiment remains highly sensitive to disappointment, and Value Line recently noted that, "the risks of a selloff are increasing."[75] The dramatic rise in the price of gold and other commodities also attests to investors' heightened concerns over prospective challenges and risks, including the overhanging threat of inflation and renewed economic turmoil. S&P noted that, "The effect of a potential financial collapse in the eurozone spreading to our shores is at the top of the list of events that could push the U.S. into recession."[76] With respect to utilities, Moody's noted the dangers to credit availability associated with exposure to European banks,[77] and concluded:

> Over the past few months, we have been reminded that global financial markets, which are still receiving extraordinary intervention benefits by sovereign governments, are exposed to turmoil. Access to the capital markets could therefore become intermittent, even for safer, more defensive sectors like the power industry.[78]

These developments have led to periodic turmoil in capital markets, with common stock prices exhibiting the dramatic volatility that is indicative of heightened sensitivity to risk. Nowhere has this been more evident than in the market for Treasury bonds, with yields being pushed significantly lower due to a global "flight to safety" in the face of rising political, economic, and capital market

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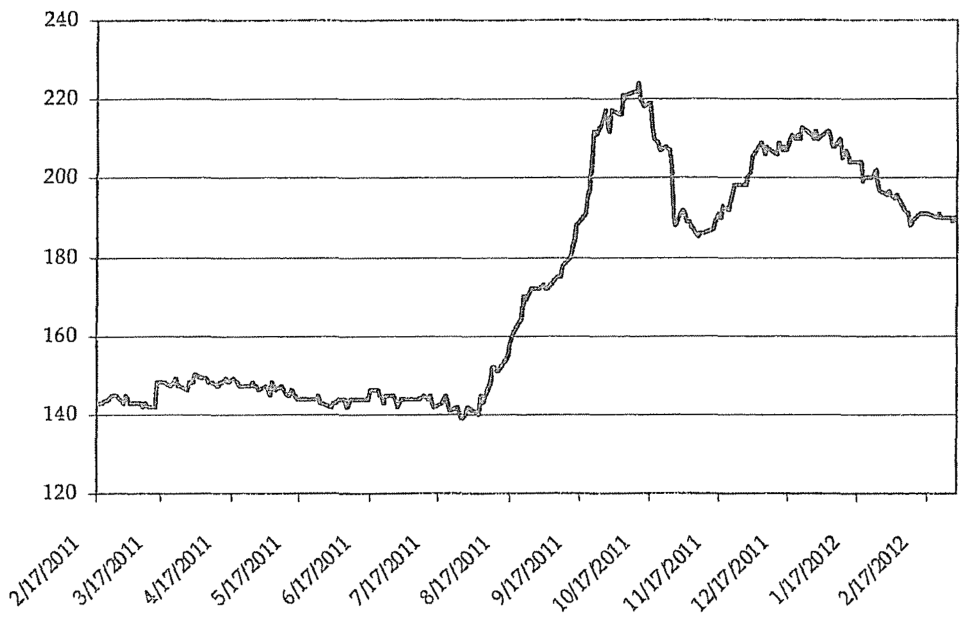
[74] Fidelity Investments, "2012 markets: Expect ups and downs," *Fidelity Viewpoints* (Dec. 21, 2011).
[75] The Value Line Investment Survey, *Selection & Opinion* (Apr. 6, 2012).
[76] Standard & Poor's Corporation, "Economic Research: U.S. Economic Forecast: Just Like Ol' Times," *RatingsDirect* (Jan 12., 2012).
[77] Moody's Investors Service, "Electric Utilities Stable But Face Increasing Regulatory Uncertainty," *Industry Outlook* (Jul. 22, 2010).
[78] Moody's Investors Service, "Regulation Provides Stability As Risks Mount," *Industry Outlook* (Jan. 19, 2011).

risks. In turn, this has led to a dramatic increase in risk premiums, as illustrated by the spreads between triple-B utility bond yields and 30-year Treasuries shown in Figure WEA-1, below:

FIGURE WEA-1
YIELD SPREAD (BASIS POINTS) BBB UTILITY – 30-YR. TREASURY



This increase in the yield spread indicates that the additional compensation investors demand to take on higher risks has increased. As S&P observed:

> Standard & Poor's U.S. speculative-grade composite spread, which measures the extra yield above U.S. Treasury bonds that investors demand to hold the bonds of riskier companies, widened by 63% to 781 basis points (bps) from April 18, 2011, to Sept. 30, 2011. This sharp expansion reflected the bond market's increasing aversion to credit risk in an uncertain and riskier environment. ... During periods of stress, correlations frequently increase among risky asset classes

> such as the relationship between the return on speculative-grade bonds and the return from equities.[79]

Equity risk premiums cannot be observed directly, but because common stock investors are the last in line with respect to their claim on a utility's cash flows, higher yield spreads imply an even steeper increase in the additional return required from an investment in common equity. In short, heightened capital market and economic uncertainties, and the increase in risk premiums demanded by investors, further undermine Dr. Woolridge's and Mr. Hill's reliance on historical studies to assess capital market trends or apply the CAPM.

Q. DID DR. WOOLRIDGE AND MR. HILL ALSO RECOGNIZE THE FRAILTIES OF THEIR HISTORICAL CAPM APPROACHES?

A. Yes. Dr. Woolridge noted that *ex-post*, historical rates of return "are not the same as *ex-ante* expectations," and observed that, "The use of historical returns as market expectations has been criticized in numerous academic studies."[80] Dr. Woolridge granted that "risk premiums can change over time ... such that *ex post* historical returns are poor estimates of *ex ante* expectations."[81] Finally, Dr. Woolridge concluded, that his historical CAPM approach provides "a less reliable indication of equity cost rates for public utilities."[82] Similarly, Mr. Hill observed that, "Cost of capital analysis is a decidedly forward-looking, or *ex-ante,* concept," and he concluded, "the CAPM analysis is not a reliable primary indicator of equity capital costs."[83]

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[79] Standard & Poor's Corporation, "Recent Expansion In Credit Spreads Shows Bond Market Stress, But Less Severe Than During The Financial Crisis," *RatingsDirect* (Oct. 11, 2011).
[80] Woolridge Direct Testimony at 41.
[81] *Id.*.
[82] *Id.* at 20.
[83] Hill Direct Testimony at 34.

Q. IS THERE EVIDENCE THAT THE STUDIES REFERENCED BY DR. WOOLRIDGE DO NOT REFLECT INVESTORS' EXPECTATIONS?

A. Yes. The vast majority of the results of the equity risk premium studies reported by Dr. Woolridge do not make economic sense and contradict his own testimony. For example, page 5 of Dr. Woolridge's Exhibit JRW-11 reveals that almost two-thirds of the historical studies included in Dr. Woolridge's review found market equity risk premiums of approximately 5.0 percent or below.[84] This was also true for over six of the ten individual risk premium studies that Dr. Woolridge relied on directly to apply the CAPM.[85] But combining a market equity risk premium of 5.0 percent with Dr. Woolridge's 4.0 percent risk-free rate results in an indicated cost of equity for the <u>market as a whole</u> of 9.0 percent, which is equal to than Dr. Woolridge's ROE recommendation for KPCO in this case. Many of his other benchmarks for the market rate of return fall *below* the anemic cost of equity he recommends for KPCO. For example, Dr. Woolridge conjures a market rate of return of 7.6 percent based on his "building blocks" approach,[86] which falls 140 basis points below his recommended ROE in this case.

Meanwhile, after noting that beta is the only relevant measure of investment risk under modern capital market theory, Dr. Woolridge concluded that his comparison of beta values (Exhibit JRW-8) indicates that investors' required return on the market as a whole should exceed the cost of equity for electric utilities.[87] Based on Dr. Woolridge's own logic, it follows that a market rate of return that does

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[84] Similarly, Dr. Woolridge reported equity risk premiums of 4.3 percent and 2.8 percent (p. 42-43) and 3.5 percent to 4.0 percent (pp. 45-46) based on selected surveys and articles.

[85] Exhibit JRW-11, p. 6.

[86] Exhibit JRW-11, p. 7. Similarly, Dr. Woolridge reported market rates of return of 6.8 percent and 6.3 percent from the selected surveys cited at page C-4 and C-5 of his testimony.

[87] Woolridge Direct Testimony at 18.

not exceed his own downward biased ROE recommendation has no relation to the current expectations of real-world investors. The fact that much of his CAPM "evidence" violates the risk-return tradeoff that is fundamental to finance clearly illustrates the frailty of Dr. Woolridge's analyses.

Q. **DR. AVERA, ARE YOU IN ANY WAY ALLEGING THAT ALL THESE STUDIES AND SURVEYS CITED BY DR. WOOLRIDGE AND MR. HILL ARE INCORRECT?**

A. No, not at all. I am challenging the inferences that Dr. Woolridge and Mr. Hill are drawing from them, and the particular use being made of the cited studies. The point that I am making is that there is more than one way to define and calculate an equity risk premium. The problem with the approach used by Dr. Woolridge and Mr. Hill is that, instead of looking directly at an equity risk premium based on current expectations – which is what is required in order to properly apply the CAPM – they undertake an unrelated exercise of compiling a list of selected computations culled from the historical record. Average realized risk premiums computed over some selected time period may be an accurate representation of what was actually earned in the past, but they do not answer the question as to what risk premium investors were actually expecting to earn on a forward-looking basis during these same time periods. Similarly, calculations of the equity risk premium developed at a point in history – whether based on actual returns in prior periods or contemporaneous projections – are not the same as the forward-looking expectations of today's investors, which are premised on an entirely different set of capital market and economic expectations.

Likewise, surveys of selected corporate executives or economists, or building blocks based on academic research, are not equivalent to investors' required returns in the coming period. Since the benchmark for a fair ROE requires that the utility be able to compete for capital in the current capital market, the relevant inquiry is to determine the return that real world investors in today's markets require from KPCO in order to compete for capital with other comparable risk alternatives. In short, while there are many potential definitions of the equity risk premium, the only relevant issue for application of the CAPM in a regulatory context is the return investors currently expect to earn on money invested today in the risky market portfolio versus the risk-free U.S. Treasury alternative.

Q. **WAS DR. WOOLRIDGE (EXHIBIT JRW-11, P. 5) OR MR. HILL (SCHEDULE 8) JUSTIFIED IN RELYING ON GEOMETRIC MEANS AS A MEASURE OF AVERAGE RATE OF RETURN WHEN APPLYING THE HISTORICAL CAPM?**

A. No. While both the arithmetic and geometric means are legitimate measures of average return, they provide different information. Each may be used correctly, or misused, depending upon the inferences being drawn from the numbers. The geometric mean of a series of returns measures the constant rate of return that would yield the same change in the value of an investment over time. The arithmetic mean measures what the expected return would have to be each period to achieve the realized change in value over time.

In estimating the cost of equity, the goal is to replicate what investors expect going forward, not to measure the average performance of an investment over an assumed holding period. When referencing realized rates of return in the past, investors consider the equity risk premiums in each year independently, with the arithmetic average of these annual results providing the best estimate of what investors might expect in future periods. *New Regulatory Finance* had this to say:

> The best estimate of expected returns over a given future holding period is the arithmetic average. *Only arithmetic means are correct for forecasting purposes and for estimating the cost of capital.* There is no theoretical or empirical justification for the use of geometric mean rates of returns as a measure of the appropriate discount rate in computing the cost of capital or in computing present values.[88]

Similarly, *Morningstar* concluded that:

> For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. ... The geometric average is more appropriate for reporting past performance, since it represents the compound average return.[89]

Q. WHAT DOES THIS IMPLY WITH RESPECT TO DR. WOOLRIDGE'S AND MR. HILL'S CAPM ANALYSES?

A. For a variable series, such as stock returns, the geometric average will <u>always</u> be less than the arithmetic average. Accordingly, Dr. Woolridge's and Mr. Hill's reference to geometric average rates of return provides yet another element of built-in downward bias.

Q. DOES THE RISK PREMIUM THAT MR. HILL DERIVES FROM IBBOTSON ASSOCIATES' DATA (SCHEDULE 8) COMPORT WHAT THIS PUBLICATION REPORTS?

A. No. Ibbotson Associates (now *Morningstar*) computes the equity risk premium by subtracting the arithmetic mean income return (not the total return) on long-term Treasury bonds from the arithmetic average return on common stocks. As *Morningstar* explained:

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[88] Morin, Roger A., "New Regulatory Finance" *Public Utilities Reports, Inc.* (2006) at 116-117, (emphasis added).
[89] Morningstar, *Ibbotson SBBI 2011 Valuation Yearbook* at 56.

> Price changes in bonds due to unanticipated changes in yields introduce price risk into the total return. Therefore, the total return on the bond series does not represent the riskless rate of return. The income return better represents the unbiased estimate of the purely riskless rate of return, since an investor can hold a bond to maturity and be entitled to the income return with no capital loss.[90]

In other words, *Morningstar* concluded that using only the income component of the long-term government bond return provides a more reliable estimate of the expected risk premium because investors do not anticipate capital losses for a risk-free security. Mr. Hill, however, calculated its equity risk premium using the *total* return for *Morningstar's* long-term government bond series. As a result, the equity risk premium falls far below what his own data source reports and the resulting CAPM cost of equity estimate is understated.

Q. WHAT EQUITY RISK PREMIUM DOES *MORNINGSTAR* REPORT?

A. The most recent edition of Mr. Hill's source of historical realized rate of return data calculates the long-horizon equity risk premium by subtracting the arithmetic mean average income return on long-term Treasury bonds from the arithmetic mean average return on the S&P 500, resulting in an equity risk premium of 6.62 percent,[91] versus the 4.4 percent and 6.0 percent values reported by Mr. Hill.[92]

Q. DOES CORRECTING THE CAPM APPLICATIONS OF DR. WOOLRIDGE AND MR. HILL CONFIRM THE REASONABLENESS OF KPCO'S 10.5 PERCENT ROE REQUEST?

A. Yes. Application of the CAPM to the firms in Dr. Woolridge's and Mr. Hill's proxy groups based on a forward-looking estimate for investors' required rate of return

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[90] Morningstar, *Ibbotson SBBI, 2010 Valuation Yearbook* at 56.
[91] Morningstar, *2012 Ibbotson SBBI Risk Premium Over Time Report* at 7.
[92] Hill Direct Testimony at Schedule 8.

from common stocks is presented on Exhibit WEA-8. In order to capture the expectations of today's investors in current capital markets, the expected market rate of return was estimated by conducting a DCF analysis on the dividend paying firms in the S&P 500.

The dividend yield for each firm was based on the year-ahead projections obtained from Value Line. The growth rate was equal to the earnings growth projections for each firm published by IBES, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value. Based on the weighted average of the projections for the 373 individual firms, current estimates imply an average growth rate over the next five years of 10.9 percent. Combining this average growth rate with the average Value Line dividend yield of 2.6 percent results in a current cost of common equity estimate for the market as a whole (R_m) of approximately 13.5 percent. Subtracting a 3.3 percent risk-free rate based on the average yield on 30-year Treasury bonds produced a market equity risk premium of 10.2 percent.

Q. **DID DR. WOOLRIDGE AND MR. HILL FAIL TO CONSIDER OTHER IMPORTANT FACTORS IN APPLYING THE CAPM?**

A. Yes. As explained by *Morningstar*:

> One of the most remarkable discoveries of modern finance is that of a relationship between firm size and return. The relationship cuts across the entire size spectrum but is most evident among smaller companies, which have higher returns on average than larger ones.[93]

Because empirical research indicates that the CAPM does not fully account for observed differences in rates of return attributable to firm size, a modification is required to account for this size effect.

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[93] *Morningstar*, "Ibbotson SBBI 2011 Valuation Yearbook," at 83.

According to the CAPM, the expected return on a security should consist of the riskless rate, plus a premium to compensate for the systematic risk of the particular security. The degree of systematic risk is represented by the beta coefficient. The need for the size adjustment arises because differences in investors' required rates of return that are related to firm size are not fully captured by beta. To account for this, *Morningstar* has developed size premiums that need to be added to the theoretical CAPM cost of equity estimates to account for the level of a firm's market capitalization in determining the CAPM cost of equity.[94] Accordingly, my CAPM analyses incorporated an adjustment to recognize the impact of size distinctions, as measured by the average market capitalization for the respective proxy groups.

Q. WHAT COST OF EQUITY ESTIMATE WAS INDICATED BY CORRECTING THEIR APPLICATION OF THE CAPM?

A. As shown on page 1 of Exhibit WEA-8, application of the forward-looking CAPM approach resulted in an unadjusted ROE of 10.4 percent for the firms in Dr. Woolridge's proxy group, or 11.2 percent after adjusting for the impact of firm size. As shown on page 2 of Exhibit WEA-8, this CAPM approach implied an an unadjusted CAPM result of 10.6 percent for Mr. Hill's proxy group, and an adjusted ROE of 11.6 percent .

Q. DR. WOOLRIDGE AND MR. HILL BOTH REFERENCE CAPITAL MARKET TRENDS. IS IT APPROPRIATE TO CONSIDER ANTICIPATED CAPITAL MARKET CHANGES IN APPLYING THE CAPM?

A. Yes. As discussed earlier, there is widespread consensus that interest rates will increase materially as the economy strengthens. Accordingly, in addition to the use

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[94] Morningstar, *2012 Ibbotson SBBI Risk Premium Over Time Report* at 7.

of current bond yields, I also applied the CAPM based on the forecasted long-term Treasury bond yields developed based on projections published by Value Line, IHS Global Insight and Blue Chip.

Q. WHAT COST OF EQUITY WAS PRODUCED BY THE CAPM AFTER CORRECTNG DR. WOOLRIDGE'S AND MR. HILL'S CAPM TO INCORPORATE FORECASTED BOND YIELDS?

A. As shown on page 1 of Exhibit WEA-9, incorporating a forecasted Treasury bond yield for 2012-2016 implied an unadjusted cost of equity of approximately 10.8 percent for the utilities in Dr. Woolridge's proxy group, or 11.5 percent after accounting for firm size. As shown on page 2 of Exhibit WEA-9, incorporating projected bond yields implied an unadjusted cost of equity of approximately 10.9 percent for Mr. Hill's proxy group, and an adjusted ROE of 11.9 percent.

VI. FLOTATION COSTS SHOULD BE CONSIDERED

Q. DID DR. WOOLRIDGE OR MR. HILL INCLUDE AN ADJUSTMENT TO RECOGNIZE COMMON STOCK FLOTATION COSTS IN HIS RECOMMENDED FAIR RATE OF RETURN ON EQUITY?

A. No. While Dr. Woolridge ignored this issue entirely, Mr. Hill asserted (pp. 47-50) that an adjustment for flotation costs was unnecessary.

Q. IS THERE ANY MERIT TO MR. HILL'S POSTION CONCERNING FLOTATION COSTS?

A. No. 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.[95] Similarly, *New Regulatory Finance* contains the following discussion:

> Another controversy is whether the flotation cost 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.[96]

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

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[95] Brigham, E.F., Aberwald, D.A., and Gapenski, L.C., "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly*, May, 2, 1985.
[96] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 335.

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:

TABLE WEA-4
NO FLOTATION COST ADJUSTMENT

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. One commonly referenced 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:

TABLE WEA-5
INCLUDING FLOTATION COST ADJUSTMENT

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%	

As shown in Table WEA-5, 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. WHAT ABOUT MR. HILL'S CONTENTION (P. 48) THAT A FLOTATION COST ALLOWANCE IS UNNECESSARY BECAUSE THE MARKET-TO-BOOK RATIO FOR ELECTRIC UTILITIES IS GREATER THAN 1.0?

A. Whether or not the market-to-book ratio is greater than, or less than, 1.0 says nothing about the need to recognize the impact of legitimate costs of issuing common stock when establishing a fair rate of return. Investors determine the price they are willing to pay for a share of common stock based on their assessment of expected cash flows and relative risks. While I don't dispute Mr. Hill's observation that sales of stock at a price that exceeds book value will cause the book value per share of existing shareholders to grow,[97] this doesn't change the fact that investors must be granted an opportunity to earn their required rate of return on *all* invested capital, including that portion paid out as issuance expenses. As I demonstrated in the example above, this can only occur if an upward adjustment to the ROE is made to account for flotation costs.

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[97] Indeed, this growth related to sales of new common stock forms the basis for the "sv" adjustment that Mr. Hill included in calculating the retention growth rates used in his DCF analysis.

Q. WHAT ABOUT MR. HILLS OTHER SPECIFIC CRITICISMS?

A. Mr. Hill mistakenly implies that a flotation cost adjustment is "predicated on the prevention of dilution of stockholder investment."[98] In fact, a flotation cost adjustment is required in order to allow the utility the opportunity to recover the issuance costs associated with selling common stock. The fact that market prices may be above book value does not alter the fact that a portion of the capital contributed by equity investors is not available to earn a return because it is paid out as flotation costs

Mr. Hill's argument (p. 49) that flotation costs are "not out-of-pocket expenses" is simply wrong. Mr. Hill apparently believes that if investors in past common stock issues had paid the full issuance price directly to the utility and the utility had then paid underwriters' fees by issuing a check to its investment bankers, that flotation cost would be a legitimate expense. Mr. Hill's observation merely highlights the absence of an accounting convention to properly accumulate and recover these legitimate and necessary costs.

With respect to Mr. Hill's contention (p. 49) that flotation costs are somehow accounted for in current stock prices, *New Regulatory Finance* has this to say:

> 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.[99]

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[98] Hill Direct Testimony at 48.

[99] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 334-335.

Similarly, the need to consider past flotation costs has been recognized in the financial literature, including sources that Dr. Woolridge 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).[100]

VII. NO ROE ADJUSTMENT IS WARRANTED FOR ECR

Q. WHAT ADJUSTMENT DOES MR. HILL RECOMMEND IN ESTABLISHING AN ROE UNDER THE ECR?

A. Mr. Hill wrongly argues (p. 47) that the ROE for KPCO should be set at the midpoint of the bottom end of his 9.0 percent to 9.75 percent range, based on his misguided contention that KPCO's relative risks fall below those of his proxy group. Moving from the midpoint of Mr. Hill's range to his 9.2 percent ROE recommendation implies a downward adjustment of 18 basis points.

Q. IS THERE ANY MERIT TO MR. HILL'S PROPOSAL TO REDUCE KPCO'S ROE?

A. No. The downward adjustment advocated by Mr. Hill is entirely baseless for two primary reasons:

1. The impact of KPCO's ECR mechanism is fully considered by investors and the investment community and reflected in the objective risk benchmarks used to establish the proxy groups. Because these

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[100] Ibbotson Associates, *Stocks, Bonds, Bills, and Inflation, Valuation Edition, 2006 Yearbook*, at 35. In addition, the July 19, 2007 decision of the Maryland Public Service Commission in Case No. 9093 cited by Dr. Woolridge (p. 55) approved an adjustment for flotation costs.

independent benchmarks demonstrate that the investment risks of KPCO are comparable to the proxy groups used to estimate the cost of equity, the ROE adjustment proposed by Mr. Hill is nothing more than a second bite from the apple; and,

2. There is no economic justification whatsoever for the magnitude of the ROE adjustment proposed by Mr. Hill, which has no demonstrable relationship to investors' requirements or observable capital market evidence.

Because of these fundamental flaws, the Commission should reject any downward adjustment to KPCO's ROE.

Q. WAS MR. HILL'S ASSESSMENT BASED ON AN ACCURATE UNDERSTANDING OF HOW THE ECR IS IMPLEMENTED FOR KPCO?

A. No. Mr. Hill's assessment of relative risks was based on his misguided understanding that KPCO earns a return on its investment in environmental compliance prior to completion of construction.[101] As discussed in the testimony of Mr. Wohnhas, unlike other utilities under the jurisdiction of the KPSC, KPCO does not earn a return on construction work in progress.

Q. DOES THE FACT THAT KPCO OPERATE UNDER THE ECR IMPLY THAT ITS INVESTMENT RISKS ARE LOWER THAN FOR THE PROXY GROUP THAT MR. HILL USED TO ESTIMATE THE COST OF EQUITY?

A. No. Mr. Hill examined KPCO's investment risks in relation to the proxy group he used to estimate the cost of equity, and he selected "a group of firms with similar characteristics," based in part on an evaluation of bond ratings. Adjustment clauses and cost trackers, along with rate design measures and other mechanisms designed

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[101] Hill Direct at 4.

to decouple a utility's revenues from customer usage, have been increasingly prevalent in the utility industry in recent years. The investment community is well aware of these developments and the implications are already reflected in observable risk measures.

Take the example of credit ratings, which were the principal risk measure that Mr. Hill relied on (Schedule 3) to identify his comparable group. Credit ratings provide investors with a broad assessment of the creditworthiness of a firm, and the rating agencies' evaluation includes virtually all of the factors normally considered important in assessing a firm's relative credit standing, including industry risk, competitive position, peer group comparisons, cash flow adequacy, and capital structure. S&P noted "all salient issues are considered" in the evaluation process that ultimately leads to published credit ratings.[102] The fact that the ECR is already considered in establishing KPCO's credit rating was highlighted by Moody's, which nevertheless noted that the "enormous" magnitude of the Company's planned environmental expenditures are expected to stress KPCO's credit standing."[103]

Q. DID MR. HILL GRANT THAT THE IMPACT OF REGULATION IS REFLECTED IN A UTILITY'S CREDIT RATINGS?

A. Yes. Mr. Hill agreed that the bond rating agencies consider the impact of regulation on a utility's risks – which includes approved adjustment mechanisms such as the ECR – when evaluating credit ratings.[104] As a result, there is no basis for Mr. Hill to

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[102] Standard & Poor's Corporation, "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," *RatingsDirect* (May 27, 2009).

[103] Moody's Investors Service, "Credit Opinion: Kentucky Power Company," *Global Credit Research* (Feb. 7, 2012).

[104] *Response of Kentucky Industrial Utility Customers, Inc. to Kentucky Power Company's Data Requests, Question 3.*

single out the ECR because the impact has already been considered in arriving at the risk measures he relied on to identify his comparable-risk group.

Q. **DID MR. HILL EVALUATE THE EXTENT TO WHICH THE COMPANIES IN HIS PROXY GROUP HAVE SIMILAR COST RECOVERY MECHANISMS?**

A. No. Mr. Hill made no attempt determine if the utilities in his proxy group operate under mechanisms analogous to the ECR. Mr. Hill claimed that "such data are not readily available, making any such study time-consuming, unnecessarily expensive and, therefore, outside the budget allotted for this proceeding."[105] Rather than basing his relative risk arguments and recommendation on objective data, Mr. Hill "is relying on his 30-year experience in utility regulation."[106]

Q. **DOES A REVIEW OF THE COST ADJUSTMENT MECHANISMS AVAILABLE TO THE UTILITIES IN MR. HILL'S PROXY GROUP SUPPORT HIS ARGUMENT THAT THE COMPANIES HAVE LOWER INVESTMENT RISK?**

A. No. Adjustment mechanisms and trackers have been increasingly prevalent in the utility industry in recent years. In response to the increasing risk sensitivity of investors to uncertainty over fluctuations in costs and the importance of advancing other public interest goals such as energy conservation, utilities and their regulators have sought to mitigate some of the cost recovery uncertainty and align the interest of utilities and their customers in favor of reducing consumption through decoupling and other adjustment mechanisms. While not always directly analogous to the specific mechanisms approved for KPCO, the objective is similar; namely, to allow

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[105] *Response of Kentucky Industrial Utility Customers, Inc. to Kentucky Power Company's Data Requests, Question 4.*
[106] *Id.*

the utility an opportunity to earn a fair rate of return and mitigate exposure to attrition in an era of rising costs.

I evaluated the regulatory adjustment mechanisms approved for each of Mr. Hill's proxy utilities by referencing the Form 10-K reports filed with the Securities and Exchange Commission, which is publicly available and free of charge.[107] Reflective of industry trends, the companies in Mr. Hill's proxy group operate under a variety of cost adjustment mechanisms. As summarized on Exhibit WEA-10, these mechanisms range from riders to recover pension and employee benefit costs to revenue decoupling and adjustment clauses designed to address the rising costs of environmental compliance measures. For example, Pacific Gas and Electric Company also operates under numerous balancing account mechanisms that cover a significant portion of its revenue requirements and effectively dampen the impact of fluctuations in electric sales and expenses on its ability to recover the costs of providing service. SCANA Corporation's electric and gas utilities operate under weather normalization and revenue decoupling mechanisms, as well as the ability to implement periodic rate adjustments to reflect new nuclear construction costs. As a result, the mitigation in risks associated with utilities' ability to attenuate fluctuations in earnings through adjustment mechanisms is already reflected in Mr. Hill's cost of equity estimates, and there is no basis for his conclusion that KPCO's risks are lower.

[107] Because this information is widely referenced by the investment community, it is also directly relevant to an evaluation of the risks and prospects that determine the cost of equity.

Q. IS THERE ANY REASONABLE BASIS FOR THE MAGNITUDE OF THE ROE ADJUSTMENT MR. HILL IS PROPOSING (P. 47)?

A, Absolutely none. As discussed earlier, the bond rating agencies consider a plethora of factors relevant to their assessment of a company's overall credit standing, including cost recovery mechanisms. The fact that KPCO's credit ratings are comparable to the utilities in Mr. Hill's proxy group directly contradicts Mr. Hill's relative risk argument, because the rating agencies consider the ECR when evaluating risk. The companies in Mr. Hill's proxy group have comparable credit ratings and benefit from a wide variety of adjustment mechanisms, and there is no basis whatsoever for his proposed ROE adjustment.

Q. WHAT DID YOU CONCLUDE WITH RESPECT TO THE RECOMMENDATIONS OF DR. WOOLRIDGE AND MR. HILL?

A. The ROE recommendations of Dr. Woolridge and Mr. Hill are flawed, inadequate to compensate investors in KPCO, and should be rejected. Correcting their analyses confirms the reasonableness of the 10.5 percent ROE requested by KPCO, which is required to support the Company's financial integrity and access to capital.

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

A. Yes.

VERIFICATION

Dr. William E. Avera being duly sworn deposes and says he is the President of FINCAP, Inc., and that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief.

DR. WILLIAM E. AVERA

STATE OF TEXAS	)	
	)	CASE NO. 2011-00401
COUNTY OF TRAVIS	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by, Dr. William E. Avera this 12th day of April 2012.

Notary Public

My Commission Expires: 1/10/15

ADRIEN MCKENZIE
Notary Public
STATE OF TEXAS
My Comm. Exp. Jan. 10, 2015

EXHIBIT WEA-1

QUALIFICATIONS OF WILLIAM E. AVERA

Q. WHAT IS THE PURPOSE OF THIS EXHIBIT?

A. This exhibit describes my background and experience and contains the details of my qualifications.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I received a B.A. degree with a major in economics from Emory University. After serving in the U.S. Navy, I entered the doctoral program in economics at the University of North Carolina at Chapel Hill. Upon receiving my Ph.D., I joined the faculty at the University of North Carolina and taught finance in the Graduate School of Business. I subsequently accepted a position at the University of Texas at Austin where I taught courses in financial management and investment analysis. I then went to work for International Paper Company in New York City as Manager of Financial Education, a position in which I had responsibility for all corporate education programs in finance, accounting, and economics. In 1977, I joined the staff of the Public Utility Commission of Texas ("PUCT") as Director of the Economic Research Division.

During my tenure at the PUCT, I managed a division responsible for financial analysis, cost allocation and rate design, economic and financial research, and data processing systems, and I testified in cases on a variety of financial and economic issues. Since leaving the PUCT, I have been engaged as a consultant. I have participated in a wide range of assignments involving utility-related matters on behalf of utilities, industrial customers, municipalities, and regulatory commissions. I have previously testified before the

Federal Energy Regulatory Commission ("FERC"), as well as the Federal Communications Commission, the Surface Transportation Board (and its predecessor, the Interstate Commerce Commission), the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies, courts, and legislative committees in over 40 states.

In 1995, I was appointed by the PUCT to the Synchronous Interconnection Committee to advise the Texas legislature on the costs and benefits of connecting Texas to the national electric transmission grid. In addition, I served as an outside director of Georgia System Operations Corporation, the system operator for electric cooperatives in Georgia.

I have served as Lecturer in the Finance Department at the University of Texas at Austin and taught in the evening graduate program at St. Edward's University for twenty years. In addition, I have lectured on economic and regulatory topics in programs sponsored by universities and industry groups. I have taught in hundreds of educational programs for financial analysts in programs sponsored by the Association for Investment Management and Research, the Financial Analysts Review, and local financial analysts societies. These programs have been presented in Asia, Europe, and North America, including the Financial Analysts Seminar at Northwestern University. I hold the Chartered Financial Analyst (CFA®) designation and have served as Vice President for Membership of the Financial Management Association. I have also served on the Board of Directors of the North Carolina Society of Financial Analysts. I was elected Vice Chairman of the National Association of Regulatory Commissioners ("NARUC") Subcommittee on Economics and appointed to NARUC's Technical Subcommittee on the National Energy Act. I have also served as an officer of various other professional organizations and societies. A resume containing the details of my experience and qualifications is attached.

WILLIAM E. AVERA

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Summary of Qualifications

Ph.D. in economics and finance; Chartered Financial Analyst (CFA ®) designation; extensive expert witness testimony before courts, alternative dispute resolution panels, regulatory agencies and legislative committees; lectured in executive education programs around the world on ethics, investment analysis, and regulation; undergraduate and graduate teaching in business and economics; appointed to leadership positions in government, industry, academia, and the military.

Employment

Principal,
FINCAP, Inc.
(Sep. 1979 to present)

Financial, economic and policy consulting to business and government. Perform business and public policy research, cost/benefit analyses and financial modeling, valuation of businesses (almost 200 entities valued), estimation of damages, statistical and industry studies. Provide strategy advice and educational services in public and private sectors, and serve as expert witness before regulatory agencies, legislative committees, arbitration panels, and courts.

Director, Economic Research Division,
Public Utility Commission of Texas
(Dec. 1977 to Aug. 1979)

Responsible for research and testimony preparation on rate of return, rate structure, and econometric analysis dealing with energy, telecommunications, water and sewer utilities. Testified in major rate cases and appeared before legislative committees and served as Chief Economist for agency. Administered state and federal grant funds. Communicated frequently with political leaders and representatives from consumer groups, media, and investment community.

Manager, Financial Education,
International Paper Company
New York City
(Feb. 1977 to Nov. 1977)

Directed corporate education programs in accounting, finance, and economics. Developed course materials, recruited and trained instructors, liaison within the company and with academic institutions. Prepared operating budget and designed financial controls for corporate professional development program.

Lecturer in Finance,
The University of Texas at Austin
(Sep. 1979 to May 1981)
Assistant Professor of Finance,
(Sep. 1975 to May 1977)

Taught graduate and undergraduate courses in financial management and investment theory. Conducted research in business and public policy. Named Outstanding Graduate Business Professor and received various administrative appointments.

Assistant Professor of Business,
University of North Carolina at Chapel Hill
(Sep. 1972 to Jul. 1975)

Taught in BBA, MBA, and Ph.D. programs. Created project course in finance, Financial Management for Women, and participated in developing Small Business Management sequence. Organized the North Carolina Institute for Investment Research, a group of financial institutions that supported academic research. Faculty advisor to the Media Board, which funds student publications and broadcast stations.

Education

Ph.D., Economics and Finance,
University of North Carolina at Chapel Hill
(Jan. 1969 to Aug. 1972)

Elective courses included financial management, public finance, monetary theory, and econometrics. Awarded the Stonier Fellowship by the American Bankers' Association and University Teaching Fellowship. Taught statistics, macroeconomics, and microeconomics.

Dissertation: *The Geometric Mean Strategy as a Theory of Multiperiod Portfolio Choice*

B.A., Economics,
Emory University, Atlanta, Georgia
(Sep. 1961 to Jun. 1965)

Active in extracurricular activities, president of the Barkley Forum (debate team), Emory Religious Association, and Delta Tau Delta chapter. Individual awards and team championships at national collegiate debate tournaments.

Professional Associations

Received Chartered Financial Analyst (CFA) designation in 1977; Vice President for Membership, Financial Management Association; President, Austin Chapter of Planning Executives Institute; Board of Directors, North Carolina Society of Financial Analysts; Candidate Curriculum Committee, Association for Investment Management and Research; Executive Committee of Southern Finance Association; Vice Chair, Staff Subcommittee on Economics and National Association of Regulatory Utility Commissioners (NARUC); Appointed to NARUC Technical Subcommittee on the National Energy Act.

Teaching in Executive Education Programs

University-Sponsored Programs: Central Michigan University, Duke University, Louisiana State University, National Defense University, National University of Singapore, Texas A&M University, University of Kansas, University of North Carolina, University of Texas.

Business and Government-Sponsored Programs: Advanced Seminar on Earnings Regulation, American Public Welfare Association, Association for Investment Management and Research, Congressional Fellows Program, Cost of Capital Workshop, Electricity Consumers Resource Council, Financial Analysts Association of Indonesia, Financial Analysts Review, Financial Analysts Seminar at Northwestern University, Governor's Executive Development Program of Texas, Louisiana Association of Business and Industry, National Association of Purchasing Management, National Association of Tire Dealers, Planning Executives Institute, School of Banking of the South, State of Wisconsin Investment Board, Stock Exchange of Thailand, Texas Association of State Sponsored Computer Centers, Texas Bankers' Association, Texas Bar Association, Texas Savings and Loan League, Texas Society of CPAs, Tokyo Association of Foreign Banks, Union Bank of Switzerland, U.S. Department of State, U.S. Navy, U.S. Veterans Administration, in addition to Texas state agencies and major corporations.

Presented papers for Mills B. Lane Lecture Series at the University of Georgia and Heubner Lectures at the University of Pennsylvania. Taught graduate courses in finance and economics for evening program at St. Edward's University in Austin from January 1979 through 1998.

Expert Witness Testimony

Testified in over 300 cases before regulatory agencies addressing cost of capital, regulatory policy, rate design, and other economic and financial issues.

Federal Agencies: Federal Communications Commission, Federal Energy Regulatory Commission, Surface Transportation Board, Interstate Commerce Commission, and the Canadian Radio-Television and Telecommunications Commission.

State Regulatory Agencies: Alaska, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Idaho, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Missouri, Nevada, New Mexico, Montana, Nebraska, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Virginia, Washington, West Virginia, Wisconsin, and Wyoming.

Testified in 42 cases before federal and state courts, arbitration panels, and alternative dispute tribunals (89 depositions given) regarding damages, valuation, antitrust liability, fiduciary duties, and other economic and financial issues.

Board Positions and Other Professional Activities

Co-chair, Synchronous Interconnection Committee established by Texas Legislature to study interconnection of Texas with national grid; Audit Committee and Outside Director, Georgia System Operations Corporation (electric system operator for member-owned electric cooperatives in Georgia); Chairman, Board of Print Depot, Inc. and FINCAP, Inc.; Appointed by Hays County Commission to Citizens Advisory Committee of Habitat Conservation Plan, Operator of AAA Ranch, a certified organic producer of agricultural products; Appointed to Organic Livestock

Advisory Committee by Texas Agricultural Commissioner; Appointed by Texas Railroad Commissioners to study group for *The UP/SP Merger: An Assessment of the Impacts on the State of Texas;* Appointed by Hawaii Public Utilities Commission to team reviewing affiliate relationships of Hawaiian Electric Industries; Chairman, Energy Task Force, Greater Austin-San Antonio Corridor Council; Consultant to Public Utility Commission of Texas on cogeneration policy and other matters; Consultant to Public Service Commission of New Mexico on cogeneration policy; Evaluator of Energy Research Grant Proposals for Texas Higher Education Coordinating Board.

Community Activities

Treasurer, Dripping Springs Presbyterian Church; Board of Directors, Sustainable Food Center; Chair, Board of Deacons, Finance Committee, and Elder, Central Presbyterian Church of Austin; Founding Member, Orange-Chatham County (N.C.) Legal Aid Screening Committee.

Military

Captain, U.S. Naval Reserve (retired after 28 years service); Commanding Officer, Naval Special Warfare Engineering (SEAL) Support Unit; Officer-in-Charge of SWIFT patrol boat in Vietnam; Enlisted service as weather analyst (advanced to second class petty officer).

Bibliography

Monographs

"Economic Perspectives on Texas Water Resources," with Robert M. Avera and Felipe Chacon in *Essentials of Texas Water Resources,* Mary K. Sahs, ed. State Bar of Texas (2012).

Ethics and the Investment Professional (video, workbook, and instructor's guide) and *Ethics Challenge Today* (video), Association for Investment Management and Research (1995)

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"The Energy Crisis and the Homeowner: The Grief Process," *Texas Business Review* (Jan.–Feb. 1980); reprinted in *The Energy Picture: Problems and Prospects*, J. E. Pluta, ed., Bureau of Business Research (1980)

"Use of IFPS at the Public Utility Commission of Texas," *Proceedings of the IFPS Users Group Annual Meeting* (1979)

"Production Capacity Allocation: Conversion, CWIP, and One-Armed Economics," *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"Some Thoughts on the Rate of Return to Public Utility Companies," with Bruce H. Fairchild in *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"A New Capital Budgeting Measure: The Integration of Time, Liquidity, and Uncertainty," with David Cordell in *Proceedings of the Southwestern Finance Association* (1977)

"Usefulness of Current Values to Investors and Creditors," in *Inflation Accounting/Indexing and Stock Behavior* (1977)

"Consumer Expectations and the Economy," *Texas Business Review* (Nov. 1976)

"Portfolio Performance Evaluation and Long-run Capital Growth," with Henry A. Latané in *Proceedings of the Eastern Finance Association* (1973)

Book reviews in *Journal of Finance* and *Financial Review*. Abstracts for *CFA Digest*. Articles in *Carolina Financial Times*.

Selected Papers and Presentations

"Economic Perspective on Water Marketing in Texas," 2009 Water Law Institute, The University of Texas School of Law, Austin, TX (Dec. 2009).

"Estimating Utility Cost of Equity in Financial Turmoil," SNL EXNET 15th Annual FERC Briefing, Washington, D.C. (Mar. 2009)

"The Who, What, When, How, and Why of Ethics," San Antonio Financial Analysts Society (Jan. 16, 2002). Similar presentation given to the Austin Society of Financial Analysts (Jan. 17, 2002)

"Ethics for Financial Analysts," Sponsored by Canadian Council of Financial Analysts: delivered in Calgary, Edmonton, Regina, and Winnipeg, June 1997. Similar presentations given to Austin Society of Financial Analysts (Mar. 1994), San Antonio Society of Financial Analysts (Nov. 1985), and St. Louis Society of Financial Analysts (Feb. 1986)

"Cost of Capital for Multi-Divisional Corporations," Financial Management Association, New Orleans, Louisiana (Oct. 1996)

"Ethics and the Treasury Function," Government Treasurers Organization of Texas, Corpus Christi, Texas (Jun. 1996)

"A Cooperative Future," Iowa Association of Electric Cooperatives, Des Moines (December 1995). Similar presentations given to National G & T Conference, Irving, Texas (June 1995), Kentucky Association of Electric Cooperatives Annual Meeting, Louisville (Nov. 1994), Virginia, Maryland, and Delaware Association of Electric Cooperatives Annual Meeting, Richmond (July 1994), and Carolina Electric Cooperatives Annual Meeting, Raleigh (Mar. 1994)

"Information Superhighway Warnings: Speed Bumps on Wall Street and Detours from the Economy," Texas Society of Certified Public Accountants Natural Gas, Telecommunications and Electric Industries Conference, Austin (Apr. 1995)

"Economic/Wall Street Outlook," Carolinas Council of the Institute of Management Accountants, Myrtle Beach, South Carolina (May 1994). Similar presentation given to Bell Operating Company Accounting Witness Conference, Santa Fe, New Mexico (Apr. 1993)

"Regulatory Developments in Telecommunications," Regional Holding Company Financial and Accounting Conference, San Antonio (Sep. 1993)

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"Making Utility Regulation Work at the Public Utility Commission of Texas," Center for Legal and Regulatory Studies, University of Texas, Austin (June 1991)

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"A Pragmatic Approach to the Capital Structure Decision Based on Long-Run Growth," with Henry A. Latané, Financial Management Association, San Diego (Oct. 1974)

"Growth Rates, Expected Returns, and Variance in Portfolio Selection and Performance Evaluation," with Henry A. Latané, Econometric Society, Oslo, Norway (Aug. 1973)

WOOLRIDGE PROXY GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	ALLETE, Inc.	9.5%	1.03612	9.8%
2	Alliant Energy Corporation	11.5%	1.02093	11.7%
3	Ameren Corporation	7.0%	1.01533	7.1%
4	American Electric Power Co.	10.5%	1.03007	10.8%
5	Avista Corporation	9.0%	1.02125	9.2%
6	Cleco Corporation	9.5%	1.02692	9.8%
7	CMS Energy Corporation	12.5%	1.03345	12.9%
8	Consolidated Edison, Inc.	9.0%	1.01904	9.2%
9	DTE Energy Company	9.0%	1.01991	9.2%
10	Edison International	8.5%	1.02435	8.7%
11	Entergy Corporation	10.5%	1.02199	10.7%
12	Exelon Corporation	13.5%	1.00838	13.6%
13	FirstEnergy Corporation	10.0%	1.01557	10.2%
14	Great Plains Energy Inc.	8.0%	1.02344	8.2%
15	Hawaiian Electric Industries	10.5%	1.03462	10.9%
16	IDACORP, Inc.	8.0%	1.03002	8.2%
17	MGE Energy, Inc.	12.0%	1.01148	12.1%
18	Nextra Energy	12.0%	1.03004	12.4%
19	OGE Energy Corp.	12.0%	1.03817	12.5%
20	Pepco Holdings, Inc.	8.0%	1.02406	8.2%
21	PG&E Corporation	11.0%	1.03244	11.4%
22	Pinnacle West Capital Corp.	9.0%	1.02723	9.2%
23	Portland General Electric	9.0%	1.02112	9.2%
24	PPL Corporation	11.0%	1.04257	11.5%
25	SCANA Corporation	9.5%	1.04685	9.9%
26	Southern Company	12.5%	1.03486	12.9%
27	TECO Energy, Inc.	13.0%	1.02504	13.3%
28	UIL Holdings Corp.	8.5%	1.01394	8.6%
29	UniSource Energy Corp.	12.5%	1.02534	12.8%
30	Westar Energy, Inc.	10.0%	1.02549	10.3%
31	Wisconsin Energy Corp.	14.0%	1.01333	14.2%
32	Xcel Energy Inc.	10.0%	1.02882	10.3%
	Average			10.6%

(a) The Value Line Investment Survey (Dec. 23, 2011, Feb. 3 & Feb. 24, 2012).

(b) Adjustment to convert year-end return to an average rate of return.

(c) (a) x (b).

HILL PROXY GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	ALLETE	9.5%	1.0361	9.8%
2	American Elec Pwr	10.5%	1.0301	10.8%
3	Avista Corp.	9.0%	1.0213	9.2%
4	Cleco Corp.	9.5%	1.0269	9.8%
5	Entergy Corp.	10.5%	1.0220	10.7%
6	FirstEnergy Corp.	10.0%	1.0156	10.2%
7	Hawaiian Elec.	10.5%	1.0346	10.9%
8	PG&E Corp.	11.0%	1.0324	11.4%
9	Pinnacle West Capital	9.0%	1.0272	9.2%
10	Portland General Elec.	9.0%	1.0211	9.2%
11	TECO Energy	13.0%	1.0250	13.3%
12	Unisource Energy	12.5%	1.0253	12.8%
13	Westar Energy	10.0%	1.0255	10.3%
	Average			**10.6%**

(a) The Value Line Investment Survey (Dec. 23, 2011, Feb. 3 & Feb. 24, 2012).

(b) Adjustment to convert year-end return to an average rate of return.

(c) (a) x (b).

ALLOWED ROE

WOOLRIDGE PROXY GROUP

	Company	Allowed Return on Common Equity
1	ALLETE, Inc.	10.38%
2	Alliant Energy Corporation	10.34%
3	Ameren Corporation	9.54%
4	American Electric Power Co.	10.65%
5	Avista Corporation	10.33%
6	Cleco Corporation	10.70%
7	CMS Energy Corporation	10.60%
8	Consolidated Edison, Inc.	9.93%
9	DTE Energy Company	10.75%
10	Edison International	10.65%
11	Entergy Corporation	10.66%
12	Exelon Corporation	10.50%
13	FirstEnergy Corporation	10.52%
14	Great Plains Energy Inc.	10.25%
15	Hawaiian Electric Industries	10.47%
16	IDACORP, Inc.	10.18%
17	MGE Energy, Inc.	10.30%
18	Nextra Energy	10.50%
19	OGE Energy Corp.	9.98%
20	Pepco Holdings, Inc.	9.95%
21	PG&E Corporation	11.35%
22	Pinnacle West Capital Corp.	11.00%
23	Portland General Electric	10.00%
24	PPL Corporation	10.30%
25	SCANA Corporation	10.72%
26	Southern Company	11.90%
27	TECO Energy, Inc.	11.00%
28	UIL Holdings Corporation	8.75%
29	UniSource Energy Corp.	9.88%
30	Westar Energy, Inc.	10.20%
31	Wisconsin Energy Corp.	10.38%
32	Xcel Energy Inc.	10.70%
	Average	**10.42%**

Source: *AUS Monthly Report* (Mar. 2012).

ALLOWED ROE

HILL PROXY GROUP

	Company	Allowed Return on Common Equity
1	ALLETE	10.38%
2	American Electric Power	10.65%
3	Avista Corporation	10.33%
4	Cleco Corporation	10.70%
5	Entergy Corp.	10.66%
6	FirstEnergy Corp.	10.52%
7	Hawaiian Electric	10.47%
8	PG&E Corporation	11.35%
9	Pinnacle West Capital	11.00%
10	Portland General	10.00%
11	TECO Energy	11.00%
12	UniSource Energy	9.88%
13	Westar	10.20%
	Average	**10.55%**

Source: *AUS Monthly Report* (Mar. 2012).

WOOLRIDGE DCF MODEL

HISTORICAL GROWTH RATES

		(a)	(b)	(b)	(b)	(b)	(c)	(c)	(c)	(c)
			Historical Growth Rates				Cost of Equity Estimates			
			Past 10 Years		Past 5 Years		Past 10 Years		Past 5 Years	
	Company	Dividend Yield	EPS	BVPS	EPS	BVPS	EPS	BVPS	EPS	BVPS
1	ALLETE, Inc.	4.6%	--	--	3.5%	6.0%	--	--	8.2%	10.7%
2	Alliant Energy Corporation	4.2%	3.0%	1.0%	9.0%	3.5%	7.2%	5.2%	13.4%	7.7%
3	Ameren Corporation	5.0%	-0.5%	3.5%	-1.5%	2.5%	4.5%	8.6%	3.5%	7.6%
4	American Electric Power Co.	4.8%	2.5%	1.0%	2.0%	5.0%	7.3%	5.8%	6.8%	9.9%
5	Avista Corporation	4.5%	4.0%	4.0%	11.5%	4.0%	8.6%	8.6%	16.2%	8.6%
6	Cleco Corporation	3.4%	4.5%	7.5%	7.5%	11.0%	7.9%	11.0%	11.0%	14.5%
7	CMS Energy Corporation	4.1%	-7.5%	-6.0%	17.5%	1.5%	-3.6%	-2.0%	21.9%	5.6%
8	Consolidated Edison, Inc.	4.1%	1.0%	3.5%	4.0%	4.5%	5.2%	7.7%	8.2%	8.7%
9	DTE Energy Company	4.6%	--	3.5%	2.5%	3.5%	--	8.2%	7.2%	8.2%
10	Edison International	3.3%	--	9.5%	10.0%	10.5%	--	13.0%	13.5%	14.0%
11	Entergy Corporation	4.9%	10.0%	4.0%	10.0%	4.0%	15.1%	9.0%	15.1%	9.0%
12	Exelon Corporation	5.0%	9.5%	5.0%	8.0%	6.5%	14.7%	10.1%	13.2%	11.6%
13	FirstEnergy Corporation	5.0%	4.5%	3.5%	9.0%	1.0%	9.6%	8.6%	14.2%	6.0%
14	Great Plains Energy Inc.	4.2%	-3.5%	4.0%	-11.5%	7.0%	0.6%	8.3%	-7.6%	11.3%
15	Hawaiian Electric Industries	5.0%	-2.5%	2.0%	-6.0%	1.0%	2.4%	7.0%	-1.2%	6.0%
16	IDACORP, Inc.	3.0%	-0.5%	3.5%	11.0%	4.5%	2.5%	6.6%	14.2%	7.6%
17	MGE Energy, Inc.	3.6%	4.5%	6.5%	7.0%	6.5%	8.2%	10.2%	10.7%	10.2%
18	Nextra Energy	3.9%	8.0%	7.5%	12.0%	9.0%	12.1%	11.6%	16.2%	13.1%
19	OGE Energy Corp.	3.0%	3.5%	5.0%	9.0%	8.5%	6.5%	8.1%	12.1%	11.6%
20	Pepco Holdings, Inc.	5.6%	-0.5%	0.5%	-0.5%	1.0%	5.1%	6.1%	5.1%	6.6%
21	PG&E Corporation	4.4%	--	5.5%	7.0%	10.5%	--	10.1%	11.6%	15.2%
22	Pinnacle West Capital Corp.	4.6%	-2.5%	2.5%	0.5%	0.5%	2.1%	7.2%	5.1%	5.1%
23	Portland General Electric	4.4%	--	--	7.5%	2.0%	--	--	12.1%	6.5%
24	PPL Corporation	4.9%	4.5%	9.5%	1.0%	7.0%	9.5%	14.6%	5.9%	12.1%
25	SCANA Corporation	4.7%	4.5%	4.0%	2.0%	4.5%	9.3%	8.7%	6.7%	9.3%
26	Southern Company	4.4%	2.0%	2.5%	2.5%	5.5%	6.4%	6.9%	6.9%	10.0%
27	TECO Energy, Inc.	4.8%	-5.5%	-1.5%	12.0%	5.0%	-0.9%	3.2%	17.1%	9.9%
28	UIL Holdings Corp.	5.2%	-1.0%	--	7.5%	-2.0%	4.2%	--	12.9%	3.1%
29	UniSource Energy Corp.	4.6%	7.0%	8.0%	8.5%	4.5%	11.7%	12.8%	13.3%	9.2%
30	Westar Energy, Inc.	4.8%	--	-3.0%	1.0%	6.0%	--	1.7%	5.8%	10.9%
31	Wisconsin Energy Corp.	3.2%	8.0%	6.0%	8.5%	7.5%	11.3%	9.3%	11.8%	10.8%
32	Xcel Energy Inc.	4.1%	-1.0%	--	4.0%	4.0%	3.1%	--	8.2%	8.2%
	Average (d)						10.2%	9.6%	12.2%	10.4%
	Range							9.6% -	12.2%	
	Midpoint							10.9%		
	Average - All Growth Rates							10.6%		

(a) Exhibit JRW-10, p. 2.
(b) Exhibit JRW-10, p. 3.
(c) Sum of dividend yield (adjusted for one-half year's growth) and respective growth rate.
(d) Excludes highlighted figures.

WOOLRIDGE DCF MODEL

PROJECTED EPS GROWTH RATES

		(a)	(b)	(c)	(c)	(c)	(d)	(d)	(d)	(d)
			Projected EPS Growth Rates				Cost of Equity Estimates			
	Company	Dividend Yield	Value Line	Yahoo	Zacks	Reuters	Value Line	First Call	Zacks	Reuters
1	ALLETE, Inc.	4.6%	6.0%	5.0%	5.0%	6.5%	10.7%	9.7%	9.7%	11.2%
2	Alliant Energy Corporation	4.2%	6.5%	4.8%	6.0%	5.3%	10.8%	9.1%	10.3%	9.6%
3	Ameren Corporation	5.0%	-2.0%	-1.0%	4.0%	-1.9%	3.0%	4.0%	9.1%	3.1%
4	American Electric Power Co.	4.8%	4.5%	3.8%	4.3%	4.2%	9.4%	8.7%	9.2%	9.1%
5	Avista Corporation	4.5%	4.5%	4.0%	4.7%	4.5%	9.1%	8.6%	9.3%	9.1%
6	Cleco Corporation	3.4%	6.0%	3.0%	N/A	3.0%	9.5%	6.4%	N/A	6.4%
7	CMS Energy Corporation	4.1%	7.0%	6.1%	5.5%	6.1%	11.2%	10.3%	9.7%	10.3%
8	Consolidated Edison, Inc.	4.1%	3.0%	3.6%	3.7%	3.7%	7.2%	7.8%	7.9%	7.9%
9	DTE Energy Company	4.6%	4.5%	4.1%	4.2%	3.8%	9.2%	8.8%	8.9%	8.5%
10	Edison International	3.3%	0.5%	3.0%	5.0%	3.0%	3.8%	6.4%	8.4%	6.4%
11	Entergy Corporation	4.9%	0.5%	-3.9%	2.0%	-0.1%	5.4%	0.9%	6.9%	4.8%
12	Exelon Corporation	5.0%	-3.0%	-7.2%	0.0%	-2.0%	1.9%	-2.4%	5.0%	2.9%
13	FirstEnergy Corporation	5.0%	0.5%	1.4%	1.0%	3.0%	5.5%	6.4%	6.0%	8.1%
14	Great Plains Energy Inc.	4.2%	6.0%	4.1%	7.0%	4.4%	10.3%	8.4%	11.3%	8.7%
15	Hawaiian Electric Industries	5.0%	11.0%	11.4%	6.5%	8.4%	16.2%	16.6%	11.6%	13.6%
16	IDACORP, Inc.	3.0%	4.0%	4.0%	5.0%	4.7%	7.1%	7.1%	8.1%	7.8%
17	MGE Energy, Inc.	3.6%	4.0%	4.0%	4.0%	4.0%	7.7%	7.7%	7.7%	7.7%
18	Nextra Energy	3.9%	4.5%	5.2%	6.4%	5.7%	8.5%	9.2%	10.5%	9.7%
19	OGE Energy Corp.	3.0%	6.5%	7.7%	5.9%	6.8%	9.6%	10.8%	9.0%	9.9%
20	Pepco Holdings, Inc.	5.6%	2.5%	2.2%	4.0%	4.9%	8.2%	7.8%	9.7%	10.6%
21	PG&E Corporation	4.4%	5.0%	2.3%	4.3%	3.5%	9.5%	6.8%	8.8%	8.0%
22	Pinnacle West Capital Corp.	4.6%	6.0%	4.8%	5.3%	5.5%	10.8%	9.5%	10.1%	10.3%
23	Portland General Electric	4.4%	7.5%	5.9%	5.0%	5.7%	12.1%	10.4%	9.5%	10.2%
24	PPL Corporation	4.9%	5.0%	4.6%	N/A	2.9%	10.0%	9.6%	N/A	7.9%
25	SCANA Corporation	4.7%	3.5%	4.2%	4.0%	4.3%	8.2%	8.9%	8.7%	9.0%
26	Southern Company	4.4%	5.0%	5.9%	5.0%	5.8%	9.5%	10.4%	9.5%	10.3%
27	TECO Energy, Inc.	4.8%	9.0%	4.2%	3.7%	4.6%	14.0%	9.1%	8.6%	9.5%
28	UIL Holdings Corp.	5.2%	3.0%	4.1%	4.0%	4.0%	8.3%	9.4%	9.3%	9.3%
29	UniSource Energy Corp.	4.6%	9.5%	3.0%	2.6%	3.0%	14.3%	7.7%	7.2%	7.7%
30	Westar Energy, Inc.	4.8%	8.5%	4.2%	6.1%	5.0%	13.5%	9.0%	11.0%	9.9%
31	Wisconsin Energy Corp.	3.2%	8.5%	6.0%	6.3%	7.3%	11.8%	9.3%	9.6%	10.6%
32	Xcel Energy Inc.	4.1%	5.0%	4.9%	5.1%	5.1%	9.2%	9.1%	9.3%	9.3%
	Average (e)						10.2%	9.3%	9.3%	9.4%
	Range							9.3% - 10.2%		
	Midpoint							9.8%		
	Average - All Growth Rates							9.6%		

(a) Exhibit JRW-10, p. 2.
(b) Exhibit JRW-10, p. 4.
(c) Exhibit JRW-10, p. 5.
(d) Sum of dividend yield (adjusted for one-half year's growth) and respective growth rate.
(e) Excludes highlighted figures.

HISTORICAL GROWTH RATES

	(a)	(b)	(b)	(b)	(b)	(c)	(c)	(c)	(c)
		Historical Growth Rates				Cost of Equity Estimates			
		Value Line		5-Yr Compound		Past 10 Years		Past 5 Years	
Company	Dividend Yield	EPS	BVPS	EPS	BVPS	EPS	BVPS	EPS	BVPS
FE	5.1%	9.0%	1.0%	-8.1%	2.5%	14.1%	6.1%	-3.0%	7.6%
TE	4.9%	12.5%	5.0%	2.1%	5.0%	17.4%	9.9%	7.0%	9.9%
ALE	4.5%	3.5%	5.0%	-0.9%	5.3%	8.0%	9.5%	3.7%	9.8%
AEP	4.6%	2.0%	5.0%	2.0%	5.1%	6.6%	9.6%	6.6%	9.7%
CNL	3.4%	7.5%	11.0%	12.5%	9.2%	10.9%	14.4%	15.9%	12.6%
ETR	4.6%	10.0%	4.0%	6.7%	4.8%	14.6%	8.6%	11.3%	9.4%
WR	4.8%	1.0%	6.0%	-1.4%	4.7%	5.8%	10.8%	3.3%	9.5%
AVA	4.5%	11.5%	4.0%	3.5%	3.1%	16.0%	8.5%	8.1%	7.6%
HE	4.8%	-6.0%	1.0%	2.4%	3.6%	-1.2%	5.8%	7.2%	8.4%
PCG	4.5%	7.0%	10.5%	0.3%	5.7%	11.5%	15.0%	4.7%	10.1%
PNW	4.4%	0.5%	0.5%	-1.8%	0.2%	4.9%	4.9%	2.6%	4.6%
POR	4.3%	7.5%	2.0%	11.3%	2.4%	11.8%	6.3%	15.6%	6.6%
UNS	4.8%	8.5%	4.5%	9.0%	4.7%	13.3%	9.3%	13.8%	9.5%
Average (c)						12.5%	10.6%	11.3%	9.5%

Range	9.5% - 12.5%
Midpoint	11.0%
Average - All Growth Rates	11.0%

(a) Exhibit_(SGH-1), Schedule 7.
(b) Exhibit_(SGH-1), Schedule 5, p. 2.
(c) Excludes highlighted figures.

HILL DCF MODEL

PROJECTED EPS GROWTH RATES

	(a)	(b)	(b)		
		Projected EPS Growth Rate			Implied
Company	Dividend Yield	IBES	Value Line	Average	Cost of Equity
FE	5.13%	1.00%	0.50%	0.75%	$\boxed{5.88\%}$
TE	4.85%	4.67%	10.50%	7.59%	12.44%
ALE	4.54%	5.00%	6.00%	5.50%	10.04%
AEP	4.60%	4.00%	4.50%	4.25%	8.85%
CNL	3.37%	n/a	6.00%	6.00%	9.37%
ETR	4.63%	2.00%	0.50%	1.25%	$\boxed{5.88\%}$
WR	4.76%	6.09%	8.50%	7.30%	12.06%
AVA	4.54%	4.67%	4.50%	4.59%	9.12%
HE	4.78%	8.03%	11.00%	9.52%	14.29%
PCG	4.45%	4.27%	5.00%	4.64%	9.09%
PNW	4.41%	5.33%	6.00%	5.67%	10.08%
POR	4.26%	5.00%	7.50%	6.25%	10.51%
UNS	4.82%	2.60%	9.50%	6.05%	10.87%
Range (c)					**8.85% -- 14.29%**
Midpoint					**11.57%**
Average (c)					**10.61%**

(a) Exhibit_(SGH-1), Schedule 7.
(b) Exhibit_(SGH-1), Schedule 5, p. 2.
(c) Excludes highlighted figures.

WOOLRIDGE PROXY GROUP

Market Rate of Return		
Dividend Yield (a)	2.6%	
Growth Rate (b)	10.9%	
Market Return (c)		13.5%
Less: Risk-Free Rate (d)		
Long-term Treasury Bond Yield		3.3%
Market Risk Premium (e)		10.2%
Woolridge Proxy Group Beta (f)		0.70
Risk Premium (g)		7.1%
Plus: Risk-free Rate (d)		
Long-term Treasury Bond Yield		3.3%
Unadjusted CAPM (h)		10.4%
Size Adjustment (i)		0.78%
Implied Cost of Equity (j)		**11.2%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (retrieved Jan. 21, 2012).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 (retrieved Jan. 23, 2012).
(c) (a) + (b)
(d) Average yield on 30-year Treasury bonds for February 2012 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/Monthly/H15_TCMNOM_Y20.txt.
(e) (c) - (d).
(f) Exhibit JRW-11, p. 3.
(g) (e) x (f).
(h) (d) + (g).
(i) *Morningstar*, "2012 Ibbotson SBBI Valuation Yearbook," at Appendix C, Table C-1 (2012).
(j) (h) + (i).

HILL PROXY GROUP

Market Rate of Return		
Dividend Yield (a)	2.6%	
Growth Rate (b)	10.9%	
Market Return (c)		13.5%
Less: Risk-Free Rate (d)		
Long-term Treasury Bond Yield		3.3%
Market Risk Premium (e)		10.2%
Hill Proxy Group Beta (f)		0.72
Risk Premium (g)		7.3%
Plus: Risk-free Rate (d)		
Long-term Treasury Bond Yield		3.3%
Unadjusted CAPM (h)		10.6%
Size Adjustment (i)		0.94%
Implied Cost of Equity (j)		**11.6%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (retrieved Jan. 21, 2012).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 (retrieved Jan. 23, 2012).
(c) (a) + (b)
(d) Average yield on 30-year Treasury bonds for February 2012 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/Monthly/H15_TCMNOM_Y20.txt.
(e) (c) - (d).
(f) Exhibit_(SGH-1), Schedule 8.
(g) (e) x (f).
(h) (d) + (g).
(i) *Morningstar*, "2012 Ibbotson SBBI Valuation Yearbook," at Appendix C, Table C-1 (2012).
(j) (h) + (i).

WOOLRIDGE PROXY GROUP

Market Rate of Return		
Dividend Yield (a)	2.6%	
Growth Rate (b)	10.9%	
Market Return (c)		13.5%
Less: Risk-Free Rate (d)		
Projected Long-term Treasury Bond Yield		4.4%
Market Risk Premium (e)		9.1%
Woolridge Proxy Group Beta (f)		0.70
Risk Premium (g)		6.4%
Plus: Risk-free Rate (d)		
Projected Long-term Treasury Bond Yield		4.4%
Unadjusted CAPM (h)		10.8%
Size Adjustment (i)		0.78%
Implied Cost of Equity (j)		**11.5%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (retrieved Jan. 21, 2012).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 (retrieved Jan. 23, 2012).
(c) (a) + (b)
(d) Average projected 30-year Treasury bond yield for 2012-2016 based on data from the Value Line Investment Survey, *Forecast for the U.S. Economy* (Feb. 24, 2012), IHS Global Insight, *U.S. Economic Outlook* at 25 (Dec. 2011), Blue Chip Financial Forecasts, Vol. 30, No. 12 (Dec. 1, 2011).
(e) (c) - (d).
(f) Exhibit JRW-11, p. 3.
(g) (e) x (f).
(h) (d) + (g).
(i) *Morningstar*, "2012 Ibbotson SBBI Valuation Yearbook," at Appendix C, Table C-1 (2012).
(j) (h) + (i).

HILL PROXY GROUP

Market Rate of Return		
Dividend Yield (a)	2.6%	
Growth Rate (b)	10.9%	
Market Return (c)		13.5%
Less: Risk-Free Rate (d)		
Projected Long-term Treasury Bond Yield		4.4%
Market Risk Premium (e)		9.1%
Hill Proxy Group Beta (f)		0.72
Risk Premium (g)		6.6%
Plus: Risk-free Rate (d)		
Projected Long-term Treasury Bond Yield		4.4%
Unadjusted CAPM (h)		10.9%
Size Adjustment (i)		0.94%
Implied Cost of Equity (j)		**11.9%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (retrieved Jan. 21, 2012).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 (retrieved Jan. 23, 2012).
(c) (a) + (b)
(d) Average projected 30-year Treasury bond yield for 2012-2016 based on data from the Value Line Investment Survey, *Forecast for the U.S. Economy* (Feb. 24, 2012), IHS Global Insight, *U.S. Economic Outlook* at 25 (Dec. 2011), Blue Chip Financial Forecasts, Vol. 30, No. 12 (Dec. 1, 2011).
(e) (c) - (d).
(f) Exhibit_(SGH-1), Schedule 8.
(g) (e) x (f).
(h) (d) + (g).
(i) *Morningstar*, "2012 Ibbotson SBBI Valuation Yearbook," at Appendix C, Table C-1 (2012).
(j) (h) + (i).

COST RECOVERY MECHANISMS

HILL PROXY GROUP

	Company	Mechanism
1	ALLETE	FCA; DSMA; ECA; TCR
2	American Elect Pwr	FCA; ECA; DSMA; TCR
3	Avista Corp.	FCA; PGA; Cost tracker for income taxes
4	Black Hills Corp.	FCA; PGA; TCR
5	Cleco Corp.	FCA
6	Entergy Corp.	FCA; PGA; DSMA
7	FirstEnergy Corp.	FCA for non-shopping customers; ICR; TCR; Cost tracker for Smart Meters
8	Hawaiian Elec.	FCA; RDM; ICR; Pension cost tracker
9	PG&E Corp.	FCA; RDM; ICR; ECA; TCR; Variety of balancing accounts cover a substantial portion of authorized revenue requirements
10	Pinnacle West Capital	FCA; DSMA; ACC has issued policy statement in support of RDM
11	Portland General Elec.	FCA; RDM; ICR
12	SCANA Corp.	FCA; PGA; RDM; DSMA; WNC
13	TECO Energy	FCA; PGA; ECA; DSMA
14	Unisource Energy	FCA; PGA; DSMA; ACC has issued policy statement in support of RDM
15	Westar Energy	FCA; ECA; Employee benefit cost tracker

BDR -- Bad Debt Cost Recovery Rider
DSMA -- Demand Side Management / Conservation Adjustment Clause
ECA -- Environmental and/or Emissions Cost Adjustment Clause
FCA -- Fuel and/or Power Cost Adjustment Clause
ICR -- Infrastructure / Renewables Cost Recovery
PGA -- Gas Cost Adjustment Clause
RDM -- Revenue Decoupling Mechanism
TCR -- Transmission Cost Recovery Tracker
WNC -- Weather Normalization Clause or other mitigants

Source : 2010 Form 10-K Reports

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

APPLICATION OF KENTUCKY POWER COMPANY	)
FOR APPROVAL OF ITS 2011 ENVIRONMENTAL	)
COMPLIANCE PLAN, FOR APPROVAL OF ITS	)
AMENDED ENVIRONMENTAL COST RECOVERY	) Case No. 2011-00401
SURCHARGE TARIFF, AND FOR THE GRANT OF A	)
CERTIFICATE OF PUBLIC CONVENIENCE AND	)
NECESSITY FOR THE CONSTRUCTION AND	)
ACQUISITION OF RELATED FACILITIES	)

REBUTTAL TESTIMONY

OF

MARK A. BECKER

April 16, 2012

REBUTTAL TESTIMONY OF
MARK A. BECKER, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2011-00401

TABLE OF CONTENTS

REBUTTAL TESTIMONY OF
MARK A. BECKER, 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 Mark A. Becker, and my business address is 212 E. 6th Street, Tulsa, Oklahoma. I am employed by the American Electric Power Service Corporation (AEPSC) as Manager – Resource Planning.

II. BACKGROUND

Q. WOULD YOU PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received a Bachelor of Science Degree in Electrical Engineering from the University of Arkansas in 1983.

I am currently employed by AEPSC as Manager – Resource Planning. I have over 28 years of experience working for municipal and investor-owned electric utilities and energy trading companies. The majority of my experience, approximately 25 years, has been related to performing a utilities' resource planning and operational analysis functions using the proprietary long-term resource optimization software known as STRATEGIST®. One of my responsibilities at Florida Power and Light (FPL) in 1983-1985, was to develop the first PROSCREEN® (predecessor to Strategist®)

database of the FPL system. While developing FPL's PROSCREEN® database, I also beta tested several modules of the PROSCREEN® software for its developer New Energy Associates. In addition, I also participated in the beta testing of EPRI's Electric Generation Expansion Analysis System (EGEAS) while at FPL. A summary of my work experience is attached as **Exhibit MAB-1**.

Q. **WHAT ARE YOUR RESPONSIBILITIES AS MANAGER – RESOURCE PLANNING?**

A. I am responsible for the coordination and performance of long-term generation resource planning studies using Strategist®. These studies include evaluating the economics of emission retrofits that could be installed on AEP's generating fleet and developing Integrated Resource Plans for AEP's operating companies.

Q. **DID YOU FILE DIRECT TESTIMONY IN THIS CASE?**

A. No.

III. PURPOSE

Q. **WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?**

A. The purpose of my rebuttal testimony will be to respond to certain assertions made by Sierra Club's witnesses Dr. Fisher as it pertains to certain inputs utilized in Kentucky Power Company's (KPCo, or "the Company") Strategist® modeling. Specifically, I will refute Dr. Fisher's argument that the Company's Strategist® modeling incorrectly represented the "installed" capital costs—and, therefore, attendant annual levelized carrying charges—for the Big Sandy retrofit alternative (Option #1) and the Big Sandy replacement options (Options #2, #3, #4A and #4B) by:

- proving that the Company did not understate the installed capital costs—and attendant annual levelized carrying charges—assumed in Strategist® for the Big Sandy retrofit alternative (Option #1);
- proving that the Company did not overstate the installed capital costs assumed in Strategist® by double-counting corporate overheads for the brownfield combined-cycle (CC) alternative modeled to replace Big Sandy (Option #2), as well as for the studied alternatives that assumed delayed construction of such replacement new build CCs (Options #4A and #4B);
- proving that the methodology Dr. Fisher utilized in his re-analysis to "correct" the Company's capital cost modeling actually understated the installed capital cost and attendant annual carrying charges for all of the alternatives that were evaluated. I will show that Dr. Fisher's methodology is not representative of the annual levelized carrying charges produced by Strategist® and utilized by the Company in its evaluation of the alternatives. In order to make this argument, I will provide a brief description of Strategist®'s capital cost modeling inputs and requirements necessary to establish the annual levelized carrying charges applicable to the capital investment[1]; and finally
- as part of this modeling input validation, I will also refute Dr. Fisher's argument that the Company, inconsistently modeled the fixed O&M costs used as an input into the Strategist® model for the Big Sandy retrofit alternative (Option #1).

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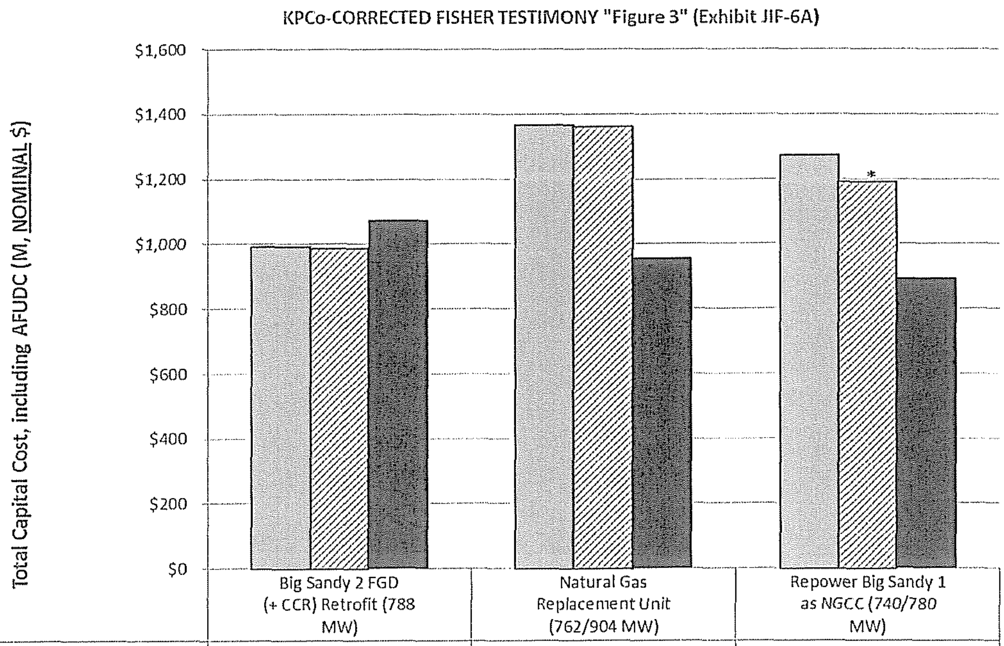
[1] Capital carrying charges representing a levelized annual proxy for a (pre-tax) return on assumed investment capitalization, depreciation charges, as well as other minor attendant administrative costs applicable to the investment.

Q. **PLEASE PROVIDE A SUMMARY OF YOUR OVERALL FINDINGS.**

A. After reviewing Dr. Fisher's testimony and methods used in his "re-analysis" of the Company's evaluation, I have found that he has overstated the in-service date capital cost of the Big Sandy retrofit alternative (Option #1) and understated the in-service date capital cost of the brownfield CC modeled to replace Big Sandy, and also the Big Sandy 1 CC repower. Figure 1 below (also Exhibit MAB-5) compares the in-service date capital costs found in the testimony of Company witness Weaver (Weaver, Table 2 (plus AFUDC)), to those utilized in the Company's Strategist® modeling (KPCo-Strategist Modeled) and to those found in Dr. Fisher's testimony (Synapse-Strategist Modeled).

Figure 1



	Big Sandy 2 FGD (+ CCR) Retrofit (788 MW)	Natural Gas Replacement Unit (762/904 MW)	Repower Big Sandy 1 as NGCC (740/780 MW)
Weaver, Table 2 (plus AFUDC)	$990	$1,366	$1,274
KPCo-Strategist Modeled	$989	$1,361	$1,190*
Synapse-Strategist Modeled	$1,073**	$955***	$894****

* See Rebuttal Exhibit MAB-4 (KPCo-Strategist modeling understated the escalation rate required to match the project's projected cost in nominal $)
** See Rebuttal Exhibit MAB-2
*** See Rebuttal Exhibit MAB-3
**** See Rebuttal Exhibit MAB-4

Figure 1 shows the KPCo-Strategist Modeled capital costs are very similar, if not somewhat understated, compared to Weaver, Table 2 (plus AFUDC). However, the Synapse-Strategist Modeled capital costs overstate the Big Sandy 2 FGD retrofit (Option #1) costs by \$83M. In addition, the capital cost for the Natural Gas CC Replacement Unit (Option #2, #4A and #4B) and the Repower Big Sandy 1 as a NGCC (Option #3) are understated by \$411M and \$380M, respectively.

IV. DESCRIPTION OF STRATEGIST® CAPITAL COST MODELING REQUIREMENTS

Q. **PLEASE DESCRIBE ANY REQUIREMENTS FOR MODELING AN ALTERNATIVE'S CAPITAL COSTS IN STRATEGIST®.**

A. One of the input requirements of Strategist® is that annual construction costs of an alternative can only be captured in the alternative's overnight capital cost without AFUDC (2011\$/kW) up to the alternative's in-service year. If an option has an in-service date other than January 1 of year X, then any year X cash flows, and any cash flows occurring after that in-service date must be captured uniquely. For example, if an alternative has an in-service date of June 30, 2016, the annual construction costs for that alternative can only be captured through 2015 in the alternative's overnight capital cost utilized by the model. Therefore, due to this requirement, any annual construction costs that occur *during* the in-service year (January 1, 2016 through June 30, 2016), as well as any estimated post-in service "clean-up costs", must be accounted for by some other mechanism.

Q. PLEASE DESCRIBE THE REQUIRED MECHANISM FOR RECOVERING ANNUAL CONSTRUCTION COSTS THAT OCCUR IN AN ALTERNATIVE'S IN-SERVICE YEAR AND BEYOND.

A. One of the mechanisms for recognizing annual construction costs that occur in an alternative's in-service year and potentially beyond is to calculate the annual levelized carrying charges for those "incremental" construction costs and simply capture them by way of some other input in the model. For example, such annual levelized carrying charges would be calculated separately and then included in the alternative's Fixed O&M Cost input within the model. This is the approach that the Company has used to capture the annual construction costs that occur in the in-service year and beyond for alternatives evaluated in this analysis, in particular, the Big Sandy 2 retrofit alternative (Option #1).

V. THE BIG SANDY RETROFIT ALTERNATIVE CAPITAL COSTS WERE MODELED CORRECTLY IN STRATEGIST

Q. DO YOU AGREE WITH DR. FISHER'S ASSERTION THAT THE CAPITAL COSTS FOR THE BIG SANDY 2 RETROFIT ALTERNATIVE (OPTION #1) WERE UNDERSTATED IN THE COMPANY'S STRATEGIST® MODELING?

A. No. The Company has correctly modeled the Big Sandy 2 retrofit alternative's capital costs in Strategist® working within the model's required capital cost inputs and modeling requirements. In fact, as shown later in my testimony, the nominal installed capital costs of the Big Sandy 2 retrofit alternative closely matches the values for that alternative set forth in Company witness Weaver's TABLE 2 from his direct testimony.

Q. **PLEASE DESCRIBE HOW THE BIG SANDY 2 RETROFIT OVERNIGHT CAPITAL COSTS WERE DERIVED FOR USE AS STRATEGIST INPUTS.**

A. As described above, the Strategist® capital cost modeling utilized in this analysis allows annual construction costs only up to the project's in-service year to be directly accounted for in the alternative's overnight capital cost without AFUDC (2011$/kW). The Big Sandy 2 retrofit alternative is assumed to be in-service by June 1, 2016. Therefore, using the annual construction expenditures for 2011 through 2015 that were the basis for Company witness Weaver's TABLE 2, an overnight capital cost without AFUDC (2011$/kW) was developed for the Big Sandy 2 retrofit alternative. Exhibit MAB-2 provides a summary of these calculations. In fact, as demonstrated in that exhibit, the total Big Sandy 2 retrofit alternative's cost per kW (2011$) input of $696/kW aligns with the figure as recognized by Sierra Club witness Rachel Wilson on page 7, line 1 of her direct testimony.

Q. **PLEASE THEN DESCRIBE HOW THE ANNUAL CONSTRUCTION COSTS OCCURING *DURING* THE IN-SERVICE YEAR AND AFTER WERE ACCOUNTED FOR IN THE MODELING OF THE BIG SANDY 2 RETROFIT.**

A. As also described above, one of the mechanisms for recovering annual construction costs that occur in an alternative's in-service year and beyond is to calculate the annual levelized carrying charges for those construction costs and capture those elements of total expended capital as part of the Fixed O&M costs for that alternative. Exhibit

MAB-2 also provides a summary of those (incremental) fixed O&M calculations for the Big Sandy 2 retrofit alternative. Exhibit MAB-2 identifies nearly $288 million of capital expenditures associated with the Big Sandy 2 retrofit project that occurred either within the in-service year (2016), or beyond, that had to be uniquely accounted for in this 'incremental' Fixed O&M modeling. Exhibit MAB-2 shows that nearly $48 million of 'incremental" Fixed O&M would be included in the unit's Fixed O&M cost modeling over the 2017-2030 period to recover the $288 million.

In summary, and counter to Dr. Fisher's contention, this exhibit clearly demonstrates that, in effect, the total of the nominal capital expenditure associated with the Big Sandy 2 DFGD retrofit alternative of $887 million as identified in Company witness Weaver's testimony in TABLE 2, were indeed properly recognized and utilized in the Strategist® cost modeling for that option.

Q. AS A RESULT, IS DR. FISHER'S RE-CALCULATION OF THE BIG SANDY ALTERNATIVE COSTS SHOWN IN "TABLE 2" (PAGE 25) OF HIS DIRECT TESTIMONY IN ERROR?

A. Yes. Dr. Fisher has overstated the costs of the Big Sandy retrofit alternative. While he applied the carrying charge methodology described in his testimony to the 'full' project' capital spend, he has not properly accounted for the capital carrying charges already captured in "incremental" Fixed O&M. Therefore, his adjustment for the Big Sandy 2 retrofit alternative has effectively double-counted the construction costs that occurred in 2016 and beyond.

VI. THE (2016) BIG SANDY CC REPLACEMENT AND DELAYED NEW BUILD CC ALTERNATIVES' CAPITAL COSTS WERE MODELED ACCURATELY IN STRATEGIST®

Q. **IS DR. FISHER CORRECT IN HIS ASSERTION THAT CORPORATE OVERHEADS WERE EFFECTIVELY "DOUBLE-COUNTED" IN THE COMPANY'S CAPITAL COST MODELING OF THE 2016 BIG SANDY CC REPLACEMENT AND DELAYED NEW-BUILD CC ALTERNATIVES (OPTION #2, #4A AND #4B)?**

A. No. It appears that Dr. Fisher believes that certain project-related direct owner's costs and corporate capital overhead (OH) allocations are one and the same. They are not. The Company's projected new-build CC "owner's costs" are reflective of $53.8 million of estimated non-engineering, procurement and construction (EPC) costs associated with the $790.2M costs for the brownfield CC option. Those costs are considered "direct" costs related to project construction and cover Project Management, Engineering, and Construction (PMEC) costs anticipated to be borne by the Company and *not* the EPC-provider, as well as start-up/unit commissioning costs, Builder's-All-Risk (BAR) insurance, etc. These $53.8 million of estimated project costs are embedded in the overall "direct" project cost estimates of $969.1M for this brownfield CC option (before a 10% contingency adder).

Contrastingly, the 7% corporate capital overheads reflected on Company witness Weaver's TABLE 2 summary (col. e) are considered "indirect" costs related to project construction and cover costs related to typical KPCo corporate overhead charges applied to capital work orders.

By sheer coincidence, the $53.8M AEP owner's cost is approximately 7% (6.8%) of the $790.2M in total EPC capital spend. The AEP owner's cost of 6.8% is comparable to the 7% used for the indirect capital overheads rate applied to KPCo capital work orders as shown on Company witness Weaver's TABLE 2. Because these two completely different rates are very similar, the Company contends that Dr. Fisher has mistakenly assumed these costs were double-counted.

VII. DESCRIPTION OF STRATEGIST® INPUTS AND METHODOLOGY FOR CALCULATING AN ALTERNATIVE'S ANNUAL LEVELIZED CARRYING CHARGES

Q. PLEASE DESCRIBE STRATEGIST®'S INPUTS AND METHODOLOGY FOR CALCULATING ANNUAL LEVELIZED CARRYING CHARGES AND THE MODEL'S ABILITY FOR REPORTING OF THOSE CHARGES.

A. Several inputs--and sequential "steps"—are required for the model to determine an alternative's fixed, on-going annual levelized carrying charges necessary to recover the capital investment of an alternative:

- The alternative's overnight capital cost without AFUDC expressed in 2011$/kW.
- The alternative's megawatt (MW) capacity used to convert the overnight capital cost (2011$/kW) to an overnight construction cost, expressed in 2011$.
- An expenditure profile that creates annual construction expenditures (2011$) by spreading the overnight construction costs over the alternative's construction period.

- An escalation rate used to convert annual construction costs (in 2011$), to nominal or "as-spent" dollars over the alternative's construction period.
- The Company's weighted average cost of capital (WACC) used to calculate the alternative's AFUDC from the annual nominal construction costs. The WACC allows the return on the investment to be recovered. The AFUDC cost is then added to the annual nominal construction costs to create a nominal total project capital cost at the alternative's in-service date.
- An annual levelized carrying charge rate used to create an annual levelized carrying charge to recover the alternative's "in-service date" total project capital cost over its projected economic recovery period. This annual levelized carrying charge rate recovers the Company's WACC, depreciation, Federal Income Taxes, property taxes and G&A expenses associated with a capital project. Through the use of a levelized carrying charge, the return of and on an investment can be captured.
- The in-service date annual levelized carrying charge for an alternative is created by multiplying the nominal total plant cost at the alternative's in-service date by the annual levelized carrying charge rate. The in-service date annual levelized carrying charge is de-escalated at the alternative's escalation rate to calculate the annual levelized carrying charge that would occur if the in-service date was earlier than what was modeled. For in-service dates occurring later than what was modeled, the in-service date levelized carrying charge is escalated to the desired in-service year at the alternative's escalation rate to determine the levelized carrying charge for that year.
- Strategist® determines the annual levelized carrying charges for each year of the study period (2011-2040) for all of the alternatives' modeled by utilizing the inputs and methodology described above. Through activating the model's diagnostic that produces the Levelized and Replacement Cost

Tables, the user can generate a table of these annual levelized carrying charges as calculated by the model over the study period.

Q. IN THE COMPANY'S ANALYSIS OF BIG SANDY ALTERNATIVES, DID THE COMPANY USE THE STRATEGIST® INPUTS, MODEL METHODOLOGY AND REPORTING DESCRIBED IN THE TESTIMONY ABOVE?

A. Yes. The Company allowed Strategist® to calculate the annual levelized carrying charges used in the analysis of Big Sandy alternatives. The Company activated the diagnostic that produces the Levelized and Replacement Cost Tables and has used that information as the basis for representing the levelized carrying charges in their calculation spreadsheets for each alternative. Dr. Fisher has referred to these calculation spreadsheets as the "Company Strategist Compilation Workbook" on page 21 lines 16-17 of his testimony.

VIII. DESCRIPTION OF DR. FISHER'S METHODOLOGY FOR CALCULATING AN ALTERNATIVE'S ANNUAL LEVELIZED CARRYING CHARGES.

Q. BRIEFLY DESCRIBE DR. FISHER'S METHODOLOGY FOR CALCULATING AN ALTERNATIVE'S ANNUAL LEVELIZED CARRYING CHARGE.

A. As described on page 24 lines 17-18 and footnote 23, Dr. Fisher created his annual levelized carrying charges by using the Excel PMT function assuming the Company's 8.64% WACC as the interest rate in that PMT function. This PMT function calculates an annual payment, similar to a mortgage payment, which must be made over the book life of the asset to recover the capital cost of that asset.

Q. **HOW DOES DR. FISHER'S METHODOLOGY FOR CALCULATING AN ALTERNATIVE'S ANNUAL LEVELIZED CARRYING CHARGE UNDERSTATE THOSE CHARGES?**

A. The Company's WACC is only one component of the cost that must be recovered when making a capital investment. In addition to the WACC, the investments depreciation cost, Federal Income Taxes (FIT), property taxes and General & Administration (G&A) Expenses must also be taken into account. Dr. Fisher has understated his annual levelized carrying charges by only taking the Company's WACC into account effectively reflecting only a return on, not return on and of the investment.

IX. COMPARISON OF THE COMPANY'S AND DR. FISHER'S NOMINAL IN-SERVICE DATE CAPITAL COSTS DERIVED FROM THE ALTERNATIVE'S IN-SERVICE DATE ANNUAL LEVELIZED CARRYING CHARGES.

Q. **HOW CAN AN ALTERNATIVE'S NOMINAL IN-SERVICE DATE CAPITAL COST BE DERIVED FROM THE ALTERNATIVE'S IN-SERVICE DATE ANNUAL LEVELIZED CARRYING CHARGE?**

A. As described in the above testimony, the in-service date annual levelized carrying charge for an alternative is created by multiplying the nominal total plant cost at the alternative's in-service date by the levelized carrying charge rate. For example, if the alternative's nominal in-service date total plant cost is $1M and the levelized carrying charge rate is 15% the annual levelized carrying charge for the alternative would be \$150,000 over the alternative's book life. (Example: \$1,000,000 * .15 = \$150,000). Therefore, if the in-service date annual levelized carrying charge and levelized carrying charge rate are known, the nominal in-service date total plant cost can be determined by dividing the in-service date annual levelized carrying charge by the levelized carrying charge rate. (Example: \$150,000 / .15% = \$1,000,000)

Q. **PLEASE DERIVE THE NOMINAL IN-SERVICE DATE CAPITAL COST FOR THE BIG SANDY RETROFIT (OPTION#1) USING THE IN-SERVICE DATE ANNUAL LEVELIZED CARRYING CHARGE UTILIZED BY THE COMPANY IN THE KPCO MODELING.**

A. The derivation of this cost can be found in Exhibit MAB-2 Section II. OVERSTATEMENT of witness Fisher "Restatement" of Option #1 (BS2 Retrofit) Project Capital Cost. The required components for this calculation were found either in workpapers provided Synapse to support Dr. Fisher's testimony, or by the Company in response to Sierra Clubs various discovery requests and are noted in Exhibit MAB-2. Using the annual levelized carrying charge of \$111,179,000 for 2016 (in-service date) and the Company's 15 year levelized carrying charge rate of 16.57% a 2016 in-service date capital cost of \$670,966,000 is calculated as shown in Exhibit MAB-2 and as follows:

$$\$111{,}179{,}000 / .1657 = \$670{,}966{,}000$$

This calculated 2016 in-service date capital cost compares closely to the capital cost (\$672,499,000) developed from the cash-flows in Exhibit MAB-2. As described above the additional \$317,770,000 in capital costs that occurred during and after the

2016 in-service date were captured in the Fixed O&M for this alternative. If these post in-service date capital costs are accounted, the total project cost of $988,736,000 ($670,966,000 + $317,770,000) is determined. This total project cost closely matches the $990,270,000 developed from the capital cash flows. Therefore, no "Corrected Capital Cost" adjustment in necessary as suggested by Dr. Fisher in Table 2 of his testimony.

Q. **PLEASE DERIVE THE NOMINAL IN-SERVICE DATE CAPITAL COST FOR THE BIG SANDY RETROFIT (OPTION#1) USING THE IN-SERVICE DATE ANNUAL CARRYING CHARGE UTILIZED BY DR. FISHER IN HIS RE-ANALYSIS WITH CORRECTED CAPITAL COSTS.**

A. The derivation of this cost can be found in Exhibit MAB-2 Section II. OVERSTATEMENT of Sierra Club witness Fisher "Restatement" of Option #1 (BS2 Retrofit) Project Capital Cost. The first step is to determine the annual carrying charge in 2011$. Using the annual cost of the Big Sandy 2 Retrofit option (Option #1) assumed by Synapse ($897.1M) and the Company's WACC of 8.64% (which is much lower than the Company's 15 year levelized carrying charge rate of 16.57%) a 2011$ annual carrying charge of $108,933,000 is calculated using the Excel PMT function as shown below and in Exhibit MAB-2.

PMT (.0864,15,$897,100,000) = $108,933,000

The 2011$ annual carrying charge is escalated at the alternative's escalation rate (2.8%) for 5 years to determine the annual carrying charge at the alternative's 2016 in-service date.

$$\$108,933,000 * 1.028^5 = \$125,063,000$$

By properly applying the Company's 15 year annual levelized carrying charge rate of 16.57% (instead of the incorrect 8.64% WACC) to the 2016 annual carrying charge, the 2016 in-service date capital cost of $754,756,000 is determined.

$$\$125,063,000 \ / \ .1657 = \$754,756,000$$

Dr. Fisher did not remove the additional $317,770,000 in capital costs that occurred after the 2016 in-service date that were captured in the Fixed O&M for this alternative in his re-analysis. By virtue of not removing these Fixed O&M cost, he essentially created a capital cost including AFUDC for this alternative of $1,072,527,000 ($754,756,000 + $317,770,000). Effectively overstating the capital cost for this alternative by approximately $82M.

Q. **PLEASE DERIVE THE NOMINAL IN-SERVICE DATE CAPITAL COST FOR THE (2016) BIG SANDY CC REPLACEMENT AND DELAYED NEW BUILD CC ALTERNATIVE (OPTION #2, #4A AND #4B) USING THE IN-SERVICE DATE ANNUAL LEVELIZED CARRYING CHARGE UTILIZED BY THE COMPANY IN THE KPCO MODELING.**

A. The derivation of this cost can be found in Exhibit MAB-3 Section II. UNDERSTATEMENT of Sierra Club witness Fisher "Restatement" of Option #2, #4A and #4B (NGCC Replacement) Project Capital Cost. The required components for this calculation were found either in workpapers provided Synapse to support Dr. Fisher's testimony, or by the Company in response to Sierra Clubs various discovery requests and are noted in Exhibit MAB-3. Using the annual levelized carrying charge of $182,739,000 for 2016 (in-service date) and the Company's 30 year levelized carrying charge rate of 13.43%, a 2016 in-service date capital cost of $1,360,678,000 is calculated as shown in Exhibit MAB-3 and as follows:

$182,739,000 / .1343 = $1,360,678,000

This calculated 2016 in-service date capital cost is lower than, but compares closely to, the capital cost ($1,365,979) developed from the cash-flows for this alternative in Exhibit MAB-3. The slight (.038%) difference is due to small differences in AFUDC calculations in the Company's Strategist® modeling of this alternative. Therefore, no "Corrected Capital Cost" adjustment is necessary by Dr. Fisher for this alternative.

Q. **PLEASE DERIVE THE NOMINAL IN-SERVICE DATE CAPITAL COST FOR THE (2016) BIG SANDY CC REPLACEMENT AND DELAYED NEW BUILD CC ALTERNATIVE USING THE IN-SERVICE DATE ANNUAL CARRYING CHARGE UTILIZED BY DR. FISHER IN HIS RE-ANALYSIS WITH CORRECTED CAPITAL COSTS.**

A. The derivation of this cost can be found in Exhibit MAB-3 Section II. UNDERSTATEMENT of Sierra Club witness Fisher "Restatement" of Option #2 (NGCC Replacement) Project Capital Cost. The first step is to determine the annual carrying charge in 2011$. Using the annual cost of the NGCC Replacement assumed by Synapse ($1,260M) and the Company's WACC of 8.64% (which is much lower than the Company's 30 year levelized carrying charge rate of 13.43%) a 2011$ annual carrying charge of $118,747,000 is calculated using the Excel PMT function as shown below and in Exhibit MAB-3.

PMT(.0864,30,$1,260,000,000) = $118,747,000

The 2011$ annual carrying charge is escalated at the alternative's escalation rate (1.55%) for 5 years to determine the annual carrying charge at the alternative's 2016 in-service date.

$$\$118{,}747{,}000 * 1.0155^5 = \$128{,}239{,}000$$

By properly applying the Company's 30 year annual levelized carrying charge rate of 13.43% (instead of the incorrect 8.64% WACC) to the 2016 annual carrying charge the 2016 in-service date capital cost of $954,870,000 is determined.

$$\$128{,}239{,}000 / .1343 = \$954{,}870{,}000$$

Dr. Fisher's use of the 8.64% WACC as an annual carrying charge rate has effectively underestimated the nominal in-service date capital cost of the NGCC Replacement by approximately $411M.

Q. **PLEASE DERIVE THE NOMINAL IN-SERVICE DATE CAPITAL COST FOR THE BIG SANDY 1 CC REPOWER (OPTION#3) USING THE IN-SERVICE DATE ANNUAL LEVELIZED CARRYING CHARGE UTILIZED BY THE COMPANY IN THE KPCO MODELING.**

A. The derivation of this cost can be found in Exhibit MAB-4 Section II, UNDERSTATEMENT of witness Fisher "Restatement" of Option #3 (BS1 CC Repowering) Project Capital Cost. The required components for this calculation were found either in workpapers provided Synapse to support Dr. Fisher's testimony, or by the Company in response to Sierra Clubs various discovery requests and are noted in Exhibit MAB-4. Using the annual levelized carrying charge of $180,208,000 for 2016(in-service date) and the Company's 20 year levelized carrying charge rate of

15.14% a 2016 in-service date capital cost of $1,190,277 is calculated as shown in Exhibit MAB-4 and as follows:

$180,208,000 / .1514 = $1,190,277

This calculated 2016 in-service date capital cost used in the Company's Strategist® modeling actually understates the capital cost ($1,273,479,000) by 7% compared to those developed from the cash-flows in Exhibit MAB-4. The understatement of the capital cost used in the Company's Strategist® modeling was due to using a capital cost escalation rate of 1.55% instead of the 2.8% used in the development of the cash flows. Therefore, there should actually be an adjustment to increase the capital costs of this option rather than an adjustment to decrease the capital cost of this option as suggested by Dr. Fisher in Table 2 of his testimony.

Q. **PLEASE DERIVE THE NOMINAL IN-SERVICE DATE CAPITAL COST FOR THE BIG SANDY 1 CC REPOWER (OPTION#3) USING THE IN-SERVICE DATE ANNUAL CARRYING CHARGE UTILIZED BY DR. FISHER IN HIS RE-ANALYSIS WITH CORRECTED CAPITAL COSTS.**

A. The derivation of this cost can be found in Exhibit MAB-4 Section II, UNDERSTATEMENT of Sierra Club witness Fisher "Restatement" of Option #3 (BS1 CC Repowering) Project Capital Cost. The first step is to determine the annual levelized carrying charge rate in 2011$. Using the annual cost of the BS1 CC Repowering assumed by Synapse ($1,174,700,000) and the Company's WACC of 8.64% (which is much lower than the Company's 20 year levelized carrying charge rate of 15.14%) a 2011$ annual carrying charge of 125,396,000 is calculated using the Excel PMT function as shown below and in Exhibit MAB-4.

PMT(.0864,20,$1,174,700,000) = $125,396,000

The 2011$ annual carrying charge is escalated at the alternatives escalation rate (1.55%) for 5 years to determine the annual carrying charge at the alternative's 2016 in-service date.

$$\$125,396,000 * 1.0155^5 = \$135,421,000$$

By properly applying the Company's 20 year annual levelized carrying charge rate of 15.14% (instead of the incorrect 8.64% WACC) to the 2016 annual carrying charge the 2016 in-service date capital cost of $894,457,000 is determined.

$$\$135,421,000 / .1514 = \$894,457,000$$

Dr. Fisher's use of the 8.64% WACC as an annual levelized carrying charge rate has effectively underestimated the nominal in-service date capital cost of the NGCC Replacement by approximately $379M.

Q. PLEASE SUMMARIZE THE COMPARISON OF THE BIG SANDY ALTERNATIVES' NOMINAL IN-SERVICE DATE CAPITAL COSTS USED IN THE COMPANY'S ANALYSIS AND DR. FISHERS ANALYSIS.

A. Exhibit MAB-5 provides a graphical comparison of the nominal in-service date capital costs used by the Company (KPCO-Strategist Modeled) and Dr. Fisher (Synapse-Strategist Modeled) compared to Company witness Weaver's Table 2. The graph indicates that the Company's in-service date capital cost modeling closely matches, or even understates (in the case of the Big Sandy 1 repower) the costs shown in witness Weaver's Table 2. However, the in-service date capital costs used by Dr. Fisher in his re-analysis with "Corrected Capital Costs" overstate the capital costs of the Big Sandy 2 retrofit alternative by $82M and significantly understate the capital costs of the Big

Sandy CC replacement alternative and the Big Sandy 1 Repower alternative by approximately $411M and $380M, respectively.

X. THE BIG SANDY RETROFIT ALTERNATIVE FIXED O&M COSTS WERE CONSISTENTLY APPLIED

Q. IS DR. FISHER CORRECT IN HIS ASSERTION THAT THE COMPANY INCONSISTENTLY APPLIED THE RETROFIT ALTERNATIVE FIXED O&M COSTS?

A. No. As previously discussed in this rebuttal testimony, due to the fact that certain Strategist® modeling requires the proxying of "post-in-service year" annual capital carrying charges under the modeling category Fixed O&M, then an explanation of the relative reduction in the on-going annual O&M costs for the Big Sandy retrofit option (Option #1) beginning in the year 2031—or the year in which the Big Sandy retrofit was assumed to be fully-amortized for modeling purposes—is readily explainable. In summary, there was no understatement of such Fixed O&M costs beginning in that out-year as suggested by Dr. Fisher.

XI. CONCLUSIONS

Q. PLEASE SUMMARIZE THE CONCLUSIONS OF YOUR TESTIMONY.

A. In summary, the Company has not understated the capital cost of the Big Sandy 2 retrofit alternative. The Company has accounted for all of those capital costs by utilizing the Strategist® capital cost modeling requirements and capturing the cost occurring in the in-service year and beyond in the alternative's "incremental" fixed O&M modeling. However, Dr. Fisher has overstated the costs of the Big Sandy 2 retrofit alternative by not removing those "incremental" fixed O&M costs in his re-analysis of this alternative.

The Company has not overstated the capital costs of the Replacement CC by double-counting the Company's overhead cost. The Company has correctly captured the approximately 7% owner's costs and the additional 7% overheads for the project.

The Company has consistently utilized Strategist®'s capabilities to represent the capital cost of the Replacement CC and Big Sandy 1 repower projects through the application of a levelized carrying charge rate that recovers all of the cost of making the investment (i.e. WACC, depreciation, FIT, insurance and G&A expenses). However, Dr. Fisher has understated those capital costs through the carrying charge methodology that he has used outside of Strategist® that recovers only the WACC component of making those investments.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

VERIFICATION

The undersigned, Mark A. Becker, being duly sworn, deposes and says he is the Manager, Resource Planning for American Electric Power Company that he has personal knowledge of the forgoing testimony, and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Mark A. Becker

MARK A. BECKER

STATE OF OKLAHOMA)
) CASE NO. 2011-00401
COUNTY OF TULSA)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by, Mark A Becker, this the 11 day of April 2012.

Angela Brown

Notary Public

My Commission Expires: 2-27-14

I. EXPLANATION of Option #1 (BS2 Retrofit) Project Capital Costs
Established & Applied in KPCo's Modeling Due to Strategist® Requirements

Nominal $000	2011	2012	2013	2014	2015	(A) Capital Expenditures Estimated UP TO "In-Service Year" (i.e., thru 2015 only): BASIS FOR DETERMINING Project "Carrying Charges" in Strategist* Subtotal (2011-2015)	Cost per kW Nominal $	Cost per kW '2011 $'	(B) Capital Exp. IN/BEYOND "In-Service Year" (1) 2016	(2) 2017	(3) 2018	Sum (1):(3) BASIS FOR DETERMINING Additonal Carrying Charges as an adder to "(Increm) Fixed O&M" in Strategist* Subtotal (2016-2018)	(4) Annual KPCo Carrying Charge Rate (15-Yrs)	= (1) x (4) (Additional) Annual '(Increm) Fixed O&M' 2016 (only)	= (Sum (1):(3)) x (4) (Additional) Annual '(Increm) Fixed O&M' (2017 thru 2030)	(A)+(B) TOTAL PROJECT CAPITAL SPEND Nominal ($000) (2011-2017)	
Total BS2 (DFGD Retrofit) Project Costs (Excl. OH & AFUDC)	2,736	32,816	98,224	164,417	239,394	537,587	$ 682	$ 626	231,562	172	0	231,733				769,320	Matches Weaver Direct Testimony "TABLE 2" (col. c, ll. 5)
AEP Owner's Costs/Allocated corp & co. capital OH (@ 9.1%)	249	2,986	8,938	14,962	21,785	48,920	$ 62	$ 57	21,072	16	0	21,088				70,008	Matches Weaver Direct Testimony "TABLE 2" (col. e, ll. 5)
TOTAL (DFGD) Project Capital Expenditure (Excl. AFUDC)	2,985	35,803	107,162	179,379	261,179	586,507	$ 744	$ 683	252,634	187	0	252,821				839,328	Matches Weaver Direct Testimony "TABLE 2" (col. f, ll. 5)
AFUDC (DFGD only)	*128*	*1,803*	*8,091*	*21,078*	*41,786*	*72,886*			*28,092*	*0*	*0*	*28,092*				*100,978*	Matches Weaver Direct Testimony (pg. 25, ll. 11 & 12)
TOTAL DFGD Project Capital Expenditure (Incl. AFUDC)	3,113	37,606	115,253	200,456	302,965	659,393	$ 837	$ 768	280,726	187	0	280,913				940,306	Matches Weaver Direct Testimony (pg. 25, ll. 11 & 12)
Total BS2 (CCR-Related) Project Costs (Excl. OH & AFUDC)				1,747	9,624	11,371	$ 14	$ 13	21,592	11,233	0	32,825				44,196	Matches Weaver Direct Testimony "TABLE 2" (col. c, ll. 7)
AEP Owner's Costs/Allocated corp & co. capital OH (@ 9.1%)				159	876	1,035	$ 1	$ 1	1,965	1,022	0	2,987				4,022	Matches Weaver Direct Testimony "TABLE 2" (col. e, ll. 7)
TOTAL (CCR) PROJECT Capital Expenditure (Excl. AFUDC)				1,906	10,500	12,406	$ 16	$ 14	23,557	12,255	0	35,812				48,218	Matches Weaver Direct Testimony "TABLE 2" (col. f, ll. 7)
AFUDC (CCR-related only)				*82*	*618*	*701*			*1,045*	*0*	*0*	*1,045*				*1,745*	
TOTAL CCR-Related Project Capital Expenditure (Incl. AFUDC)				1,988	11,118	13,106	$ 17	$ 15	24,602	12,255	0	36,857				49,963	
Total DFGD Retrofit + CCR Related Capital Expenditures (Excl. AFUDC)				181,285	271,679	598,913	$ 760	$ 696	276,191	12,442	0	288,633				887,546	Matches Weaver Direct Testimony "TABLE 2" (col. f, ll. 8)
Total DFGD Retrofit + CCR Related Capital Expenditures (Incl. AFUDC)				202,445	314,083	672,499	$ 853	$ 781	305,328	12,442	0	317,770	16.57%	50,593	52,655	990,270	

Note: Matches SC witness Wilson testimony, page 7 (Company representation of retrofit project cost @ $696/kW in real '11$, excluding AFUDC)

Note: Correlates with SC witness Fisher testimony, page 27 (which discusses assumed Fixed O&M "discrepancies" for the years 2016-2030)

II. OVERSTATEMENT of Sierra Club witness Fisher "Restatement" of Option #1 (BS2 Retrofit) Project
Capital Costs (and Resultant 'Corrected Carrying Charges' reflected in Exhibit JIF-3B (his 'Table 2'))

Data Source:

CORRECT Representation of Option #1 Capital Cost in KPCo Modeling:

	111,179	($000)	Annual Option #1 (Retrofit) Levelized Carrying Charge per KPCo modeling eff: 2016 (Nominal $)
/	16.57%		Annual Levelized Carrying Charge rate (15-Yr recovery) applied in KPCo modeling
=	670,966	($000)	Equivalent ("Partial") Option #1 Cost (incl. AFUDC) utilized in determination of " Carrying Charges" (Nominal $) *(note: slight (0.25%) difference due to small "CCR-related" cost refinements not reflected in KPCo Strategist modeling)*
PLUS	317,770	($000)	Equivalent ("Partial") Option #1 Cost (incl. AFUDC). Cost including AFUDC applied to " Fixed O&M" *due to modeling requirements* (Nominal $)
=	988,736	($000)	TOTAL Option #1 Project Cost (incl. AFUDC) established & applied in KPCo Strategist modeling (Nominal $)

"Matches" total Option #1 Project Cost (incl. AFUDC), hence, no "Corrected Capital Cost" adjustment is required

o Synapse workpaper file: "Exhibit JIF-2,3 & 6 Strategist_Compilation_Workbook_Synapse.xlsx", tab: "Carrying Charges KPCO New Adds", cell O:16
o KPCo filed workpaper "KPCo CarryingCost Rates2011.xls" (response to Sierra Club 1-69)

INCORRECT Representation of Option #1 Capital Cost per Fisher Exhibits:

	897.1	($Millions)	Assumed Cost of Option #1 with AFUDC (2011 $)
Variables used on Proxied "Carrying Charge" Calculation...			
	15 Yrs.		Recovery Period
	8.64%		KPCo Weighted Average Cost of Capital 'only' (i.e., NOT a Levelized Carrying Charge Rate)
	108,933	($000)	CALCULATED Annual Option #1 (Retrofit) "Carrying Charge" assumed by Synapse in its modeling (2011 $) (utilizing Excel "PMT" function: =PMT(0.0864,15,$897.1M)) ...In this calculation, Synapse applied a WACC *instead of* a full Carrying Charge Rate (incl. depreciation & FIT), this results only reflects an "(After-Tax) Return ON" capital... not an appropriate "(Pre-Tax) Return ON and OF" capital (i.e., true revenue requirement)
x	1.028⁵		Escalation to get to 'Nominal' $ @ 2016 (2.8% per annum for 5 years used in Strategist)
=	125,063	($000)	CALCULATED Annual Option #1 (Retrofit) "Carrying Charge" assumed by Synapse in its modeling (Nominal $)
/	16.57%		Annual Levelized Carrying Charge rate (15-Yr recovery)... *as above*
=	754,756	($000)	Equivalent ("Partial") Option #1 Cost (incl. AFUDC) utilized in determination of " Carrying Charges" (Nominal $)
PLUS	317,770	($000)	Equivalent ("Partial") Option #1 Cost (incl. AFUDC) applied to " Fixed O&M"... *as above* (Nominal $) ...By virtue that Synapse did NOT seek to reduce such incremental Fixed O&M as part of its "Corrected Capital Cost" adjustment
=	1,072,527	($000)	TOTAL Option #1 Cost (incl. AFUDC) effectively established & applied in *Synapse* Strategist modeling (Nominal $)
-	990,270		
	82,257	($000)	Overstatement of Option #1 Capital Cost by Sierra Club

o Synapse workpaper file: "Exhibit JIF-6B AFUDC Calc for modeling - all projects.xlxs", cell M:51
and Synapse workpaper file: "Exhibit JIF-2,3 & 6 Strategist_Compilation_Workbook_Synapse.xlsx", tab: "Carrying Charges KPCO New Adds", cell BU:7
o Synapse workpaper file: "Exhibit JIF-2,3 & 6 Strategist_Compilation_Workbook_Synapse.xlsx", tab: "Carrying Charges KPCO New Adds", cell BH:5
o "UtilDiscRate" per Synapse workpaper file: "Exhibit JIF-2,3 & 6 Strategist_Compilation_Workbook_Synapse.xlsx", tab: "StratComp - Syn", cell C:6

o Synapse workpaper file: "Exhibit JIF-2,3 & 6 Strategist_Compilation_Workbook_Synapse.xlsx", tab: "Carrying Charges KPCO New Adds", cell BU:11
and Fisher testimony, page 24 (footnote #23)

o Synapse workpaper file: "Exhibit JIF-2,3 & 6 Strategist_Compilation_Workbook_Synapse.xlsx", tab: "Carrying Charges KPCO New Adds",
cells BU:16, CH:16 , CU:17

I. Option #2, #4A and #4B (NGCC Replacement) Project Capital Costs Established & Applied by KPCo

Nominal $000	2011	2012	2013	2014	2015	* BASIS FOR DETERMINING Project "Carrying Charges" in Strategist* Total (2011-2015)	Cost per kW Nominal $	Cost per kW '2011 $'	
Total NGCC Replacement Project Costs (Excl. OH & AFUDC)	5,330	58,625	319,770	490,314	191,862	1,065,900	$ 1,179	$ 1,092	Totals Match Weaver Direct Testimony "TABLE 2" (col. c, ll. 13) AND Exhibit JIF-6B (pg. 2 of 2)
AEP Owner's Costs/Allocated corp & co. capital OH (@ 7.0%)	373	4,104	22,384	34,322	13,430	74,613	$ 83	$ 76	Totals Match Weaver Direct Testimony "TABLE 2" (col. e, ll. 13)
TOTAL NGCC Replacement Project Capital Expenditure (Excl. AFUDC)	5,703	62,728	342,154	524,636	205,292	1,140,513	$ 1,262	$ 1,169	Totals Match Weaver Direct Testimony "TABLE 2" (col. f, ll. 13) AND Exhibit JIF-6B (pg. 2 of 2)
AFUDC	*245*	*3,201*	*20,546*	*59,819*	*141,356*	*225,467*			Totals Match Exhibit JIF-6B (pg. 2 of 2) (Synapse workpaper file: "Exhibit JIF-6B AFUDC Calc for modeling all projects.xlsx" cell M:69
TOTAL NGCC Replacement Project Capital Expenditure (Incl. AFUDC)	5,947	65,930	362,999	584,455	346,648	$\boxed{1,365,979}$	$ 1,511	$ 1,395	Totals Match Exhibit JIF-6B (pg. 2 of 2) (Synapse workpaper file: "Exhibit JIF-6B AFUDC Calc for modeling all projects.xlsx" cell M:70

Capital Expenditures (Total)

* Note: Project in-service date is 1/1/2016... Therefore, for Strategist input purposes, the relative small *post*-in service (2016) project cash flow was assumed to be expended in 2015 so as to avoid the need to modify the cost category 'Fixed O&M' with such incremental carrying costs (as required with 'Option #1').

II. UNDERSTATEMENT of Sierra Club witness Fisher "Restatement" of Option #2, #4A and #4B (NGCC Replacement) Project Capital Costs (and Resultant 'Corrected Carrying Charges' reflected in Exhibit JIF-3B [his 'Table 2'])

Data Source:

CORRECT Representation of Option #1 Capital Cost in KPCo Modeling:

			Data Source
	182,739 ($000)	Annual Option #2 (NGCC Replacement) Levelized Carrying Charge per KPCo modeling eff: 2016 (Nominal $)	o Synapse workpaper file: "Exhibit JIF-2,3 & 6 Strategist_Compilation_Workbook_Synapse.xlsx", tab: "Carrying Charges KPCO New Adds", cell X:60
/	13.43%	Annual Levelized Carrying Charge rate (30-Yr recovery) applied in KPCo modeling	o KPCo filed workpaper "KPCo CarryingCost Rates2011.xls" (response to Sierra Club 1-69)
=	$\boxed{1,360,678}$ ($000)	TOTAL Option #2 Cost (incl. AFUDC) established & applied in KPCo Strategist modeling (Nominal $)	
		(note: slight (0.35%) difference due to small differences in AFUDC calculation in KPCo Strategist modeling)	

"Matches" total Option #2 Project Cost (incl. AFUDC), hence, no "Corrected Capital Cost" adjustment is required

INCORRECT Representation of Option #1 Capital Cost per Fisher Exhibits:

			Data Source
	1,260.0 ($Millions)	Assumed Cost of Option #2, #4A and #4B with AFUDC (2011 $)	o Synapse workpaper file: "Exhibit JIF-6B AFUDC Calc for modeling - all projects.xlxs", cell M:72; and Synapse workpaper file: "Exhibit JIF-2,3 & 6 Strategist_Compilation_Workbook_Synapse.xlsx", tab: "Carrying Charges KPCO New Adds", cell CD:51
	Variables used on Proxied "Carrying Charge" Calculation...		
	30 Yrs.	Recovery Period	o Synapse workpaper file: "Exhibit JIF-2,3 & 6 Strategist_Compilation_Workbook_Synapse.xlsx", tab: "Carrying Charges KPCO New Adds", cell BQ:49
	8.64%	KPCo Weighted Average Cost of Capital 'only' (i.e., NOT a Levelized Carrying Charge Rate)	o "UtilDiscRate" per Synapse workpaper file: "Exhibit JIF-2,3 & 6 Strategist_Compilation_Workbook_Synapse.xlsx", tab: "StratComp - Syn", cell C:6
	118,747 ($000)	CALCULATED Annual Option #1 (Retrofit) "Carrying Charge" assumed by Synapse in its modeling (2011 $) (utilizing Excel "PMT" function: =PMT(0.0864,30,$1260.0M)) ...In this calculation, Synapse applied a WACC *instead of* a full Carrying Charge Rate (incl. depreciation & FIT), this results only reflects an "(After-Tax) Return ON" capital... not an appropriate "(Pre-Tax) Return ON and OF" capital (i.e., true revenue requirement)	o Synpase workpaper file: "Exhibit JIF-2,3 & 6 Strategist_Compilation_Workbook_Synapse.xlsx", tab: "Carrying Charges KPCO New Adds", cell CD:55 *and* Fisher testimony, page 24 (footnote #23)
x	1.0155^5	Escalation to get to 'Nominal' $ @ 2016 (1.55% per annum for 5 years used in Strategist)	
=	128,239 ($000)	CALCULATED Annual Option #2 (NGCC Replacement) "Carrying Charge" assumed by Synapse in its modeling (Nominal $)	o Fisher workpaper file- "Exhibit JIF-2,3 & 6 Strategist_Compilation_Workbook_Synapse.xlsx", tab: "Carrying Charges KPCO New Adds", cells CD:60, CQ:60 , DD:61
/	13.43%	Annual Levelized Carrying Charge rate (30-Yr recovery)... *as above*	
=	$\boxed{954,870}$ ($000)	Equivalent Option #2 Cost (incl. AFUDC) utilized in determination of "Carrying Charges" (Nominal $)	
-	1,365,979		
	411,109 ($000)	Understatement of Option #2, #4A and #4B Capital Cost by Sierra Club	

I. Option #3 (BS1 CC Repowering) Project Capital Costs
Established & Applied by KPCo

Nominal $000	2011	2012	2013	2014	2015	*	Capital Expenditures (Total) — BASIS FOR DETERMINING Project "Carrying Charges" in Strategist* Total (2011-2015)	Cost per kW Nominal $	Cost per kW '2011 $'	
Total BS1 CC Repowering Project Costs (Excl. OH & AFUDC)	4,969	54,655	298,116	457,111	178,870		993,720	$ 1,274	$ 1,180	Totals Match Weaver Direct Testimony "TABLE 2" (col. c, ll. 18) AND Exhibit JIF-6B (pg. 2 of 2)
AEP Owner's Costs/Allocated corp & co. capital OH (@ 7.0%)	348	3,826	20,868	31,998	12,521		69,561	$ 89	$ 83	Totals Match Weaver Direct Testimony "TABLE 2" (col. e, ll. 18)
TOTAL BS1 CC Repowering Project Capital Expenditure (Excl. AFUDC)	5,316	58,480	318,984	489,109	191,390		1,063,280	$ 1,363	$ 1,263	Totals Match Weaver Direct Testimony "TABLE 2" (col. f, ll. 18) AND Exhibit JIF-6B (pg. 2 of 2)
AFUDC	228	2,985	19,434	55,769	131,783		210,199			Totals Match Exhibit JIF-6B (pg. 2 of 2) (Synapse workpaper file: "Exhibit JIF-6B AFUDC Calc for modeling all projects.xlsx" cell M:92
TOTAL BS1 CC Repowering Project Capital Expenditure (Incl. AFUDC)	5,544	61,465	338,418	544,878	323,173		$\boxed{1,273,479}$	$ 1,633	$ 1,506	Totals Match Exhibit JIF-6B (pg. 2 of 2) (Synapse workpaper file: "Exhibit JIF-6B AFUDC Calc for modeling all projects.xlsx" cell M:93

* Note: Project in-service date is 1/1/2016... Therefore, for Strategist input purposes, the relative smallpost -in service (2016) project cash flow was assumed to be expended in 2015 so as to avoid the need to modify the cost category 'Fixed O&M' with such incremental carrying costs (as required with 'Option #1').

II. UNDERSTATEMENT of Sierra Club witness Fisher "Restatement" of Option #3 (BS1 CC Repowering) Project
Capital Costs (and Resultant 'Corrected Carrying Charges' reflected in Exhibit JIF-3B [his 'Table 2'])

Data Source:

CORRECT Representation of Option #1 Capital Cost in KPCo Modeling:

180,203	($000)	Annual Option #3 (BS1 CC Repowering) Levelized Carrying Charge per KPCo modeling eff: 2016 (Nominal $)	o Synapse workpaper file: "Exhibit JIF-2,3 & 6 Strategist_Compilation_Workbook_Synapse.xlsx", tab: "Carrying Charges KPCO New Adds",cell X:104
/ 15.14%		Annual Levelized Carrying Charge rate (20-Yr recovery) applied in KPCo modeling	o KPCo filed workpaper "KPCo CarryingCost Rates2011.xls" (response to Sierra Club 1-69)
= $\boxed{1,190,277}$	($000)	TOTAL Option #3 Cost (incl. AFUDC) established & applied in KPCo Strategist modeling (Nominal $)	
		(note: 7% difference is due to the use of a 2.6% escalation rate in the cashflows and only a 1.55% in KPCo Strategist modeling)	

KPCo Strategist modeled (Nominal) Total Option #3 Project Cost (incl. AFUDC) UNDERSTATED the estimated costs...

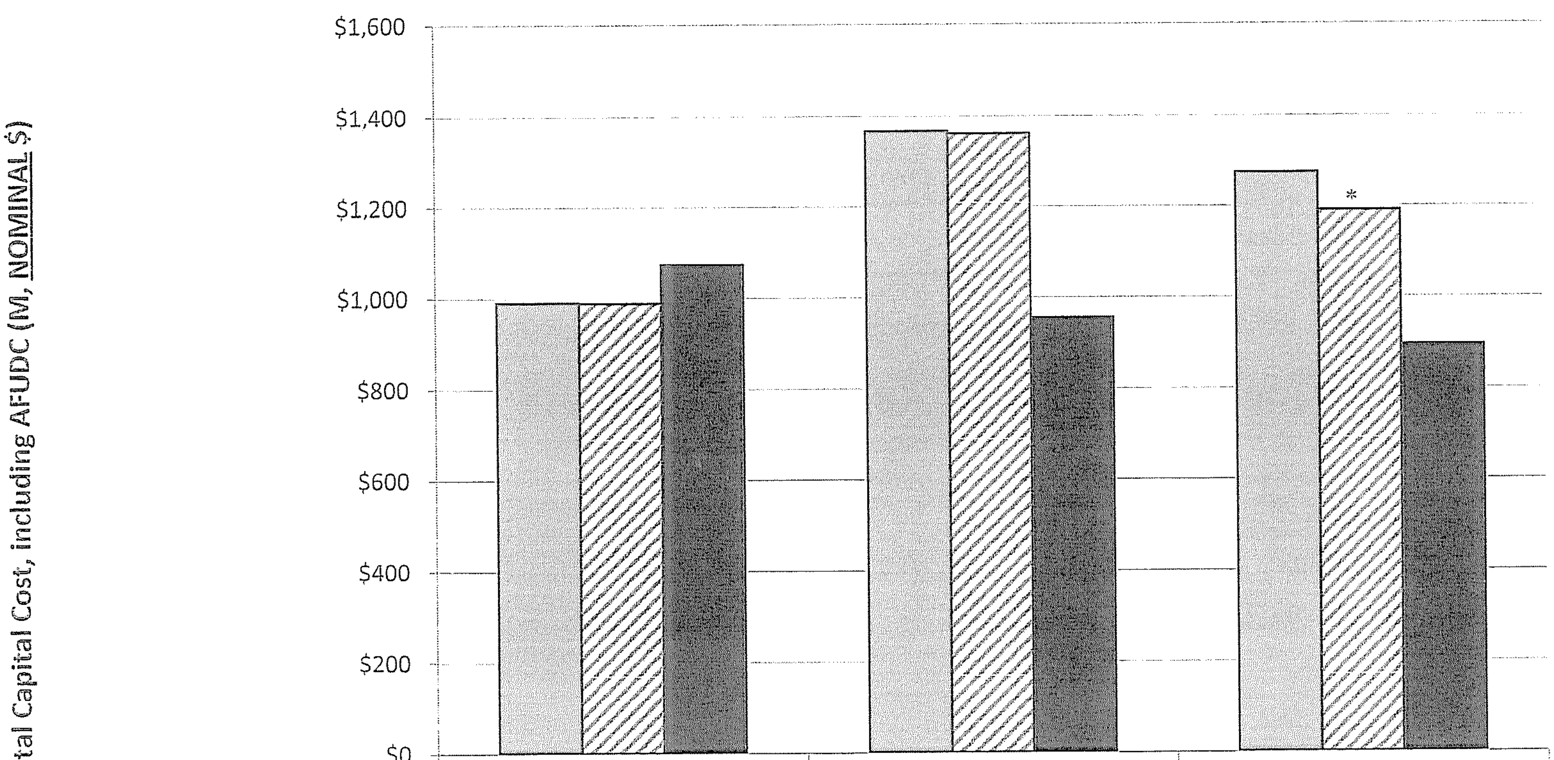
Therefore, any ultimate adjustment to 'Corrected Carrying Costs' for this option should have been an INCREASE in to the CPW costs

INCORRECT Representation of Option #1 Capital Cost per Fisher Exhibits:

1,174.7	($Millions)	Assumed Cost of Option #3 with AFUDC (2011 $)	o Synapse workpaper file: "Exhibit JIF-6B AFUDC Calc for modeling - all projects.xlxs", cell M:95; and Synapse workpaper file: "Exhibit JIF-2,3 & 6 Strategist_Compilation_Workbook_Synapse.xlsx", tab: "Carrying Charges KPCO New Adds",cell CD:95
Variables used on Proxied "Carrying Charge" Calculation...			
20 Yrs.		Recovery Period	o Synapse workpaper file: "Exhibit JIF-2,3 & 6 Strategist_Compilation_Workbook_Synapse.xlsx", tab: "Carrying Charges KPCO New Adds",cell BQ:93
8.64%		KPCo Weighted Average Cost of Capital 'only' (i.e., NOT a Levelized Carrying Charge Rate)	o "UtilDiscRate" per Synapse workpaper file: "Exhibit JIF-2,3 & 6 Strategist_Compilation_Workbook_Synapse.xlsx", tab: "StratComp - Syn",cell C:6
125,396	($000)	CALCULATED Annual Option #1 (Retrofit) "Carrying Charge" assumed by Synapse in its modeling (2011 $) (utilizing Excel "PMT" function: =PMT(0.0864,20,$1174.7M)) **...In this calculation, Synapse applied a WACC *instead of* a full Carrying Charge Rate (incl. depreciation & FIT), this results only reflects an "(After-Tax) Return ON" capital... not an appropriate "(Pre-Tax) Return ON and OF" capital (i.e., true revenue requirement)**	o Synapse workpaper file: "Exhibit JIF-2,3 & 6 Strategist_Compilation_Workbook_Synapse.xlsx", tab: "Carrying Charges KPCO New Adds",cell CD:99 *and* Fisher testimony, page 24 (footnote #23)
x 1.0155[5]		Escalation to get to 'Nominal' $ @ 2016 (1.55% per annum for 5 years used in Strategist)	
= 135,421	($000)	CALCULATED Annual Option #3 (BS1 CC Repowering) "Carrying Charge" assumed by Synapse in its modeling (Nominal $)	o Synapse workpaper file: "Exhibit JIF-2,3 & 6 Strategist_Compilation_Workbook_Synapse.xlsx", tab: "Carrying Charges KPCO New Adds", cells CD:104, CQ:104 , DD:105
/ 15.14%		Annual Levelized Carrying Charge rate (20-Yr recovery)... as above	
= $\boxed{894,457}$	($000)	Equivalent Option #3 Cost (incl. AFUDC) utilized in determination of 'Carrying Charges" (Nominal $)	
- 1,273,479			
379,021	($000)	Understatement of Option #2, #4A and #4B Capital Cost by Sierra Club	

Rebuttal Exhibit MAB 3-R

KPCo-CORRECTED FISHER TESTIMONY "Figure 3" (Exhibit JIF-6A)



	Big Sandy 2 FGD (+ CCR) Retrofit (788 MW)	Natural Gas Replacement Unit (762/904 MW)	Repower Big Sandy 1 as NGCC (740/780 MW)
Weaver, Table 2 (plus AFUDC)	$990	$1,366	$1,274
KPCo-Strategist Modeled	$989	$1,361	$1,190*
Synapse-Strategist Modeled	$1,073**	$955***	$894****

* See Rebuttal Exhibit MAB-4 (KPCo-Strategist modeling understated the escalation rate required to match the project's projected cost in nominal $)

** See Rebuttal Exhibit MAB-2

*** See Rebuttal Exhibit MAB-3

**** See Rebuttal Exhibit MAB-4

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

APPLICATION OF KENTUCKY POWER COMPANY FOR APPROVAL OF ITS 2011 ENVIRONMENTAL COMPLIANCE PLAN, FOR APPROVAL OF ITS AMENDED ENVIRONMENTAL COST RECOVERY SURCHARGE TARIFF, AND FOR THE GRANT OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION AND ACQUISITION OF RELATED FACILITIES	)	Case No. 2011-00401

REBUTTAL TESTIMONY

OF

KARL R. BLETZACKER

April 16, 2012

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

CASE NO. 2011-00401

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REBUTTAL TESTIMONY OF KARL R. BLETZACKER, 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 Karl R. Bletzacker, and my business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by the American Electric Power Service Corporation ("AEPSC") as Director-Fundamentals Analysis.

Q. DID YOU FILE DIRECT TESTIMONY IN THIS CASE?

A. No.

II. PURPOSE

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to certain arguments made by Kentucky Industrial Utility Customers, Inc. ("KIUC") witness Lane Kollen and Sierra Club, et al, ("SC") witness Mr. Jeremy Fisher in their respective direct testimonies. I will counter Mr. Kollen's contention that the natural gas pricing projections utilized in KPCo's economic analyses presented in Company witness Weaver's direct testimony are "on the high side" because of Mr. Kollen's misplaced comparison to the EIA's Annual Energy Outlook(s) and to the NYMEX futures market. Also, I will refute Mr. Fisher's assertion that CO_2 pricing projections are not reasonable and understated.

III. AEP INTERNAL NATURAL GAS PRICE PROJECTIONS ARE REASONABLE AND NOT OVERSTATED

Q. IS MR. KOLLEN CORRECT IN HIS ASSERTION THAT THE AEP PROJECTIONS OF LONG-TERM PRICING OF NATURAL GAS ARE "ON THE HIGH SIDE" WHEN COMPARED TO OTHER PUBLICLY AVAILABLE FORECASTS SUCH AS THOSE PUBLISHED BY THE EIA?

A. No, Mr. Kollen's assertion is incorrect. His anecdotal comparison on pages 19 and 20 of his testimony is flawed and is clearly unsubstantiated. First and foremost, the natural gas pricing forecast from the Energy Information Administration (EIA) Annual Energy Outlook (AEO) for both 2011 and 2012 were created under the assumption that current laws and regulations remain *unchanged*. That is, even reasonably known and emerging regulations are specifically excluded from the assumptions for such EIA-AEO projection purposes. The following excerpts are from the respective opening paragraphs of the AEO2011 and AEO2012 (Early Release) Executive Summaries.

> "Under the assumption that current laws and regulations remain unchanged throughout the projections, the *AEO2011* Reference case provides the basis for examination and discussion of energy production, consumption, technology, and market trends and the direction they may take in the future."

> "Projections in the Annual Energy Outlook 2012 (AEO2012) Reference case focus on the factors that shape U.S. energy markets in the long term, under the assumption that current laws and regulations remain generally unchanged throughout the projection period."[1]

In contrast, the AEP Fundamental Analysis group's most recent suite of natural gas price forecasts ("Fleet Transition") reflects prudent demand-induced price responses to the impending regulations that are <u>not</u> captured by the EIA. For

[1] The AEO2012 represents an "Early Release" document issued in January, 2012. The "Full Report" release of AEO2012 will occur in the spring of 2012.

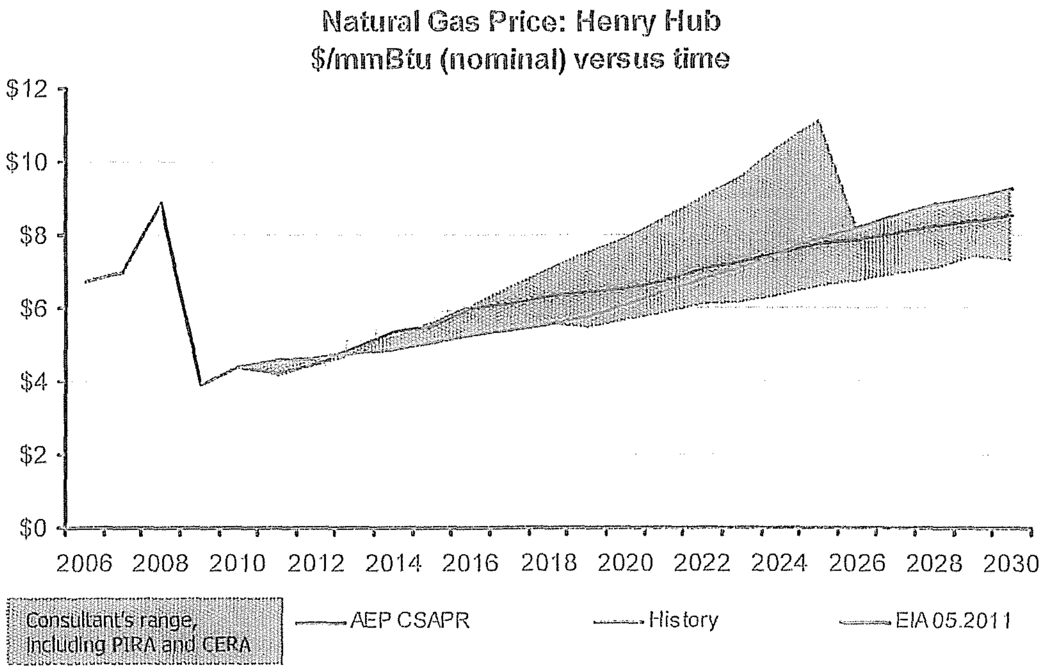
example, AEP takes into consideration the recently-finalized MATS rules, as well as subsequent emerging EPA rulemaking addressing Coal Combustion Residuals, the Clean Water Act rule 316(b) later this decade, and the prospect of a future carbon tax. It is well understood that none of these laws and regulations are factored in the EIA-AEO projections.

Mr. Kollen incorrectly ignored this difference in environmental rule assumptions, so there is no basis for his conclusions regarding a resulting increase in forecasted natural gas prices. The application of generally accepted natural gas price elasticities of supply to the increased natrual gas demand would naturally yield a "Base" ("FT-CSAPR") price forecast above these EIA's AEO projections. In contrast with Mr. Kollen's approach, the AEP "FT-LOWER Band" pricing is well-supported and reasonable, as it provides a complementing sensitivity to KPCo's Base case view. The natural gas price projections in the AEP "FT-LOWER Band" are approximately one standard deviation below those in the Base case (only a 16% likelihood of being lower – based on 5-year history). This scenario implicitly includes a somewhat lesser impact of these impending regulations.

Q. IS MR. KOLLEN'S USE OF NYMEX FORWARD PRICING REASONABLE?

A. No, it is not. The main flaw in Mr. Kollen's price comparison using the Natural gas forwards from the New York Mercantile Exchange ("NYMEX") as a benchmark is that this NYMEX forward pricing is not intended to be a reliable forecast of future, long-term natural price fundamentals. NYMEX forwards certainly represent the prices that a buyer and a seller can realize price certainty, but those commercial expectations may not represent the fundamentals of demand, supply and the resulting price. Nearer-term natural gas prices are primarily affected by weather's deviation from normal (measured as heating degree-days) which then results in deficit or surplus levels of natural gas storage. A warmer-than-normal or colder-than-normal winter has a direct effect on winter prices, but the effect also extends throughout the storage refill season until the storage inventory is fully replenished. NYMEX forwards may be affected beyond storage replenishment because the cost of gas in storage will affect withdrawal decisions within the context of winter season's cash natural gas price (again affected by weather). Mr. Kollen's chart of January 2012 NYMEX natural gas forwards, for example, illustrates the lingering effect of this winter's much warmer-than-normal temperatures.

Consequently, it is unreasonable for Mr. Kollen not to place also KPCo's Base natural gas price forecast in the context of the range of recently-established industry consultant's Base case forecasts—which, likewise, do incorporate anticipated current and emerging future environmental rulemaking—and which is represented below:



Note: PIRA's forecast ends in 2025 resulting in the steep decline in the Consultant's Range

IV. KPCO's CO_2 PRICE PROJECTIONS ARE REASONABLE AND NOT UNDERSTATED

Q. HOW DO YOU JUSTIFY THE INITIAL TIMING OF THE CO_2 PRICES UTILIZED IN KPCO'S LONG-TERM FUNDAMENTAL FORECAST?

A. It is the assessment of Company experts, external consultants and others that the likelihood of any federal climate legislation is very low over the next three years and still unlikely through the tenure of the 113th Congress. Passage of federal climate legislation would almost certainly require Democratic control of both the House and Senate and at least a 60 vote majority in the Senate. There are virtually no political analysts who believe this is even remotely possible and there is considerable doubt as to whether this could even be accomplished after the 2014 elections with the 2015-16 Congress. This suggests that the earliest reasonable date for a climate proposal to pass through committee, reach the floor, and be approved by both House and Senate for eventual passage is 2017. Given that any legislation will require an implementation period of approximately five years (as seen in previous climate proposals or other major Clean Air Act legislation), 2022 is the earliest reasonable projection as to when such legislation *could* become effective. Consequently, KPCo believes Mr. Fisher's 2018 implementation of any CO_2 legislation to be highly speculative for a "Base Case" view.

Q. DO YOU BELIEVE THAT THE KPCO CO_2 PRICE FORECASTS REASONABLY CAPTURE THE POTENTIAL COST IMPACTS IF THERE IS FUTURE FEDERAL CLIMATE LEGISLATION ON THE BIG SANDY POWER PLANT?

A. Yes. I do. In fact, Mr. Fisher's claims that KPCo price forecasts are "insignificant" and low is completely false. The forecast price of CO_2, or KPCo's "forecast modeling proxy," is a moderately aggressive CO_2 value. This is especially true because this price was applied to all CO_2 tonnes produced, whereas, in the cap and trade programs considered by Congress previously, there were provisions for an allocation of "free" allowances – which effectively reduced the CO_2 costs to incumbent generators. (Note that such "free" allocation provisions were politically very popular for states that were most affected by climate legislation, since lower generator costs in regulated cost-of-service states such as Kentucky meant significantly lower electricity cost and rate impacts to customers of regulated utilities such as KPCo under a climate bill. As such, if there is eventual passage of federal legislation, it will almost certainly include such provisions.) Thus, if the ultimate legislation that does pass contains a 50% free allocation of allowances, for example, then the effective cost of our KPCo modeling proxy of $15 per ton which is applied to all tons in the analysis is equivalent to a CO_2 price of $30 per ton which is a very aggressive price.

Also, new regulations and standards in just the past couple of years such as EPA's recently finalized MATS (i.e. mercury and air toxics standards), and CSAPR (cross-state air pollution rule) as well as its proposed CCR (coal combustion residuals) rule will likely result in a minimum of a 50,000 MW (or a 15-20%) national reduction in more inefficient coal-fired electric capacity based on utility plans or filings on retirements or gas conversions of such plants that have been announced to date. This factor alone is expected to result in an estimated 5-10% reduction in electric utility CO_2 emissions since 2010. This creates a de facto system of CO_2 reductions that is certain to reduce the required CO_2 values or prices needed to hit reduction targets than prices that came from earlier (now outdated) cap and trade program estimates.

Q. DO YOU AGREE WITH MR. FISHER'S ASSERTION THAT KPCO'S CO_2 PRICE IS NOT EFFECTIVE OR LIKELY; IT IS A "TOKEN" PRICE THAT HAS NO IMPACT?

A. No, I do not agree with Mr. Fisher's assertions. The forecast modeling proxy for CO_2 used by KPCo is far more realistic than much higher values because; 1) near-term action on cap and trade legislation is highly unlikely, 2) in order for any federal cap and trade legislation to ultimately pass, the effective price will have to be moderate at least for the early years of the program, and, 3) actions to regulate CO_2 from electric generation will more likely take other forms that won't necessarily put a price on carbon – such as through further energy efficiency standards, or renewable or clean-energy standards for utility generation . Further, a price of approximately $15/tonne for every tonne produced is "not effective" or a "token" value in that it would add approximately $81,000,000 to the variable costs of Big Sandy 2 in 2022 – a very significant cost increase

Q. WHAT IS YOUR ASSESSMENT OF THE SYNAPSE ENERGY ECONOMICS, INC. CARBON DIOXIDE PRICE FORECAST DATED FEBRUARY 11, 2011 ("SYNAPSE STUDY") WITH RESPECT TO GREENHOUSE GAS ALLOWANCE PRICE PROJECTIONS?

A. The Synapse Study represents a high level overview of climate change policy action/inaction and a summary of older, now very "dated" analyses of prior cap-and-trade legislative proposals in support of a range of CO_2 pricing trajectories. These CO_2 prices represent dated point-forecasts of various climate proposals that were not enacted and have no current political movement. Further, they were also all based on a very different set of price projections for natural gas (generally much higher) which biased their CO_2 price estimates to much higher levels than would be currently more realistic. As such, these past analyses are currently irrelevant in speculating what is an appropriate CO_2 price for the future. .

Q. DOES THE SYNAPSE STUDY REFLECT A CURRENT CONSENSUS VIEW OF CO_2 PRICE RISK?

A. The Synapse Study does not represent a current consensus view of carbon pricing but rather a range of potential outcomes for CO_2 pricing under a single legislative regime, cap-and-trade, that might have resulted from past federal legislative proposals that did NOT pass into law. The Synapse Study cannot be used as support for a current reasonable forecast of CO_2 pricing in the future. Such a view, including Mr. Fisher's, is flawed for several reasons. First, none of the proposals considered in the Synapse Study were passed into law and their defeat was largely due to the high economic impacts of the legislation. This strongly suggests that an ultimate federal legislative solution would have to be one that contained more moderate emission caps and hence lower CO_2 prices. Second, all the pricing analyses of the underlying proposals were conducted two to three years ago when other complementary EPA regulations and standards that will dramatically limit emissions were not yet promulgated. These regulations include more stringent CAFÉ standards, tighter energy efficiency standards and other EPA regulations on coal fired power plants such as the utility MATS rule and CSAPR rule as described earlier which will result in significantly reduced CO_2 emissions from coal and oil combustion during the coming decade. Third and perhaps most significantly, natural gas prices have substantially declined since these analyses were conducted. All of these factors would suggest the resulting CO_2 pricing of the proposals, if remodeled with current assumptions, would be substantially lower.

Lastly and most crucially, Synapse largely ignored other possible pathways that could address CO_2, such as federal alternative clean energy requirements or clean energy standards which at this point appear more likely to garner political support in the future instead of federal climate legislation. Such regulations would not directly result in a CO_2 price but at the very least would result in a lower effective CO_2 price on coal fired generators in the event climate legislation is also passed.

Q. DOES SYNAPSE USE OF THE CO_2 PRICES IN THE KPCO ANALYSIS EXAGERATE THE COST IMPACTS OF CO_2 PRICING UNDER LIKELY FEDERAL LEGISLATION?

A. Yes. In addition to the problems with the Synapse price forecasts themselves which causes them to be very high relative to a more realistic assessment, Synapse's USE of these prices as applying to EVERY ton of CO_2 emissions at Big Sandy is a substantial exaggeration of the actual cost impacts under federal climate cap and trade legislation. As noted, the use of the CO_2 prices referenced by Synapse did not address the implications that a free allocation system would have on reducing effective CO_2 costs to incumbent existing generators.

Q. IS MR. FISHER CORRECT IN THE APPLICATION OF HIS CO_2 ASSUMPTIONS AND OTHER NECESSARY INPUTS FOR THE PURPOSE OF COMPARING THE CUMULATIVE PRESENT WORTH OF REVENUE REQUIREMENTS OF KPCO POWER SUPPLY OPTIONS, AS PRESENTED IN EXHIBIT JIF-3E?

A. No, Mr. Fisher has not correctly applied his CO_2 assumptions. Without question, the creation of a Long-Term Forecast which considers a range of CO_2 costs MUST include correlative changes to other input drivers. It is imprudent to ignore: 1) the effect of coal plant dispatch costs on coal prices due to changes in coal-fired generation demand, 2) changes in gas-fired plant utilization and the effect on natural gas prices, 3) changes in plant retirement schedules and new-build profiles, or 4) the price elasticity of residential, commercial and industrial demand, for example. These "feedback loops" (iterations) are critically necessary to create a prudent set of long-term forecasts to be used as the foundation for comparison of KPCo's power supply options. In its simplest form, the imposition of "high" CO_2 prices would necessitate a "high" gas price response in reaction to increased gas demand – which creates an inconsistency in Mr. Fisher's conclusions. "High" CO_2 values coupled with "low" gas prices is misleading as one or the other is incorrect. Mr. Fisher's "a la carte" usage of dated Synapse Study CO_2 values to produce discrete CPW of Revenue Requirement results as presented in Exhibit JIF-3E without the mandatory feedback/iteration of other model inputs is erroneous and should be ignored.

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

A. Yes.

VERIFICATION

The undersigned, KARL R. BLETZACKER, being duly sworn, deposes and says he is Director, Fundamental Analysis for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing testimony and that the information contained therein is true and correct to the best of his information, knowledge, and belief.

Karl R Bletzacker

KARL R. BLETZACKER

STATE OF OHIO)
) CASE NO. 2011-00401
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Karl R. Bletzacker, this the 13 day of April 2012.

Holly M. Charles

Notary Public

NOTARY PUBLIC STATE OF OHIO

Holly M. Charles
Notary Public-State of Ohio
My Commission Expires
March 7, 2016

My Commission Expires: March 7, 2016

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

APPLICATION OF KENTUCKY POWER COMPANY	)	
FOR APPROVAL OF ITS 2011 ENVIRONMENTAL	)	
COMPLIANCE PLAN, FOR APPROVAL OF ITS	)	
AMENDED ENVIRONMENTAL COST RECOVERY	)	Case No. 2011-00401
SURCHARGE TARIFF, AND FOR THE GRANT OF A	)	
CERTIFICATE OF PUBLIC CONVENIENCE AND	)	
NECESSITY FOR THE CONSTRUCTION AND	)	
ACQUISITION OF RELATED FACILITIES	)	

REBUTTAL TESTIMONY

OF

JOHN M. MCMANUS

April 16, 2012

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

CASE NO. 2011-00401

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REBUTTAL TESTIMONY OF JOHN M. MCMANUS, 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 John M. McManus. I am employed by American Electric Power Service Corporation as Vice President - Environmental Services. American Electric Power Service Corporation (AEPSC) is a wholly owned subsidiary of American Electric Power Company, Inc. (AEP), the parent of Kentucky Power Company (KPCo or the Company). My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q: **ARE YOU THE SAME JOHN MCMANUS THAT FILED DIRECT TESTIMONY IN THIS PROCEEDING ON THE BEHALF OF KPCO?**

A: Yes, I am.

II. PURPOSE OF TESTIMONY

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

A: The purpose of my testimony is to explain why Kentucky Industrial Utility Customers (KIUC) witness Lane Kollen's recommendation to idle Big Sandy Unit 2 and restart the Big Sandy Unit 2 environmental retrofit process at a later date, as stated on page 18 - lines 1-4 of his Direct Testimony, is impractical. The recommendation overlooks certain current compliance obligations and future environmental permitting-related impacts that could occur as a result of idling a plant for an extended period of time.

Q. **ARE YOU SPONSORING ANY EXHIBITS?**

A. No, I am not.

III. AIR PERMITTING

Q: **KIUC WITNESS KOLLEN SUGGESTS ON PAGE 18, LINES 1-2 OF HIS DIRECT TESTIMONY, THAT THE COMPANY "RESTART THE RETROFIT PROCESS AT A LATER DATE IF AND WHEN THE COMMISSION SUBSEQUENTLY FINDS THAT THE RETROFIT IS ECONOMIC." WHAT ARE THE IMPLICATIONS OF WITNESS KOLLEN'S RECOMMENDATION?**

A. Under the current project schedule, Big Sandy Unit 2 will be taken out of service at the beginning of 2016 to tie-in the completed FGD system and will return to service about mid-year with the FGD system operational. This schedule assumes that the unit will be granted a one year extension of the MATS compliance deadline while the retrofit project is being completed. Delaying the FGD retrofit project an extended period of time will likely result in Big Sandy 2 having to be taken out of service by April 16, 2015, the initial MATS deadline, as an extension of the deadline would not be granted if the Company is not fully engaged in a retrofit project, and the unit cannot meet the MATS emissions limits with its current emissions controls. Placing the retrofit process on hold now and restarting at some point in the future will require 4 ½ - 5 years before Big Sandy Unit 2 could be placed in-service with the new controls, resulting in an extended period during which the unit would be idled.

Idling the unit for such an extended period could introduce significant risk and additional capital costs to comply with potential increased scope and stringency of future air emission requirements. EPA has a well-established policy that allows facilities to select a baseline level of emissions from the highest consecutive 24-month period during the previous five years to determine whether changes at the facility are subject to the Prevention of Significant Deterioration ("PSD") / New Source Review ("NSR") air permitting requirements. 40 CFR §51.165(a)(1)(xxxv)(*A*). In addition, the current general provisions of the New Source Performance Standards (NSPS) exclude existing facilities from the new source standards if the changes made at an existing facility do not increase the hourly emission rates for any regulated pollutant above the rate achievable at the facility within five years prior to the change. 40 CFR §60.14(h). Electing to idle a facility for an extended period of time imposes a serious risk that could result in a requirement to obtain a PSD/NSR air permit and meet Best Available Control Technology (BACT) requirements, and/or trigger the application of NSPS at Big Sandy 2 in order to commence construction of any emission control technologies and eventually return the unit to service.

Q. PLEASE EXPLAIN WHAT ADDITIONAL RISKS OR COSTS MIGHT BE INCURRED IF BIG SANDY IS CONSIDERED A NEW SOURCE FOR PURPOSES OF THE PSD/NSR OR NSPS PROGRAMS.

A. In general, standards for "new" sources are more stringent than those that apply to existing sources. In addition, PSD/NSR air permitting for a new or modified source is much more complex and time-consuming than permitting an emission control project for an existing source in operation, which can often be accomplished with a minor source permit. For example, treatment as a new source would subject all emission sources at the facility, including the main boiler, auxiliary boiler, emergency generators, and material handling sources, to a Best Available Control Technology ("BACT") analysis. This could result in more stringent emission limits and the requirement to install additional emission controls on such sources. Conversely, the air permitting process for an existing unit undertaking an emission control project would be focused only on new emission sources or changes to the emissions profile of existing emissions units resulting from that project. In addition, idling Big Sandy 2 for any extended period of time could subject the unit to the NSPS, including the recently proposed NSPS for carbon dioxide or any future CO_2 NSPS for modified sources.

Q. **DESCRIBE THE GREENHOUSE GAS NEW SOURCE PERFORMANCE STANDARD RECENTLY PROPOSED BY THE U.S. ENVIRONMENTAL PROTECTION AGENCY (EPA).**

A. The EPA announced a proposal for a NSPS for GHGs from new power plants on March 27, 2012. The proposed rulemaking only concerns new fossil fuel-fired electric generating units (EGUs) that will be built in the future, and does not apply to existing units already operating or units that will start construction over the next 12 months. For purposes of this rule, fossil fuel-fired EGUs include fossil fuel-fired boilers, integrated gasification combined cycle (IGCC) units and stationary combined cycle turbine units that generate electricity for sale and are larger than 25 megawatts (MW). The proposal would not apply to existing units, including modifications such as changes needed to meet other air pollution standards. The proposed standard would require that new fossil fuel-fired power plants meet an output-based standard of 1,000 lbs. of CO_2 per megawatt-hour (lb. CO_2/MWh Gross).

Q. **IF THE BIG SANDY UNIT 2 FGD PROJECT IS SUSPENDED AND RESTARTED AT A LATER DATE, HOW COULD THE EPA'S PROPOSED CO_2 STANDARD FOR NEW POWER PLANTS IMPACT THE UNIT?**

A. If EPA finalizes the new source CO_2 NSPS as proposed, or develops a CO_2 NSPS for modified sources, and Big Sandy 2 became subject to one or the other as a result of an extended period without operation, the unit would have to meet the applicable limit before returning to operation. This could require the unit to be equipped with technology to capture and sequester CO_2 emissions, with the associated cost of that technology (assuming it is even available), or it would have to be permanently shutdown.

Q. **ARE THERE ANY ADDITIONAL RISKS ASSOCIATED WITH IDLING BIG SANDY 2 FOR AN EXTENDED PERIOD?**

A. Yes. Over the past several years the Environmental Protection Agency has revised and reduced the level of various National Ambient Air Quality Standards (NAAQS) repeatedly. Each new round of revisions creates additional compliance planning obligations for the state agencies, and has resulted in more stringent air emission requirements, particularly for new sources. There is a risk that Big Sandy could be located in a nonattainment area for one or more pollutants at the time it would be reactivated, resulting in requirements to achieve the "Lowest Achievable Emission Rate" (LAER) for any nonattainment pollutant, and to obtain offsets from other sources in order to resume operations. LAER emission rates are the most stringent under the Clean Air Act, and offsets can be difficult to obtain.

Q. **WHAT OTHER ISSUES WOULD ARISE FROM KIUC WITNESS KOLLEN'S RECOMMENDATION?**

A. The Company is required by its 2007 New Source Review (NSR) Consent Decree to equip Big Sandy Unit 2 with a flue gas desulfurization (FGD) system by December 31, 2015. Witness Kollen's recommendation to restart the retrofit process at a date that would occur after the NSR compliance deadline would require the consent of all of the signatories in order to modify the consent decree. While AEP has successfully negotiated modest changes to FGD retrofit schedules for two of the Amos Units, AEP has not requested any change as significant as the one proposed by witness Kollen, and has no ability to compel the other parties to agree to such a significant change.

IV. CONCLUSION

Q. **PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.**

A. A strategy of idling the unit for an extended period and then restarting the retrofit project is not a viable option as such an approach could subject the unit to a more complex and time-consuming air permitting process, could result in more stringent air emission limits, and may require more extensive emission control systems to be installed. In addition, the Company would not be in compliance with the existing requirements of the 2007 NSR Consent Decree for Big Sandy Unit 2, and successful renegotiation of the existing compliance obligations cannot be assumed.

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

A. Yes.

VERIFICATION

The undersigned, John M. McManus being duly sworn, deposes and says he is the Vice President of Environmental Services for American Electric Power that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief.

JOHN M. MCMANUS

STATE OF OHIO)
) CASE NO. 2011-00401
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by John M. McManus, this the 12 day of April 2012.

Notary Public

My Commission Expires: 12/31/2014

NOTARIAL SEAL
STATE OF OHIO

PATRICK R OTT
NOTARY PUBLIC - OHIO
MY COMMISSION EXPIRES
DECEMBER 31, 2014

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

APPLICATION OF KENTUCKY POWER COMPANY	)	
FOR APPROVAL OF ITS 2011 ENVIRONMENTAL	)	
COMPLIANCE PLAN, FOR APPROVAL OF ITS	)	
AMENDED ENVIRONMENTAL COST RECOVERY	)	Case No. 2011-00401
SURCHARGE TARIFF, AND FOR THE GRANT OF A	)	
CERTIFICATE OF PUBLIC CONVENIENCE AND	)	
NECESSITY FOR THE CONSTRUCTION AND	)	
ACQUISITION OF RELATED FACILITIES	)	

REBUTTAL TESTIMONY

OF

ROBERT L. WALTON

April 16, 2012

REBUTTAL TESTIMONY OF
ROBERT L. WALTON, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2011-00401

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REBUTTAL TESTIMONY OF ROBERT L. WALTON, 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 Robert L. Walton, 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 of Projects and Controls. AEPSC supplies engineering, financing, accounting, project management and planning and advisory services to the eleven electric operating companies of the American Electric Power System, one of which is Kentucky Power (KPCo) Company.

Q: ARE YOU THE SAME ROBERT L. WALTON THAT FILED DIRECT TESTIMONY IN THIS PROCEEDING ON THE BEHALF OF KPCO?

A. Yes, I am.

II. PURPOSE OF TESTIMONY

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

A: The purpose of my testimony is to explain why Kentucky Industrial Utility Customers (KIUC) witness Lane Kollen's recommendation to suspend current work on the Big Sandy Unit 2 environmental retrofit project and restart the process at a much later date, as stated on page 18 - lines 1-4 of his Direct Testimony, is impractical. The recommendation overlooks the significant maintenance costs that will occur as a result of idling or mothballing the unit for an extended period of time and the risk associated with unit reliability upon the attempt to return the unit to service

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. No, I am not.

III. MAINTENANCE

Q. KIUC WITNESS KOLLEN SUGGESTS ON PAGE 18, LINES 1-2 OF HIS DIRECT TESTIMONY, THAT THE COMPANY "RESTART THE RETROFIT PROCESS AT A LATER DATE IF AND WHEN THE COMMISSION SUBSEQUENTLY FINDS THAT THE RETROFIT IS ECONOMIC." IS KOLLEN'S RECOMMENDATION PRACTICAL?

A. No. In addition to the complex environmental permitting requirements that arise from idling the unit for a long period of time, as discussed by Company witness McManus, there will be significant incurred costs associated with placing the unit in a mothballed condition and for maintaining the unit and preventing deterioration.

Q. WHAT TYPE OF MAINTENANCE WORK WOULD HAVE TO BE CONDUCTED TO IDLE BIG SANDY 2 FOR A LONG PERIOD OF TIME?

A. Besides the upfront work and cost associated with the initial long-term layup of the steam generator, stream turbines and all other auxiliary equipment, ongoing maintenance and monitoring of electrical equipment and systems required to remain in service, the boiler, the turbine, as well as with air pollution control equipment would be necessary. Constant monitoring and attention to ensure the integrity and condition of the equipment would be required, as well as site security, resulting in the necessary presence of an on-site full-time staff.

IV. CONCLUSION

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. The strategy of mothballing or idling of Big Sandy Unit 2 for an extended period ignores the upfront layup costs and the incurred additional cost associated with maintaining and monitoring of the condition of the unit.

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

A. Yes.

VERIFICATION

The undersigned, Robert L. Walton being duly sworn, deposes and says he is the Managing Director of Projects and Controls for American Electric Power that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief.

ROBERT L. WALTON

STATE OF OHIO)
) CASE NO. 2011-00401
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Robert L. Walton, this the 11 day of April 2012.

Notary Public

PETRA G. MYERS
Notary Public
Fairfield County
State of Ohio
My Commission Expires May 29, 2012

My Commission Expires: 5-29-12

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

APPLICATION OF KENTUCKY POWER COMPANY	)	
FOR APPROVAL OF ITS 2011 ENVIRONMENTAL	)	
COMPLIANCE PLAN, FOR APPROVAL OF ITS	)	
AMENDED ENVIRONMENTAL COST RECOVERY	)	Case No. 2011-00401
SURCHARGE TARIFF, AND FOR THE GRANT OF A	)	
CERTIFICATE OF PUBLIC CONVENIENCE AND	)	
NECESSITY FOR THE CONSTRUCTION AND	)	
ACQUISITION OF RELATED FACILITIES	)	

REBUTTAL TESTIMONY

OF

SCOTT C. WEAVER

April 16, 2012

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

CASE NO. 2011-00401

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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.

Q. DID YOU FILE DIRECT TESTIMONY IN THIS CASE?

A. Yes. I filed direct testimony on behalf of Kentucky Power Company (KPCo or Company).

II. PURPOSE

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to certain arguments made by Kentucky Industrial Utility Customers, Inc. (KIUC) witness Lane Kollen and Sierra Club, et al, (SC) witnesses J. Richard Hornby and Dr. Jeremy Fisher in their respective direct testimonies.

For Mr. Kollen, I will first refute his suggestion that a Company-evaluated option (Option #4B)—which would assume, rather than retrofitting and retaining Big Sandy Unit 2 (BS2), a dependence on capacity and energy from PJM for 10-years followed by the construction of a replacement natural gas combined cycle (CC) facility in 2025—should be considered the least-cost solution when viewed from a limited, 10-year (2016-2025) timeframe as opposed to the appropriate full, 30-year life-cycle study period. Further, I will offer testimony that indicates that Mr. Kollen has clearly ignored separate risk modeling the Company performed which confirms that this Option #4B contributes to a greater level of cost risk to KPCo's customers than the recommended BS2 retrofit alternative. As part of this discussion I will also refer to the rebuttal testimonies of Company witnesses John McManus and Robert Walton that dismiss the suggestion by Mr. Kollen that KPCo "can restart the retrofit process at a later date..."

For Mr. Hornby and Dr. Fisher, I will first refute their collective contention concerning the manner in which off-system sales (OSS) revenues were modeled within the Company's Strategist®-based Big Sandy unit disposition analysis. Further, I will also offer testimony that addresses three specific concerns of Dr. Fisher as it pertains to the results of the Company's Aurora^{XMP}-based stochastic (*i.e.*, Monte Carlo simulation) risk modeling. The first of those rebuttals will focus on Dr. Fisher's incorrect attempt to compare and contrast "absolute" modeling results from just a single extracted simulation result from the Aurora^{XMP} modeling—even after that modeling was appended to address two assumption issues raised—versus the discrete modeling results *that emanated from the Strategist® tool*. The second portion of this rebuttal will focus on refuting the challenges Dr. Fisher offers surrounding the relative correlation of key risk variables used in that Monte Carlo modeling. I will also address concerns expressed by Dr. Fisher regarding the perceived lack of data transparency surrounding the Company's use of the Aurora^{XMP} tool.

Lastly, I will summarize the impact of certain rebuttal testimony of Company witnesses Mark Becker and Karl Bletzacker as each addresses specific aspects of Dr. Fisher's testimony. Among other things, Mr. Becker will be rebutting Dr. Fisher's incorrectly-derived capital costs for the various Big Sandy unit disposition options evaluated in KPCo's Strategist® modeling exercise; while Mr. Bletzacker refutes Dr. Fisher's introduction of Synapse-determined long-term pricing assumptions for the costing of carbon dioxide (CO_2) emissions in SC's restatement of the Strategist modeling as being speculative and unnecessary. As part of those discussions, each of those subject-matter experts will refute certain "adjustments" Dr. Fisher offers to the Company's relative Strategist®-based alternative economic results offered within my original direct testimony in this case.

KOLLEN REBUTTAL

III. OPTION #4B DOES NOT REPRESENT THE OPTIMUM ALTERNATIVE FOR KPCO'S CUSTOMERS

Q. AS IT IS RELEVANT TO YOUR REBUTTAL TESTIMONY, WHAT IS MR. KOLLEN'S POSITION ON WHICH OF THE BIG SANDY DISPOSITION ALTERNATIVES EVALUATED SHOULD BE CONSIDERED "LEAST-COST"?

A. Mr. Kollen suggests company-evaluated Option #4B—which, again, calls for BS2 to be retired by January 1, 2016, and replaced for 10-years with PJM market capacity and energy purchases followed by the construction of (roughly MW-equivalent) new

CC capacity by 2025—should be considered the least-cost option. He makes this assertion based initially on the results of the Strategist®-based 30-year study period analysis performed on behalf of the Company and offered as part of my direct testimony.[1]

Q. DO YOU CONCUR WITH THAT CONCLUSION?

A. No. As I had described on page 37, li. 21 through page 38, li. 7 of my direct testimony—as well as on Exhibit SCW-4 of that testimony—depending on whether a 15-year or 20-year BS2 retrofit recovery period is considered, under the 'Base' ("Fleet Transition-CSAPR") long-term commodity pricing scenario utilized, the Strategist®-determined relative cumulative present worth (CPW) of the full, 30-year study period cost differences between that BS2 retrofit (Option #1) alternative and this Option #4B was $10-to-$47 million. I further describe in that testimony that when comparing these Strategist®-modeled results for Option #4B versus Option #1 across the *full set* of five (5) long-term commodity pricing scenarios examined, those results indicated a relative higher <u>cost</u> for the Option #4B replacement/10-year market purchase alternative of $229 million (under "HIGHER Band" pricing) to a relative lower (benefit) level for that alternative of $119 million (under "LOWER Band" pricing).

In summary, and as indicated in my direct testimony, I have characterized the Strategist®-modeled differences as offering no firm conclusion as to the optimum

[1] Although the Strategist® analysis encompassed a 30-year study period (2011-2040), the applicable period for purposes of the comparative unit disposition analyses is, in fact, the 2016-2040, or 25-year timeframe given that the Strategist® results for the preceding years 2011 through 2015 would be the same (or nearly the same in the case of the year 2015) under all options evaluated.

outcome between this Option #1 and Option #4B; rather referring to these modeled economic differences as being a relative "wash".

Q. WERE THERE OTHER FACTORS—OVER AND ABOVE THE STRATEGIST® MODELING RESULTS—THAT WERE NECESSARY TO CONSIDER WHEN ASSESSING THE OPTIMUM SOLUTION AMONG THESE TWO EVALUATED UNIT DISPOSITION ALTERNATIVES?

A. Yes. As then further discussed on pages 38 through 40 of my direct testimony, I describe the attendant (PJM) market pricing and performance risks that could be borne by KPCo's customers assuming Option #4B were selected. To reiterate that testimony, I offered:

- the lack of capacity pricing certainty associated with the PJM Reliability Pricing Model (RPM) capacity market construct given that market's relative immaturity;
- an acknowledgement that based on the (internal) AEP Fundamental Analysis group's own forecast of such capacity values—values that were used as part of the establishment of the cost of Option #4B—remain well below even the PJM-RPM "baseline" of Net Cost of New Entry (Net CONE), thereby potentially quickly negating any Strategist®-modeled cost advantage of that alternative should *actual* capacity values ultimately clear at prices that would approach or exceed Net CONE;
- the fact that the PJM-RPM construct currently clears on a *single* incremental planning year basis, with no assurances as to the sustainability of prices from year-to-year; and certainly not over a 10-year period; and finally,
- as discussed here as well as on page 50 of my direct testimony, PJM "price-taker" risk would also be applicable to the attendant market *energy* that would be required under a 10-year market-solution offered under Option #4B.

Q. **DID MR. KOLLEN CONSIDER ANY OF THESE FACTORS AS PART OF HIS ASSERTION THAT A 10-YEAR PJM MARKET SOLUTION UNDER OPTION #4B OFFERED THE BEST (*i.e.*, LEAST-COST) SOLUTION FOR KPCO AND ITS CUSTOMERS?**

A. No. Mr. Kollen's direct testimony offers no such consideration or assessment of these factors. His failure to do so renders his analysis incomplete.

Q. **WERE THERE OTHER FACTORS AND CONSIDERATIONS THAT MR. KOLLEN ALSO FAILED TO RECOGNIZE WHEN ASSESSING THE MERITS OF OPTION #4B?**

A. Yes. Mr. Kollen also ignored the additional extensive risk modeling that was offered as part of my direct testimony. Specifically, this was modeling performed utilizing the Aurora^{XMP} tool that addressed—via stochastic or "Monte Carlo" simulations—the attendant cost risks under each BS2 disposition option evaluated.

Q. **PLEASE BRIEFLY REVIEW THE RESULTS OF THIS RISK MODELING AND, THEREFORE, THE CRITICALITY OF MR. KOLLEN'S OMISSION OF THOSE RESULTS WHEN ESTABLISHING HIS RECOMMENDATION.**

A. As summarized on page 46, li. 15 through page 48, li. 9 of my direct testimony (as well as on Exhibit SCW-1 Section III, and Exhibit SCW-5 of that testimony) this risk modeling identified that the "Revenue Requirement at Risk (RRaR)" was greatest under Option #4B. In fact, the RRaR for that Option #4B was $1,179 million over the same (30-year) long-term study period; or a figure that was nearly $364 million (or, 44.6 percent) *greater* than the RRaR for the Company's recommended Option #1 approach. Moreover, the attendant RRaR for that Option #4B was greatest among *all*

4 options evaluated in the Aurora^{XMP} modeling. Finally, to substantiate the subjective risk factors previously discussed in this rebuttal testimony, the following conclusion from my direct testimony states:

> "Therefore, this risk modeling… <u>empirically-confirms the previous notion identified within this testimony that described the attendant "price taker" risk associated with a market solution (Option #4) would not be in the best interest of KPCo's customers</u>."[2] (original emphasis)

IV. <u>A LIMITED (10-YEAR) ASSESSMENT OF ANNUAL MODELED ECONOMIC RESULTS IS NOT AN APPROPRIATE BASIS FOR PURPOSES OF THIS UNIT DISPOSITION ANALYSIS</u>

Q. ON PAGES 10-15 OF HIS DIRECT TESTIMONY, MR. KOLLEN CONSIDERED ONLY A 10-YEAR (2016-2025) "EXTRACTION" OF ANNUAL ECONOMIC RESULTS FROM THE COMPANY'S STRATEGIST® MODELING WHEN SUGGESTING RELATIVE MERIT OF TWO OF THE BIG SANDY 2 DISPOSITION OPTIONS. WHY IS THAT NOT AN APPROPRIATE APPROACH?

A. First and foremost, it addresses only a portion of the value prospect behind true "long-term" planning. As described on page 15 of my direct testimony:

> "…these evaluations were performed over a 30-year economic study period (2011 through 2040) in the Strategist® tool so as to emulate the potential life-cycle of the respective asset alternatives as well as in recognition of the various "down-stream" impacts on KPCo overall resource planning needs." (original emphasis)

[2] Weaver direct testimony, page 48.

Q. PLEASE DESCRIBE THOSE "DOWN-STREAM" IMPACTS AND WHY THEY CANNOT BE IGNORED AS MR. KOLLEN WOULD SUGGEST.

A. By definition, the concept of down-stream impacts simply represents that the alternative resource "options" may have multiple stages and timing of investment/re-investment as well as attendant costs and attributes.

For example, Option #1 calls for the clearly significant (fixed cost) investment in Big Sandy 2 retrofit technology and boiler modifications that would be in-service in June, 2016. With that, however, *variable* cost sustainability associated with avoidance of market pricing exposures would be enjoyed by KPCo customers beginning at that point. Contrastingly, under an Option #4B alternative which would seek to rely on a (PJM) market solution for some period—in this case up to as much as 10 years—then incur the significant metal-in-the-ground investment associated with a generic new-build CC in the out-year 2025, that attendant variance price/cost risk exposure would be placed on KPCo customers during this interim period. Such price/revenue requirement risk has been clearly attributed to this Option #4B identified as part of the Monte Carlo simulations discussed previously in this rebuttal testimony and set forth on Exhibit SCW-5 of my direct testimony.

Even setting that risk exposure aside, Mr. Kollen's testimony conveniently eliminates this critical down-stream cost of a new-build CC associated with Option #4B. One cannot simply compare the initial temporary—in this case, even as much as 10-years of—costs and attributes for Option #4B versus "only" the initial 10-years of costs and attributes of another option (Option #1) that was assumed to offer benefits through the full, 2040 study period. Unlike computer software which may have an economic value/life measured over one -to- a few years, the decisions around generating asset dispositions in this instance case are, by their very nature, long-term decisions that will benefit customers for decades. Hence, the relative economics have to be considered over the full breadth of this timeframe.

Additionally, since the Strategist® modeling results were predicated on a full 30-year study period view and were *not* intended to—as I clearly indicated on page 16 of my direct testimony—represent a "cost-of-service" perspective, any criticism offered by Mr. Kollen on pages 16 and 17 of his testimony as to the model's use of a levelized carrying charge methodology as opposed to a "declining annual revenue requirements" approach are likewise explainable and therefore unfounded.

Q. **DO YOU TAKE EXCEPTION TO OTHER ASPECTS OF MR. KOLLEN'S EXTRACTION OF COSTS FOR ONLY THE INITIAL 10-YEARS OF THE MODELED ECONOMIC STUDY PERIOD?**

A. Yes. So as to offer some rationale as to the supposed optionality that such a 10-year analytical perspective would offer, on page 18, li. 1 and 2 of his direct testimony Mr. Kollen also suggests that; "The Company can restart the retrofit process at a later date if and when the Commission subsequently finds that the retrofit is economic."

Q. **WHY IS SUCH A DELAY IN THE TIMING OF THIS BIG SANDY 2 RETROFIT NOT A VIABLE ALTERNATIVE?**

A. As more fully described in the rebuttal testimonies of Company witnesses McManus and Walton, due largely to known environmental regulation and permitting, as well as project layup and interim maintenance issues, Big Sandy Unit 2 would not be able to effectively be idled or mothballed for any extended timeframe, and then be able to be retrofitted with pollution control equipment at a later date. In short, their testimony indicates that the opportunity to retrofit this unit is a near-term opportunity as represented in the Company's unit disposition planning, as any significant delay would be both impracticable and not workable.

Q. **DO YOU HAVE ANY OTHER OBJECTIONS TO THE EXTRACTED 10-YEAR VIEW OF COSTS AS SET FORTH BY MR. KOLLEN?**

A. In addition to ignoring unique option-specific "down-stream" costs, Mr. Kollen's data on the tables found on pages 13 through 15 of his testimony are flawed in that they reflect comparative cumulative cost values on a <u>nominal</u> dollar basis. Given the timing and resulting year-to-year spending/cost vagaries among modeled options as I have alluded to previously, it is the well-established practice in these types of long-lived option analyses to look at comparative cost profiles in "present value" dollars. Therefore, while continuing to object to the legitimacy of this 10-year data "extraction" approach, Mr. Kollen's tables should, minimally, be restated as follows in **TABLE 1** (also reproduced as Rebuttal Exhibit SCW-1R), which represents a summary-level reproduction—and correction—of Mr. Kollen's table found on pages 13 of his direct testimony, which focused on the 'Base' long-term pricing scenario examined by the Company:

TABLE 1

Fleet Transition-CSAPR Commodity Pricing

	PER KOLLEN TESTIMONY (Page 13)					CORRECTION (TO PROPERLY REFLECT RESULTS IN PRESENT DOLLARS)	
	(1) Big Sandy 2 Retrofit (Option #1)	(2) Market Replacmnt to 2025 (Option #4B)	(3)=(1)-(2) Savings fr Market Purchases	Cumul Savings fr Purchases		= PV of (3) PRESENT VALUE of Savings fr Mkt Purchases	Cumulative Present Value
	NOMINAL ($000)					REAL (2011) ($000)	
2016	621,065	509,433	111,632	111,632	2016	73,763	73,763
2017	563,763	500,781	62,982	174,615	2017	38,307	112,071
2018	569,255	489,883	79,372	253,986	2018	44,436	156,507
2019	580,129	512,944	67,185	321,172	2019	34,622	191,129
2020	580,242	523,156	57,086	378,258	2020	27,078	218,207
2021	598,301 *	548,927	49,374	427,631	2021	21,557	239,765
2022	713,673	648,370	65,303	492,934	2022	26,245	266,010
2023	743,111	677,380	65,730	558,665	2023	24,316	290,326
2024	753,290	699,595	53,695	612,359	2024	18,284	308,609
2025	781,919	805,776	(23,856)	**588,503**	2025	(7,477)	**301,132**
2026	797,372	825,255	(27,883)	560,620	2026	(8,044)	293,088
2027	814,067	834,667	(20,600)	540,021	2027	(5,470)	287,617
2028	829,421	855,391	(25,970)	514,050	2028	(6,348)	281,269
2029	849,520	876,687	(27,167)	486,884	2029	(6,112)	275,157
2030	864,102	881,100	(16,998)	469,885	2030	(3,520)	271,636
2031	722,471	903,931	(181,460)	288,426	2031	(34,593)	237,043
2032	725,518	905,571	(180,053)	108,373	2032	(31,595)	205,449
2033	741,623	922,963	(181,340)	(72,967)	2033	(29,290)	176,159
2034	766,323	940,184	(173,861)	(246,828)	2034	(25,849)	150,310
2035	788,772	968,278	(179,506)	(426,333)	2035	(24,565)	125,745
2036	803,304	981,982	(178,678)	(605,012)	2036	(22,507)	103,237
2037	814,624	991,429	(176,805)	(781,817)	2037	(20,500)	82,737
2038	840,837	1,015,542	(174,705)	(956,521)	2038	(18,646)	64,091
2039	853,549	1,028,426	(174,877)	(1,131,398)	2039	(17,180)	46,911
2040	1,055,057	1,050,837	4,219	**(1,127,179)**	2040	382	**47,293**

View that Should Be Taken IF Focus were to be Incorreclty Based on Results Thru 2025 ONLY, as Suggested by Mr. Kollen (301,132)

View that Should Be Taken IF Focus were to be Based on Nominal Dollars ONLY, as Suggested by Mr. Kollen ((1,127,179))

Ties to Weaver Exhibit SCW-4 (Option #1 v. Option #4B) (47,293)

* Note: Mr. Kollen's calculation of this 2021 value value was incorrect @ 598,242, therefore his 'Cumulative Savings' variance (thru 2025) was also misstated in his testimony @ 588,444.

In summary and, again, *setting aside the flaws in his arguments for such a limited, 10-year view of comparative costs*, the restatements reflected in TABLE 1 above would indicate:

1) that the purported cumulative "savings" Mr. Kollen identifies in his direct testimony of Option #4B versus Option #1, if incorrectly viewed through a limited, 10-year period (through 2025 only) would be reduced by an order of magnitude of nearly one-half (from his approximate $588.5 million, to $301.1 million) if his calculation had been correctly preform on a present value (real dollar) basis; and

2) if it *were* to have been viewed on such a nominal dollar basis, but rather through the full evaluated study period, this cumulative savings of that Option #4B of $588.5 M would, in fact, become a cumulative cost to KPCo's customers of $1.127 billion.

Similarly, consistent relative restatements would be in order for the calculations offered by Mr. Kollen for the remaining four pricing scenario tables he offers on pages 14 and 15 of his testimony.

HORNBY AND FISHER REBUTTAL

V. VALUE OF OFF SYSTEM SALES WERE APPROPRIATELY REPRESENTED IN THE COMPANY'S MODELING

Q. WHAT IS MR. HORNBY'S CONTENTION CONCERNING THE MANNER IN WHICH OFF SYSTEM SALES WAS MODELED WITHIN THE COMPANY'S STRATEGIST®-BASED UNIT DISPOSITION ANALYSES?

A. Mr. Hornby suggests that there is an inconsistency between the manner in which off system sales (OSS) margins were modeled—and reflected in the Company's final Strategist® results—in these analyses versus the manner in which such amounts are shared in rates by KPCo's retail customers. He further suggests, and Dr. Fisher then attempts to incorporate in his direct testimony, an adjustment is required that would effectively <u>reduce</u> the level of OSS margins that would be attributed (*i.e.*, "credited") to the overall CPW costs each of the options/alternatives studied by the Company. Specifically, Mr. Hornby indicates that these modeled OSS "credit" values should be reduced by 40 percent; or a level that is equal to 1 minus the current KPCo retail customer OSS sharing level of 60 percent within the Company's current, tariff-based System Sales Clause (Tariff S.S.C.) which is reproduced as Rebuttal Exhibit SCW-2R.

Q. **DO YOU CONCUR WITH THAT SUGGESTION?**

A. I do not, for a couple of reasons. First, as I had described on page 16, li. 2 through 7 of my direct testimony, the resulting Strategist®-modeled output was not intended to represent, or even proxy, a formal ratemaking/cost-of-service exercise. Rather its intent was to holistically assess the relative *economics* of the modeled options. To the extent that specific, unquestioned "benefits" due to receipt of OSS margins would then advantage both the KPCo customer and, potentially, flow to the Company under any of the particular modeled options, no specific adjustments were then made to the modeling. Stated otherwise, even if Mr. Hornby was correct, any modification or adjustments to the modeling would not change the relative economics of the options evaluated.

Having said this, the second reason for disagreeing with Mr. Hornby's contention is that the need for any perceived Strategist® analysis adjustment pertaining to OSS margins that would *not* flow to KPCo customers is unnecessary. This is based on the recognition of, in the same Company 'System Sales Clause' cited by Mr. Hornby, a threshold or "base" level of OSS margin—clearly identified in that tariff—that would need to be achieved <u>before</u> such incremental OSS margin sharing would occur.[3] Further, to establish the value to be compared to that "base" OSS Margin, an additional adjustment calls for the netting out from KPCo's OSS Margin, monthly environmental costs allocated to non-associated utilities as part of the Company's Environmental Surcharge Report. In recognition of this, and that base OSS margin threshold in the tariff (currently, $15.290 million annually), the going-in notion was that subsequent years achievement of such adjusted KPCo OSS margin levels would either approach, or not materially exceed this base level; hence, no OSS "sharing adjustment" was deemed necessary.

Q. DID THAT GOING-IN ASSUMPTION PROVE TO BE REASONABLY ACCURATE?

A. Yes. After recognizing the proper method for calculating "shared" OSS margins, in all years modeled, under all (unit disposition) options assessed, OSS margins as determined under Tariff S.S.C. were generally below that margin threshold, hence no adjustment was necessary in any event. Rebuttal Exhibit SCW-3R offers a summary as well as a year-by-year calculation of Strategist®-based KPCo OSS margins for each of the options modeled.

Q. RECOGNIZING THE COMPANY'S TARIFF S.S.C., MR. HORNBY AND DR. FISHER NONETHELESS PROPOSE THAT ADJUSTMENTS ARE REQUIRED TO THE COMPANY'S OPTION-SPECIFIC, STRATEGIST®-DETERMINED RESULTS—AS REPRESENTED IN THE COMPANY'S

[3] Such "base" levels of OSS margins being currently credited to retail cost-of-service base rates. Further, Tariff S.S.C. also prescribes that customers would incur an incremental *charge* equal to 60% of the difference between actual monthly/annual OSS margins and these monthly/actual "base" levels, if such actual amounts fall <u>below</u> the base.

EXHIBIT SCW-4—THAT WOULD BE REFLECTIVE OF THIS PERCEIVED NEED TO INCORPORATE SUCH OSS SHARING. ARE THEIR ADJUSTMENTS ACCURATE?

A. No, they are inaccurate for several reasons. First, as indicated above, the adjustment that Dr. Fisher sets forth in "Table 1" (Exhibit JIF-3A) of his direct testimony ignores that "base" or threshold level of OSS margin. Therefore his adjustment, which seeks to effectively add-back 40 percent of the OSS value to the respective options' cost, is initially overstated by the cumulative present worth (CPW) of the current base threshold amount—assumed to be held constant into perpetuity—or, $15.290 million for each year of the analysis.

Second, and even more critically, Dr. Fisher ignores the fact that the Company's OSS sharing mechanism is predicated on OSS "margins" (*i.e.*, net revenues) and *not* total (gross) revenues. As reflected in Rebuttal Exhibit SCW-3R, his calculations of the option-specific "OSS adjustments" found on Table 1 of his testimony were proven to be based on such gross revenues. The impact of his OSS adjustment misstatement is more particularly harmful to the Option #1 (Big Sandy 2 retrofit) inasmuch as this option created a relative higher level of OSS—due to the baseload energy contribution of the BS2 coal unit—than the other options which would retire that unit.

Q. **SHOULD MR. HORNBY'S EXHIBIT JRH-7 AND DR. FISHER'S TABLE 1 (EXHIBIT JIF-3A), ADDRESSING OSS ADJUSTMENTS, BE REJECTED?**

A. Yes. Setting aside the modeling philosophy issue as to whether a specific rate treatment of certain costs/credits should be considered as part of the Strategist®-

based least-cost modeling process, as a practical matter, the proposed OSS adjustment identified by both Mr. Hornby and Dr. Fisher should be ignored. That said, as reflected in TABLE 2 below (as well as Rebuttal Exhibit SCW-3R), based on the Company's current Tariff S.S.C. I have modified the calculation to show a corrected view of Dr. Fisher's "Table 1" (Exhibit JIF-3A). Note first the relative overstatement to this (CPW) "OSS Adjustment 'Add-Back'" made by Dr. Fisher, but also note that the relative impact of this corrected change *between* options is now relatively minor.

TABLE 2

KPCo-CORRECTED FISHER DIRECT TESTIMONY "Table 1" (Exhibit JIF 3-A)

Cumulative Present Worth of Revenue Requirements (M 2011$)
Re-Analysis with Adjusted Off System Sales

		Option #1 Retrofit Big Sandy 2 w/DFGD	Option #2 (Brownfield) NGCC Replacement	Option #3 Big Sandy 1 NGCC Repower	Option #4A Market to 2020; NGCC in 2020	Option #4B Market to 2025; NGCC in 2025
"As-Filed" in Fisher Testimony...						
Company Assumptions						
	CPW	6,839	7,075	7,091	6,918	6,792
	Net benefit of retrofit (CPW)		236	252	79	(47)
Adjusted Off System Sales						
(A)	CPW	~~7,228~~	~~7,377~~	~~7,394~~	~~7,201~~	~~7,055~~
	Net benefit of retrofit (CPW)		~~149~~	~~166~~	~~(27)~~	~~(172)~~
As-Corrected...						
KPCo-Determined Fisher Overstatement of OSS Adjustment 'Add-Back'						
(B)	*CPW*	*404*	*341*	*341*	*327*	*311*
'KPCo-CORRECTED' Adj. Off System Sales						
(C) = (A) - (B)	CPW	6,824	7,036	7,053	6,874	6,744
	Net benefit of retrofit (CPW)		212	229	50	(80)

Q. HAS DR. FISHER ACKNOWLEDGED A CORRECTION IN HIS "TABLE 1" (EXHIBIT JIF-3A) SUBSEQUENT TO HIS PRE-FILED TESTIMONY?

A. Apparently he has. In response to Company data request #7, Dr. Fisher offers a "corrected" version of his Table 1. Those results, reproduced in TABLE 2A below, would suggest that Dr. Fisher's OSS adjustments now recognize the utilization of

OSS margins, instead of OSS gross revenues, as previously discussed. While he continues to ignore the relative OSS "base" level within Company Tariff S.S.C., his absolute (dollar) adjustment to the study-period CPW costs continue to be misstated. However, the *relative* impact that error would have across the five options analyzed is consistent, so the Company is in agreement with his ultimate "Net benefit retrofit (CPW)" calculations as those figures now essentially match the qualified Company-derived results shown in my TABLE 2.

TABLE 2A

Cumulative Present Worth of Revenue Requirements (M 2011$)
Re-Analysis with Adjusted Off System Sales

		Option #1 Retrofit Big Sandy 2 w/DFGD	Option #2 (Brownfield) NGCC Replacement	Option #3 Big Sandy 1 NGCC Repower	Option #4A Market to 2020; NGCC in 2020	Option #4B Market to 2025; NGCC in 2025
Per Fisher Filed Response to KPCo Discovery #1-07...						
('Synapse-CORRECTED') Adjusted Off System Sales						
(D)	CPW	*6,943*	*7,154*	*7,171*	*6,993*	*6,862*
('CORRECTED') **Net benefit of retrofit (CPW)**			*211*	*228*	*49*	*(81)*
KPCo-Determined (Continued) Fisher Overstatement of OSS Adjustment 'Add-Back'						
(D) - (C)	*CPW*	*119*	*118*	*118*	*118*	*118*

VI. CRITICISMS OF THE RISK MODELING PERFORMED IN THE AURORA^{XMP} TOOL ARE UNWARRENTED

Q. ON PAGE 40 OF HIS TESTIMONY, DR. FISHER SUGGESTS, "WHETHER IN ERROR OR PURPOSEFULLY, THE COMPANY MISREPRESENTS THE POINT AND POTENTIAL VALUE OF THE AURORA ANALYSIS, WHICH IS TO ESTIMATE THE UNCERTAINTY ASSOCIATED WITH THE ECONOMIC OUTCOME OF THEIR VARIOUS OPTIONS, RATHER THAN THE ABSOLUTE OUTCOME." DO YOU AGREE WITH THIS SUGGESTION?

A. Absolutely not. In fact, Dr. Fisher has apparently ignored the stated intent of this Aurora^{XMP}-based risk modeling and its primary measurement focus; RRaR. As described beginning on page 46 of my direct testimony I state:

> "...RRaR represents the **difference** between the calculated "G"-Cost CPW 50th percentile (median) and 95th percentile outcome across the 100 simulations modeled. The 95th percentile representing a level of required revenue sufficiently high that it will be exceeded, assuming that the given plan were adopted, with an estimated probability of just 5.0 percent. Therefore, RRaR represents a measure of customer risk or uncertainty inherent in each portfolio. The *larger* the RRaR, the *greater* the level of risk that KPCo's customers could be subjected to a higher generation cost-of-service/revenue requirement." **(bold-type emphasis added)**

In no way did the body of my direct testimony focus on the "absolute" outcomes from this model. (In fact, as will be discussed later in this rebuttal testimony it is rather Dr. Fisher who is centered on such absolute Aurora^{XMP}-modeled results.) Rather, my *only* focus in that section of my direct testimony was to describe and discuss the relative simulated results as represented by measuring customer RRaR. Nowhere in my direct testimony explanations do I address the absolute "50th CPW percentile" results from the Aurora^{XMP} modeling as having any bearing on the Company's interpretation of the results, let alone point it out as a basis for decision-making. Rather, I focus on, again, the relative "RRaR" results among the studied options. This would seem to suggest that Dr. Fisher instead should concur with the approach taken by the Company, not only the use of this tool, but in its application and outcome as well.

Q. **DOES DR. FISHER OBJECT TO THE COMPANY'S USE OF SUCH RISK MODELING?**

A. No, quite the contrary. In fact, on pages 40 and 41 of his direct testimony he seemingly commends the Company's actions stating:

- "…this type of evaluation could, and should, be used to determine just how much any Option differs from another…";
- "…I applaud the use of multiple models to converge on a robust answer, particularly in the face of uncertainty…"; and
- "…I would encourage the Company to continue developing the use of other models to support decision-making."

The Company does appreciate this acknowledgement, and emphasizes that it will continue to improve and fine-tune such multi-model analyses.

Q. **HOWEVER, IN SPITE OF THIS ACKNOWLEDGEMENT, WHAT ARE DR. FISHER'S SPECIFIC CONCERNS?**

A. This is what is puzzling to me. In summarizing these platitudes on page 41 of his testimony, Dr. Fisher somehow draws the conclusion that, presumably, based on its utilization of the results of this Aurora^{XMP} risk modeling, the Company has chosen to "…reject results from the Strategist® model".

Q. **HAS THE COMPANY REJECTED THE STRATEGIST® RESULTS?**

A. Certainly not. To assume otherwise is not borne by the evidence offered in this case. The Company stands behind the modeling results from the Strategist® tool. As demonstrated in direct testimony and as summarized on Exhibit SCW-4 of that testimony, the Strategist® results offer the preponderance of the economic data that serve as the underpinning for the recommendations being made to this Commission.

In no way is the Company suggesting that the results produced by this additional Aurora^{XMP}-based risk modeling are offering anything more than an amplification of the results that emanated from Strategist®. In my opinion, the two tools and the results offered in this case are indeed complementary; not, as intimated by Dr. Fisher, are they somehow contradictory. In fact, it would seem Dr. Fisher, again, shares the same sentiment when he states, "(G)generally speaking, I applaud the use of multiple models to converge on a robust answer, particularly in the face of uncertainty, and I would encourage the Company to continue developing the use of other models to support decision-making."[4]

Q. DOES DR. FISHER OFFER ANY CLUE AS TO HIS ASSERTION THAT THE COMPANY HAS "REJECTED" THE STRATEGIST® MODELING?

A. He points to the fact that my direct testimony, including the discrete Strategist® results I offer in Exhibit SCW-4 of that testimony, would suggest that the CPW study-period cost differences for "Option #4B" (Retire BS2, and delay a replacement CC new-build until 2025, relying on [PJM] capacity and energy markets in the interim) are, in my words, a "near-wash". Dr. Fisher fails to mention the other objective concerns offered in my direct testimony surrounding an option (#4B) in which KPCo's customers would be significantly more dependent upon potentially volatile energy and capacity markets within PJM. (These objective issues and concerns were previously listed in the rebuttal of Mr. Kollen's testimony on page 7.) Rather, he dismisses the Company's "interpretation" of the Aurora^{XMP}-based results;

[4] Fisher direct, page 40, li. 28 through page 41, li. 2.

alluding that various "upside benefits" associated with, particularly, natural gas purchases were ignored.

Q. **DO YOU AGREE WITH THAT CONTENTION?**

A. No. First, any evaluated resource option could be certainly expected to express "upside benefit" potential. For instance, in the case of the Company's recommended Option #1 BS2 retrofit alternative, delivered coal prices could likewise be reduced over time versus current fundamental forecasted levels; a carbon "tax"—which was projected as part of these analyses—may never emerge; the cost to retrofit BS2 could come in below its projected cost. While such reduced cost, or "upside benefits" outcomes are indeed a plausible result from the stochastic risk modeling, the *particular* focus and emphasis of this cost prudency exercise should rather be on the potential for <u>increased</u> cost risk to customers. By virtue of his Exhibit JIF-9, Dr. Fisher would seek to establish essentially equal objective weighting to both cost upside and downside potential. We disagree. Not that the potential for the upside benefit of reduced costs should be dismissed completely; but as a practical matter, it should be the responsibility of the Company to focus more heavily on the downside risk of increased cost potential, and resultant exposure, to its customers. That is the primary purpose of the RRaR measurement.

A. <u>RECONCILIATION VERSUS STRATEGIST® RESULTS</u>

Q. **PLEASE DESCRIBE DR. FISHER'S SPECIFIC CONCERNS SURROUNDING THE INABILITY TO RECONCILE MODELED RESULTS BETWEEN THE COMPANY'S DISCRETE MODELING PERFORMED**

USING THE STRATEGIST® TOOL *VERSUS* THE STOCHASTIC RISK MODELING FROM THE AURORA^{XMP} APPLICATION.

A. Dr. Fisher spends several pages of his direct testimony (pages 43-50) suggesting that the relevance of the Company's Aurora^{XMP}-modeled results are suspect based on his assertion that the summarized output results he offers cannot be readily reconciled with the Strategist®-based resource cost-optimization modeling also performed by the Company (and, presumably, emulated by SC witness Wilson).

Q. **HOW DO YOU RESPOND TO THAT CONCERN?**

A. There are two parts to this answer. The first is that the models are not directly comparable; they are apples-and-oranges. The second is that, in the interest of complete transparency, the Company's detailed assessment of Dr. Fisher's claim did uncover two Aurora^{XMP} modeling assumption issues that a) were not originally reflected at the time of the Company's filing, but b) the Company has now subsequently considered. The short answer is—as I will discuss describe more fully later in this rebuttal testimony—the fundamental risk modeling results and conclusions set forth in my direct testimony are unchanged as a result of this appended modeling.[5]

Q. **PLEASE FIRST ELABORATE ON WHY THIS COMPARISON OF RESULTS BETWEEN THE TWO MODELS SHOULD BE CONSIDERED AN "APPLES-TO-ORANGES" COMPARISON.**

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[5] Supporting workpapers for this appended Aurora^{XMP} risk modeling to be discussed are being prepared and will be provided when available.

A. The two modeling tools are fundamentally unique. Strategist® utilizes discrete, non-risk adjusted input variables. For example, for any given year/month/day/sub-period, this tool performs a production costing/dispatch algorithm based on singular, non-varying sets of input parameters; be it native customer load (company resource obligation), fuel and emissions costs, market energy pricing, etc. That is why it is necessary to create modeling results from the Strategist® tool using a range or variations of such key variables—fundamental commodity pricing chief among them—so as to demonstrate the desired modeling/evaluation rigor. As discussed in my direct testimony, and reflected on my Exhibit SCW-4 Strategist® output summary, this was achieved largely by way of running the model under five (5) unique scenarios, or sets, of such long-term commodity pricing. As also identified in my direct testimony, these ranges of commodity pricing reflected fairly significant band-widths for natural gas pricing, coal pricing, (PJM) on and off-peak energy pricing, as well as the extent and timing of carbon (tax) initiatives.

Contrastingly, as also described in more detail as part of Exhibit SCW-1 (pages 10 through 14) of my direct testimony, the Aurora^{XMP} tool can perform stochastic or random variable (Monte Carlo) analyses. For this modeling it performed 100 risk simulations utilizing six risk factors. So, for instance, if the average "Base" nominal price of natural gas assumed in the Strategist® profiling for Year X was, say, $4.50/MMBtu... for purposes of the Aurora^{XMP} risk modeling, that randomly-selected price could have been within a normally-distributed range of, roughly, -25% to +25%. The same applicable randomness would be true for any of the other modeled key risk drivers, such as the Company's forecasted demand/(load).

Therefore, unlike the "discrete" Strategist® results, in the Aurora^{XMP} modeling—for each simulated model iteration—a data point could be randomly-selected for the respective independent variable being modeled.

In summary, the two models are indeed unique in terms of their respective approach in developing a long-term cost profile. Therefore, as amplified in this rebuttal testimony, one cannot take a specific iterated result from Aurora^{XMP} modeling—even one at the median or 50th (CPW) percentile result of the 100 simulations, as Dr. Fisher has done in his Figure 6 and 7 comparisons—and assume it would result in an apples-to-apples comparison with a "base" pricing scenario case result from Strategist®.

Q. PLEASE EXPLAIN THE FIRST OF THE TWO AURORA^{XMP} MODELING ASSUMPTION ISSUES THAT WERE IDENTIFIED.

A. As suggested on page 50 of Dr. Fisher's testimony, the Company's risk modeling and subsequent output reporting, did exclude option-specific, on-going capital carrying charges associated with major projected capital expenditures.

Q. WOULD THIS OMISSION OF CAPITAL CARRYING CHARGES HAVE ANY BEARING ON THIS RELATIVE AURORA^{XMP}-BASED RISK MODELING EXERCISE?

A. No. As shown in Rebuttal Exhibit SCW-4R, after having re-run the Aurora^{XMP} modeling to now reflect such capital carrying charges, the cost variations that manifested across the spectrum of the 100 simulations were very small. Therefore, the relative impact on *RRaR*—the exclusive purpose and intent of this risk analysis—among the options analyzed would essentially <u>not</u> be impacted.

Q. PLEASE DESCRIBE THE SECOND AURORA^{XMP} MODELING ASSUMPTION ISSUE.

A. The Aurora^{XMP} risk modeling has the ability to introduce an initial "demand vector" as part of its parameter set-up. This demand vector is available in the tool to offer the user a means to provide a "block increase" to a utility/load serving entity's native demand (internal load) by way of an initial percentage change above a base projected level. The intent being to initially stratify or significantly "stress" that demand variable as part of the risk modeling. This "stressor" of internal demand, or— *viewed from another perspective*—the utility's overall "(market) energy position", could potentially then be incrementally challenged in some significant manner. Stated another way, this so-called "demand" vector could serve as a proxy for any combination of potential demand-side increases *or* supply-side (*i.e.*, generating unit capability) decreases.

In this case, the Aurora^{XMP}-based stochastic modeling for KPCo was originally set-up to utilize such an initial demand vector. That level was set equal to <u>20 percent</u> for all options analyzed. This means that beginning in "Year 1" of the forecasted risk analysis period (2011), the projected native demand/internal load of KPCo was increased by 20 percent for each alternative modeled. From that modified (higher) demand "base", or starting point, the tool then performed demand-risk variations as part of the tool's Monte Carlo risk simulation routine. Generally speaking, and as manifested in Dr. Fisher's assessment of the Aurora^{XMP} "Net Import (Market Purchase) Costs" output, it naturally resulted in such energy purchases being higher, *particularly* when compared to Strategist® results as he discusses on page 49 of his testimony (and optically on his Figure 7 chart).

For example, assuming a KPCo internal demand/load level of roughly 7,600 Gwh in 2011, this 20 percent initial ratcheting impact due to that demand vector application in the modeling was over +1,500 Gwh. This variation then proceeded to grow annually at the same "per forecast" level of year-to-year forecasted demand growth. Therefore KPCo's net energy position (or, energy import/export position) was naturally then impacted by as much +1,500-1,600 per year over the 30-year study period. For the option cases evaluated, this effective demand increase would have resulted in a similar order-of-magnitude change in market purchase.

Q. FOR PURPOSE OF THIS AURORA^{XMP} RISK MODELING IS THE USE OF SUCH A "DEMAND VECTOR" INPUT PARAMETER REASONABLE?

A. Yes it is. As suggested, it brings into the risk modeling exercise the prospect that overall energy position—again, based on proxied swings in either demand-side *or* supply-side factors—could be impacted in a way that would be helpful to capture as part of an overall risk assessment.

Q. IN THE INTEREST OF TRANSPARENCY AND FOR PURPOSES OF "BOUNDING" THIS ENERGY POSITION (DEMAND VECTOR) "STRESSOR", HAVE ADDITIONAL AURORA^{XMP} RISK MODELING RUNS BEEN MADE?

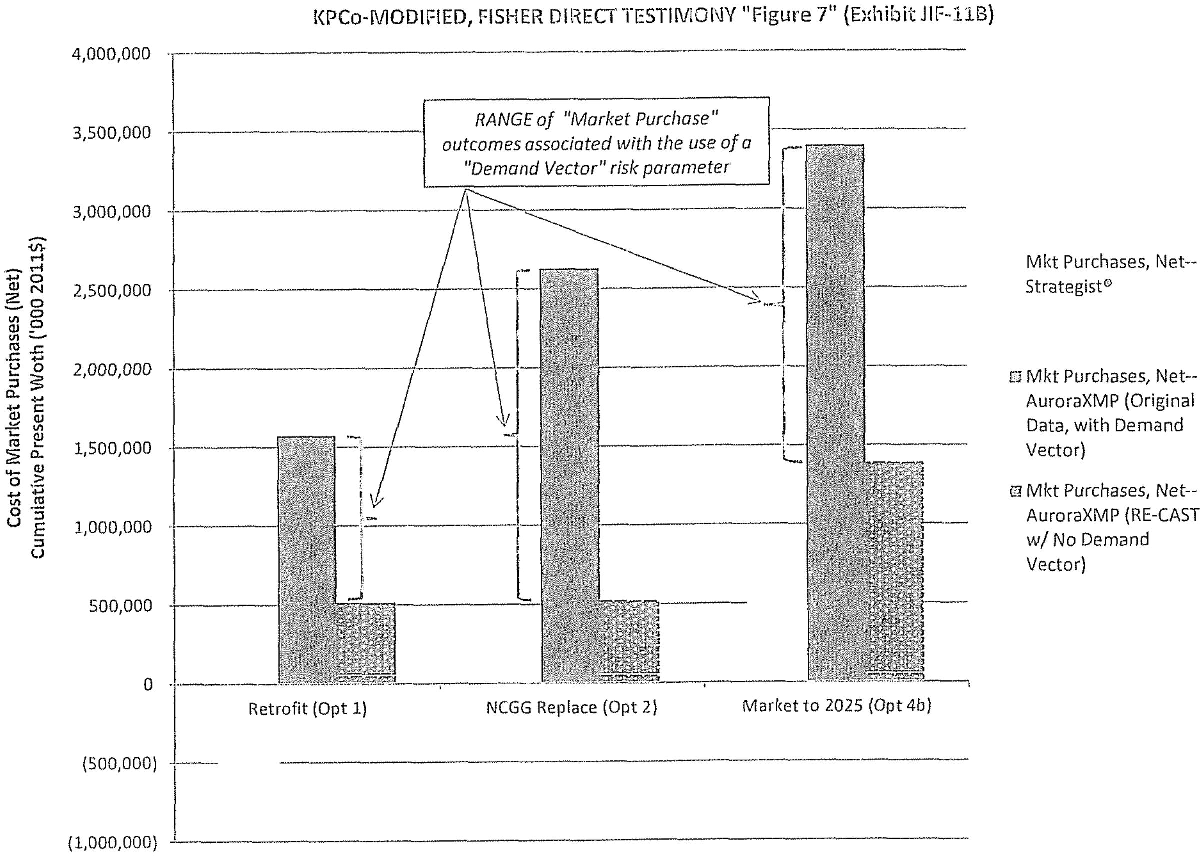
A. Yes. So as to address the concerns expressed by Dr. Fisher related to the extent of market purchases that naturally emanated from the Company's risk profiling that included an assumption of a demand vector, the modeling was re-cast to remove this input parameter *in its entirety.*

In fact, my original-filed Exhibit SCW-5 has now been restated as Rebuttal Exhibit SCW-5R to reflect this. As will be summarized later in this rebuttal testimony, the updated version of this exhibit now offers a range of comparative RRaR results recognizing the more significant market exposure brought on by the use of such a market vector *versus* a view that would not consider such a parameter.

Q. **BASED ON THESE RE-CAST AURORA^{XMP} MODEL RESULTS, FOCUSING SPECIFICALLY ON THE ISSUE DR. FISHER TAKES WITH THE MODEL-COMPARATIVE RESULTS FOR "MARKET PURCHASES" IN HIS FIGURE 7 (EXHIBIT JIF-11B), HOW WOULD THOSE "STRATEGIST VS. AURORA^{XMP}" RESULTS NOW COMPARE?**

A. First, the **FIGURE 1** chart below (also reproduced as Rebuttal Exhibit SCW-6R) offers a modified version of Dr. Fisher's Figure 7 (Exhibit JIF-11B), by now incorporating a re-cast comparative view of such "Market Purchases" between the two tools; however now offering a market purchase range that both includes and excludes this demand vector input parameter:

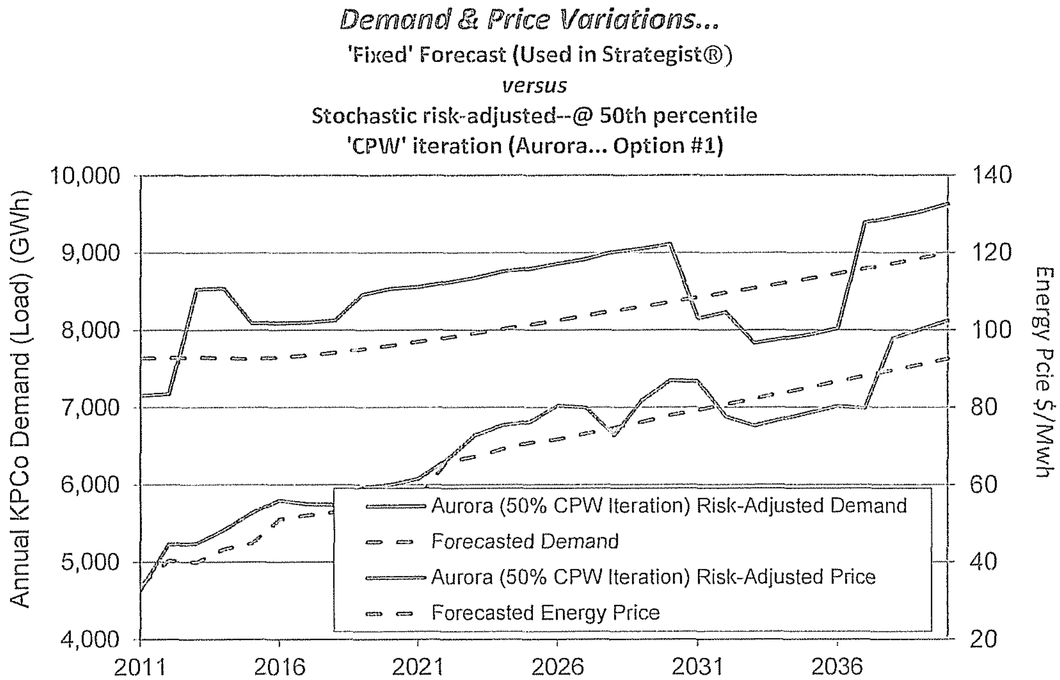
FIGURE 1



This re-casting of a market purchase range offers a clearer "reconciliation" of the Aurora^{XMP}-modeled results for that cost category vis-à-vis the discrete results from the Strategist® modeling.

However, despite this there are other issues when comparing these cost category results due to the inherent differences in the two models and the functions they are performing. As previously described, the Aurora^{XMP} model is varying KPCo demand (load) and energy price with *each* simulated iteration, while in Strategist® such projections are "static" (*i.e.*, per the long-term forecast). Thus, when one examines just a single one of the 100 Aurora^{XMP} simulations, *even if* it is the median (50th CPW percentile) simulated result, it is highly unlikely that demand and price levels underpinning the Aurora^{XMP} production cost modeling will equate to that base demand (internal load) assumptions in Strategist®. This variation of the "demand and energy pricing" forecast components at the risk-modeled 50th percentile iteration can be seen in the FIGURE 2 chart below:

FIGURE 2



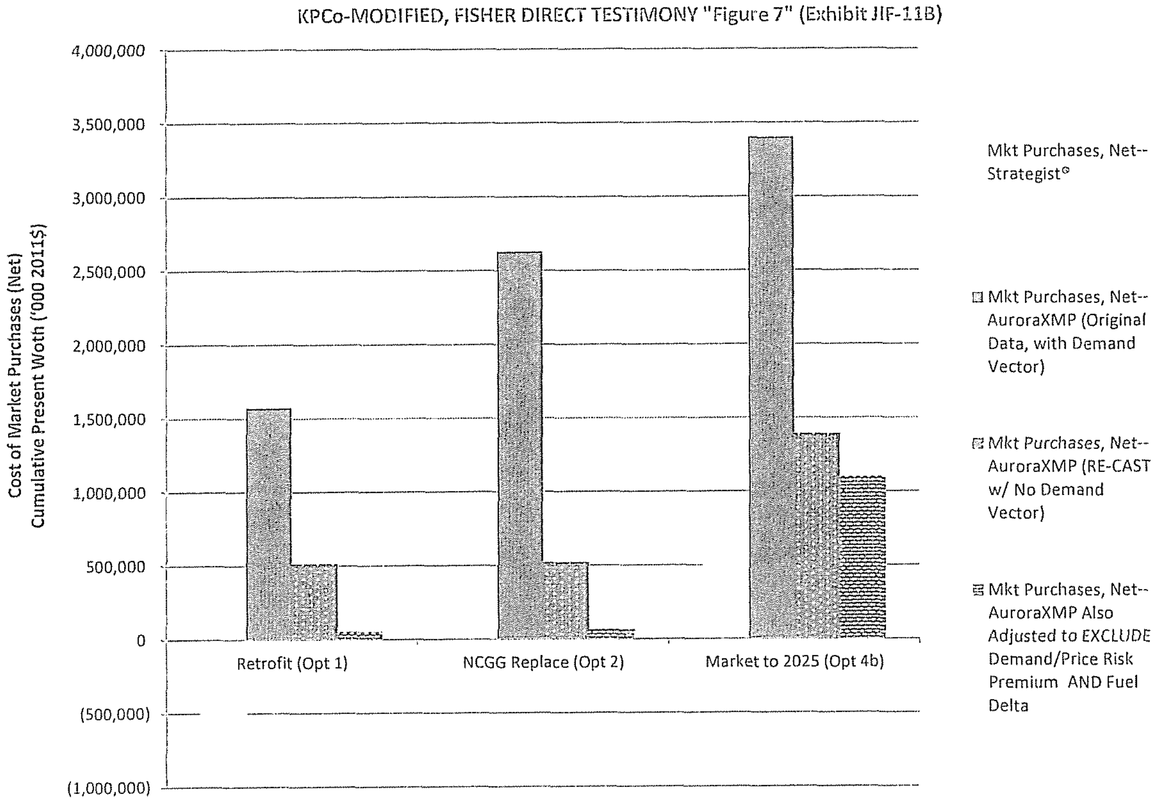
Q. BASED ON THESE INHERENT "DEMAND AND PRICE VARIATIONS" IN THE AURORA^{XMP} MODELING, WHAT ADDITIONAL RECONCILIATION COULD BE MADE TO ALLAY CONCERNS RAISED BY DR. FISHER THAT SUCH MARKET PURCHASES FROM THE COMPANY'S AURORA^{XMP} MODELING DO NOT PROPERLY ALIGN WITH COMPARABLE COST CATEGORY RESULTS FROM THE STRATEGIST® TOOL?

A. As described in this rebuttal testimony, one simply cannot compare any of the 100 individual simulated Aurora^{XMP} outcomes and perform an apples-to-apples view versus results from Strategist®. As indicated, comparing on-the-margin demand and price variations (FIGURE 2) established in the risk-adjusted Aurora^{XMP} simulations utilized in that "50th CPW percentile" result for Option # 1—and for which Dr. Fisher focused his attention—would create another relative $31 million CPW cost variation between the two tools. That is, since such Aurora^{XMP}-simulated (customer) demand and (market) pricing for Option #1 was *higher* than the "base" levels used by Strategist®, it would then naturally result in a comparative increase in the relative market purchase cost for Option #1.

Further, another model-to-model reconciling item necessary to be considered when focusing exclusively on just the "Market Purchases" cost category would be the unique differences in the models' respective KPCo consumed fuel costs. To the extent that such projected consumed fuel cost amounts differ largely as a function of (generation) volume variations, such supply-side differences would then have to be made up by increases (or decreases) in Market Purchases.

The following **FIGURE 3** (also reproduced within Rebuttal Exhibit SCW-6R) offers an adjusted version of the previous FIGURE 1 to reflect these additional reconciliation adjustments:

FIGURE 3



This FIGURE 3 would suggest a far more meaningful comparison between the Aurora^{XMP} and Strategist® results for this modeled cost category—before the consideration of even additional modeling nuances and differences not captured here.

Q. **TO SUMMARIZE, UPON RECOGNIZING THESE APPENDED MODELING ASSUMPTIONS, IN YOUR OPINION DOES DR. FISHER CONTINUE TO HAVE AN ARGUMENT THAT THE AURORA^{XMP}-MODELED RESULTS SHOULD BE BROUGHT INTO QUESTION BASED ON COMPARISONS VERSUS THE STRATEGIST® MODELING?**

A. No he does not. In fact, after considering the Company's efforts in this rebuttal testimony to ensure this risk modeling is set forth in as transparent and open manner as is possible based on the explanations offered, the results continue to serve to support the complementary nature of the two modeling tools.

Q. PLEASE NOW ELABORATE ON THE "RANGE" OF RRaR RESULTS NOW BEING OFFERED.

A. As provided in Rebuttal Exhibit SCW-5R, a range of option-specific RRaR outcomes has now been quantified that would consider up to and including the full removal of the originally-modeled demand vector parameter. These results *continue to indicate* that Option #1 (BS2 Retrofit) offers the lowest relative RRaR (50^{th} vs. 95^{th} percentile CPW differential) then the other three alternatives evaluated. Specifically, it indicates that Option #1 ranks first in terms of having the lowest RRaR at a range of $623 -to- $815 million, while Option #3 (BS1 CC Repowering) ranks second, Option #2 (NGCC Replacement), ranks third and, finally, Option #4B (Retire BS w/ Market Purchases to 2025, then CC) ranking fourth; with RRaR ranges of $665 -to- $1,075 million, $754 -to- $1,173 million, and $789 -to- $1,179 million, respectively.

B. <u>CONCERNS OVER CORRELATIONS USED IN AURORA RISK MODELING</u>

Q. WHAT ARE DR. FISHER'S ADDITIONAL CONCERNS EXPRESSED IN REGARD TO THE RELATIVE CORRELATIONS OF THE RISK-VARIABLES MODELED IN THE AURORA^{XMP} TOOL?

A. On page 55, lines 2 through 4, Dr. Fisher indicates that the correlations utilized in the Company's Aurora^{XMP}-based stochastic (Monte Carlo) risk modeling exercise "…deeply influenced the outcome, and may have unduly biased the results." More specifically, on page 56 of he offers some "technical" criticisms that such correlations used by the Company in its modeling were predicated upon "incorrectly-used data" or are "non-robust".

Q. HOW DO YOU RESPOND TO THESE CRITICISMS?

A. The Company strongly disagrees with Dr. Fisher's assertion, *particularly* the notion of attempted modeling bias. First, the Company's risk modeling used existing, publicly-available data to calculate these correlations. Dr. Fisher is picking around the edges as to the appropriateness of certain data sets, time periods examined, and calculation methods in an effort to entirely dismiss the results. For example, Dr. Fisher points out that "(B)because there is not yet an active national market for CO_2 in the US, the Company turned to Europe to represent an active carbon market…"[6] and then disparages the use of data from the only significant market in existence that trades coal, power, natural gas, *and* CO_2 emission credits simultaneously. He further suggests that because the CO_2 futures shift from quarterly to annual periods somehow invalidates the data, and further grasps at straws by proving that randomly removing data points changes the result. The Company's "choice" to use European data was one of necessity in order to observe how those commodity pricing elements interact when they are all—inclusive of CO_2—in play. As distant or sparse as his interpretation of the data may be, the Company believes this is a superior approach to using "no correlations" as Dr. Fisher even suggests on page 63, li 7 and 8, of his testimony. To even suggest that approach would have to be a considered a self-admission by Dr. Fisher that he has no greater insight as to the appropriate correlation of long-term commodity prices that would be linked to a potential carbon regime.

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[6] Fisher Direct, page 61, li. 24-26.

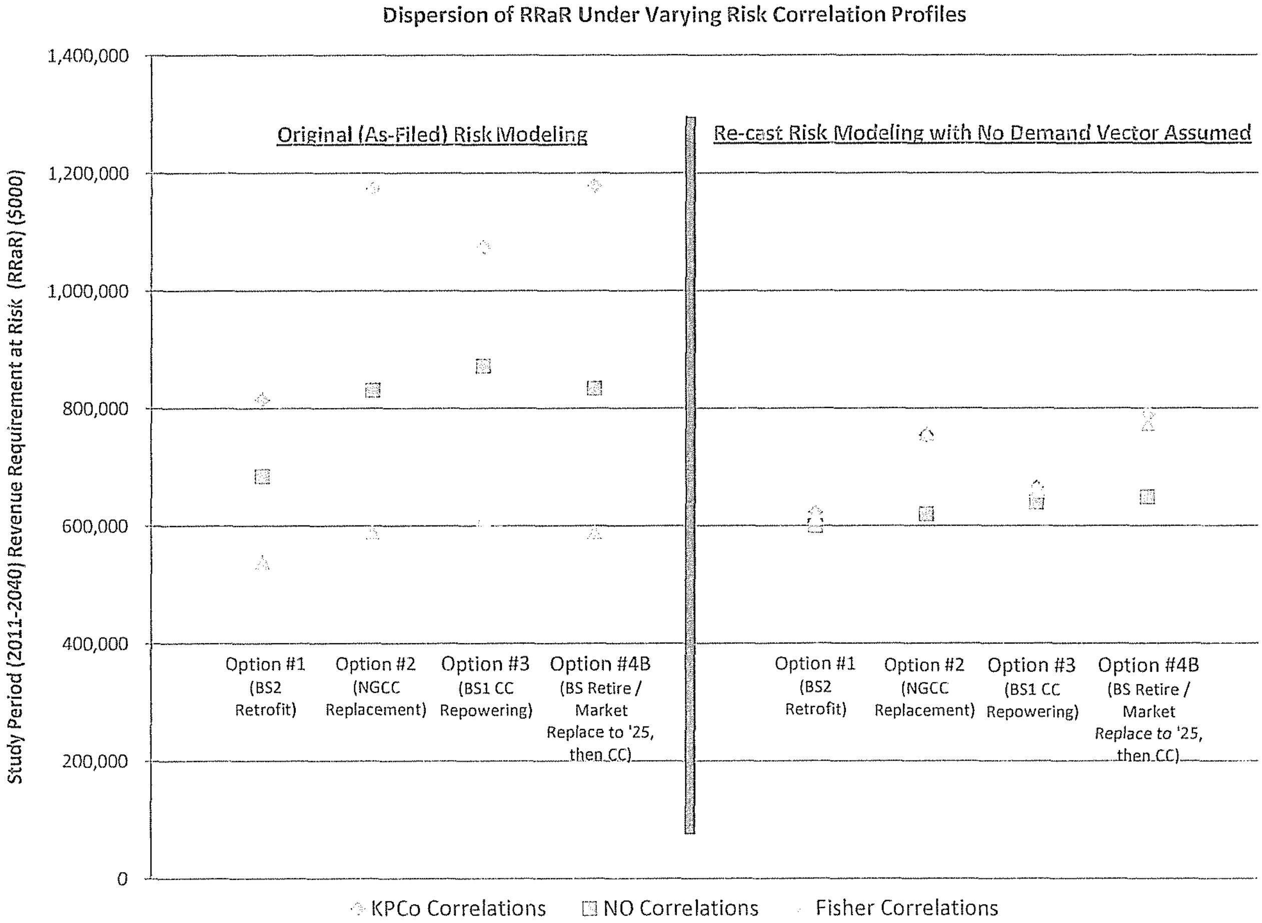
Q. PLEASE ELABORATE ON DR. FISHER'S ASSERTIONS THAT THE CORRELATIONS RELIED UPON WERE INADEQUATE, HENCE MAKING THE ENTIRETY OF THE COMPANY'S RISK MODELING INAPPROPRIATE.

A. When attempting to model data relationships that have scant history, such as carbon pricing with demand, coal, natural gas, and power prices, there are few, if not only a sole source of data. Dr. Fisher does not offer any preferred sources of data or methods, but does calculate an alternative set of relationships with the data provided, as well as suggest that in absence of better information, correlation values of "zero" (*i.e.*, "no" correlation) would be preferred. He concludes that the entire analysis should be disregarded for what he feels is imprecision in the correlations.

However, these arguments around appropriate risk variable correlations to be used for modeling purposes are merely noise. Correlations between key, risk-driving variables are but one factor of the larger stochastic analysis. The Company utilized what it believed to be reasonable correlation estimates for such modeling and it stands behind those estimates. More critical to the risk modeling results are the underlying distributions of possible (commodity) prices, which are not in dispute. For instance, nowhere in his testimony does Dr. Fisher specifically question those underlying distribution ranges of risk variables/pricing inputs utilized over the 100 simulated iterations performed for each alternative option by the Company. Also, nowhere in Dr. Fisher's testimony is there any suggestion that, for instance, natural gas prices are not potentially volatile. Since such "variable" costs constitute a greater part of total costs for the natural gas/market options (Options #2 through #4), it is certainly intuitive that they may be subject to more volatility.

So to demonstrate this point regarding the ultimate impact of the assumed correlations used in this risk modeling, and *in spite of* Dr. Fisher's own potentially flawed methods or motivations in determining them, the Company re-ran the Aurora^{XMP} stochastic modeling using the alternative correlations as suggested by Dr. Fisher and reflected on Table 10, page 64 of his testimony (and Exhibit JIF-12B), as well as a view that assumed <u>no</u> correlations as he suggested should be done in the absence of more "robust" data. The results continue to show the ultimate conclusion that the Big Sandy retrofit option offers the relative less risk exposure of all options evaluated. **FIGURE 4** (also reproduced as Rebuttal Exhibit Exhibit SCW-7R) shows, in chart form, the results of these additional simulation trials that were performed as part of the original risk modeling utilized for this filing, as well as based on the risk modeling that was re-cast as previously described.

FIGURE 4



As reflected on FIGURE 4—and, again, without attempting to delve deeper into the veracity of the correlations offered by Dr. Fisher in his Table 10—it would indicate that the Option #1 retrofit would continue to have a lower relative RRaR (*i.e.*, less risk of an adverse outcome), versus the other alternative options modeled, by virtue of having adopted either Dr. Fisher's offered correlations or assuming—as suggested by Dr. Fisher on page 63 of his testimony, "...in the absence of robust and supportable information"—<u>no</u> correlations altogether.

Q. BASED ON THESE RESULTS, PLEASE FURTHER ADDRESS DR. FISHER'S ASSERTION ON PAGE 54 OF HIS TESTIMONY THAT THE CORRELATIONS UTILIZED BY THE COMPANY "...DEEPLY INFLUENCED THE OUTCOME, AND MAY HAVE UNDULY BIASED THE RESULTS".

A. Generally speaking, these risk variable correlations, which are uncertain themselves, can only move the needle so far in either direction. This point is particularly shown when assessing the RRaR differentials that were performed under the "re-cast" risk modeling (right-hand portion of FIGURE 4). Rather, the greater cause for future cost uncertainty is that of the underlying commodity pricing/variability assumptions which, for instance, have historically impacted natural gas-intensive options to a greater degree.

To amplify this discussion, such risk modeling, and its measurement via RRaR, specifically seeks to quantify the dispersion of possible (cost) outcomes given historical or anticipated behavior of key input variables—*acting independently*, and in correlation with each other. As previously suggested, Dr. Fisher's testimony largely addresses and focuses on the correlational aspect of these risk variables; not the attendant underlying distributed commodity pricing points. So in that regard, the modeled "correlation ranges" reflected in FIGURE 4 would suggest that irrespective of the correlated relationships among independent and dependent variables assumed, the overall RRaR relationships among the options evaluated *did not* flip or change.

C. CONCERNS OVER THE TRANSPARENCY OF THE AURORA MODELING

Q. **HOW DO YOU ADDRESS THE CONCERN ALSO EXPRESSED BY DR. FISHER THAT THE AURORA^{XMP} MODELING OFFERED BY THE COMPANY LACKED "TRANSPARENCY"?**

A. The Company was transparent. Dr. Fisher's concern was perhaps due to some level of frustration—unlike the Strategist® modeling tool which he did have access to—of not having the capability to run the Aurora^{XMP} model. Dr. Fisher contends on page 51 of his direct testimony that Sierra Club had requested input and output files from the Aurora model. The Company made it clear in its responses to those requests that the requisite input and output (I/O) data files necessary to execute (and report directly out of) this model are a proprietary product of the model developer, EPIS, Inc. Therefore, without evidence that the intervener had a current license agreement for the tool with EPIS, the Company was legally bound to harbor those proprietary I/O files. That said, the Company nonetheless believes it made a good-faith effort to offer sufficient I/O information. Sierra Club should recognize that the exchange of information was meaningful given that the Company has made a further good-faith effort by recognizing, as part of this rebuttal testimony, the prospect of appending its Aurora^{XMP} modeled results to provide a fuller "range" of option-specific RRaR measures for the reasons previously-described.

Q. **IS IT COMMON THAT INTERVENING PARTIES IN UTILITY REGULATORY PROCEEDINGS WOULD HAVE ACCESS TO AND/OR ARE ABLE TO EXECUTE THE SAME PROPRIETARY MODELING TOOLS SUCH AS DR. FISHER IS SUGGESTING?**

A. Unless they would have the required model licensing agreement, it would not at all be common for case interveners to have access to such information. Rather it has been, and continues to be, the Company's obligation to provide the input assumptions and results of any such modeling assessment in as transparent and rigorous manner as is possible for the vast majority of parties not having such modeling capabilities.

Q. FINALLY, AS PART OF HIS INITIAL ISSUES WITH THE COMPANY'S AURORA^{XMP}-BASED RISK MODELING, DR. FISHER ALSO SUGGESTS THAT EXHIBIT SCW-5 OF MY DIRECT TESTIMONY—WHICH SETS FORTH THE MODELING'S OPTION-SPECIFIC DETERMINATION OF RRaR--SHOULD BE "WITHDRAWN" OR "DISREGARDED". HOW DO YOU RESPOND TO THAT?

A. Based on the preceding rebuttal of various concerns raised by Dr. Fisher, it is clear that this suggestion should itself be dismissed as unwarranted.

VII. HORNBY / FISHER REBUTTAL SUMMARY

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS SURROUNDING MR. HORNBY AND DR. FISHER'S CRITICISMS AND RECOMMENDATIONS TO THIS COMMISSION.

A. To summarize this rebuttal testimony, as well as the rebuttal testimonies of Company witnesses Becker and Bletzacker, the following was established.

- The recommended adjustments to the Strategist®-determined study period CPW costs to reflect a view of OSS margin-sharing is unnecessary, with very limited implications after correcting for errors in that adjustment as determined by Dr. Fisher;

- the recommended adjustments to the Strategist®-determined study period costs associated with perceived understated Big Sandy 2 retrofit costs, and perceived overstated replacement natural gas installed costs, were proven incorrect and should be dismissed;
- the Aurora^{XMP} risk modeling results performed by the Company were demonstrated to be reasonable, were properly interpreted and an adequate explanation of the approach and modeled output was offered, including a transparent effort to append these results to reflect an RRaR "range", thereby affirming that Dr. Fisher's assertion that such modeled results should be "withdrawn" is itself unfounded and should be dismissed; and
- the recommended adjustments to the study period costs for a far higher—than Company-forecasted—CO_2 pricing level to be utilized in the modeling is also unfounded and highly-speculative, was premised on inaccurate attendant fundamental pricing/modeling, and should likewise be dismissed.

Finally, to offer an optic as to the Company's position on, particularly, the cumulative merit of the Strategist® modeling-based "adjustments" offered by Dr. Fisher on page 38 (Table 6; Exhibit JIF-3F) of his testimony, the following TABLE 3 (also reproduced as Rebuttal Exhibit SCW-8R) offers a corrected view of Dr. Fisher's exhibit.

TABLE 3
'CORRECTED' FISHER DIRECT TESTIMONY (Exhibit JIF-3F)

Cumulative Present Worth of Revenue Requirements (M 2011$) Re-Analysis with Synapse Low CO2, Corrected Capital Costs & Adj. Off System Sales					
		Option #1 Retrofit Big Sandy 2 w/DFGD	**Option #2** (Brownfield) NGCC Replacement	**Option #4A** Market to 2020; NGCC in 2020	
"As-Filed" in Fisher Testimony...					
Company Assumptions					
	CPW	6,839	7,075	6,918	
	Net benefit of retrofit (CPW)		236	79	*
Synapse Low CO2 Price, Corrected Capital Costs & Off-System Sales					
(A)	CPW	~~8,063~~	~~7,445~~	~~7,367~~	
	Net benefit of retrofit (CPW)		~~(618)~~	~~(696)~~	*
			* reflects rounding differences from filed Exhibit JIF-3F		
As-Corrected...					
Fisher Overstatement of ALL Adjustments (Combined)					
(B)	*CPW*	*1,239*	*409*	*493*	
'KPCo-CORRECTED' Results					
(A) - (B)	CPW	6,824	7,036	6,874	
	Net benefit of retrofit (CPW)		212	50	

Other than the *potential* consideration of a slight adjustment of the relative CPW cost impacts of the treatment of OSS offered in TABLE 2 earlier in this rebuttal testimony, the Company believes that based on the rebuttal testimony of Company witness Becker there are no "Capital Cost" adjustments that would be called for. Further, based on the rebuttal of the Synapse CO_2 pricing profiles offered by Company witness Bletzacker, there are likewise no adjustments—versus those levels of CO_2 that had been incorporated into the Company's modeling—that would be warranted for a "(Synapse) Low Carbon" cost view.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

VERIFICATION

The undersigned, Scott C. Weaver being duly sworn, deposes and says he is the Managing Director Resource Planning and Operation Analysis for American Electric Power that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief.

SCOTT C. WEAVER

STATE OF OHIO)
) CASE NO. 2011-00401
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Scott C. Weaver, this the 12 day of April 2012.

Notary Public

NOTARIAL SEAL STATE OF OHIO

Cheryl L. Strawser
Notary Public, State of Ohio
My Commission Expires 10-01-2016

My Commission Expires: October 1, 2016

Fleet Transition-CSAPR
Commodity Pricing

PER KOLLEN TESTIMONY (Page 13) — NOMINAL ($000)

CORRECTION (TO PROPERLY REFLECT RESULTS IN PRESENT DOLLARS) — REAL (2011) ($000)

Year	(1) Big Sandy 2 Retrofit (Option #1)	(2) Market Replacmnt to 2025 (Option #4B)	(3)=(1)-(2) Savings fr Market Purchases	Cumul Savings fr Purchases	= PV of (3) PRESENT VALUE of Savings fr Mkt Purchases	Cumulative Present Value
2016	621,065	509,433	111,632	111,632	73,763	73,763
2017	563,763	500,781	62,982	174,615	38,307	112,071
2018	569,255	489,883	79,372	253,986	44,436	156,507
2019	580,129	512,944	67,185	321,172	34,622	191,129
2020	580,242	523,156	57,086	378,258	27,078	218,207
2021	598,301 *	548,927	49,374	427,631	21,557	239,765
2022	713,673	648,370	65,303	492,934	26,245	266,010
2023	743,111	677,380	65,730	558,665	24,316	290,326
2024	753,290	699,595	53,695	612,359	18,284	308,609
2025	781,919	805,776	(23,856)	**588,503**	(7,477)	**301,132**
2026	797,372	825,255	(27,883)	560,620	(8,044)	293,088
2027	814,067	834,667	(20,600)	540,021	(5,470)	287,617
2028	829,421	855,391	(25,970)	514,050	(6,348)	281,269
2029	849,520	876,687	(27,167)	486,884	(6,112)	275,157
2030	864,102	881,100	(16,998)	469,885	(3,520)	271,636
2031	722,471	903,931	(181,460)	288,426	(34,593)	237,043
2032	725,518	905,571	(180,053)	108,373	(31,595)	205,449
2033	741,623	922,963	(181,340)	(72,967)	(29,290)	176,159
2034	766,323	940,184	(173,861)	(246,828)	(25,849)	150,310
2035	788,772	968,278	(179,506)	(426,333)	(24,565)	125,745
2036	803,304	981,982	(178,678)	(605,012)	(22,507)	103,237
2037	814,624	991,429	(176,805)	(781,817)	(20,500)	82,737
2038	840,837	1,015,542	(174,705)	(956,521)	(18,646)	64,091
2039	853,549	1,028,426	(174,877)	(1,131,398)	(17,180)	46,911
2040	1,055,057	1,050,837	4,219	**(1,127,179)**	382	**47,293**

2025 Cumulative Present Value (301,132): View that Should Be Taken IF Focus were to be Incorreclty Based on Results Thru 2025 ONLY, as Suggested by Mr. Kollen

2040 Cumul Savings (1,127,179): View that Should Be Taken IF Focus were to be Based on Nominal Dollars ONLY, as Suggested by Mr. Kollen

2040 Cumulative Present Value (47,293): Ties to Weaver Exhibit SCW-4 (Option #1 v. Option #4B)

* Note: Mr. Kollen's calculation of this 2021 value value was incorrect @ 598,242, therefore his 'Cumulative Savings' variance (thru 2025) was also misstated in his testimony @ 588,444.

KENTUCKY POWER COMPANY

Original Sheet No. 19-1
Canceling ______ Sheet No. 19-1

P.S.C. ELECTRIC NO. 9

TARIFF S. S. C.
(System Sales Clause)

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, S.G.S., Experimental S.G.S.-T.O.D., M.G S., M.G S.-T.O.D., L.G.S., L.G.S.-T.O.D., Q.P., C.I.P.-T.O.D., C.S.- I.R.P., M.W., O.L. and S.L.

RATE.

1. When the monthly net revenues from system sales are above or below the monthly base net revenues from system sales, as provided in paragraph 3 below, an additional credit or charge equal to the product of the KWHs and a system sales adjustment factor (A) shall be made, where "A", calculated to the nearest 0.0001 mill per kilowatt-hour, is defined as set forth below.

   System Sales Adjustment Factor (A) = (.6 [Tm - Tb])/Sm

   In the above formulas "T" is Kentucky Power Company's (KPCo) monthly net revenues from system sales in the current (m) and base (b) periods, and "S" is the KWH sales in the current (m) period, all defined below.

2. The net revenue from American Electric Power (AEP) System sales to non-associated companies that are shared by AEP Member Companies, including KPCo, in proportion to their Member Load Ratio and as reported in the Federal Energy Regulatory Commission's Uniform System of Accounts under Account 447, Sales for Resale, shall consist of and be derived as follows:

   a. KPCo's Member Load Ratio share of total revenues from system sales as recorded in Account 447, less b. and c. below.

   b. KPCo's Member Load Ratio share of total out-of-pocket costs incurred in supplying the power and energy for the sales in a. above.

      The out-of-pocket costs include all operating, maintenance, tax, transmission losses and other expenses that would not have been incurred if the power and energy had not been supplied for such sales, including demand and energy charges for power and energy supplied by Third Parties.

   c. KPCo's environmental costs allocated to non-associated utilities in the Company's Environmental Surcharge Report.

(Cont'd on Sheet No. 19-2)

DATE OF ISSUE ________________ DATE EFFECTIVE Service rendered on and after June 29, 2010

ISSUED BY E.K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No.2009-00459 dated

KENTUCKY POWER COMPANY

Original Sheet No. 19-2
Canceling _____ Sheet No. 19-2

P.S.C. ELECTRIC NO. 9

TARIFF S. S. C. (Cont'd.)
(System Sales Clause)

3. The base monthly net revenues from system sales are as follows:

Billing Month	System Sales (Total Company Basis)	
January	$ 2,661,693	*$ 528.886*
February	2,236,268	*335,167*
March	1,732,591	*1,530,489*
April	2,706,860	*1,371,521*
May	2,365,563	*1,307,472*
June	3,101,556	*767,124*
July	2,658,364	*616,234*
August	1,660,434	*2,136,652*
September	1,497,772	*1,850,577*
October	950,190	*1,739,665*
November	1,258,779	*1,538,455*
December	2,025,256	*1,568,121*
	$ 24,855,326	*15,290,363*

4. Sales (S) shall be equated to the sum of (a) generation (including energy produced by generating plant during the construction period), (b) purchase, and (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) inter-system sales and less (f) total system losses.

5. The system sales adjustment factor shall be based upon estimated monthly revenues and costs for system sales, subject to subsequent adjustment upon final determination of actual revenues and costs.

6. The monthly System Sales Clause shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

7. Copies of all documents required to be filed with the Commission under this regulation shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

DATE OF ISSUE ____________________ DATE EFFECTIVE Service rendered on and after June 29, 2010

ISSUED BY E.K. WAGNER (NAME) DIRECTOR OF REGULATORY SERVICES (TITLE) FRANKFORT, KENTUCKY (ADDRESS)

Issued by authority of an Order of the Public Service Commission in Case No. 2009-00459 dated

KPCo-CORRECTED FISHER DIRECT TESTIMONY "Table 1" (Exhibit JIF 3-A)

Cumulative Present Worth of Revenue Requirements (M 2011$)
Re-Analysis with Adjusted Off System Sales

		Option #1 Retrofit Big Sandy 2 w/DFGD	**Option #2** (Brownfield) NGCC Replacement	**Option #3** Big Sandy 1 NGCC Repower	**Option #4A** Market to 2020; NGCC in 2020	**Option #4B** Market to 2025; NGCC in 2025
"As-Filed" in Fisher Testimony...						
Company Assumptions						
	CPW	6,839	7,075	7,091	6,918	6,792
	Net benefit of retrofit (CPW)		236	252	79	(47)
Adjusted Off System Sales						
(A)	CPW	~~7,228~~	~~7,377~~	~~7,394~~	~~7,201~~	~~7,055~~
	Net benefit of retrofit (CPW)		~~149~~	~~166~~	~~(27)~~	~~(173)~~
As-Corrected...						
KPCo-Determined Fisher Overstatement of OSS Adjustment 'Add-Back'						
(B)	*CPW*	*404*	*341*	*341*	*327*	*311*
'KPCo-CORRECTED' Adj. Off System Sales						
(C) = (A) - (B)	CPW	6,824	7,036	7,053	6,874	6,744
	Net benefit of retrofit (CPW)		**212**	**229**	**50**	**(80)**

Big Sandy Retrofit Alternative (**Option 1**) *Under FT-CSAPR Pricing*
Calculated OSS Impact on Overall KPCo Strategist®-modeled CPW Costs

	Used by Dr. Fisher in Exhibit JIF-3A (Table 1)			*'Corrected' Calculation reflected in Exhibit SCW-3R (Summary)*									
	(A) Market Export Billing ($000)	x Fisher 'OSS Sharing Adj' CPW 'Add-Back' @(1-60%) ($000)	= PV of Fisher Adjustment	(B) Market Export (fr 2-pgr) (Gwh)	(C)=(A)/(B) Average Total OSS Realization ($/MWh)	(D) Average Energy Cost ($/MWh)	(E)=(C)-(D) Average *NET* OSS Realization ($/MWh)	(F)=(B)x(E) OSS **Margin** ($000)	(G) 'BASE' * OSS Margin threshold BEFORE Sharing ($000)	(H) Other (Env. ** Surcharge) Cost Adj., Non-Affil. ($000)	(I)=(F)-(G)-(H) OSS Margin that may be Shared ($000)	(I)x 40% '(Above/<Below> Base Sharing)'... CPW 'Add-Back' @(1-60%) ($000)	PV of Sharing
			PV Factor										*PV Factor*
			0.0864										*0.0864*
2011	52,477	20,991	20,991	1,247	42.08	26.28	15.80	19,706	15,290	1,699	2,717	1,087	1,087
2012	98,389	39,355	36,226	2,136	46.06	37.25	8.81	18,814	15,290	1,589	1,935	774	712
2013	62,692	25,077	21,247	1,172	53.48	38.02	15.46	18,121	15,290	1,750	1,081	432	366
2014	79,152	31,661	24,692	1,367	57.89	49.39	8.50	11,621	15,290	1,584	(5,253)	(2,101)	(1,639)
2015	57,101	22,841	16,396	1,242	45.98	39.42	6.56	8,145	15,290	1,563	(8,708)	(3,483)	(2,500)
2016	38,705	15,482	10,230	743	52.10	37.98	14.12	10,488	15,290	16,448	(21,250)	(8,500)	(5,617)
2017	45,361	18,145	11,036	855	53.05	39.38	13.67	11,685	15,290	16,814	(20,419)	(8,167)	(4,968)
2018	60,402	24,161	13,526	1,139	53.05	40.00	13.05	14,862	15,290	16,774	(17,202)	(6,881)	(3,852)
2019	42,559	17,024	8,773	772	55.15	40.84	14.30	11,039	15,290	17,159	(21,410)	(8,564)	(4,413)
2020	61,123	24,449	11,597	1,132	53.97	39.60	14.37	16,273	15,290	17,780	(16,797)	(6,719)	(3,187)
2021	67,202	26,881	11,737	1,223	54.96	40.52	14.44	17,660	15,290	17,725	(15,355)	(6,142)	(2,682)
2022	68,111	27,244	10,949	1,044	65.24	54.04	11.20	11,688	15,290	17,209	(20,810)	(8,324)	(3,345)
2023	30,750	12,300	4,550	450	68.38	54.90	13.48	6,062	15,290	16,708	(25,936)	(10,374)	(3,838)
2024	48,954	19,582	6,668	702	69.78	56.68	13.10	9,191	15,290	16,221	(22,320)	(8,928)	(3,040)
2025	147,664	59,066	18,513	1,775	83.18	58.10	25.08	44,520	15,290	15,749	13,482	5,393	1,690
2026	165,337	66,135	19,080	1,990	83.06	59.68	23.38	46,544	15,290	15,290	15,964	6,386	1,842
2027	154,501	61,801	16,412	1,832	84.32	60.24	24.09	44,131	15,290	14,844	13,996	5,598	1,487
2028	166,958	66,783	16,325	1,930	86.50	62.01	24.49	47,268	15,290	14,412	17,566	7,026	1,717
2029	154,576	61,831	13,912	1,720	89.85	62.96	26.89	46,267	15,290	13,992	16,985	6,794	1,529
2030	155,474	62,190	12,880	1,712	90.83	63.81	27.03	46,261	15,290	13,585	17,386	6,954	1,440
2031	158,855	63,542	12,113	1,683	94.37	65.75	28.61	48,167	15,290	13,189	19,688	7,875	1,501
2032	179,061	71,624	12,568	1,888	94.82	66.23	28.59	53,990	15,290	12,805	25,895	10,358	1,818
2033	176,763	70,705	11,420	1,829	96.67	67.54	29.13	53,260	15,290	12,432	25,538	10,215	1,650
2034	147,959	59,184	8,799	1,447	102.26	68.46	33.80	48,903	15,290	12,070	21,543	8,617	1,281
2035	144,082	57,633	7,887	1,349	106.84	70.29	36.55	49,291	15,290	11,718	22,283	8,913	1,220
2036	144,617	57,847	7,287	1,317	109.78	71.77	38.00	50,064	15,290	11,377	23,397	9,359	1,179
2037	154,907	61,963	7,185	1,410	109.84	72.38	37.46	52,829	15,290	11,046	26,494	10,597	1,229
2038	131,734	52,694	5,624	1,123	117.34	74.12	43.22	48,520	15,290	10,724	22,506	9,002	961
2039	139,177	55,671	5,469	1,169	119.05	74.85	44.20	51,674	15,290	10,412	25,972	10,389	1,021
2040	127,580	51,032	4,615	1,020	125.12	76.76	48.36	49,308	15,290	10,108	23,910	9,564	865

* Per current KPCo System Sales Clause tariff sheet... Such 'base' OSS margin amounts are currently credited to KPCo customers' 'base rate' cost-of-service.

** Based on a preliminary forecast through 2021. Subsequent year's cost reduced by ~3% per year to represent amortization of such underlying investments... while ignoring potential 'carbon'-related costs.

Sum

CPW Add-Back ($000) = 388,706

Proof...

6,839 ← "Company-Filed" CPW (Option #1) ($M, 2011$)

7,228 ← "Fisher-Adjusted" CPW (Option #1) in his 'Table 1' ($M, 2011$)

DELTA ($M) 389

Sum

CPW Add-Back ($000) = (14,486)

"Company-Filed" CPW (Option #1) ($M, 2011$) 6,839

CORRECTED "Fisher-Adjusted" CPW (Option #1) in 'Table 1' 6,824

DELTA ($M) (14)

Big Sandy CC Replacement Alternative (**Option 2**) *Under FT-CSAPR Pricing*

Calculated OSS Impact on Overall KPCo Strategist®-modeled CPW Costs

	Used by Dr. Fisher in Exhibit JIF-3A			*'Corrected' Calculation reflected in Exhibit SCW-3R (Summary)*									
	(A) Market Export Billing ($000)	x Fisher 'OSS Sharing Adj' CPW 'Add-Back' @(1-60%) ($000)	= PV of Fisher Adjustment *PV Factor*	(B) Market Export (fr 2-pgr) (Gwh)	(C)=(A)/(B) Average Total OSS Realization ($/MWh)	(D) Average Energy Cost ($/MWh)	(E)=(C)-(D) Average *NET* OSS Realization ($/MWh)	(F)=(B)x(E) OSS Margin ($000)	(G) 'BASE' * OSS Margin threshold BEFORE Sharing ($000)	(H) Other (Env. ** Surcharge) Cost Adj., Non-Affil. ($000)	(I)=(F)-(G)-(H) OSS Margin that may be Shared ($000)	(I)x 40% '(Above/<Below> Base Sharing)'... CPW 'Add-Back' @(1-60%) ($000)	PV of Sharing *PV Factor*
			0.0864										*0.0864*
2011	52,477	20,991	20,991	1,247	42.08	26.28	15.80	19,706	15,290	1,699	2,717	1,087	1,087
2012	98,389	39,355	36,226	2,136	46.06	37.25	8.81	18,814	15,290	1,589	1,935	774	712
2013	62,692	25,077	21,247	1,172	53.48	38.02	15.46	18,121	15,290	1,750	1,081	432	366
2014	79,152	31,661	24,692	1,367	57.89	49.39	8.50	11,621	15,290	1,584	(5,253)	(2,101)	(1,639)
2015	57,101	22,841	16,396	1,242	45.96	39.42	6.54	8,126	15,290	1,563	(8,727)	(3,491)	(2,506)
2016	22,784	9,114	6,022	410	55.50	42.10	13.41	5,503	15,290	16,448	(26,235)	(10,494)	(6,934)
2017	17,458	6,983	4,247	316	55.23	43.28	11.95	3,777	15,290	16,814	(28,327)	(11,331)	(6,892)
2018	20,563	8,225	4,605	355	57.94	44.03	13.91	4,936	15,290	16,774	(27,128)	(10,851)	(6,075)
2019	17,865	7,146	3,683	311	57.45	45.27	12.18	3,789	15,290	17,159	(28,660)	(11,464)	(5,908)
2020	22,257	8,903	4,223	384	57.94	43.30	14.64	5,624	15,290	17,780	(27,446)	(10,978)	(5,208)
2021	25,439	10,176	4,443	436	58.35	44.75	13.60	5,930	15,290	17,725	(27,085)	(10,834)	(4,730)
2022	29,556	11,822	4,751	427	69.19	55.20	13.99	5,976	15,290	17,209	(26,522)	(10,609)	(4,264)
2023	20,842	8,337	3,084	298	70.03	56.81	13.23	3,937	15,290	16,708	(28,061)	(11,224)	(4,152)
2024	22,548	9,019	3,071	309	73.06	58.67	14.39	4,442	15,290	16,221	(27,069)	(10,828)	(3,687)
2025	127,555	51,022	15,992	1,465	87.08	59.91	27.17	39,801	15,290	15,749	8,762	3,505	1,099
2026	125,504	50,202	14,483	1,449	86.59	61.44	25.15	36,455	15,290	15,290	5,875	2,350	678
2027	131,759	52,704	13,996	1,502	87.70	62.21	25.49	38,296	15,290	14,844	8,162	3,265	867
2028	126,000	50,400	12,320	1,398	90.10	64.06	26.04	36,422	15,290	14,412	6,720	2,688	657
2029	118,331	47,332	10,650	1,286	92.03	65.24	26.80	34,455	15,290	13,992	5,172	2,069	466
2030	130,654	52,262	10,824	1,401	93.26	66.02	27.24	38,168	15,290	13,585	9,293	3,717	770
2031	124,931	49,972	9,527	1,319	94.69	67.77	26.92	35,514	15,290	13,189	7,035	2,814	536
2032	140,261	56,105	9,845	1,460	96.07	67.95	28.11	41,048	15,290	12,805	12,953	5,181	909
2033	134,749	53,900	8,706	1,359	99.13	69.16	29.97	40,736	15,290	12,432	13,014	5,206	841
2034	134,483	53,793	7,998	1,334	100.84	70.29	30.55	40,741	15,290	12,070	13,381	5,352	796
2035	115,511	46,205	6,323	1,099	105.11	71.92	33.19	36,473	15,290	11,718	9,465	3,786	518
2036	116,042	46,417	5,847	1,072	108.25	73.39	34.86	37,370	15,290	11,377	10,703	4,281	539
2037	119,277	47,711	5,532	1,078	110.67	73.75	36.92	39,791	15,290	11,046	13,455	5,382	624
2038	106,127	42,451	4,531	915	116.01	75.49	40.53	37,075	15,290	10,724	11,061	4,424	472
2039	108,854	43,541	4,277	920	118.27	76.13	42.13	38,780	15,290	10,412	13,079	5,231	514
2040	97,876	39,150	3,540	785	124.67	77.94	46.73	36,687	15,290	10,108	11,289	4,515	408

* Per current KPCo System Sales Clause tariff sheet... Such 'base' OSS margin amounts are currently credited to KPCo customers' 'base rate' cost-of-service.

** Based on a preliminary forecast through 2021. Subsequent year's cost reduced by ~3% per year to represent amortization of such underlying investments... while ignoring potential 'carbon'-related costs.

Sum

CPW Add-Back ($000) = 302,071

Proof...

7,075 "Company-Filed" CPW (Option #2) ($M, 2011$)

7,377 "Fisher-Adjusted" CPW (Option #2) in his 'Table 1' ($M, 2011$)

DELTA ($M) 302

Sum

CPW Add-Back ($000) = (39,135)

"Company-Filed" CPW (Option #2) ($M, 2011$) 7,075

CORRECTED "Fisher-Adjusted" CPW (Option #2) in 'Table 1' 7,036

DELTA ($M) (39)

Big Sandy 1 CC Repowering Alternative (**Option 3**) *Under FT-CSAPR Pricing*

Calculated OSS Impact on Overall KPCo Strategist®-modeled CPW Costs

	Used by Dr. Fisher in Exhibit JIF-3A			*'Corrected' Calculation reflected in Exhibit SCW-3R (Summary)*									
	(A) Market Export Billing ($000)	x Fisher 'OSS Sharing Adj' CPW 'Add-Back' @(1-60%) ($000)	= PV of Fisher Adjustment	(B) Market Export (fr 2-pgr) (Gwh)	(C)=(A)/(B) Average Total OSS Realization ($/MWh)	(D) Average Energy Cost ($/MWh)	(E)=(C)-(D) Average *NET* OSS Realization ($/MWh)	(F)=(B)x(E) OSS Margin ($000)	(G) 'BASE' * OSS Margin threshold BEFORE Sharing ($000)	(H) Other (Env. ** Surcharge) Cost Adj., Non-Affil. ($000)	(I)=(F)-(G)-(H) OSS Margin that may be Shared ($000)	(I)x 40% '(Above/<Below> Base Sharing)'... CPW 'Add-Back' @(1-60%) ($000)	PV of Sharing
			PV Factor *0.0864*										*PV Factor* *0.0864*
2011	52,477	20,991	20,991	1,247	42.08	26.28	15.80	19,706	15,290	1,699	2,717	1,087	1,087
2012	98,389	39,355	36,226	2,136	46.06	37.25	8.81	18,814	15,290	1,589	1,935	774	712
2013	62,692	25,077	21,247	1,172	53.48	38.02	15.46	18,121	15,290	1,750	1,081	432	366
2014	79,152	31,661	24,692	1,367	57.89	49.39	8.50	11,621	15,290	1,584	(5,253)	(2,101)	(1,639)
2015	98,751	39,500	28,356	1,927	51.25	39.86	11.38	21,932	15,290	1,563	5,079	2,032	1,458
2016	20,280	8,112	5,360	368	55.11	42.02	13.09	4,816	15,290	16,448	(26,922)	(10,769)	(7,116)
2017	15,530	6,212	3,778	284	54.60	43.19	11.41	3,246	15,290	16,814	(28,858)	(11,543)	(7,021)
2018	18,344	7,338	4,108	319	57.54	43.93	13.61	4,339	15,290	16,774	(27,725)	(11,090)	(6,209)
2019	15,839	6,336	3,265	279	56.83	45.17	11.66	3,249	15,290	17,159	(29,200)	(11,680)	(6,019)
2020	19,871	7,948	3,770	346	57.50	43.19	14.32	4,947	15,290	17,780	(28,123)	(11,249)	(5,336)
2021	22,766	9,107	3,976	393	57.88	44.62	13.26	5,215	15,290	17,725	(27,800)	(11,120)	(4,855)
2022	26,763	10,705	4,302	390	68.66	55.10	13.56	5,285	15,290	17,209	(27,213)	(10,885)	(4,375)
2023	18,563	7,425	2,747	268	69.17	56.70	12.47	3,347	15,290	16,708	(28,650)	(11,460)	(4,239)
2024	20,119	8,048	2,740	278	72.40	58.56	13.84	3,845	15,290	16,221	(27,666)	(11,067)	(3,768)
2025	122,440	48,976	15,351	1,408	86.99	59.84	27.15	38,217	15,290	15,749	7,179	2,872	900
2026	119,845	47,938	13,830	1,384	86.62	61.36	25.26	34,943	15,290	15,290	4,363	1,745	504
2027	126,154	50,461	13,401	1,439	87.66	62.13	25.53	36,738	15,290	14,844	6,603	2,641	701
2028	120,349	48,140	11,767	1,336	90.08	63.98	26.10	34,875	15,290	14,412	5,173	2,069	506
2029	112,598	45,039	10,134	1,223	92.04	65.14	26.90	32,906	15,290	13,992	3,623	1,449	326
2030	124,711	49,884	10,331	1,338	93.22	65.93	27.29	36,504	15,290	13,585	7,629	3,052	632
2031	119,064	47,625	9,079	1,259	94.61	67.69	26.92	33,878	15,290	13,189	5,399	2,159	412
2032	134,021	53,608	9,407	1,397	95.95	67.87	28.08	39,225	15,290	12,805	11,130	4,452	781
2033	129,031	51,612	8,336	1,307	98.75	69.12	29.62	38,709	15,290	12,432	10,987	4,395	710
2034	126,514	50,606	7,524	1,250	101.19	70.19	31.00	38,756	15,290	12,070	11,396	4,558	678
2035	109,146	43,658	5,975	1,038	105.15	71.85	33.30	34,567	15,290	11,718	7,559	3,024	414
2036	109,346	43,739	5,510	1,009	108.34	73.31	35.03	35,352	15,290	11,377	8,685	3,474	438
2037	113,204	45.282	5.250	1,024	110.57	73.68	36.90	37,774	15,290	11,046	11,438	4,575	531
2038	99,711	39,885	4,257	859	116.05	75.40	40.64	34,923	15,290	10,724	8,909	3,563	380
2039	102,244	40,897	4,018	864	118.32	76.05	42.28	36,533	15,290	10,412	10,831	4,332	426
2040	92,515	37,006	3,346	743	124.57	77.88	46.68	34,671	15,290	10,108	9,273	3,709	335

* Per current KPCo System Sales Clause tariff sheet... Such 'base' OSS margin amounts are currently credited to KPCo customers' 'base rate' cost-of-service.

** Based on a preliminary forecast through 2021. Subsequent year's cost reduced by ~3% per year to represent amortization of such underlying investments... while ignoring potential 'carbon'-related costs.

Sum

CPW Add-Back ($000) = 303,074

Proof...

7,091 ← "Company-Filed" CPW (Option #3) ($M, 2011$)

7,394 ← "Fisher-Adjusted" CPW (Option #3) in his 'Table 1' ($M, 2011$)

DELTA ($M) 303

Sum

CPW Add-Back ($000) = (38,281)

"Company-Filed" CPW (Option #3) ($M, 2011$) 7,091

CORRECTED "Fisher-Adjusted" CPW (Option #3) in 'Table 1' 7,053

DELTA ($M) (38)

Big Sandy Retire with Market Purchase to 2020 Alternative (**Option 4A**) *Under FT-CSAPR Pricing*

Calculated OSS Impact on Overall KPCo Strategist®-modeled CPW Costs

	Used by Dr. Fisher in Exhibit JIF-3A			*'Corrected' Calculation reflected in Exhibit SCW-3R (Summary)*									
	(A) Market Export Billing ($000)	x Fisher 'OSS Sharing Adj' CPW 'Add-Back' @(1-60%) ($000)	= PV of Fisher Adjustment	(B) Market Export (fr 2-pgr) (Gwh)	(C)=(A)/(B) Average Total OSS Realization ($/MWh)	(D) Average Energy Cost ($/MWh)	(E)=(C)-(D) Average *NET* OSS Realization ($/MWh)	(F)=(B)x(E) OSS Margin ($000)	(G) 'BASE' * OSS Margin threshold BEFORE Sharing ($000)	(H) Other (Env. ** Surcharge) Cost Adj., Non-Affil. ($000)	(I)=(F)-(G)-(H) OSS Margin that may be Shared ($000)	(I)x 40% '(Above/<Below> Base Sharing)'... CPW 'Add-Back' @(1-60%) ($000)	PV of Sharing
			PV Factor										*PV Factor*
			0.0864										*0.0864*
2011	52,477	20,991	20,991	1,247	42.08	26.28	15.80	19,706	15,290	1,699	2,717	1,087	1,087
2012	98,389	39,355	36,226	2,136	46.06	37.25	8.81	18,814	15,290	1,589	1,935	774	712
2013	62,692	25,077	21,247	1,172	53.48	38.02	15.46	18,121	15,290	1,750	1,081	432	366
2014	79,152	31,661	24,692	1,367	57.89	49.39	8.50	11,621	15,290	1,584	(5,253)	(2,101)	(1,639)
2015	57,101	22,841	16,396	1,242	45.96	39.42	6.54	8,126	15,290	1,563	(8,727)	(3,491)	(2,506)
2016	0	0	0		0.00	34.10	-34.10	-	15,290	16,448	(31,738)	(12,695)	(8,389)
2017	0	0	0		0.00	33.94	-33.94	-	15,290	16,814	(32,104)	(12,842)	(7,810)
2018	0	0	0		0.00	34.54	-34.54	-	15,290	16,774	(32,064)	(12,826)	(7,180)
2019	0	0	0		0.00	35.19	-35.19	-	15,290	17,159	(32,449)	(12,979)	(6,689)
2020	22,257	8,903	4,223	384	57.94	43.30	14.64	5,624	15,290	17,780	(27,446)	(10,978)	(5,208)
2021	25,439	10,176	4,443	436	58.35	44.75	13.60	5,930	15,290	17,725	(27,085)	(10,834)	(4,730)
2022	29,556	11,822	4,751	427	69.19	55.20	13.99	5,976	15,290	17,209	(26,522)	(10,609)	(4,264)
2023	20,842	8,337	3,084	298	70.03	56.81	13.23	3,937	15,290	16,708	(28,061)	(11,224)	(4,152)
2024	22,548	9,019	3,071	309	73.06	58.67	14.39	4,442	15,290	16,221	(27,069)	(10,828)	(3,687)
2025	127,555	51,022	15,992	1,465	87.08	59.91	27.17	39,801	15,290	15,749	8,762	3,505	1,099
2026	125,504	50,202	14,483	1,449	86.59	61.44	25.15	36,455	15,290	15,290	5,875	2,350	678
2027	131,759	52,704	13,996	1,502	87.70	62.21	25.49	38,296	15,290	14,844	8,162	3,265	867
2028	126,000	50,400	12,320	1,398	90.10	64.06	26.04	36,422	15,290	14,412	6,720	2,688	657
2029	118,331	47,332	10,650	1,286	92.03	65.24	26.80	34,455	15,290	13,992	5,172	2,069	466
2030	130,654	52,262	10,824	1,401	93.26	66.02	27.24	38,168	15,290	13,585	9,293	3,717	770
2031	124,931	49,972	9,527	1,319	94.69	67.77	26.92	35,514	15,290	13,189	7,035	2,814	536
2032	140,261	56,105	9,845	1,460	96.07	67.95	28.11	41,048	15,290	12,805	12,953	5,181	909
2033	134,749	53,900	8,706	1,359	99.13	69.16	29.97	40,736	15,290	12,432	13,014	5,206	841
2034	134,483	53,793	7,998	1,334	100.84	70.29	30.55	40,741	15,290	12,070	13,381	5,352	796
2035	115,511	46,205	6,323	1,099	105.11	71.92	33.19	36,473	15,290	11,718	9,465	3,786	518
2036	116,042	46,417	5,847	1,072	108.25	73.39	34.86	37,370	15,290	11,377	10,703	4,281	539
2037	119,277	47,711	5,532	1,078	110.67	73.75	36.92	39,791	15,290	11,046	13,455	5,382	624
2038	106,127	42,451	4,531	915	116.01	75.49	40.53	37,075	15,290	10,724	11,061	4,424	472
2039	108,854	43,541	4,277	920	118.27	76.13	42.13	38,780	15,290	10,412	13,079	5,231	514
2040	97,876	39,150	3,540	785	124.67	77.94	46.73	36,687	15,290	10,108	11,289	4,515	408

* Per current KPCo System Sales Clause tariff sheet... Such 'base' OSS margin amounts are currently credited to KPCo customers' 'base rate' cost-of-service.

** Based on a preliminary forecast through 2021. Subsequent year's cost reduced by ~3% per year to represent amortization of such underlying investments... while ignoring potential 'carbon'-related costs.

Sum

CPW Add-Back ($000) = 283,514

Proof...

6,918 ◄---------- "Company-Filed" CPW (Option #4A) ($M, 2011$)

7,201 ◄---------- "Fisher-Adjusted" CPW (Option #4A) in 'Table 1' ($M, 2011$)

DELTA ($M) 283

Sum

CPW Add-Back ($000) = (43,394)

"Company-Filed" CPW (Option #4A) ($M, 2011$) 6,918

CORRECTED "Fisher-Adjusted" CPW (Option #4A) in 'Table 1' 6,874

DELTA ($M) (43)

Big Sandy Retire with Market Purchase to 2025 Alternative (**Option 4B**) *Under FT-CSAPR Pricing*

Calculated OSS Impact on Overall KPCo Strategist®-modeled CPW Costs

	Used by Dr. Fisher in Exhibit JIF-3A			*'Corrected' Calculation reflected in Exhibit SCW-3R (Summary)*									
	(A) Market Export Billing ($000)	x Fisher 'OSS Sharing Adj' CPW 'Add-Back' @(1-60%) ($000)	= PV of Fisher Adjustment *PV Factor 0.0864*	(B) Market Export (fr 2-pgr) (Gwh)	(C)=(A)/(B) Average Total OSS Realization ($/MWh)	(D) Average Energy Cost ($/MWh)	(E)=(C)-(D) Average *NET* OSS Realization ($/MWh)	(F)=(B)x(E) OSS **Margin** ($000)	(G) 'BASE' * OSS Margin threshold BEFORE Sharing ($000)	(H) Other (Env. ** Surcharge) Cost Adj., Non-Affil. ($000)	(I)=(F)-(G)-(H) OSS Margin that may be Shared ($000)	(I)x 40% '(Above/<Below> Base Sharing)'... CPW 'Add-Back' @(1-60%) ($000)	PV of Sharing *PV Factor 0.0864*
2011	52,477	20,991	20,991	1,247	42.08	26.28	15.80	19,706	15,290	1,699	2,717	1,087	1,087
2012	98,389	39,355	36,226	2,136	46.06	37.25	8.81	18,814	15,290	1,589	1,935	774	712
2013	62,692	25,077	21,247	1,172	53.48	38.02	15.46	18,121	15,290	1,750	1,081	432	366
2014	79,152	31,661	24,692	1,367	57.89	49.39	8.50	11,621	15,290	1,584	(5,253)	(2,101)	(1,639)
2015	57,101	22,841	16,396	1,242	45.96	39.42	6.54	8,126	15,290	1,563	(8,727)	(3,491)	(2,506)
2016	0	0	0		0.00	34.10	-34.10	-	15,290	16,448	(31,738)	(12,695)	(8,389)
2017	0	0	0		0.00	33.94	-33.94	-	15,290	16,814	(32,104)	(12,842)	(7,810)
2018	0	0	0		0.00	34.54	-34.54	-	15,290	16,774	(32,064)	(12,826)	(7,180)
2019	0	0	0		0.00	35.19	-35.19	-	15,290	17,159	(32,449)	(12,979)	(6,689)
2020	0	0	0		0.00	30.77	-30.77	-	15,290	17,780	(33,070)	(13,228)	(6,275)
2021	0	0	0		0.00	31.62	-31.62	-	15,290	17,725	(33,015)	(13,206)	(5,766)
2022	0	0	0		0.00	45.63	-45.63	-	15,290	17,209	(32,499)	(13,000)	(5,224)
2023	0	0	0		0.00	46.02	-46.02	-	15,290	16,708	(31,998)	(12,799)	(4,735)
2024	0	0	0		0.00	48.03	-48.03	-	15,290	16,221	(31,511)	(12,604)	(4,292)
2025	127,555	51,022	15,992	1,465	87.08	59.91	27.17	39,801	15,290	15,749	8,762	3,505	1,099
2026	125,504	50,202	14,483	1,449	86.59	61.44	25.15	36,455	15,290	15,290	5,875	2,350	678
2027	131,759	52,704	13,996	1,502	87.70	62.21	25.49	38,296	15,290	14,844	8,162	3,265	867
2028	126,000	50,400	12,320	1,398	90.10	64.06	26.04	36,422	15,290	14,412	6,720	2,688	657
2029	118,331	47,332	10,650	1,286	92.03	65.24	26.80	34,455	15,290	13,992	5,172	2,069	466
2030	130,654	52,262	10,824	1,401	93.26	66.02	27.24	38,168	15,290	13,585	9,293	3,717	770
2031	124,931	49,972	9,527	1,319	94.69	67.77	26.92	35,514	15,290	13,189	7,035	2,814	536
2032	140,261	56,105	9,845	1,460	96.07	67.95	28.11	41,048	15,290	12,805	12,953	5,181	909
2033	134,749	53,900	8,706	1,359	99.13	69.16	29.97	40,736	15,290	12,432	13,014	5,206	841
2034	134,483	53,793	7,998	1,334	100.84	70.29	30.55	40,741	15,290	12,070	13,381	5,352	796
2035	115,511	46,205	6,323	1,099	105.11	71.92	33.19	36,473	15,290	11,718	9,465	3,786	518
2036	116,042	46,417	5,847	1,072	108.25	73.39	34.86	37,370	15,290	11,377	10,703	4,281	539
2037	119,277	47,711	5,532	1,078	110.67	73.75	36.92	39,791	15,290	11,046	13,455	5,382	624
2038	106,127	42,451	4,531	915	116.01	75.49	40.53	37,075	15,290	10,724	11,061	4,424	472
2039	108,854	43,541	4,277	920	118.27	76.13	42.13	38,780	15,290	10,412	13,079	5,231	514
2040	97,876	39,150	3,540	785	124.67	77.94	46.73	36,687	15,290	10,108	11,289	4,515	408

* Per current KPCo System Sales Clause tariff sheet... Such 'base' OSS margin amounts are currently credited to KPCo customers' 'base rate' cost-of-service.

** Based on a preliminary forecast through 2021. Subsequent year's cost reduced by ~3% per year to represent amortization of such underlying investments... while ignoring potential 'carbon'-related costs.

Sum

CPW Add-Back ($000) = 263,942

Proof...

6,792 ← "Company-Filed" CPW (Option #4B) ($M, 2011$)

7,055 ← "Fisher-Adjusted" CPW (Option #4B) in 'Table 1' ($M, 2011$)

DELTA ($M) 263

Sum

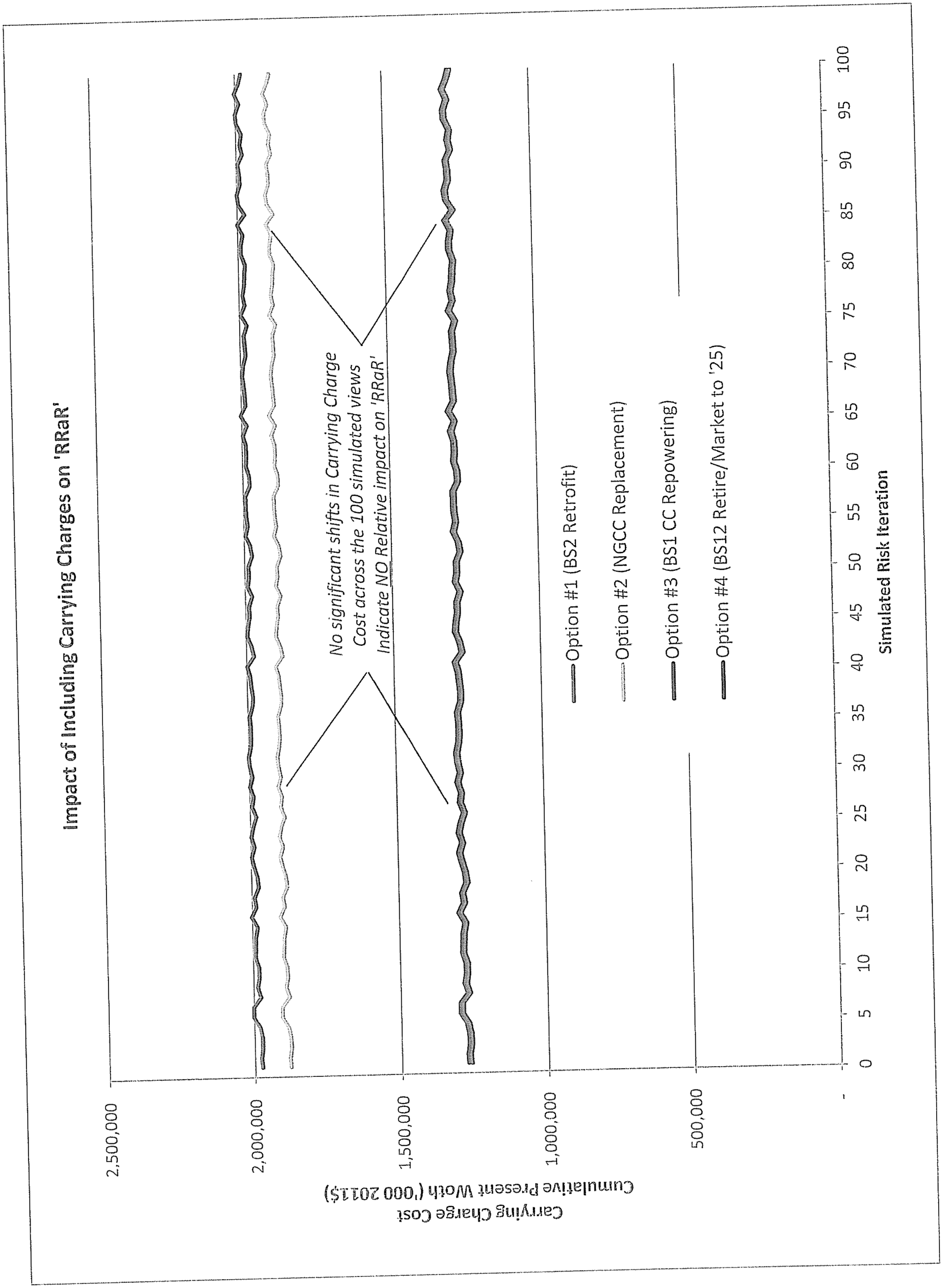
CPW Add-Back ($000) = (47,645)

"Company-Filed" CPW (Option #4B) ($M, 2011$) 6,792

CORRECTED "Fisher-Adjusted" CPW (Option #4B) in 'TABLE 1' 6,744

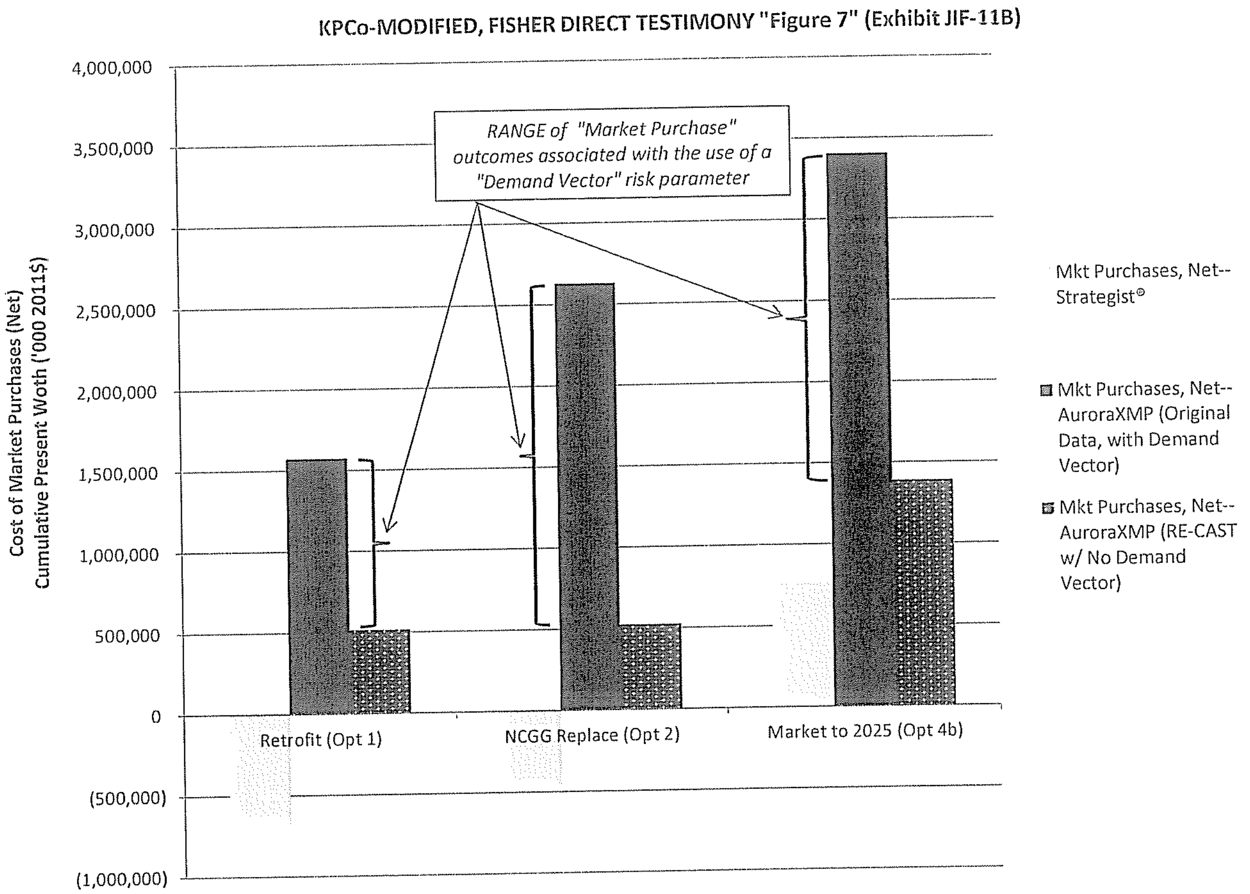
DELTA ($M) (48)

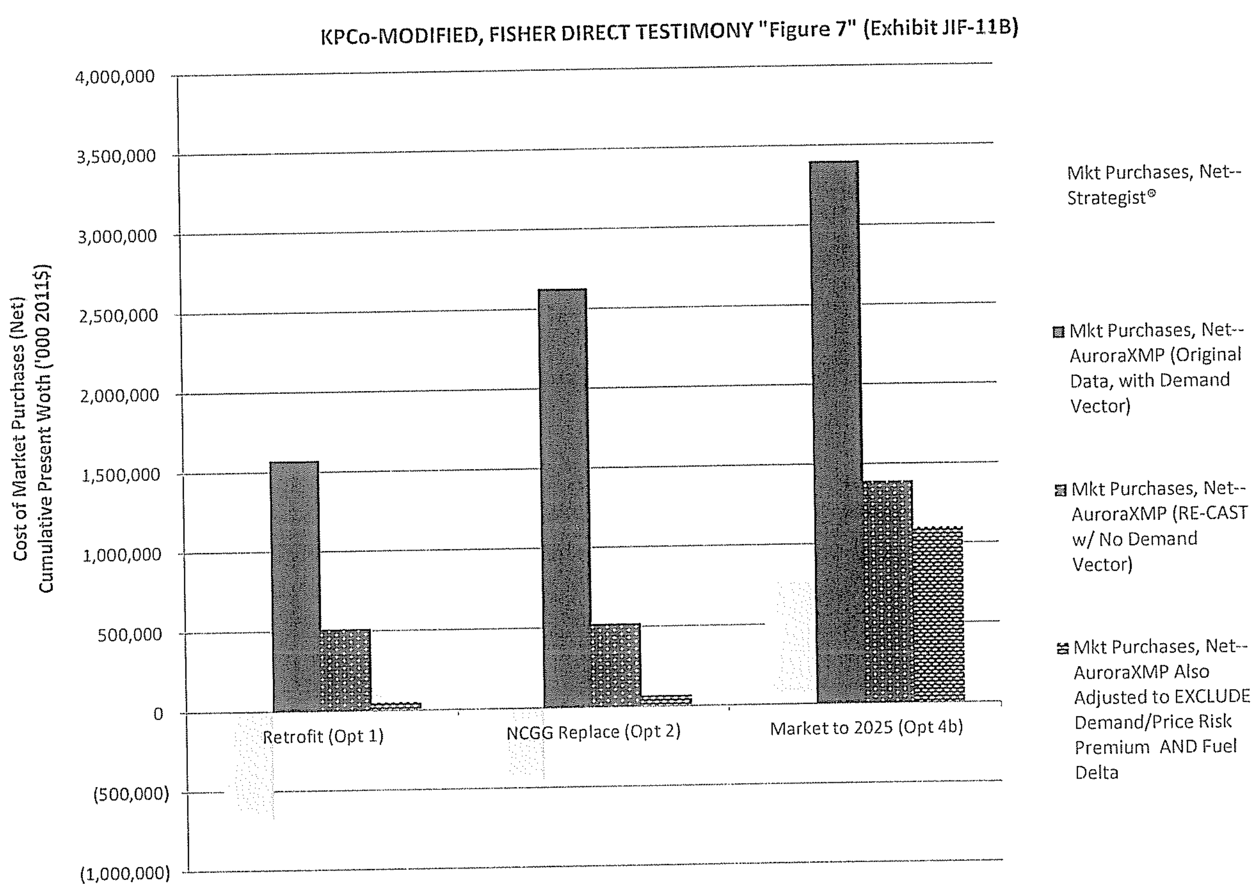
Rebuttal Exhibit SCW-4R

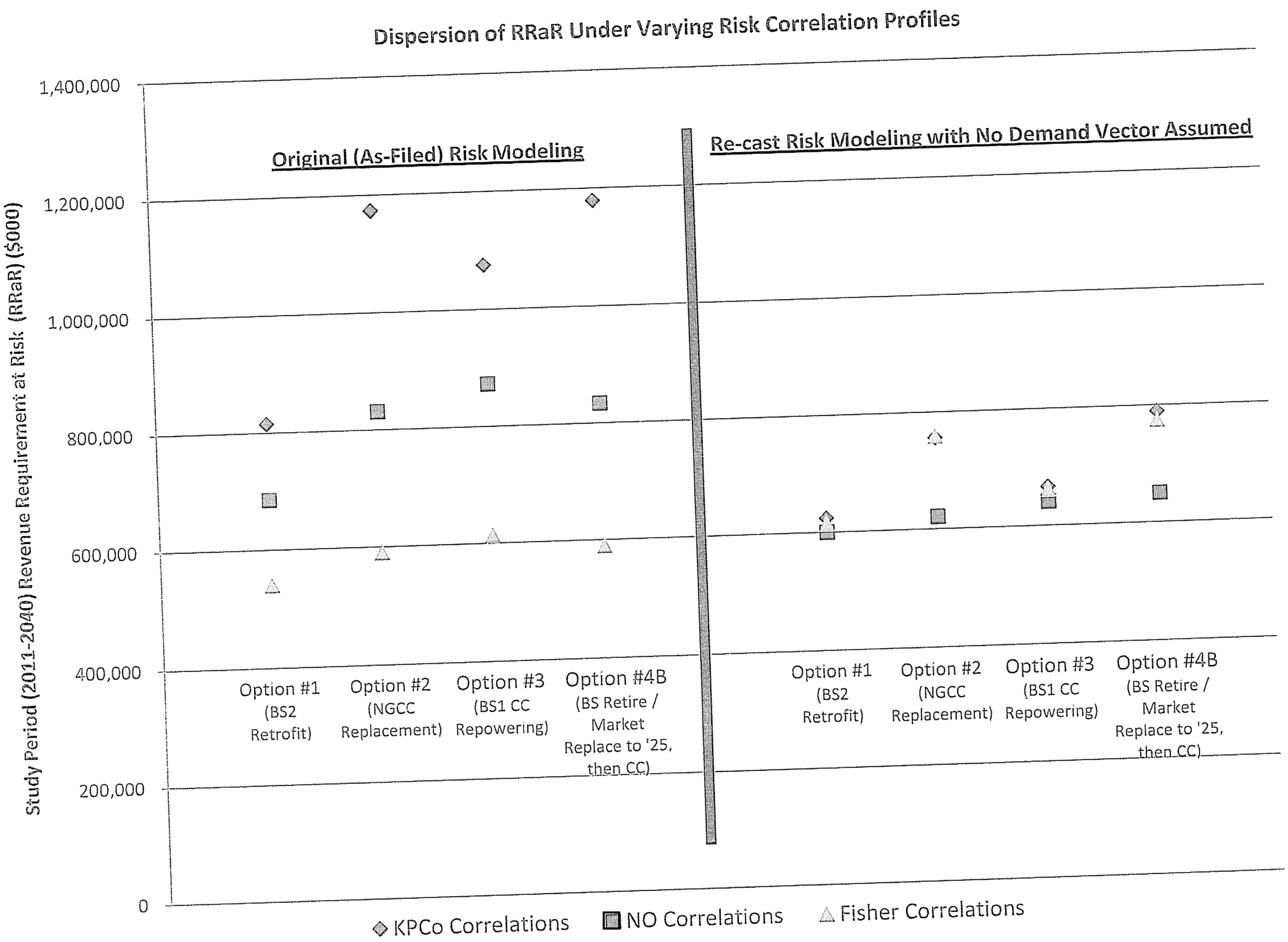


RANGE of Potential RRaR

		Option #1	Option #2	Option #3	Option #4B			
RRaR ($000)	*Cumul. CPW Distribution Percentile*	BS2 Retrofit	NGCC Replacement	BS1 Repower	Market Repl to '25, then CC	*Delta* Retrofit - NGCC	*Delta* Retrofit - Repower	*Delta* Retrofit - Mkt to '25/CC
Per Original Filing (Exhibit SCW-5)...								
Relative Rank		1	3	2	4			
	95th vs. 50th	815,143	1,173,446	1,075,034	1,178,726	(358,303) *-33.3%*	(259,891) *-24.2%*	(363,583) *-33.8%*
Re-cast...								
o Including Carrying Charges								
o FULL Removal of Demand Vector	*95th vs. 50th*	622,612	754,226	664,842	788,919	(131,614) *-19.8%*	(42,230) *-6.4%*	(166,307) *-25.0%*
Relative Rank		1	3	2	4			


KPCo-MODIFIED, FISHER DIRECT TESTIMONY "Figure 7" (Exhibit JIF-11B)
Cost of Market Purchases (Net)
Cumulative Present Woth ('000 2011$)
4,000,000
3,500,000
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
(500,000)
(1,000,000)
RANGE of "Market Purchase" outcomes associated with the use of a "Demand Vector" risk parameter
Retrofit (Opt 1)
NCGG Replace (Opt 2)
Market to 2025 (Opt 4b)
Mkt Purchases, Net--Strategist®
Mkt Purchases, Net--AuroraXMP (Original Data, with Demand Vector)
Mkt Purchases, Net--AuroraXMP (RE-CAST w/ No Demand Vector)


KPCo-MODIFIED, FISHER DIRECT TESTIMONY "Figure 7" (Exhibit JIF-11B)
Cost of Market Purchases (Net)
Cumulative Present Woth ('000 2011$)
4,000,000
3,500,000
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
(500,000)
(1,000,000)
Retrofit (Opt 1)
NCGG Replace (Opt 2)
Market to 2025 (Opt 4b)
Mkt Purchases, Net--Strategist®
Mkt Purchases, Net--AuroraXMP (Original Data, with Demand Vector)
Mkt Purchases, Net--AuroraXMP (RE-CAST w/ No Demand Vector)
Mkt Purchases, Net--AuroraXMP Also Adjusted to EXCLUDE Demand/Price Risk Premium AND Fuel Delta



Dispersion of RRaR Under Varying Risk Correlation Profiles
Study Period (2011-2040) Revenue Requirement at Risk (RRaR) ($000)
1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
Original (As-Filed) Risk Modeling
Re-cast Risk Modeling with No Demand Vector Assumed
Option #1 (BS2 Retrofit)
Option #2 (NGCC Replacement)
Option #3 (BS1 CC Repowering)
Option #4B (BS Retire / Market Replace to '25, then CC)
Option #1 (BS2 Retrofit)
Option #2 (NGCC Replacement)
Option #3 (BS1 CC Repowering)
Option #4B (BS Retire / Market Replace to '25, then CC)
KPCo Correlations
NO Correlations
Fisher Correlations

'CORRECTED' FISHER DIRECT TESTIMONY (Exhibit JIF-3F)

Cumulative Present Worth of Revenue Requirements (M 2011$)

Re-Analysis with Synapse Low CO2, Corrected Capital Costs & Adj. Off System Sales

		Option #1 Retrofit Big Sandy 2 w/DFGD	Option #2 (Brownfield) NGCC Replacement	Option #4A Market to 2020; NGCC in 2020	
"As-Filed" in Fisher Testimony...					
Company Assumptions	CPW	6,839	7,075	6,918	
Net benefit of retrofit (CPW)			236	79	*
Synapse Low CO2 Price, Corrected Capital Costs & Off-System Sales					
(A)	CPW	~~8,063~~	~~7,445~~	~~7,367~~	
Net benefit of retrofit (CPW)			~~(618)~~	~~(696)~~	*
As-Corrected...					
Fisher Overstatement of ALL Adjustments (Combined) (B)	*CPW*	*1,239*	*409*	*493*	
'KPCo-CORRECTED' Results (A) - (B)	CPW	6,824	7,036	6,874	
Net benefit of retrofit (CPW)			**212**	**50**	

* reflects rounding differences from filed Exhibit JIF-3F

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

APPLICATION OF KENTUCKY POWER COMPANY	)	
FOR APPROVAL OF ITS 2011 ENVIRONMENTAL	)	
COMPLIANCE PLAN, FOR APPROVAL OF ITS	)	
AMENDED ENVIRONMENTAL COST RECOVERY	)	Case No. 2011-00401
SURCHARGE TARIFF, AND FOR THE GRANT OF A	)	
CERTIFICATE OF PUBLIC CONVENIENCE AND	)	
NECESSITY FOR THE CONSTRUCTION AND	)	
ACQUISITION OF RELATED FACILITIES	)	

REBUTTAL TESTIMONY

OF

RANIE K. WOHNHAS

April 16, 2012

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

CASE NO. 2011-00401

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 Managing Director, Regulatory and Finance, Kentucky Power Company (Kentucky Power, KPCo or Company). My business address is 101 A Enterprise Drive, Frankfort, Kentucky 40602.

Q: ARE YOU THE SAME RANIE K. WOHNHAS THAT FILED DIRECT TESTIMONY IN THIS PROCEEDING ON BEHALF OF KPCO?

A. Yes, I am.

II. PURPOSE OF TESTIMONY

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

A: The purpose of my testimony is to correct KIUC witness Mr. Hill and his improper statements of how Construction Work in Progress is used in the Company's environmental surcharge mechanism and to clarify statements made by KIUC witness Mr. Kollen on how retirement of environmental facilities are processed through the environmental surcharge mechanism.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. No, I am not.

III. CONSTRUCTION WORK IN PROGRESS

Q. **DOES MR. HILL PROPERLY SUMMARIZE THE USE OF CONSTRUCTION WORK IN PROGRESS (CWIP) FOR KENTUCKY POWER COMPANY IN ITS ENVIRONMENTAL SURCHARGE MECHANISM?**

A. No. Mr. Hill's testimony on page 3 beginning on line 18 thru page 4 line 5 is completely incorrect. Kentucky Power does not recover CWIP during construction, but rather calculates Allowance For Funds Used During Construction (AFUDC) and adds that cost to the total cost of the project which is recovered after the project in placed into service. The Electric Plant In Service cost of the project will not be included in the monthly environmental surcharge calculation until the first of the year following the in service date. This is consistent with Kentucky Power Company's current process with all projects flowing through the environmental surcharge mechanism.

Q. **DID THE COMPANY FILE ITS APPLICATION WITH AFUDC AS A COMPONENT OF THE TOTAL COST FOR THE DRY FLUE GAS DESULFURIZATION (DFGD)?**

A. Yes it did. In the direct testimony of Company witness Weaver on page 25 he states that "the total cost excluding AFUDC was $839 million" and that the "DFGD project cost inclusive of AFUDC would be approximately $940 million". The difference is $101 million of AFUDC. The $940 million inclusive of AFUDC was used by Company witness Munsey as the total cost of the DFGD on

Exhibit LPM-1 that is to be recovered through the environmental surcharge mechanism.

Q. **WOULD THE COMPANY BE WILLING TO CHANGE ITS CURRENT PROCESS FOR THIS DFGD PROJECT ONLY TO INCLUDE A RETURN ON CWIP VERSUS CALCULATION OF AFUDC?**

A. Yes it would. A return on CWIP versus an AFUDC calculation would provide a small benefit to our customers by reducing the total overall cost that they would be requested to pay for this project.

Q. **DOES THE COMPANY INTEND TO CHANGE ITS ACCOUNTING PROCESS FROM CALCULATION OF AFUDC TO A RETURN ON CWIP FOR ALL OF ITS FUTURE PROJECTS (ENVIRONMENTAL AND NON-ENVIRONMENTAL)?**

A. Not at this time. If the Company were to decide to request such a change, it would make a separate filing to address the accounting change.

IV. ESP DEMOLITION AND REMOVAL

Q. **KIUC WITNESS KOLLEN RAISES TWO CONCERNS ON PAGE 43, LINES 13-18 OF HIS DIRECT TESTIMONY SURROUNDING THE DEMOLITION AND REMOVAL OF EXISTING PLANT ASSETS. ARE DEMOLITION AND REMOVAL COSTS FOR EXISTING PLANT INCLUDED IN THE BIG SANDY UNIT 2 RETROFIT PROJECTS COST ESTIMATE?**

A. No. The costs for the demolition and removal costs associated with the boiler modifications and ESP are not included in the Big Sandy Unit 2 retrofit project cost estimate. Also, the costs associated with demolition and removal of retired plant assets will not be included in the installed cost of new equipment.

Q. **HOW WILL THE COMPANY ACCOUNT FOR THE COST OF DEMOLITION AND REMOVAL OF RETIRED PLANT ASSETS?**

A. The cost of demolition and removal of existing plant that is part of the Company's existing environmental compliance plan projects as listed in Tariff E.S. will continue to be accounted for in the same manner as today, as part of the calculation of the monthly environmental surcharge mechanism. Net Electric Plant In Service costs will be reduced from the total plant in service as currently calculated in the monthly surcharge. Also, monthly depreciation and O&M expenses related to those projects will no longer flow through the surcharge.

Q. **WHEN WILL THE CUSTOMER SEE A REDUCTION FOR THE RETIREMENT OF EXISTING ENVIRONMENTAL FACILITIES?**

A. When the existing plant is taken out of service, no further O&M or depreciation costs will flow through the environmental surcharge mechanism. The related net book value is updated at the end of each calendar year for purposes of use for the subsequent calendar year of monthly environmental surcharge calculations.

IV. CONCLUSION

Q. **PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.**

A. KPCo has not received a return on CWIP for any of its environmental projects. However, the Company is willing to change its accounting process for the DFGD project only to receive a return on CWIP versus calculating AFUDC, as this will reduce the overall impact to the end use customer.

The retirement of existing environmental facilities has always flowed through the environmental surcharge mechanism and will continue in that same manner with any retirement of environmental facilities associated with the installation of the DFGD.

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

A. Yes.

VERIFICATION

The undersigned, Ranie K. Wohnhas, being duly sworn, deposes and says he is the Managing Director Regulatory and Finance for Kentucky Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge, and belief

Ranie K. Wohnhas

Ranie K. Wohnhas

COMMONWEALTH OF KENTUCKY	)	
	)	CASE NO. 2011-00401
COUNTY OF FRANKLIN	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Ranie K. Wohnhas, this the 13th day of April 2012.

Judy K Rosquist

Notary Public

My Commission Expires: January 23, 2013