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KPOW.92585

July 26, 2016

VIA EMAIL & FEDEX:
David Jones, Chairman
c/o Sharla Dillon, Dockets & Records Manager
Tennessee Regulatory Authority
502 Deaderick Street, 4th Floor
Nashville, TN 37243

Re: Petition of Kingsport Power Company d/b/a AEP Appalachian Power General Rate Case
TRA Docket No.: 16-00001

Dear Chairman Jones:

On behalf of Kingsport Power Company, we transmit herewith the rebuttal testimony of the following witnesses:

1. William K. Castle
2. Dr. Phillip R. Daves
3. Renee V. Hawkins
4. Philip A. Wright
5. Chad M. Burnett
6. Cheryl L. Strawser
7. Jeffrey B. Bartsch
8. A. Wayne Allen
9. Douglas R. Buck
10. Alex E. Vaughan

The originals and four (4) copies are being sent via Federal Express.

Please contact the writer with any questions.

Very sincerely yours,

HUNTER, SMITH & DAVIS, LLP

William C. Bovender

Enclosures

c: Monica L. Smith-Ashford, Esq.
David Foster
Charles Welch, Jr., Esq.
Henry Walker, Esq.
Thad B. Culley, Esq.
Michael J. Quinan, Esq.
Wayne Irvin, Esq.
James R. Bacha, Esq.
Hector Garcia, Esq.
Noelle Coates, Esq.
William Castle
Larry Foust
Brian West
Joseph B. Harvey, Esq.

BEFORE THE TENNESSEE REGULATORY AUTHORITY

NASHVILLE, TENNESSEE

IN RE:

PETITION OF KINGSPORT POWER COMPANY
d/b/a AEP APPALACHIAN POWER
GENERAL RATE CASE

DOCKET NO.: 16-00001

Rebuttal Testimony and Exhibits of Kingsport Power Company

William K. Castle

Dr. Phillip R. Daves

Renee V. Hawkins

Philip A. Wright

Chad M. Burnett

Cheryl L. Strawser

Jeffrey B. Bartsch

A. Wayne Allen

Douglas R. Buck

Alex E. Vaughan

Castle

**REBUTTAL TESTIMONY OF
WILLIAM K. CASTLE
ON BEHALF OF KINGSPORT POWER COMPANY
D/B/A AEP APPALACHIAN POWER
BEFORE THE TENNESSEE REGULATORY AUTHORITY
DOCKET NO. 16-00001**

Q. PLEASE STATE YOUR NAME.

A. My name is William K. Castle.

Q. ARE YOU THE SAME WILLIAM K. CASTLE WHO SUBMITTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony responds to the direct testimony of Consumer Protection and Advocate Division (CPAD) witness Novak's comments on the Company's filing - the use of a 2015 test year, the proposed inclusion of street lighting in the case, the removal of fuel and purchased power costs from base rates, his eschewal of a cost-of-service based approach to apportion the revenue requirement, and the recommendation not to fund demand-side management and distribution reliability (the "Tennessee Reliability Strategy") programs. I discuss CPAD witness Smith's recommendation to use an estimate for rate case expense in lieu of actual test year expense. Additionally, I address criticisms of the Company's proposed changes to some of its terms and conditions raised by Mr. Novak, as Company witness Simmons is currently unavailable to testify. I further briefly discuss the recommendations of the East Tennessee Energy Consumers' witness Baron regarding rate design.

Q. WHAT OTHER WITNESSES WILL BE OFFERING REBUTTAL TESTIMONY?

A. The following witnesses will offer rebuttal testimony as follows:

1. Dr. Phillip R. Daves will respond to the direct testimony of CPAD witness Dr. Klein with respect to the cost of capital.
2. A. Wayne Allen will respond to specific adjustments made to rate base and operating expenses by CPAD witnesses Novak and Smith.
3. Jeffrey B. Bartsch will respond to CPAD witness Mr. Smith on property tax adjustments and Mr. Novak on the amount of Accumulated Deferred Income Tax (ADIT) included in rate base.
4. Douglas R. Buck will respond to CPAD witness Mr. Novak in regards to various issues related to revenue recovery, allocation factors and the class cost-of-service study.
5. Chad M. Burnett will respond to the weather normalization calculations performed by CPAD witness Novak.
6. Renee V. Hawkins will adopt the direct testimony of Company witness Bourke and address the direct testimony of CPAD witnesses Dr. Klein and Mr. Smith in regards to computing the cost of capital by imputing a parent leverage calculation and the sale of receivables.
7. Alex E. Vaughan will address the testimony of the Alliance for Solar Choice witness Sanders.
8. Philip A. Wright will address the criticisms of CPAD witnesses that the Company's proposal for an increased level of reliability spending was not

justified and will address the appropriate level of storm expense to include in base rates.

9. Cheryl L. Strawser will address CPAD witness Smith's recommendations to reduce the going level amount for employee compensation and benefit expenses.

KINGSPORT'S PREPARATION OF ITS FILING

Q. PLEASE ADDRESS THE COMMENTS MADE BY CPAD WITNESS NOVAK WITH REGARD TO THE COMPANY'S PREPARATION AND PRESENTATION OF ITS FILING (NOVAK PAGE 4, LINES 4-16).

A. Kingsport Power Company ("KgPCo," "Kingsport" or the "Company") takes issue with Mr. Novak's comments concerning its case filing and responses to the so-called minimum filing requirements. The Company provided proper schedules and even offered to allow Consumer Advocate witnesses access to data which could only be reviewed at AEP offices in Columbus, Ohio. Mr. Novak did not choose to take advantage of that access opportunity. As to minimum filing requirements, there are no published or codified minimum filing requirements for electric utility base rate cases. After discussions with the TRA Staff, the Company was provided a set of data requests which had been modified from filing requirements which were apparently developed jointly, and informally, by the TRA and gas utility companies regulated by the TRA. The Company properly provided information requested by this set of data requests which related to electricity. The Company also met with both the TRA and the Consumer Advocate in advance of the filing of the base rate case to discuss filing fundamentals. The content of its Petition was consistent with base rate case filings made by American

Electric Power, through its subsidiaries, in ten other jurisdictions. The Company welcomes the opportunity to develop formal filing requirements for use in base rate cases in the future. It is unreasonable, however, to fault the Company for not providing information in a format which was not standardized nor part of the Rules and Regulations of the TRA.

USE OF A 2015 TEST YEAR

Q. DOES THE COMPANY AGREE WITH THE CPAD WITNESSES USE OF A 2015 TEST YEAR AND A 2017 ATTRITION YEAR (NOVAK PAGE 6, LINES 1-12)?

A. The Company filed using a 2014 test year, as that was the information available at the time of the filing. Either a 2014 or 2015 test year is representative of the Company's on-going business. Consequentially, the change of test years results in immaterial differences, and as a result the Company does not oppose this recommendation. However, while the change in test year is not consequential, the adjustments necessary to arrive at the attrition year are different from a 2014 to a 2015 test year. These differences will be discussed by the Company's witnesses.

STREET LIGHTING

Q. PLEASE COMMENT ON THE RECOMMENDATION TO INCLUDE STREET LIGHTING IN THIS CASE (NOVAK PAGE 30, LINES 13-14).

A. The Company provides street lighting to the City of Kingsport and the Town of Mt. Carmel pursuant to the terms of contracts that have been in place for decades. In fact, in Kingsport's last base case in 1992, in which Mr. Novak was a witness, these same street lighting contracts were similarly excluded as part of the settled case. To include street lighting, now, as part of this base rate proceeding and to assign a portion of the revenue requirement to these entities will have the effect of "trapping" costs in the presence of the contracts that remain in force. The Company has properly excluded street lighting, and opposes this recommendation.

FUEL AND PURCHASED POWER COSTS

Q. PLEASE COMMENT ON THE RECOMMENDATION TO EXCLUDE COSTS ASSOCIATED WITH FUEL AND PURCHASED POWER FROM BASE RATES (NOVAK PAGE 29, LINES 1-9).

A. Currently, the Company has a level of fuel and purchased power and transmission costs in rates, and the balance in the fuel or PPAR riders, as appropriate. As a result of customer input, the Company proposed to consolidate costs, at their current level into base rates, while keeping the fuel and PPAR riders in place to adjust for differences as they arise. The net result would be, all things being equal, larger base rates, and lower fuel and purchased power rider expenses, with the total bill for customers unchanged. Putting all costs into the riders, as suggested by the CPAD will have the opposite effect. While unaffected financially by the CPAD's proposal, the Company notes that as a practical matter, the delineation of these costs on the bill for a residential customer can cause as much confusion as it is perhaps designed to alleviate. This is particularly the case since the fuel, purchased power, and base energy charges are all based on consumption for a residential customer, are not independent of each other, and thus are not individually controllable. Simply put, some customers do not understand why they would be charged for "energy," as well as "fuel" and "purchased power" which all seem to be the same thing.

APPLICATION OF INCREMENTAL REVENUE REQUIREMENT

Q. PLEASE COMMENT ON THE PROPOSAL TO APPLY THE INCREMENTAL REVENUE REQUIREMENT GRANTED IN THIS CASE EQUALLY TO ALL CUSTOMERS (NOVAK PAGE 24, LINES 12-16).

A. While seemingly financially indifferent to this proposal, KgPCo strongly recommends the TRA adopt a cost causation approach for setting rates. A cost of service study is the standard starting point in the electric utility industry for setting rates. Commissions, Authorities, or Boards may have public policy considerations that dictate deviations from a purely cost causation approach, but it is better to make those informed adjustments away from a value that has a theoretically sound basis. The need to communicate, through rates, economic signals that are not distortionary, is essential to the economic functioning of the electric system. By merely increasing rates by equal percentages to all customers, economic signals that are already distorted, become even more so, making future changes even more necessary and even more difficult. Further, this simplistic method indiscriminately applies costs to all customers regardless of whether there is any benefit. For example, for customers that take service at transmission level, work that is done on the (downstream) distribution system provides no benefit. Thus, pursuing this philosophy invites opposition to investment on the distribution system for necessary and desirable improvements in reliability and service quality. Finally, there may be long-term consequences of merely prorating incremental revenue requirements across rate classes, including those that are already paying more than a standard cost-of-service based rate design would dictate. Energy-intensive businesses could become uncompetitive as it is likely their competitors, in different jurisdictions, will have a more cost-based approach than Mr. Novak is advocating.

DEMAND-SIDE MANAGEMENT PROGRAMS

Q. CPAD WITNESS NOVAK DOES NOT RECOMMEND FUNDING A LOW-INCOME WEATHERIZATION PROGRAM OR LOAD CONTROL PROGRAM ON THE BASIS THAT THEY "VIOLATE THE STATE'S CONSERVATION POLICY" (NOVAK PAGE 32, LINES 3-12). PLEASE DISCUSS.

A. The state's conservation policy is:

> "a general policy that ensures that utility financial incentives are aligned with helping their customers use energy more efficiently and that provides timely cost recovery and a timely earnings opportunity for utilities associated with cost-effective measurable and verifiable efficiency savings, in a way that sustains or enhances utility customers' incentives to use energy more efficiently[1]."

The policy is in place to ensure that utilities are encouraged or at least indifferent to making investments in energy efficiency. The policy is not in place to actively discourage utility investment in conservation as the Consumer Advocate seeks to do. The proposed programs are cost-effective as demonstrated in my direct testimony[2] and the savings are measurable and verifiable[3].

[1] Tenn. Code Ann. § 65-4-126
[2] Castle Direct Testimony, Exhibit No. 2 (WKC) page 5 and page 9, also Castle Direct page 9 and page 14.
[3] Castle Direct page 10-11

Q. CPAD WITNESS NOVAK FURTHER STATES THAT THE BENEFITS WOULD BE RECEIVED BY AS FEW AS 300 CUSTOMERS (NOVAK PAGE 32, LINE 10). IS THIS ACCURATE?

A. No. First, it is important to understand that demand-side management programs benefit all customers, not just participating ones, as explained in the Company's response to CPAD 1-188. They do this in two ways: first, they reduce demand at peak periods, as the Residential Peak Reduction Program (RPRP) is specifically designed to do, and the Low Income Weatherization Program does concomitant with its reduction of consumption in all periods. This reduced demand translates directly into reduced charges to Kingsport. Second, the reduced consumption during periods of higher energy prices can reduce the average cost of fuel for all customers. Last, the participation number of 300 quoted by Mr. Novak appears to be only the first year participation estimates for just the RPRP program. As shown in my direct testimony, that number will grow each year so that there are expected to be 900 participants in that program in the third year. Additionally, the Company expects to weatherize 150 low-income households over the same period, and distribute efficient lightbulbs to 3,000 households through the food bank, as shown in the Company's response to Staff's initial data request[4].

TENNESSEE RELIABILITY STRATEGY

Q. CPAD WITNESS NOVAK OPPOSES INCREASED SPENDING FOR THE COMPANY'S PROPOSED TENNESSEE RELIABILITY STRATEGY (NOVAK PAGE 33, LINES 3-5). PLEASE COMMENT.

[4] See Staff Informal 1-024, "Staff Informal 1_24_DSM Workpapers.xlsx", "RLIWP" tab

A. Mr. Novak cites as his rationale for opposing the increased level of spending that, “the rate case already includes a going level for tree trimming expense” and that he could not “find where the Company has supported such a material increase.” The direct and rebuttal testimony of Company witness Wright addresses the need for the program and the associated costs in detail, so I will only expand on that to emphasize that the Company has not sought an increase in base rates since 1992 and Mr. Wright has explained, that migrating to a cycle-based trimming program is now industry practice and overdue at Kingsport. It is a fantasy to expect anything other than continued deterioration in KgPCo’s reliability unless this is addressed.

<u>TENNESSEE INSPECTION RIDER</u>

Q. CPAD WITNESS NOVAK RECOMMENDS REMOVING THE TENNESSEE INSPECTION RIDER FROM THE COMPANY’S TARIFF AND PUTTING IT INTO BASE RATES (NOVAK PAGE 33, LINE 12). PLEASE COMMENT.

A. The Company does not oppose this recommendation. However, the Company notes that Mr. Novak’s workpapers seem to indicate that he has not increased the incremental revenue requirement by the fee. Since the fee will apply to all revenues, the Company requests that the incremental revenue requirement reflect the fee.

<u>RECOVERY OF REVENUE DEFICIENCY</u>

Q. CPAD WITNESS NOVAK RECOMMENDS RECOVERING THE ENTIRE REVENUE DEFICIENCY THROUGH INCREASED CUSTOMER CHARGES (NOVAK PAGE 26, LINES 20-22). PLEASE COMMENT.

A. The Company agrees with this recommendation for the residential (Tariffs R.S., R.S.-E., R.S.-D., R.S.-T.O.D.) and small commercial tariffs (S.G.S., S.G.S.-D.). In the larger commercial and industrial tariff, this one-size-fits-all approach would hit smaller business disproportionately. In these cases, the Company recommends apportioning the incremental revenue requirement between the demand component and the customer charge such that the resultant customer charge is no more than double the current customer charge, with the balance apportioned to the demand charge.

PROPOSED DEMAND CHARGES FOR TARIFFS S.G.S.-D. AND M.G.S.

Q. SHOULD THE COMPANY'S PROPOSED DEMAND CHARGES FOR TARIFF S.G.S.-D. AND TARIFF M.G.S. BE IMPLEMENTED?

A. Yes. Mr. Novak did not discuss these issues in his testimony nor did he account for these new provisions in his rate design (Attachment WHN-2, Schedule 2, Lines 5-6). As such, the Company's proposals to introduce a new demand-metered Small General Service Tariff (S.G.S.-D.) and to implement demand charges for Tariff M.G.S. should be implemented.

Although Mr. Novak did not account for these provisions in his rate design, he does not discuss nor identify any reasons that they should not be implemented.

RATE CASE EXPENSE

Q. CPAD WITNESS SMITH RECOMMENDS USING THE COMPANY'S ESTIMATE OF RATE CASE EXPENSE INSTEAD OF THE 2015 TEST YEAR EXPENSE (SMITH PAGE 17, LINES 20-22). PLEASE COMMENT.

A. Because the Company did not have any rate case expense in the 2014 test year, it necessarily estimated that expense and amortized it over five years and treated it as an adjustment to the test year. In the 2015 test year, actual rate case expense was recorded. Although CPAD witness Smith states that when "analyzing Kingsport's operating expense, I started with the recorded 2015 expense," he inexplicably chooses the Company's lower estimate over the actual expenses included on the books of the adopted test year. KgPCo should not be held to a standard "lower of estimate or actual" without good cause.

CHARITABLE CONTRIBUTIONS

Q. CPAD WITNESS SMITH REMOVES CHARITABLE CONTRIBUTIONS (SMITH PAGE 7 LINES 18-22, PAGE 8, LINES 1-3) FROM THE TEST YEAR. PLEASE COMMENT.

A. Mr. Smith argues that charitable contributions should not be allowable expenses because they are, "not necessary for the provision of public utility service" and that, "the Company, not ratepayers select the charities." These statements miss one of the central elements of running an electric distribution utility, and that is that the utility is integral to the community that it serves. Customers look to the utility to not only to keep the lights on, but, where appropriate, to be an active participant in the community. While much of the time that merely involves Kingsport employees donating their own time and talents, there are times where monetary donations are appropriate.

Q. CPAD WITNESS SMITH FURTHER STATES THAT CHARITABLE CONTRIBUTIONS ARE, "TYPICALLY CONSIDERED TO BE A BELOW-THE-

LINE EXPENSE IN UTILITY RATEMAKING" (SMITH PAGE 7, LINE 22-PAGE 8, LINE 3). PLEASE COMMENT.

A. Commissions and Authorities have full discretion on whether to allow, in full or in part, charitable contributions made in the communities that utilities serve. In neighboring Virginia, the State Corporation Commission allows fifty percent of charitable contributions.

<u>CORPORATE AVIATION COSTS</u>

Q. CPAD WITNESS SMITH PROPOSES TO EXCLUDE AEP CORPORATE AVIATION COSTS FROM THE COST OF SERVICE BECAUSE THEY ARE USED FOR "EXECUTIVE AND AEP DIRECTOR TRAVEL" (SMITH PAGE 33 line 15). IS THIS ACCURATE?

A. No. The AEP Board of Directors certainly utilize AEPSC aircraft, but those trips are billed directly to the Parent Company (AEP) and none of those costs are billed to Kingsport or other operating companies in the AEP system. The costs that are billed to Kingsport consist of charges for trips that directly benefit Kingsport (billed directly) and the allocated portion of costs for trips that benefit all operating companies. Travel via AEPSC Aviation Services avoids not only commercial round-trip airfare, but also hotel stays, meals and the charged time of those avoiding multi-day travel and thus is a cost-competitive travel alternative and should not be dismissed out-of-hand and without any critical review.

<u>EQUIPMENT INSTALLATION SURCHARGE</u>

Q. CPAD WITNESS NOVAK SEEKS TO BLOCK THE COMPANY'S PROPOSED EQUIPMENT INSTALLATION SURCHARGES (NOVAK PAGE 37 LINES 1-7) CITING A LACK OF SUPPORTING DATA. PLEASE DISCUSS THE PURPOSE OF THE COMPANY'S PROPOSAL.

A. The proposed surcharge is completely voluntary and is in lieu of a Contribution in Aid of Construction (CIAC). As with a project that is eligible for CIAC, a customer who seeks improvements above standard service is responsible for those costs. These projects are most likely "capital" expenditures for customers. In some cases a customer may be better able to justify this project in an "O&M budget." This proposal merely allows an interested customer to effectively finance that capital expenditure by paying a monthly charge on their bill. The surcharge is designed to recover the "carrying costs" of that project and would not be considered part of rate base. Thus, there would be no impact on revenue requirements for other customers.

<u>TAX LIABILITY THRESHOLD FOR CIAC</u>

Q. CPAD WITNESS NOVAK IS OPPOSED TO THE COMPANY'S PROPOSED REMOVAL OF THE $100,000 INCOME TAX LIABILITY THRESHOLD FOR CIAC CITING AFFORDABILITY CONCERNS AND A LACK OF SUPPORTING EVIDENCE THAT IT IS CURRENTLY AN ISSUE (NOVAK PAGE 37-38). PLEASE DISCUSS.

A. First, I will address the affordability concern by emphasizing that projects that fall under this provision are voluntary. A typical example of a project is for a customer to underground the line from the service drop to their house for aesthetics. When the customer makes the CIAC payment for the difference between this service and standard service, the Company must treat that as income and is thus subject to taxes on that income. The question before the TRA is whether all customers should pay for this tax that is a result of voluntary upgrade or whether the cost should be borne by the customer getting the benefit of that upgrade. In the past six years, all such projects have been for less than $100,000. CIAC has averaged $328 thousand annually for the last 7 years and was $281 thousand in 2015 (this information was provided in CPAD 1-042 supplemental).

<u>COST-OF-SERVICE BASED RATE STRUCTURE</u>

Q. DO YOU HAVE ANY COMMENTS ON THE TESTIMONY OF EAST TENNESSEE ENERGY CONSUMERS' WITNESS BARON?

A. Yes. In general, Mr. Baron's testimony is supportive of the Company's cost-of-service study and the plan to gradually shift rates from their current state to a cost-of-service based rate structure. However, Mr. Baron puts forth his own schedule which accelerates the shift. The Company stands by its original proposal as a reasonable and gradual approach to implementing rates based on electric industry standard practice.

Q. DOES THE COMPANY AGREE WITH MR. BARON'S RECOMMENDATION THAT THE CAPACITY RESERVATION CHARGE INCLUDED IN THE PROPOSED RIDER A.F.S. BE REDUCED FROM $4.36 PER KW/KVA PER MONTH TO $2.46 PER KW/KVA?

A. Yes. In short, the Company's agrees that the rate should be based on the cost of service calculation, not the proposed interim "year 1" rate.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Daves

REBUTTAL TESTIMONY OF
PHILLIP R. DAVES
ON BEHALF OF KINGSPORT POWER COMPANY
D/B/A AEP APPALACHIAN POWER
BEFORE THE TENNESSEE REGULATORY AUTHORITY
DOCKET NO. 16-00001

Q. PLEASE STATE YOUR NAME.

A. My name is Phillip R. Daves.

Q. ARE YOU THE SAME PHILLIP R. DAVES WHO SUBMITTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony responds to the direct testimony of Christopher C. Klein as follows below.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following exhibits:

- Rebuttal Exhibit No. 1 (PRD): Comparison of the Capital Asset Pricing Model required returns using Dr. Klein's CAPM methodology for a long-term risk-free rate and Dr. Daves' CAPM methodology.
- Rebuttal Exhibit No. 2 (PRD): Unlevered and Levered Costs of Equity for the 8 Companies, AEP, and Kingsport Power Company Using Kingsport's Actual Capital Structure.

Q. WERE THE EXHIBITS THAT YOU ARE SPONSORING PREPARED OR ASSEMBLED BY YOU OR UNDER YOUR DIRECTION?

A. Yes.

COST OF CAPITAL

Q. DO YOU AGREE WITH WITNESS CHRISTOPHER KLEIN'S RECOMMENDATION FOR KINGSPORT'S COST OF CAPITAL?

A. No, I do not.

Q. ON WHICH POINTS DO YOU DISAGREE?

A. I disagree with Dr. Klein's fundamental premise that Kingsport's required return should be calculated as AEP's required return corrected for double leverage. He has applied his techniques to the incorrect entity, AEP, rather than Kingsport, and hence his conclusions about required return are irrelevant to the required return on Kingsport. I also disagree with the methodology he has applied to AEP calculating AEP's required return. To the extent this methodology conflicts with the methodology I presented in my direct testimony, I will explain those differences. Specifically:

- I disagree with Dr. Klein's selection of comparable companies.
- I disagree with one component of Dr. Klein's implementation of the DCF model.
- I disagree with Dr. Klein's methodology for implementing the Capital Asset Pricing Model.
- I also disagree with Dr. Klein's characterization and dismissal of the technique of calculating unlevered required returns and re-levering to account for capital structure.

Q. CAN YOU ELABORATE ON YOUR CRITIQUE OF DR. KLEIN'S USE OF AEP'S REQUIRED RETURN AND THE DOUBLE LEVERAGE CORRECTION?

A. Yes. This critique refers to P. 9 lines 12 to 18 in Dr. Klein's direct testimony. In that section Dr. Klein contends that Kingsport's required return on equity calculation should begin with AEP's required return on equity and then be corrected for double leverage. He refers to the academic paper, "Modified Double Leverage—A New Approach," *Public Utilities Fortnightly*, March 31, 1983, by Michael S. Rozeff" in support of this analysis. Dr. Klein has incorrectly and inappropriately applied the methodology described in the article. As the article states "…unmodified double leverage overestimates a subsidiary's return on equity if that subsidiary's true required equity return is less than the required equity returns on the remaining subsidiaries, and vice versa." Dr. Klein has used in his calculations the *unmodified* double leverage technique that the article criticizes. The results of this article show that when a holding company has more than one subsidiary, as does AEP, it is economically *incorrect* to begin with the holding company's required return and modify it for leverage to obtain the required return on one of the several subsidiaries, which is what Dr. Klein has done. There are only two cases in which this technique could be applied to Kingsport as Dr. Klein does. The first one is if Kingsport is AEP's only subsidiary, which is certainly not the case. The second one is if each of AEP's other subsidiaries has an unlevered cost of equity identically equal to that of Kingsport. This is also not the case. AEP's subsidiaries are in different markets with different product mixes. Their regulatory structures differ and some are vertically integrated, engaging in both generation and distribution, while Kingsport is a distribution-only subsidiary. With all of these different markets and services, it is incorrect to assume each subsidiary has an unlevered cost of capital identical to that of Kingsport.

Q. IS THERE A WAY TO PROPERLY APPLY DR. KLEIN'S METHODOLOGY TO ESTIMATE KINGSPORT'S REQUIRED RETURN ON EQUITY?

A. In theory, there is a way to apply his approach correctly as described in the Rozeff paper Dr. Klein references, but doing so is impractical in that it simply replaces the problem of determining Kingsport's required return on equity with the problem of determining, from comparables, the required returns on equity for each of AEP's other subsidiaries. To properly apply the double leverage concept to Kingsport as laid out in the Rozeff paper, the required returns on each of AEP's other subsidiaries must be known or estimated before solving for the required return on equity of Kingsport. This estimation for each subsidiary would proceed just as I've estimated Kingsport's required return on equity—by identifying companies comparable to each subsidiary (not comparable to AEP), calculating unlevered required returns on these comparables and then re-levering to account for the subsidiaries' capital structures.

Q. WHAT DOES THIS IMPLY ABOUT THE BALANCE OF DR. KLEIN'S TESTIMONY ON THE COST OF EQUITY CAPITAL?

A. The balance of Klein's testimony on cost of capital is irrelevant to the cost of Kingsport's equity capital in that he is estimating the cost of capital of the wrong entity—that of AEP rather than that of Kingsport. In lines 7 to 9 of page 10, Klein asserts that the double leverage correction technique has very little effect (15 basis points) on the overall cost of capital, but that doesn't mitigate the problem that he estimated the cost of capital for the wrong entity in the first place.

Q. DO YOU HAVE CONCERNS WITH THE COST OF CAPITAL CALCULATION METHODOLOGY IN THE BALANCE OF KLEIN'S TESTIMONY, EVEN THOUGH IT IS APPLIED TO AEP RATHER THAN KINGSPORT?

A. Yes. I have concerns about his implementation of the DCF model, his choice of comparable companies, his implementation of the CAPM and his correction for leverage.

Q. WHAT ARE YOUR CONCERNS ABOUT DR. KLEIN'S IMPLEMENTATION OF THE DCF MODEL?

A. On page 11 lines 7 to 10, Dr. Klein states correctly that "… some simple mathematics show that the rate of return an investor expects on stock ownership in the company is the dividend yield for the current period plus the expected growth rate in that dividend. The dividend yield is just the expected dividend divided by the current price of the stock." However, Dr. Klein's calculations use the dividend yields posted in the *Wall Street Journal*, which are not expected dividends over the next 12 months but are, instead, the most recent dividend multiplied by 4. This would correctly represent investors' expectations of dividend payments over the next 12 months only if the stock price and dividend data were taken before the first quarterly dividend ex-date, since most companies maintain a constant quarterly dividend in a given fiscal year. But this calculation is not correct at any other time if dividends are growing, as is assumed with the DCF model. Since Dr. Klein has taken dividend yields and stock prices as of June 1, the *Wall Street Journal* dividend yield underestimates investors' expected dividend yields by one quarter of dividend growth for December fiscal year end companies, two quarters for September fiscal year end companies, and three quarters for June fiscal year end companies. On average, this means that investors actually expect about half a year's increase in dividends received over the next twelve months holding period—two quarters of the most recent dividend payment, and two quarters of the higher dividend expected during the next fiscal year from the expected dividend growth rate, or $D_0(1 + g/2)$ for the expected dividend over the next twelve months. It appears that Dr. Klein misinterprets my correction for dividend growth as some sort of correction for compounding in his testimony on pages 16 and 17, which it is not. Rather, my calculation is the correct, uncompounded dividend yield investors expect over the next twelve months, as required for the correct implementation of the DCF model. Omitting this required correction will bias downward the expected dividend yield and the resulting DCF cost of capital. For dividend yields of 4% and growth rates of 5%, this resulting bias will be approximately 4%x(5%/2) = 0.1% or 10 basis points. I conclude that the DCF methodology I presented in my direct testimony is consistent with Dr. Klein's DCF methodology, once Dr. Klein's methodology is corrected for the actual expectations that an investor would have of dividend payments over the next twelve months.

Q. WHAT ARE YOUR CONCERNS ABOUT DR. KLEIN'S SELECTION OF COMPARABLE COMPANIES?

A. To correctly estimate the cost of capital for Kingsport, companies comparable to Kingsport should be used, not companies chosen to be comparable to AEP. Consistent with his implementation of the double-leverage correction, Dr. Klein has chosen companies that "…are comparable in size and riskiness to AEP" (page 16 lines 7 and 8 of Dr. Klein's direct testimony), rather than to Kingsport. As I discuss above, this is not the correct entity whose cost of capital must be estimated. Kingsport is a distribution company and generates none of its own electricity. My selection of companies is chosen as the universe of all publicly-traded electric utilities covered by Valueline that generate less than 50% of the power that they distribute. This is a small universe, with only eight companies. Dr. Klein has chosen a smaller set of companies that are similar to AEP, not to Kingsport.

Q. WHAT ARE YOUR CONCERNS ABOUT DR. KLEIN'S IMPLEMENTATION OF THE CAPITAL ASSET PRICING MODEL?

A. Best practices implementations of the CAPM use a long-term risk-free rate as the base risk-free rate. In Brotherson, W. Todd and Eades, Kenneth M. and Harris, Robert S. and Higgins, Robert C., 'Best Practices' in Estimating the Cost of Capital: An Update (July 15, 2013). *Journal of Applied Finance,* Spring/Summer 2013, Volume 23, No. 1, the authors survey corporations, practitioners and corporate finance textbooks on how they actually implement cost of capital calculations. All of the respondents recommended using a long-term risk-free rate in the CAPM calculations, with recommended maturities between 10 years and 30 years. None recommended using a short-term rate. Dr. Klein uses a short-term rate in his calculations, which produces substantially lower costs of equity capital than if a long-term rate were used. A long-term risk-free rate is commonly used in CAPM cost of capital calculations because when there is a difference in short- and long-term risk-free rates, it is economically correct to match the term of the risk-free rate to the term of the investment. Since common stock is assumed to be a long-term investment, a long-term risk-free rate is usually used. In Panel A of Rebuttal Exhibit 1 (PRD), I present Dr. Klein's lower and upper bounds for the CAPM-derived required returns on equity for his selection of comparison companies as reported in his page 4 exhibit. I also present the required return on equity that would result if Klein had used his own data but instead employed a best practices choice of risk-free rate by using his long-term risk-free rate. Since Dr. Klein uses a historical market risk premium rather than a forward-looking one in all of his calculations, I've used his reported long-term historical market risk premium in these calculations. Note that in each case, the best practices choice of risk-free rate gives a required return greater than Dr. Klein's upper bound. The required return calculated using a best practices risk-free rate exceeds on average Dr. Klein's lower bound by 105 basis points, and exceeds Dr. Klein's upper bound by 16 basis points. Therefore, Dr. Klein's reported CAPM-derived required returns for his comparison companies are significantly biased downward relative to the required returns calculated employing a best practices choice of risk-free rate.

Q. HOW DO THE REQUIRED RETURNS FOR YOUR SELECTION OF COMPARABLE COMPANIES AS PRESENTED IN YOUR DIRECT TESTIMONY COMPARE TO THE REQUIRED RETURNS ON THOSE SAME COMPANIES THAT WOULD BE CALCULATED USING DR. KLEIN'S DATA AND A LONG-TERM RISK FREE-RATE?

A. There is variation among the respondents to the best practices survey as to whether a historical market risk premium is used or a forward-looking market risk premium is used. Economic theory specifies a forward-looking market risk premium, but practitioners find it difficult to estimate one and often use a historical one instead. Dr. Klein uses a short-term Treasury rate and a historical market risk premium corresponding to a short-term risk free rate, but also provides the information necessary to calculate required returns using a long-term risk-free rate and a historical market risk premium based on long-term rates. I used these figures in the calculations for Panel A of Rebuttal Exhibit 1 (PRD). The calculations in my direct testimony use the 2-year average of the 30-year Treasury Bond rate as the risk-free rate and a forward-looking market risk premium that I estimate.

Rebuttal Exhibit 1 (PRD), Panel B compares returns for my selection of comparable companies reported in my direct testimony with the required returns I calculated using Dr. Klein's long-term risk-free rate and his long-term historical market risk premium. Although the returns differ from company to company, they are largely quite similar, with the average required return using Dr. Klein's data 19 basis points greater than the average required return using the methodology in my direct testimony. I conclude that a best practices implementation of Dr. Klein's methodology provides levered costs of equity for my comparable companies that are consistent with and slightly larger than the levered costs of equity that I obtained and reported in my direct testimony.

Dr. Klein attempted to do something similar in the second table on page 4 of his exhibit by applying the risk premium from my testimony to his selection of comparison companies, but did so incorrectly. In this exhibit, he applied the forward-looking risk premium I calculated on April 30, 2015 to the betas he took from Valueline 13 months later and used the 30-year risk free T-Bond rate he obtained at that same time. Forward-looking risk premia can be quite variable over time. Indeed, Aswath Damodaran has calculated forward-looking risk premia back to 1960 in Figure 7.1 on page 175 of his textbook *Investment Valuation: Tools for Determining the Value of Any Asset*, 3rd edition. Since the year 2000, his estimates of the forward-looking market risk premium have varied by more than 400 basis points. With such variability, it is economically inappropriate to apply a forward-looking risk premium that is not calculated at the same time as the beta and risk-free rate. If Dr. Klein wanted to know the CAPM required rate of return based on a forward-looking market risk premium as of the date of my analysis, he should have used betas calculated on that date and a risk-free rate representative of investor expectations of the long-term risk-free rate on that date. If Dr. Klein wanted to know the CAPM required rate of return based on a forward-looking market risk premium as of the date of his analysis, June 1, 2016, then he should have calculated such a forward-looking market risk premium as of that date.

Q. DO YOU AGREE WITH DR. KLEIN'S METHOD OF DEALING WITH KINGSPORT'S LEVERAGE?

A. No, I do not. As I stated above, Dr. Klein has calculated AEP's required return and attempted to apply a leverage correction to it to obtain Kingsport's required return. This technique would work if Kingsport were AEP's only subsidiary, or all of AEP's subsidiaries had the same equity costs. This is not the case and the technique as applied by Dr. Klein is inappropriate and produces an incorrect result. I have employed a standard method of calculating the cost of capital for an untraded company. See Financial Management 15th Edition, by Eugene Brigham and Michael Ehrhardt, Chapters 21 and 22. I calculated the levered costs of capital for comparable companies and unlevered those costs of capital to account for their differing capital structures. I then re-levered these costs of capital to account for Kingsport's capital structure. Dr. Klein references the paper "On the Risk-Neutral Value of Debt Tax Shields" by Massimiliano Barbi in *Applied Financial Economics*, Volume 22, Issue 3, 2012 to argue that my use of the unlevered cost of equity to value debt tax shields is inappropriate. On the contrary, this paper demonstrates that the unlevered cost of equity is precisely the correct discount rate for discounting debt tax shields. Specifically, Barbi's Equation 14 shows that under standard assumptions about growth and maintaining a constant market value capital structure, the value of a company's interest tax shield is indeed the present value of its tax shields discounted at the unlevered cost of capital. Barbi employs a small correction for discrete time with the factor $(1+r_U)/(1+r_d)$ which he states vanishes in continuous time. If his correction factor is zero, then his result gives rise to precisely the same formulas I use for levering and unlevering required returns in my direct testimony:

$$r_L = r_U + (r_U - r_d)\frac{w_d}{w_S}$$

If Barbi's discrete time correction is employed rather than continuous time formula I use, the resulting formula for levering and unlevering is virtually unchanged:

$$r_L = r_U + (r_U - r_d)\frac{w_d}{w_S} - C$$

where

$$C = \frac{r_U - r_d}{1 + r_d} r_d T \frac{w_d}{w_S}$$

For the companies analyzed, unlevered costs of equity are on the order of 7%, the costs of debt are on the order of 3%, tax rates are on the order of 35% and w_d/w_S is approximately equal to 1.0. For parameters in this range, this correction factor is on the order of

$$C = \frac{0.07 - 0.03}{1.03} 0.03\text{x}0.35\text{x}1 \quad = \quad 0.0004$$

or 4 basis points for companies like the ones comparable to Kingsport. Therefore the formulas I use in my direct testimony for levering and unlevering required returns give virtually the same results as would be obtained if the formulas and assumptions in the Barbi paper on computing the value of a company's interest tax shield referenced by Dr. Klein were used. With this issue settled, the formula I used to lever and unlever required returns is precisely the correct formula to accomplish this purpose. Dr. Klein also argues that capital structures are difficult to estimate and since this estimation introduces errors, required returns should not be un-levered or re-levered, even though this is what he attempts to do in applying the double leverage correction. In reality, every component of a cost of capital estimation--CAPM betas, the market risk premium, expected dividend yield, expected dividend growth rate and capital structure—requires judgment and estimation. Leverage matters in the required return calculation for a non-traded entity and so must be accommodated. I've employed a method that is widely accepted and theoretically justified.

Q. WHAT DO YOU CONCLUDE ABOUT DR. KLEIN'S TESTIMONY?

A. Dr. Klein estimated the cost of capital for the wrong entity and so his results are not germane to the calculation of Kingsport's cost of capital. However, the economically correct and best practices implementation of Dr. Klein's methodology is entirely consistent with the calculations in my direct testimony.

Q. WOULD YOUR COST OF CAPITAL RECOMMENDATION BE DIFFERENT IF YOU HAD USED KINGSPORT'S ACTUAL CAPITAL STRUCTURE?

A. Yes. The cost of capital recommendation in my direct testimony was based on a capital structure for Kingsport of 47% equity and 53% debt, which was provided to me by the Company in error as Kingsport's regulatory capital structure. This capital structure resulted in a range of 10.02% to 11.06% with a point estimate of 10.66% as reflected in Exhibit 10 (PRD) of my direct testimony. As a result of a data request, we determined that this capital structure is AEP's and not Kingsport's. I am reporting here the results of my analysis using Kingsport's actual capital structure, which I would have used in my original analysis. Kingsport's actual capital structure as reflected in Mr. Bourke's testimony is 42.43% equity and 57.57% debt. I have provided a version of my direct testimony's Exhibit 10 (PRD) as Rebuttal Exhibit 2 (PRD) that reflects this actual capital structure. This exhibit shows the levered cost of equity estimates for Kingsport using Kingsport's actual capital structure.

Q. WHAT RANGE OF RATES AND POINT ESTIMATE WOULD RESULT FROM USING KINGSPORT'S ACTUAL CAPITAL STRUCUTRE?

A. Kingsport's required rate of return to equity based on its actual capital structure and the required rates of return to a sample of eight comparison electric utilities would be between 10.85% and 12.01% with a point estimate of 11.56%. This is about 90 basis points higher than my recommendation because Kingsport's actual capital structure has more leverage than the capital structure provided to me for my initial analysis. In that this range is higher than the range I provided, it provides further support for the magnitude of my original required return recommendation.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Rebuttal Exhibit No. 1 (PRD)

Comparison of the Capital Asset Pricing Model required returns using Dr. Klein's CAPM methodology for a long-term risk-free rate and Dr. Daves' CAPM methodology.

Panel A: Dr. Klein's companies and Dr. Klein's calculations.

	Beta	CAPM Long-term	CAPM Short-term. Lower bound in Exhibit 4	Klein's upper bound in Exhibit 4
AEP	0.7	7.48%	6.31%	7.37%
Edison Int.	0.7	7.48%	6.31%	7.37%
First Energy	0.65	7.13%	5.88%	6.94%
NextEra En	0.7	7.48%	6.31%	7.37%
Southern Co.	0.6	6.78%	5.45%	6.51%
Average		7.27%	6.06%	7.11%

Panel B: Comparison of Dr. Klein's long-term CAPM and Dr. Daves' CAPM using Daves' betas and Daves' comparison companies.

Company	1-year Betas	Klein CAPM Long-term	Daves CAPM
American Electric Power	0.647	7.10%	7.02%
Ameren	0.702	7.49%	7.34%
Black Hills Corp	1.086	10.18%	9.55%
Centerpoint Energy	0.944	9.19%	8.73%
Edison International	0.550	6.42%	6.46%
ITC Holdings	0.537	6.34%	6.39%
PG&E corp	0.550	6.43%	6.46%
Sempra Energy	0.863	8.62%	8.26%
UIL Holdings	0.676	7.31%	7.19%
Average		7.68%	7.49%

Assumptions:

For Dr. Klein's long-term CAPM the risk free rate is 2.58% and the historical market risk premium is 7.0%. For Dr. Daves' CAPM the risk-free rate is 3.30% and the forward-looking market risk premium is 5.75%. Klein's betas are from Valueline. Daves' betas are 1-year betas calculated from daily returns and the S&P 500 as the market.

Rebuttal Exhibit No. 2 (PRD)

Unlevered and Levered Costs of Equity for the 8 Companies, AEP, and Kingsport Power Company Using Kingsport's Actual Capital Structure

Panel A: Summary Statistics for the Unlevered Costs of Equity for the 8 Comparison Companies and for AEP

		Excluding AEP			AEP
	Mean	33%	Median	67%	
DCF r_u	6.31%	6.28%	6.85%	7.11%	6.20%
CAPM r_u	5.67%	5.57%	5.61%	5.73%	5.30%
Average of DCF and CAPM	5.99%	5.93%	6.23%	6.42%	5.75%

Panel B: Kingsport's Levered Required Return on Equity Based on Each Summary Measure of Unlevered Required Return using Kingsport's Actual Capital Structure

		Excluding AEP			AEP
Kingsport r_L based on:	Mean	33%	Median	67%	
DCF r_u	11.76%	11.69%	13.01%	13.63%	11.49%
CAPM r_u	10.24%	10.01%	10.11%	10.39%	9.36%
Average of DCF and CAPM	**11.00%**	**10.85%**	**11.56%**	**12.01%**	**10.42%**

Re-Levering Assumptions:

Kingsport w-equity	42.43%
Kingsport w-debt	57.57%
Kingsport weighted r_d	2.30%
Market risk premium	5.75%

Hawkins

KgPCo Rebuttal Exhibit No. ___
Witness: RVH

REBUTTAL TESTIMONY OF
RENEE V. HAWKINS
ON BEHALF OF KINGSPORT POWER COMPANY
D/B/A AEP APPALACHIAN POWER
BEFORE THE TENNESSEE REGULATORY AUTHORITY
DOCKET NO. 16-00001

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

A. My name is Renee V. Hawkins. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by the American Electric Power Service Corporation (AEPSC) as a Managing Director, Corporate Finance overseeing the raising of capital for Kingsport and various American Electric Power Company, Inc. (AEP) utilities. AEPSC supplies engineering, financing, accounting, and planning and advisory services to the subsidiaries of the American Electric Power (AEP) System, one of which is Kingsport Power Company (KgPCo or the Company).

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I earned a Bachelor of Science in Business Administration in Finance and International Business from the Ohio State University in 1987. I earned a Master of Business Administration from the Simon School at the University of Rochester in 1991.

I was first employed by State Teachers Retirement System of Ohio in 1987 in the Real Estate section where I was assigned to asset management. In June 1991, I was employed by General Motors as an analyst for AC Delco, which is now a subsidiary of Delphi East. This rotational program included positions in cost accounting, division finance, and capital planning. In June 1993, I was hired by Cablevision Systems.

In 1996, I joined AEPSC as a Corporate Finance Senior Analyst supporting financing activity for the AEP System operating companies. In 1999, I was named Manager – Corporate Finance of AEPSC. In June 2000, I was named Director – Corporate Finance of the Service Corporation, a position that was renamed Director – Regulated Finance in 2001. In that capacity, I was responsible for capital markets activity for all of the regulated utilities, establishing dividend recommendations and capitalization targets, supporting the rating agency relationships to maintain credit ratings and assisting in the management of liquidity for AEP and its subsidiaries. I was promoted to Managing Director, Corporate Finance in 2003. In January 2008, my responsibilities expanded to include Assistant Treasurer of AEP and its operating companies.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY AS A WITNESS BEFORE ANY REGULATORY COMMISSION?

A. Yes. In addition to previously testifying and submitting testimony on behalf of the Companies before the Public Service Commission of West Virginia, most recently in Case No. 14-1152-E-42T, I have provided testimony and testified before the Virginia State Corporation Commission on behalf of Appalachian Power Company, the Public Utilities Commission of Ohio on behalf of Ohio Power Company, the Arkansas Public Service Commission and Public Utility Commission of Texas on behalf of Southwestern Electric Power Company, the Indiana Utility Regulatory Commission and the Michigan Public Service Commission on behalf of Indiana Michigan Power Company and the Oklahoma Corporation Commission on behalf of Public Service Company of Oklahoma. These companies are all subsidiaries of AEP.

Q. ARE YOU ADOPTING THE TESTIMONY OF A COMPANY WITNESS IN THIS PROCEEDING?

A. Yes. I am adopting the direct testimony of Company witness Patrick M. Bourke who has since left the Company. When the testimony was filed, Mr. Bourke reported to me so I am familiar with the analysis.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony responds to the direct testimony of Consumer Protection and Advocate Division (CPAD) witness Dr. Christopher C. Klein regarding his recommendation to reduce Kingsport's cost of capital by imputing a parent leverage calculation and CPAD witness Ralph C. Smith's recommendation that costs related to the sale of receivables be removed from the revenue requirement.

CAPITAL STRUCTURE AND IMPUTING PARENT LEVERAGE

Q. HOW DO YOU RESPOND TO CPAD WITNESS KLEIN'S RECOMMENDATION (7:17-10:9) TO IMPUTE LEVERAGE FROM AEP ONTO KINGSPORT'S CAPITAL STRUCTURE IN ORDER TO REDUCE THE COST OF CAPITAL?

A. I disagree with Mr. Klein's adjustments to Kingsport's capital structure. Company witness Daves will address the research regarding use of double leverage for a utility and I discuss how the AEP subsidiaries are financed and why it is unreasonable to attribute parent debt costs to Kingsport.

Kingsport as well as the other AEP subsidiaries each has a capital structure based on their own characteristics. There is a nominal amount of short-term and long-term debt at AEP and the majority of that funding is used to finance AEP Credit, the utility money pool and the direct borrowers. To use a portion of this parent debt in the capital structure at Kingsport is inconsistent with how Kingsport's capital structure is managed and how the parent borrowings are utilized.

Q. HOW ARE CAPITAL STRUCTURES CONSIDERED FOR THE AEP SUBSIDIARIES?

A. Each AEP utility's capital structure is a result of the overall earnings, cash flow, targeted credit ratings and capital spending for the utility. Using Kingsport as an example, the capital structure for Kingsport from 2012 through March 31, 2016 is included below:

Kingsport Power
Capital Structure by Year
($ Thousands)

	2012	%	2013		2014		2015		1Q 2016	
Short-Term Debt	17,342		19,083		22,039		32,297		28,184	
Long-Term Debt	20,000		20,000		20,000		20,000		20,000	
Total Debt	37,342	55%	39,083	56%	42,039	57%	52,297	64%	48,184	56%
Common Equity	29,956	45%	31,081	44%	31,277	43%	29,626	36%	37,484	44%
Total Capital Structure	67,298		70,164		73,316		81,923		85,668	

As you can see, Kingsport has been traditionally managed to a 55% debt and 45% equity capital structure based upon the level of capital spending and dividends. However, in 2015, there was an unexpected loss as well as higher capital spending which resulted in leverage jumping to 64%. The higher leverage at year-end was corrected with an equity contribution in early 2016. This support of KgPCo's financial strength is consistent with AEP's history of providing support to the other utilities in times of heavy capital expenditure in order to maintain a capital structure appropriate with the rating or the regulatory capital structure.

Q. WHAT WAS AEP'S CAPITAL STRUCTURE DURING THAT SAME PERIOD?

A. The equity ratios for AEP Consolidated have been about the same as those of Kingsport and ranged from 44.8% to 45.7% for the years 2012 to 2015. Those ratios were provided to CPAD witness Klein in a data request which he used to develop his capital structure recommendation.

Q. WHY IS AEP'S CAPITAL STRUCTURE RELEVANT?

A. Typically a discussion of double leverage involves the assumption that the parent is more highly levered than the utility and borrows the debt and contributes it to the utility. In the case of Kingsport and AEP, the parent leverage has actually been the same or lower than Kingsport. As such there is no basis to assume that any double leverage has occurred.

Q. PLEASE DISCUSS THE DEBT ISSUED AT AEP.

A. The short-term debt attributed to AEP actually included the external commercial paper issued for the entire AEP family since it resides on the balance sheet for AEP. It was $125 million and $602 million, respectively on December 31, 2015 and 2014. For example, the $32 million of short-term debt outstanding at Kingsport on December 31, 2015, is part of the utility money pool borrowings which are netted against each other and then financed externally by AEP.

The short-term debt at AEP includes the net requirements for all of the utilities as well as such needs as the short-term debt required at AEP Credit (up to 20% of AEP Credit's funding requirement can be short-term debt).

The long-term debt issued at AEP mostly relates to vestige businesses that had been financed in the past. The last long-term notes issued at AEP were in 2009.

Q. DO YOU HAVE COMMENTS REGARDING WITNESS KLEIN'S RESPONSE (8:9-8:16) ON WHY THE PARENT-SUBSIDIARY RELATIONSHIP IS SO IMPORTANT TO KINGSPORT?

A. Yes. Until Kingsport can meet the interest coverage test requirements of the Federal Energy Regulatory Commission (FERC), that governmental entity will not authorize Kingsport to issue long-term debt. This has stymied the Company's efforts to replace a portion of its short-term debt with long-term debt. The FERC requires that a utility have an interest coverage ratio of 2x, based on the required calculation, in order to receive an order authorizing the issuance of debt. Kingsport is benefitting from being part of the AEP System and having access to the utility money pool for its short-term borrowing.

Q. DO YOU HAVE ANY COMMENTS REGARDING WITNESS KLEIN'S ASSERTION (22:7-22:22) THAT COMPANY WITNESS PATRICK BOURKE COMMITTED AN ERROR IN THE DEVELOPMENT OF THE WEIGHTED AVERAGE COST OF CAPITAL (WACC) IN HIS DIRECT TESTIMONY?

A. I disagree that there was any error in the development of the WACC. The WACC was the result of using a conventional development of capital structure and cost of debt with the adjustments that were discussed in Mr. Bourke's direct testimony. The recommended cost of equity was then applied to produce the proposed WACC. Witness Klein's Exhibit 1 includes the same capital structure recommendations and debt costs, but with his own recommended cost of equity. Simply put, there are differing views on the cost of equity recommendations, but there was not an error in the analysis.

<u>SALE OF RECEIVABLES</u>

Q. DO YOU HAVE ANY COMMENTS REGARDING CPAD WITNESS SMITH'S ASSERTION (18:15 – 22:15) THAT THE CHARGES RELATED TO THE SALE OF RECEIVABLES SHOULD BE DISALLOWED?

A. Yes. Kingsport entered into an agreement to sell its receivables (also known as factoring) to AEP Credit in 2001 to provide an alternative low cost funding source to Kingsport. Nearly every utility within the AEP family[1] sells its receivables.

Q. WHAT COSTS ARE CHARGED TO KGPCO FROM AEP CREDIT?

A. The costs charged to Kingsport included in Account 4265009 are the carrying cost including the banks' funding cost, the short-term debt and equity provided by AEP and the bank line of credit fees which were $302,054 for 2015. Also included in the factoring cost in Account 4265010 is the bad debt expense associated with the accounts receivables sold to AEP Credit which is addressed by Company witness Allen.

Q. WHAT ARE THE BENEFITS OF THE SALE OF RECEIVABLES?

A. Kingsport benefits from a low cost funding source from the sale of receivables due to two separate factors. Kingsport's receivables are financed with a low equity percentage, which can vary depending on the quality of the receivables, but is currently 5% equity, 18% short-term debt (provided by AEP) and the remainder from the bank advance rate. The bank advance rate results in a transaction that is structured as A-rated credit (which caps the amount of leverage within the structure), thereby providing a very low funding cost. The return component on the cost of equity is paid to AEP Credit, Inc. as part of the factoring cost and is based on the most recently authorized return for an AEP utility.

[1] Appalachian Power securitizes only the Virginia receivables

Q. WHY IS THE SALE OF RECEIVABLES INITIALLY AN AFFILIATE TRANSACTION?

A. The receivables sales agreement requires the use of a special purpose entity (SPE) for segregating the receivables and obtaining the true sale opinion. For utilities such as AEP, the SPE can either be an affiliate of all of the utilities or alternatively, each utility could have a subsidiary that acts as the SPE. For AEP, a decision was made to continue the use of a single SPE to capture all of the utilities receivables and then sell from AEP Credit to the banks. There are operational benefits from using a single SPE, but the receivables are now on the balance sheet of AEP due to the SPE consolidation accounting rules instead of on the balance sheet of the utilities.

AEP Credit then sells the receivables to banks that finance the receivables using short-term interest rates which are included in the bank advance rate.

Q. WHAT WOULD BE THE ALTERNATIVE TO KINGSPORT SELLING ITS RECEIVABLES?

A. If the Authority does not agree that the Company can recover the costs associated with AEP Credit, the Company could in effect reverse the transaction that occurs when the receivables are initially sold, this would involve recapitalizing, for the receivables no longer sold, with additional debt and equity at a more expensive capital structure similar to the 45% equity and 55% debt ratios at which Kingsport is currently financed.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Wright

REBUTTAL TESTIMONY OF
PHILIP A. WRIGHT
ON BEHALF OF KINGSPORT POWER COMPANY
D/B/A AEP APPALACHIAN POWER
BEFORE THE TENNESSEE REGULATORY AUTHORITY
DOCKET NO. 16-00001

Q. PLEASE STATE YOUR NAME.

A. My name is Philip A. Wright.

Q. ARE YOU THE SAME PHILIP A. WRIGHT WHO SUBMITTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony responds to the direct testimonies of Consumer Protection and Advocate Division (CPAD) witnesses William H. Novak and Ralph C. Smith. In regards to both Mr. Novak and Mr. Smith, I respond to their assertions that the Company did not adequately justify its proposed Tennessee Reliability Strategy (TRS). Additionally, I respond to Mr. Smith's recommendation related to the Company's requested Major Storm Expense.

TENNESSEE RELIABILITY STRATEGY

Q. HOW DO YOU RESPOND TO WITNESSES NOVAK'S AND SMITH'S RECOMMENDATION TO DENY THE COMPANY'S PROPOSED TRS?

A. Both Mr. Novak (page 33, lines 1-5) and Mr. Smith (page 15, lines 3-9) recommend that the Authority deny the Company's proposed TRS on the basis that the Company did not adequately justify its request. However, the Company provided adequate justification for the TRS.

Q. WHAT JUSTFICATION DID THE COMPANY PROVIDE IN SUPPORT OF ITS TRS?

A. The Company has been experiencing declining reliability over the last several years primarily due to vegetation-related outages. In my direct testimony in this proceeding and in response to discovery, I clearly demonstrated that the Company's distribution reliability, in terms of both System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI), has been degrading since 2010. (Direct, page 10, lines 4-10, and the Company's response to discovery request CPAD 1-148) Also, I provided data that conclusively showed that the number one cause of customer service interruptions in Kingsport's service territory is vegetation-related outages. (Direct pages 10-11, lines 11-23, and 1-3)

Q. PLEASE BRIEFLY STATE THE PURPOSE OF THE TRS.

A. In order to reverse the declining reliability trend that the Company is currently experiencing, Kingsport has proposed its TRS. Specifically, the TRS is comprised of four primary programs; chief among these is the Cycle-based Vegetation Management Program. The Cycle-based Vegetation Management Program is designed to minimize the number one cause of outages on Kingsport's distribution system (vegetation-related outages) and improve overall reliability. (Direct, pages 11-12, lines 15-30, and 1-22)

Q. WHAT IS THE DIFFERENCE BETWEEN THE COMPANY'S CURRENT PERFORMANCE-BASED VEGETATION MANAGEMENT PROGRAM AND

THE CYCLE-BASED VEGETATION MANAGEMENT PROGRAM COMPONENT OF THE TRS?

A. The Company presently uses a performance-based approach to allocate available labor and financial resources to areas where tree-related outage concerns exist. Therefore, under the current program, it is common that a circuit may not be completely cleared end-to-end for some number of years. A strict cycle-based program stands in contrast to this approach providing for trees along lines to be managed on a fixed time frame.

Q. IS THE COMPANY'S CURRENT PERFORMANCE-BASED APPROACH TO VEGETATION MANAGEMENT WORKING?

A. No. In the past, the performance-based approach has allowed the Company to allocate vegetation management resources where they would be able to provide the most benefit. However, the program has not produced the desired results in reliability with tree-caused outages on the rise. Better reliability for the Company's customers is possible with a cycle-based approach to vegetation management.

Q. HAVE THE BENEFITS AND RELIABILITY IMPROVEMENTS OF A CYCLE-BASED VEGETATION MANAGEMENT PROGRAM BEEN EXPERIENCED BY COMPANY AFFILIATES?

A. Yes. Appalachian Power Company (APCo) began the implementation of a system-wide Cycle-Based Vegetation Management Program in its West Virginia service territory in 2014. Also, a Cycle-Based Vegetation Management Program Pilot was implemented in its Virginia service territory in 2013. As of the end of 2015, APCo's West Virginia service territory has shown an average improvement in tree-related SAIDI of approximately 24 percent and an average improvement in tree-related SAIFI of approximately 32 percent. This information was filed with the Public Service Commission of West Virginia (PSC) on March 1, 2016, in Case No. 16-0240-E-P and is summarized below in Figure 1. This filing was a PSC requirement, as the PSC approved a rider cost recovery mechanism that tracks related vegetation management costs that are trued-up on an annual basis.

Figure 1

APCo WV			
Metric	**2012-2014 Average**	**2015**	**% Improvement**
SAIDI	162.2	123.3	24.0%
SAIFI	0.572	0.389	32.0%

Similarly, the Cycle-Based Vegetation Management Program Pilot implemented in APCo's Virginia service territory has shown a tree-related SAIDI improvement of approximately 31 percent, and a tree-related SAIFI improvement of approximately 40 percent. These improvements are summarized in Figure 2 and are detailed in an annual report that was filed with the Virginia State Corporation Commission (SCC) on March 31, 2016, as required by the SCC's final order in Case No. PUE-2012-00069.

Figure 2

APCo VA			
Metric	**2008 – 2012 Average**	**2013-2015 Average**	**% Improvement**
SAIDI	159	110	30.8%
SAIFI	0.615	0.370	39.8%

These levels of improvement, which are consistent with anticipated TRS benefits, support the implementation of the proposed TRS to benefit Kingsport's customers.

As indicated in my direct testimony, Kingsport customers will experience enhanced distribution reliability as soon as vegetation management is implemented in the form of decreasing outages and outage durations. (Direct, page 12, lines 23-30)

Additionally, the Company provided a detailed analysis as part of its response to discovery request CPAD 1-147 showing an anticipated overall reliability improvement of approximately 25 percent once the TRS is fully implemented.

MAJOR STORM EXPENSE

Q. PLEASE RESPOND TO MR. SMITH'S RECOMMENDATION RELATED TO THE COMPANY'S MAJOR STORM EXPENSE.

A. Mr. Smith recommends lowering the amount of the Company's Major Storm Expense from $490,477 to $392,381 using an incorrect methodology. He arrives at this amount by modifying the Company's methodology to include Major Storm Expense for 2015, of which the amount was zero. Using the Company's original methodology of taking the average Major Storm Expense for the years of 2010-2012 and 2014, yields the Major Storm Expense average of $490,477. Using Mr. Smith's methodology and including 2015 Major Storm Expenses of zero lowers this average to his recommended amount of $392,381 (page 11, lines 2-20, and Exhibit RCS-1, Schedule 3). However, Mr. Smith should not have included the Company's 2015 Major Storm Expense in his calculations.

Q. WHY SHOULD MR. SMITH NOT HAVE USED THE COMPANY'S 2015 MAJOR STORM EXPENSE AMOUNT IN MAKING HIS RECOMMENDATION?

A. Simply put, a year with zero Major Events is an anomaly and is rarely ever experienced by the Company. Figure 3 shows the number of Major Events that the Company experienced from 2010-2015, as well as the average number of Major Events experienced for this time period.

Figure 3

Year	Number of Major Events
2010	4
2011	7
2012	2
2013	3
2014	2
2015	0
Average	**3**

As can be seen, even including 2015, the Company experiences an average of three Major Events per year. Therefore, the Company recommends excluding the anomalous years (2013 and 2015, yielding $490,477) and not “cherry picking” data to artificially lower the Company’s Major Event Expense.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Burnett

**REBUTTAL TESTIMONY OF
CHAD M. BURNETT
ON BEHALF OF KINGSPORT POWER COMPANY
D/B/A AEP APPALACHIAN POWER
BEFORE THE TENNESSEE REGULATORY AUTHORITY
DOCKET NO. 16-00001**

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

A. My name is Chad M. Burnett. My business address is 212 East Sixth Street, Tulsa, Oklahoma 74119. I am employed by the American Electric Power Service Corporation (AEPSC) as the Director of Economic Forecasting. AEPSC supplies engineering, financing, accounting, and planning and advisory services to the subsidiaries of the American Electric Power (AEP) System, one of which is Kingsport Power Company (KgPCo or the Company).

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I received a Bachelor of Science degree in Business Administration from the University of Tulsa in 1998 with emphasis in Economics and Finance. In 2002, I received a Master of Business Administration degree from the University of Tulsa. In 2005, I completed the Executive Strategic Leadership program at Ohio State University.

I have worked in the utility industry as an economist since 1997 when I was employed by Central and South West Service Corporation, which later merged with American Electric Power Company (AEP) in June 2000. I became the Manager of Economic Forecasting in June 2007. In October 2013, I was promoted to Director of Economic Forecasting. In my current role, I am responsible for preparing customer, sales, peak demand, and revenue forecasts for each of the AEP operating companies in the eleven jurisdictions and three regional transmission organizations (RTOs) that cover the AEP service territory. In addition I am responsible for the weather normalization calculations, and sales and revenue variance reports for each of the AEP operating companies.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY AS A WITNESS BEFORE ANY REGULATORY COMMISSION?

A. Yes. I presented testimony on behalf of Public Service Company of Oklahoma before the Oklahoma Corporation Commission in Case No. 20080014 and on behalf of Southwestern Electric Power Company before the Public Utility Commission of Texas in Docket Nos. 36966, 37364, 40443, and 44701.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony responds to the direct testimony of Consumer Protection and Advocate Division (CPAD) witness William H. Novak with regards to his proposed weather normalization adjustments to the test year billing determinants.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following exhibits:

- Rebuttal Exhibit No. 1 (CMB): Usage Pattern for Churches, Schools, and Medium & Large Commercial Classes
- Rebuttal Exhibit No. 2 (CMB): Results of Regression Models Showing that Churches, Schools, and Medium & Large Commercial Classes are Weather Sensitive

Q. WERE THE EXHIBITS THAT YOU ARE SPONSORING PREPARED OR ASSEMBLED BY YOU OR UNDER YOUR DIRECTION?

A. Yes.

<u>WEATHER NORMALIZATION ADJUSTMENTS</u>

Q. DO YOU AGREE WITH THE MAJOR CHANGES MR. NOVAK PROPOSES TO THE COMPANY'S BILLING DETERMINANTS?

A. Absolutely not. The methodology utilized by Mr. Novak to come up with his weather adjustments yields unreasonable results and should be not be used in this case. Mr. Novak arbitrary excluded some obvious weather sensitive tariffs (rate codes) from his weather normalization. By excluding these weather-sensitive rate codes from his weather analysis, he has grossly understated the impact weather has on Kingsport's energy sales. Furthermore, Mr. Novak used differently defined weather data in his normalization models that causes his estimated weather impact during the heating season to be grossly understated. Mr. Novak also appears to have mistakenly proposed using billing cycle weather impacts, even though the Company's filed billing determinants were on a calendar month basis. Finally, Mr. Novak's deficient weather normalization models do not exhibit the stability and reliability over time to provide confidence that the weather adjustments from those models are reliable and appropriate for adjusting the billing determinants that will be used for setting rates.

Q. MR. NOVAK'S WEATHER ESTIMATE WAS BASED ON A DIFFERENT YEAR THAN WHAT WAS FILED BY THE COMPANY. WAS THE WEATHER DATA FOR THE KINGSPORT SERVICE TERRITORY SIMILAR BETWEEN 2014 AND 2015?

A. No it was not. Weather patterns change from year to year and the change from 2014 to 2015 for the Bristol, TN weather station, which is used for the Kingsport service territory, is no exception. 2014 happened to be the fourth coldest year (in terms of heating degree days) for the Kingsport service territory over the past 30 years. By contrast, 2015 was the sixth warmest over the past 30 years. Cooling degrees show a similar pattern (2015 was much warmer than 2014). When these degree days variances are translated into sales impacts, weather increased Kingsport's retail sales by 29.4 GWh in 2014 while it actually lowered retail sales by 6 GWh in 2015. Thus, to normalize the test year billing determinants for weather to the Company subtracted 29.4 GWh from the actual sales in 2014. For 2015, the Company would add 6 GWh to weather normalize the 2015 results.

Q. ARE MR. NOVAK'S CALCULATED WEATHER IMPACTS CLOSE TO WHAT YOU WOULD EXPECT FOR 2015?

A. Not at all. Not only is Mr. Novak's estimated weather impact understated, but his flawed weather normalization process is producing results for 2015 that are directionally incorrect. In other words, his calculations would suggest weather was favorable in 2015, meaning Kingsport's actual sales were higher than they would have been under normal weather conditions, when the weather data and the Company's weather normalization calculations clearly show it was unfavorable. More specifically, Mr. Novak calculated that weather increased Kingsport's sales in 2015 by 2,347,559 kWh. The Company's weather estimate for 2015 using sound and reliable weather normalization methods shows that Kingsport's sales in 2015 were actually 5,972,553 kWh lower than they would have been under normal weather conditions.

Q. WHY DO YOU THINK MR. NOVAK'S WEATHER CALCULATIONS ARE SO DIFFERENT FROM WHAT YOU BELIEVE TO BE THE TRUE IMPACT OF WEATHER ON KINGSPORT'S SALES?

A. The first and most obvious reason why Mr. Novak's estimated weather impact would be understated is that he has excluded some weather sensitive rate codes from his analysis. This omission would certainly cause an understatement of the true impact of weather.

Q. WHAT WEATHER SENSTIVE CODES WERE EXCLUDED FROM MR. NOVAK'S WEATHER NORMALIZATION ANALYSIS?

A. According to Mr. Novak's calculations, he does not believe that churches, schools, or medium to larger sized commercial customers respond to changes in temperatures.

Q. DO YOU AGREE THAT CHURCHES, SCHOOLS, AND MEDIUM TO LARGE SIZED COMMERCIAL CUSTOMERS USAGE PATTERNS ARE NOT AFFECTED BY WEATHER?

A. Of course not. It would be nonsensical to exclude churches, schools, and larger commercial customers from a weather normalization process. If one considers the major end-uses for a church, school, hospital, or shopping mall, obviously the HVAC load makes up a significant component of the overall customer load profile.

Q. DO YOU HAVE ANY EVIDENCE OR ANALYSIS YOU COULD SHOW THAT WOULD ILLUSTRATE WHY KINGSPORT INCLUDED CHURCHES, SCHOOLS, AND MEDIUM TO LARGE COMMERCIAL CUSTOMERS IN THEIR FILED WEATHER IMPACTS?

A. Perhaps the easiest way to illustrate this point is to simply plot the monthly sales pattern for each of these classes over the course of a year. If a customer class is weather sensitive, its load should increase in the winter and summer months (when heating and cooling loads are on) with a corresponding drop in usage during the shoulder months where there is typically little to no heating and/or cooling load necessary. If the class is not weather sensitive, you would expect the sales to be relatively constant throughout the year, regardless of whether it is a typical heating or cooling month or not. Rebuttal Exhibit No. 1 (CMB) shows the usage pattern for customers in these classes and there is clearly a correlation between the customer's usage and weather, as would have been reasonably and logically predicted.

Q. DO YOU HAVE ANY STATISTICAL EVIDENCE TO SHOW THAT CHURCHES, SCHOOLS, AND MEDIUM TO LARGE COMMERCIAL CUSTOMERS ARE WEATHER SENSITIVE?

A. Yes I do. I ran regression models for the Churches, Schools, Medium General Service, and Large General Service classes with heating and cooling degree day variables as independent explanatory variables and included the model statistics from this analysis in Rebuttal Exhibit No. 2 (CMB). It shows for each of these classes, the correlation between customer usage and heating and cooling degree days is statistically significant.

Q. WAS THE COMPANY CORRECT TO APPLY A WEATHER ADJUSTMENT TO CHURCHES, SCHOOLS, AND MEDIUM TO LARGE SIZED COMMERCIAL CUSTOMERS?

A. Absolutely. There is clearly a strong link between weather and usage for Commercial customers like churches, schools, and medium to large commercial customers like hospitals, shopping malls, etc.

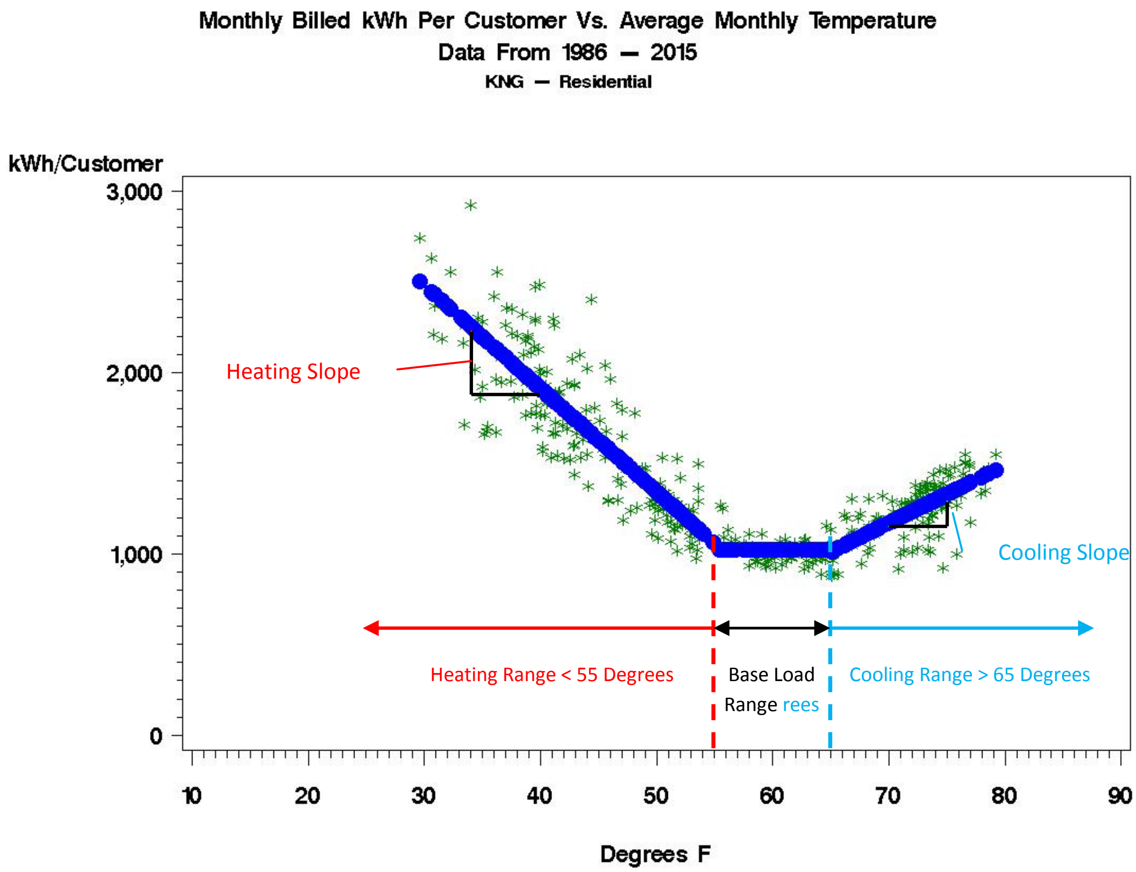
Q. ARE THERE OTHER REASONS WHY YOU THINK MR. NOVAK'S WEATHER NORMALIZATION METHODOLOGY WOULD UNDERSTATE THE TRUE IMPACT OF WEATHER?

A. After examining Mr. Novak's weather normalization workpapers, I noticed that his approach does not properly account for the way in which Kingsport customers respond to temperature changes during the heating season. Mr. Novak defines his heating-degree-day variable using 65 degrees as a basis rather than the 55 degrees day basis used by the Company. This has the effect of understating or dampening the estimated response of customers to cooler temperatures and understating the weather adjustment necessary for heating-degree-day departures from normal.

Q. HOW DO YOU KNOW WHICH TEMPERATURE IS APPROPRIATE TO USE IN DEFINING THE HEATING AND COOLING DEGREE DAYS THAT GO INTO A WEATHER NORMALIZATION CALCULATION?

A. The easiest way is to simply look at the data. According to the Company's analysis of customers' response to weather, customers typically do not begin to respond to colder temperatures through use of electrical heating appliances until the average daily temperature drops below 55 degrees. Conversely, they do not begin cooling until average daily temperatures have risen beyond 65 degrees. The gap that exists when the average daily temperature is between 55 degrees and 65 degrees is often referred to as "baseline load" where customers are neither utilizing cooling nor heating end-use appliances. This relationship can be seen clearly in Figure 1 below.

Figure 1



Q. ARE THERE OTHER OBSERVATIONS THAT CAN BE MADE FROM LOOKING AT THE TEMPERATURE RESPONSE CHART FOR KINGSPORT LOAD?

A. Yes. The other item that is fairly evident from looking at the weather response chart on Kingsport's load is that the slope of the line when heating loads would be used (i.e. when average temperature is less than 55 degrees) is steeper than the part of the line when cooling loads would be present (when temperatures are greater than 65 degrees). Thus you would expect the heating degree day coefficient to be larger than the cooling degree day coefficient for Kingsport. Unfortunately, Mr. Novak's degree day coefficients are backwards, meaning his estimated cooling degree day coefficient is larger than his heating degree day coefficient. This is yet another example of how Mr. Novak's deficient approach to weather normalization has understated the heating degree day impact for the test year.

Q. CAN YOU EXPLAIN WHAT A WEATHER COEFFICIENT IS SUPPOSED TO REPRESENT IN SIMPLE, NON-TECHNICAL TERMS?

A. In simple terms, the weather coefficient is supposed to quantify how much the customer's usage will change for each temperature change. So for example, if yesterday's average daily temperature was 80 degrees and today's average temperature is 81 degrees, one would expect that a customer's air conditioner would run longer and use more electricity than it did yesterday to maintain the same level of comfort indoors, assuming all other electrical end-use loads were unchanged. The weather coefficient quantifies how much each degree change in the average daily temperature will be worth in terms of the customer's electricity usage. For an individual customer, one would expect this coefficient to remain relatively constant over time until the customer replaced their HVAC system. When thousands of customers are aggregated together to develop weather coefficients for the Residential class, for example, there may be slight fluctuations from year to year as certain percentage of older HVAC systems are replaced each year, but overall they should still remain relatively stable.

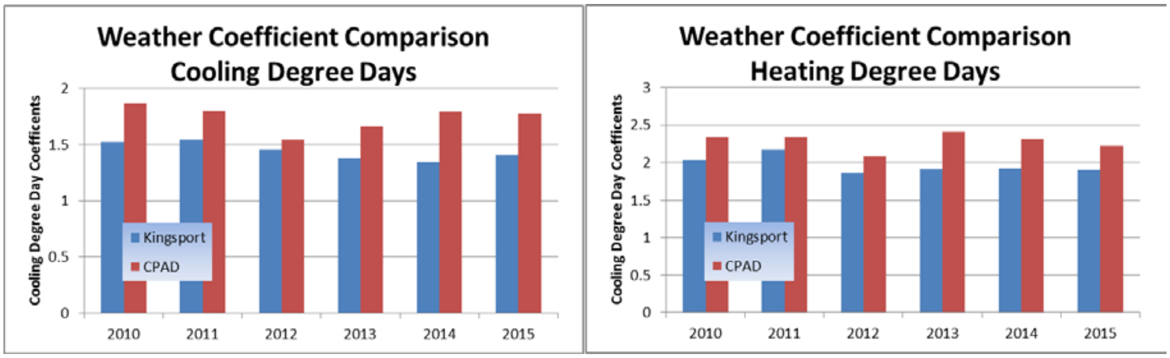
Q. IF MR. NOVAK HAD PROPERLY DEFINED HIS HEATING DEGREE DAYS USING A 55 DEGREE BASIS INSTEAD OF A 65 DEGREE BASIS, WOULD IT HAVE MATERIALLY IMPROVED HIS WEATHER ESTIMATE?

A. Yes, it would have. If the heating degree days from Mr. Novak's normalization calculations that were computed using the 65 degree temperature basis are replaced with heating degree days computed using 55 degrees as the basis, the heating degree day coefficient switches back to being larger than the cooling degree day coefficient which better aligns with the observed weather response with Kingsport's load data.

Q. ARE THE WEATHER COEFFICIENTS USED BY THE COMPANY MORE STABLE THAN THOSE INCLUDED IN MR. NOVAK'S WEATHER NORMALIZATION ANALYSIS?

A. Yes, they are. In Mr. Novak's workpapers, he ran his weather normalization process for each year going back to 2010. The Company also updates its forecast models which are used in the weather normalization process each year. After comparing the two sets of weather coefficients, I discovered that CPAD's weather coefficients are much more volatile from year to year than what the Company used as illustrated in Figure 2 below. The erratic changes from year to year in CPAD's weather coefficients do not make logical sense and are most likely indicates that the weather normalization models used by CPAD are not properly specified. As a result, they should not be used to adjust test year billing determinants in this case.

Figure 2



Q. YOU ALSO MENTIONED THAT MR. NOVAK COMPUTED BILLING CYCLE WEATHER IMPACTS INSTEAD OF CALENDAR MONTH WEATHER IMPACTS. WHY IS THIS A PROBLEM WITH CPAD'S WEATHER ADJUSTMENT?

A. The billing determinants filed by the Company were calendar month billing determinants, not billing cycle month. The Company filed calendar month billing determinants to ensure consistency between the revenues and expenses, which are also reported on a calendar month basis. However Mr. Novak included in his testimony the billing cycle weather impacts instead of his computed calendar month impacts[1]. In reviewing his workpapers, I noticed that Mr. Novak computed both billing cycle and calendar month weather impacts. However, his calendar month weather coefficients were even less stable than his billing cycle coefficients. According to Mr. Novak's workpapers, if CPAD used calendar month weather for 2015 instead of billing cycle weather, the impact of weather would switch from favorable 2,347,559 kWh (CPAD's billing cycle weather

[1] Attachment WHN-3, Schedules 1-5 from direct testimony of William H. Novak contain 'Cycle Weather Normalization'.

impact) to unfavorable 10,788,879 kWh (CPAD's calendar month weather impact). This could explain why he did not use his calendar month weather estimates[2].

Q. IN MR. NOVAK'S TESTIMONY, HE REJECTS THE COMPANY'S WEATHER NORMALIZATION CALCULATION BECAUSE THE MODELS "DID NOT PROVIDE A CORRELATION FACTOR (R^2) TO EXPLAIN HOW MUCH OF THE DEVIATION IN CUSTOMER USAGE IS EXPLAINED BY WEATHER CHANGES." IS MR. NOVAK'S CRITIQUE ACCURATE AND IF SO, WOULD THIS BE A SUFFICIENT REASON TO REJECT THE COMPANY'S WEATHER ADJUSTMENT?

A. Absolutely not. I believe in this instance, Mr. Novak has confused the concept of a correlation coefficient and the R^2 statistic with the parameter estimate (or weather coefficient). While the correlation coefficient is informative in that it tells you whether the regression variables are positively or negatively related (i.e. does temperature cause an increase or decrease in customer usage), it does not tell you how much customer usage will change with a temperature deviation. If it is already known that there is positive relationship between customer usage and heating and cooling degree days (which logic and the temperature response chart in Figure 1 shows there is), then the correlation coefficient is not needed for the actual weather normalization calculations. The weather coefficient is the statistic that actually quantifies how much a change in temperature impacts customer usage, which is what is ultimately used in a weather normalization calculation.

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[2] In workpapers WHN Residential Revenue Calculation.xlsx, WHN SGS Revenue Calculation.xlsx, and WHN EHG Revenue Calculation.xlsx, Mr. Novak computes both calendar month weather impacts and billing cycle impacts.

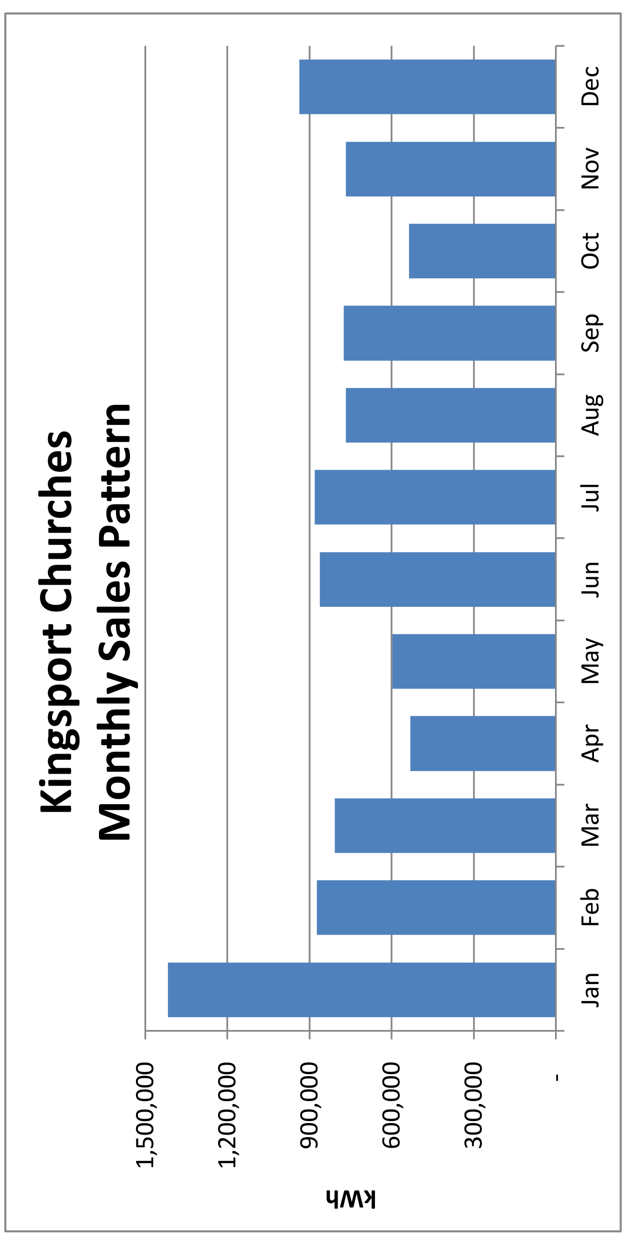
Finally, while it is true that no R^2 statistic is published in the standard model output from the Company's weather normalization models, it can easily be computed from the results of the model. When computed, the resulting R^2 statistics for the residential, commercial, and other ultimate class models used by the Company are .967, .959, and .953 respectively indicating large amounts of the sales variation for each class are explained with these models.

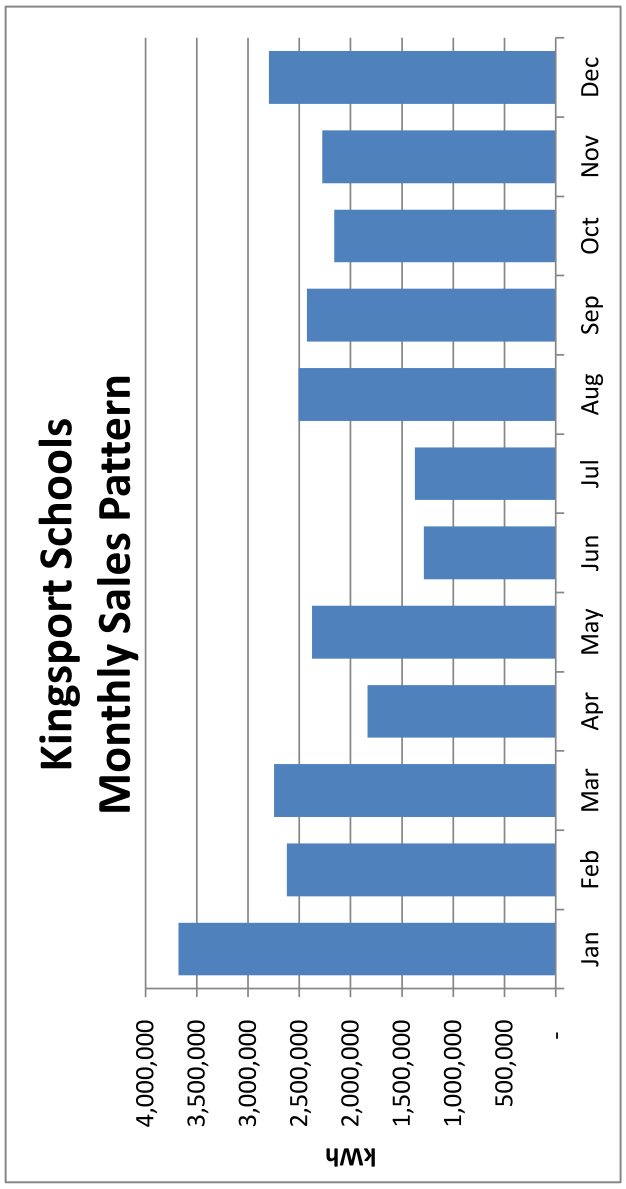
Q. ARE THE STATISTICAL ESTIMATION METHODS UTILIZED BY THE COMPANY IN ITS WEATHER NORMALIZATION COMPUTATIONS RECOGNIZED AS SOUND BY OTHERS WITHIN THE INDUSTRY AND BY OTHER COMMISSIONS?

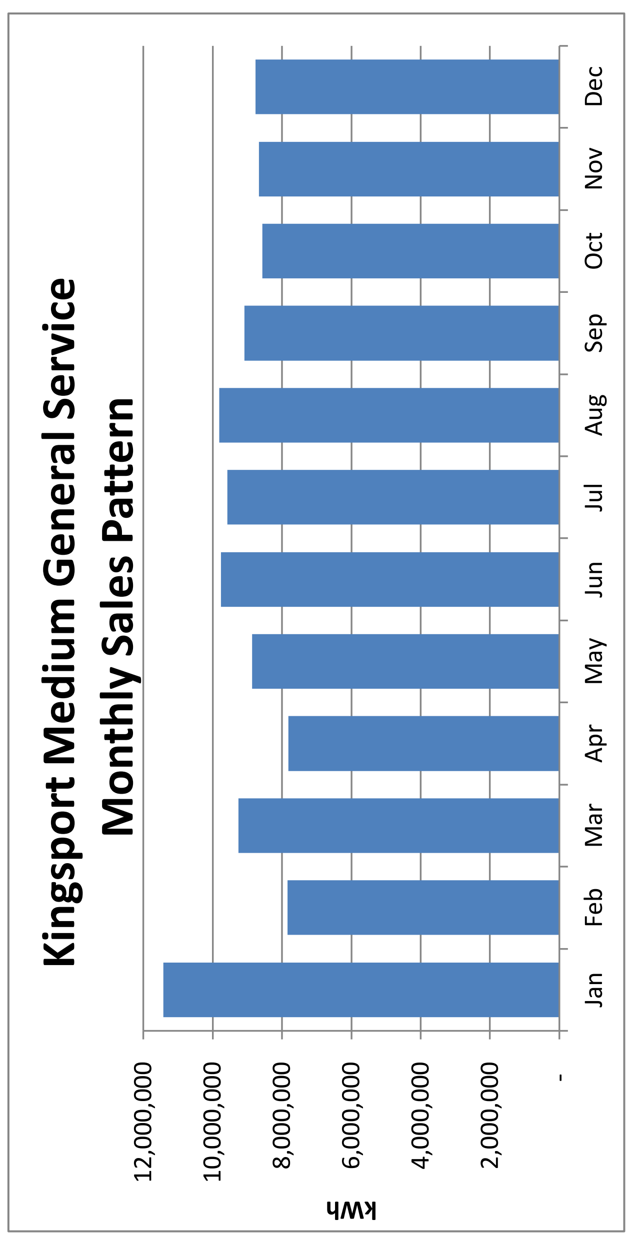
A. Yes. These methods or very similar methods are utilized throughout the electric utility industry in the production of short-term kWh sales forecasting and weather normalization. Furthermore, the Company's methodology has been reviewed by many of the commissions that oversee the various operating companies of AEP in its many jurisdictions.

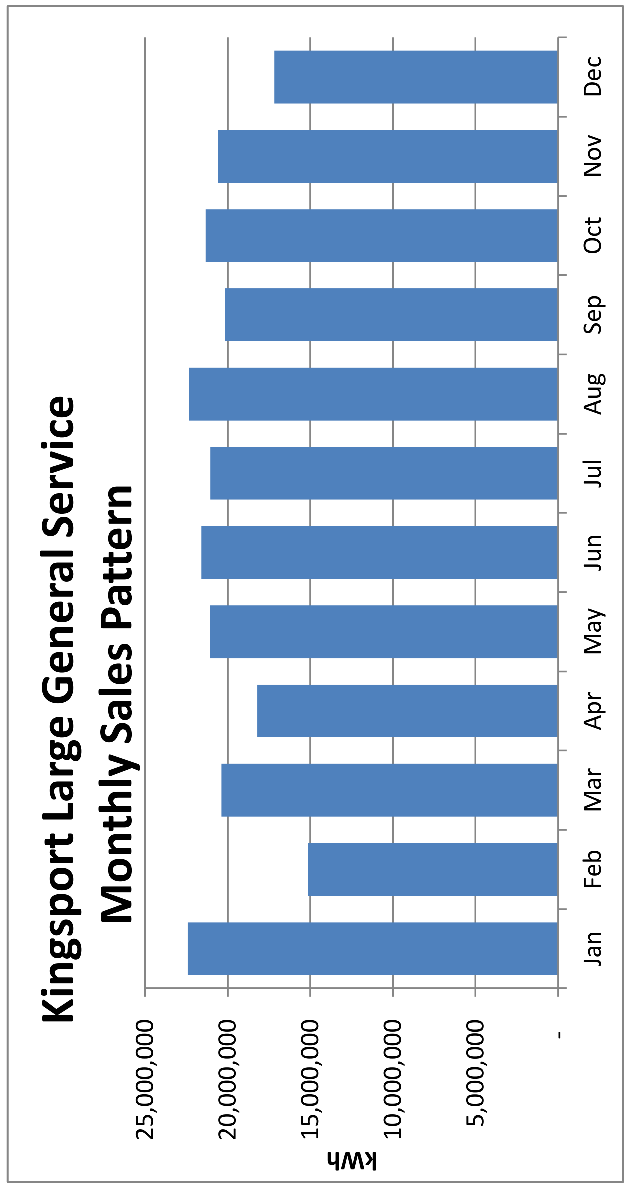
Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.


Kingsport Churches
Monthly Sales Pattern
kWh
1,500,000
1,200,000
900,000
600,000
300,000
-
Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec


Kingsport Schools
Monthly Sales Pattern
kWh
4,000,000
3,500,000
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
-
Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec


Kingsport Medium General Service
Monthly Sales Pattern
kWh
12,000,000
10,000,000
8,000,000
6,000,000
4,000,000
2,000,000
-
Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec


Kingsport Large General Service
Monthly Sales Pattern
kWh
25,000,000
20,000,000
15,000,000
10,000,000
5,000,000
-
Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec

Churches

The ARIMA Procedure

Conditional Least Squares Estimation

Parameter	Estimate	Standard Error	t Value	Approx Pr > |t|	Lag	Variable	Shift
MU	-24.69493	13.16615	-1.88	0.0634	0	USAGE	0
MA1,1	0.63569	0.08343	7.62	<.0001	12	USAGE	0
NUM1	6.86194	0.85080	8.07	<.0001	0	BCDD65	0
NUM2	4.88463	0.40747	11.99	<.0001	0	BHDD55	0
NUM3	97.86094	40.79838	2.40	0.0182	0	MET_DAYS	0

Constant Estimate	-24.6949
Variance Estimate	103392.9
Std Error Estimate	321.5477
AIC	1644.682
SBC	1658.363
Number of Residuals	114

* AIC and SBC do not include log determinant.

Correlations of Parameter Estimates

Variable	Parameter	USAGE MU	USAGE MA1,1	BCDD65 NUM1	BHDD55 NUM2	MET_DAYS NUM3
USAGE	MU	1.000	-0.111	-0.081	0.025	-0.031
USAGE	MA1,1	-0.111	1.000	0.006	-0.099	-0.143
BCDD65	NUM1	-0.081	0.006	1.000	0.020	-0.021
BHDD55	NUM2	0.025	-0.099	0.020	1.000	0.169
MET_DAYS	NUM3	-0.031	-0.143	-0.021	0.169	1.000

Autocorrelation Check of Residuals

To Lag	Chi-Square	DF	Pr > ChiSq	Autocorrelations					
6	4.86	5	0.4333	0.056	-0.143	-0.086	-0.024	0.097	-0.011
12	10.20	11	0.5126	0.136	-0.083	-0.124	-0.015	0.027	-0.036
18	13.99	17	0.6678	-0.018	0.045	0.015	-0.048	0.134	0.072
24	16.33	23	0.8409	0.058	0.061	-0.033	-0.029	0.053	0.067

Model for variable USAGE

Estimated Intercept	-24.6949
Period(s) of Differencing	12

Moving Average Factors

Factor 1: 1 - 0.63569 B**(12)

Churches

The ARIMA Procedure

Input Number 1

Input Variable	BCDD65
Period(s) of Differencing	12
Overall Regression Factor	6.86194

Input Number 2

Input Variable	BHDD55
Period(s) of Differencing	12
Overall Regression Factor	4.884629

Input Number 3

Input Variable	MET_DAYS
Period(s) of Differencing	12
Overall Regression Factor	97.86094

Churches

R_square

0.91708

The ARIMA Procedure

Conditional Least Squares Estimation

Parameter	Estimate	Standard Error	t Value	Approx Pr > |t|	Lag	Variable	Shift
MU	-219.16358	514.76467	-0.43	0.6711	0	USAGE	0
MA1,1	0.45698	0.09061	5.04	<.0001	12	USAGE	0
AR1,1	0.41746	0.08893	4.69	<.0001	1	USAGE	0
NUM1	38.53975	16.19064	2.38	0.0190	0	BCDD65	0
NUM2	58.63248	6.93043	8.46	<.0001	0	BHDD55	0
NUM3	1763.5	561.86237	3.14	0.0022	0	MET_DAYS	0

Constant Estimate	-127.671
Variance Estimate	29587384
Std Error Estimate	5439.429
AIC	2290.48
SBC	2306.897
Number of Residuals	114

* AIC and SBC do not include log determinant.

Correlations of Parameter Estimates

Variable	Parameter	USAGE MU	USAGE MA1,1	USAGE AR1,1	BCDD65 NUM1	BHDD55 NUM2	MET_DAYS NUM3
USAGE	MU	1.000	0.096	0.036	-0.035	0.023	-0.005
USAGE	MA1,1	0.096	1.000	0.105	0.007	0.026	0.075
USAGE	AR1,1	0.036	0.105	1.000	-0.072	0.020	-0.113
BCDD65	NUM1	-0.035	0.007	-0.072	1.000	-0.019	-0.002
BHDD55	NUM2	0.023	0.026	0.020	-0.019	1.000	0.212
MET_DAYS	NUM3	-0.005	0.075	-0.113	-0.002	0.212	1.000

Autocorrelation Check of Residuals

To Lag	Chi-Square	DF	Pr > ChiSq	Autocorrelations					
6	6.68	4	0.1537	-0.089	0.166	0.050	0.122	0.025	0.051
12	15.24	10	0.1236	0.053	0.151	-0.119	0.167	-0.000	0.006
18	19.00	16	0.2687	0.090	-0.076	0.052	-0.017	0.103	0.026
24	22.73	22	0.4169	0.050	-0.037	0.037	-0.048	0.128	-0.043

Model for variable USAGE

Estimated Intercept -219.164

Period(s) of Differencing 12

Autoregressive Factors

Factor 1: 1 - 0.41746 B**(1)

The ARIMA Procedure

Moving Average Factors

Factor 1: 1 - 0.45698 B**(12)

Input Number 1

Input Variable	BCDD65
Period(s) of Differencing	12
Overall Regression Factor	38.53975

Input Number 2

Input Variable	BHDD55
Period(s) of Differencing	12
Overall Regression Factor	58.63248

Input Number 3

Input Variable	MET_DAYS
Period(s) of Differencing	12
Overall Regression Factor	1763.545

R_square

0.89146

The ARIMA Procedure

Conditional Least Squares Estimation

Parameter	Estimate	Standard Error	t Value	Approx Pr > |t|	Lag	Variable	Shift
MU	514.57285	151.40980	3.40	0.0010	0	USAGE	0
MA1,1	-0.22650	0.09620	-2.35	0.0204	1	USAGE	0
MA1,2	-0.34475	0.10147	-3.40	0.0010	6	USAGE	0
AR1,1	0.33096	0.08766	3.78	0.0003	2	USAGE	0
AR1,2	0.36308	0.08711	4.17	<.0001	3	USAGE	0
AR1,3	0.25674	0.10215	2.51	0.0135	5	USAGE	0
AR2,1	-0.35571	0.10462	-3.40	0.0010	12	USAGE	0
NUM1	4.37093	0.54251	8.06	<.0001	0	BCDD65	0
NUM2	2.66702	0.24792	10.76	<.0001	0	BHDD55	0
NUM3	148.80624	24.61440	6.05	<.0001	0	MET_DAYS	0

Constant Estimate	34.33752
Variance Estimate	58002.36
Std Error Estimate	240.8368
AIC	1583.431
SBC	1610.793
Number of Residuals	114

* AIC and SBC do not include log determinant.

Correlations of Parameter Estimates

Variable Parameter		USAGE MU	USAGE MA1,1	USAGE MA1,2	USAGE AR1,1	USAGE AR1,2
USAGE	MU	1.000	-0.086	-0.060	0.054	0.042
USAGE	MA1,1	-0.086	1.000	0.012	-0.287	0.079
USAGE	MA1,2	-0.060	0.012	1.000	0.095	0.190
USAGE	AR1,1	0.054	-0.287	0.095	1.000	-0.190
USAGE	AR1,2	0.042	0.079	0.190	-0.190	1.000
USAGE	AR1,3	0.049	0.143	-0.194	-0.535	-0.531
USAGE	AR2,1	0.018	0.032	-0.283	-0.102	0.143
BCDD65	NUM1	0.041	-0.104	-0.029	0.108	-0.115
BHDD55	NUM2	-0.063	-0.138	0.129	0.136	-0.002
MET_DAYS	NUM3	-0.071	0.102	0.198	0.050	-0.025

Correlations of Parameter Estimates

Variable Parameter		USAGE AR1,3	USAGE AR2,1	BCDD65 NUM1	BHDD55 NUM2	MET_DAYS NUM3
USAGE	MU	0.049	0.018	0.041	-0.063	-0.071
USAGE	MA1,1	0.143	0.032	-0.104	-0.138	0.102
USAGE	MA1,2	-0.194	-0.283	-0.029	0.129	0.198
USAGE	AR1,1	-0.535	-0.102	0.108	0.136	0.050
USAGE	AR1,2	-0.531	0.143	-0.115	-0.002	-0.025
USAGE	AR1,3	1.000	-0.089	-0.008	-0.123	-0.019
USAGE	AR2,1	-0.089	1.000	-0.024	0.004	-0.209
BCDD65	NUM1	-0.008	-0.024	1.000	0.013	0.028
BHDD55	NUM2	-0.123	0.004	0.013	1.000	0.175

The ARIMA Procedure

Correlations of Parameter Estimates

Variable	Parameter	USAGE AR1,3	USAGE AR2,1	BCDD65 NUM1	BHDD55 NUM2	MET_DAYS NUM3
MET_DAYS	NUM3	-0.019	-0.209	0.028	0.175	1.000

Autocorrelation Check of Residuals

To Lag	Chi-Square	DF	Pr > ChiSq	Autocorrelations					
6	.	0	.	-0.017	-0.001	-0.042	0.087	-0.039	-0.023
12	7.70	6	0.2613	-0.013	0.033	-0.198	-0.060	0.052	-0.057
18	11.12	12	0.5183	0.023	-0.054	0.053	0.061	-0.120	-0.031
24	19.32	18	0.3725	0.128	0.005	0.058	0.043	0.084	-0.168

Model for variable USAGE

Estimated Intercept	514.5728
Period(s) of Differencing	12

Autoregressive Factors

Factor 1: 1 - 0.33096 B**(2) - 0.36308 B**(3) - 0.25674 B**(5)
Factor 2: 1 + 0.35571 B**(12)

Moving Average Factors

Factor 1: 1 + 0.2265 B**(1) + 0.34475 B**(6)

Input Number 1

Input Variable	BCDD65
Period(s) of Differencing	12
Overall Regression Factor	4.370929

Input Number 2

Input Variable	BHDD55
Period(s) of Differencing	12
Overall Regression Factor	2.667017

Input Number 3

Input Variable	MET_DAYS
Period(s) of Differencing	12
Overall Regression Factor	148.8062

R_square
0.91810

Large General Service

The ARIMA Procedure

Conditional Least Squares Estimation

Parameter	Estimate	Standard Error	t Value	Approx Pr > abs(t)	Lag	Variable	Shift
MU	2015.2	544.72826	3.70	0.0003	0	USAGE	0
MA1,1	0.83189	0.07218	11.53	<.0001	12	USAGE	0
AR1,1	0.30108	0.08904	3.38	0.0010	1	USAGE	0
AR1,2	0.43972	0.09115	4.82	<.0001	6	USAGE	0
AR2,1	0.30789	0.09648	3.19	0.0019	2	USAGE	0
AR2,2	0.31435	0.09379	3.35	0.0011	3	USAGE	0
NUM1	26.46870	6.15740	4.30	<.0001	0	BCDD65	0
NUM2	14.38273	2.90932	4.94	<.0001	0	BHDD55	0
NUM3	913.12778	244.03377	3.74	0.0003	0	MET_DAYS	0

Constant Estimate	197.3137
Variance Estimate	6482704
Std Error Estimate	2546.115
AIC	2120.193
SBC	2144.819
Number of Residuals	114

* AIC and SBC do not include log determinant.

Correlations of Parameter Estimates

Variable		USAGE	USAGE	USAGE	USAGE	USAGE	USAGE	BCDD65	BHDD55	MET_DAYS
Parameter		MU	MA1,1	AR1,1	AR1,2	AR2,1	AR2,2	NUM1	NUM2	NUM3
USAGE	MU	1.000	0.212	0.012	0.083	0.020	0.024	0.013	-0.092	0.053
USAGE	MA1,1	0.212	1.000	0.090	0.237	-0.073	-0.154	0.124	-0.120	0.009
USAGE	AR1,1	0.012	0.090	1.000	-0.139	-0.344	-0.107	0.040	0.042	-0.013
USAGE	AR1,2	0.083	0.237	-0.139	1.000	-0.105	-0.252	-0.114	-0.009	-0.091
USAGE	AR2,1	0.020	-0.073	-0.344	-0.105	1.000	-0.113	0.123	-0.002	0.047
USAGE	AR2,2	0.024	-0.154	-0.107	-0.252	-0.113	1.000	-0.021	-0.070	0.026
BCDD65	NUM1	0.013	0.124	0.040	-0.114	0.123	-0.021	1.000	-0.079	0.185
BHDD55	NUM2	-0.092	-0.120	0.042	-0.009	-0.002	-0.070	-0.079	1.000	0.211
MET_DAYS	NUM3	0.053	0.009	-0.013	-0.091	0.047	0.026	0.185	0.211	1.000

Autocorrelation Check of Residuals

To Lag	Chi-Square	DF	Pr > ChiSq	--------------------Autocorrelations--------------------					
6	0.51	1	0.4757	0.052	0.022	0.021	0.022	0.007	0.013
12	7.67	7	0.3622	-0.090	-0.057	-0.150	-0.097	0.115	0.008
18	13.49	13	0.4108	0.128	-0.088	-0.013	0.133	0.019	-0.036
24	17.10	19	0.5834	0.096	-0.023	0.008	-0.047	0.109	0.036

Model for variable USAGE

Estimated Intercept	2015.163
Period(s) of Differencing	12

Large General Service

The ARIMA Procedure

Autoregressive Factors

Factor 1: 1 - 0.30108 B**(1) - 0.43972 B**(6)
Factor 2: 1 - 0.30789 B**(2) - 0.31435 B**(3)

Moving Average Factors

Factor 1: 1 - 0.83189 B**(12)

Input Number 1

Input Variable	BCDD65
Period(s) of Differencing	12
Overall Regression Factor	26.4687

Input Number 2

Input Variable	BHDD55
Period(s) of Differencing	12
Overall Regression Factor	14.38273

Input Number 3

Input Variable	MET_DAYS
Period(s) of Differencing	12
Overall Regression Factor	913.1278

Large General Service

R_square

0.91044

The ARIMA Procedure

Conditional Least Squares Estimation

Parameter	Estimate	Standard Error	t Value	Approx Pr > |t|	Lag	Variable	Shift
MU	25087.8	7040.3	3.56	0.0006	0	USAGE	0
MA1,1	0.85228	0.07266	11.73	<.0001	12	USAGE	0
AR1,1	0.30429	0.09776	3.11	0.0024	3	USAGE	0
NUM1	1498.4	501.62779	2.99	0.0035	0	BCDD65	0
NUM2	-260.27049	237.96209	-1.09	0.2765	0	BHDD55	0
NUM3	13264.5	23208.2	0.57	0.5688	0	MET_DAYS	0

Constant Estimate	17453.94
Variance Estimate	3.673E10
Std Error Estimate	191649.9
AIC	3048.283
SBC	3064.594
Number of Residuals	112

* AIC and SBC do not include log determinant.

Correlations of Parameter Estimates

Variable		USAGE	USAGE	USAGE	BCDD65	BHDD55	MET_DAYS
Parameter		MU	MA1,1	AR1,1	NUM1	NUM2	NUM3
USAGE	MU	1.000	0.240	-0.037	-0.059	-0.002	-0.072
USAGE	MA1,1	0.240	1.000	-0.119	0.121	0.080	-0.004
USAGE	AR1,1	-0.037	-0.119	1.000	-0.171	-0.048	-0.170
BCDD65	NUM1	-0.059	0.121	-0.171	1.000	0.044	0.058
BHDD55	NUM2	-0.002	0.080	-0.048	0.044	1.000	0.204
MET_DAYS	NUM3	-0.072	-0.004	-0.170	0.058	0.204	1.000

Autocorrelation Check of Residuals

To Lag	Chi-Square	DF	Pr > ChiSq	--------------------Autocorrelations--------------------					
6	5.22	4	0.2656	0.142	-0.076	0.055	0.071	-0.004	-0.120
12	11.15	10	0.3463	-0.105	0.129	-0.029	-0.028	0.058	-0.161
18	14.84	16	0.5361	-0.069	0.049	-0.034	-0.170	-0.042	0.006
24	22.07	22	0.4559	0.074	-0.167	-0.147	0.044	0.153	-0.018

Model for variable USAGE

Estimated Intercept	25087.8
Period(s) of Differencing	12

Autoregressive Factors

Factor 1: 1 - 0.30429 B**(3)

The ARIMA Procedure

Moving Average Factors

Factor 1: 1 - 0.85228 B**(12)

Input Number 1

Input Variable	BCDD65
Period(s) of Differencing	12
Overall Regression Factor	1498.444

Input Number 2

Input Variable	BHDD55
Period(s) of Differencing	12
Overall Regression Factor	-260.27

Input Number 3

Input Variable	MET_DAYS
Period(s) of Differencing	12
Overall Regression Factor	13264.49

R_square

0.68978

Strawser

**REBUTTAL TESTIMONY OF
CHERYL L. STRAWSER
ON BEHALF OF KINGSPORT POWER COMPANY
D/B/A AEP APPALACHIAN POWER
BEFORE THE TENNESSEE REGULATORY AUTHORITY
DOCKET NO. 16-00001**

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

A. My name is Cheryl L. Strawser. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by the American Electric Power Service Corporation (AEPSC) as Compensation & Executive Benefits Consultant. AEPSC supplies engineering, financing, accounting, and planning and advisory services to the subsidiaries of the American Electric Power (AEP) System, one of which is Kingsport Power Company (KgPCo or the Company).

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I received a Bachelor of Science in Business Administration Degree from Ohio Dominican University in 2006. I also received a Master's of Public Administration Degree from Central Michigan University in 2011.

I joined AEP in 1983 and held various administrative support positions within the Company prior to being promoted to Fuel, Emissions and Logistic Coordinator in 2005. In 2007, I was promoted to a Regulatory Analyst within the same department developing and supporting regulatory fuel filings and was then offered a position in Regulatory Services in 2010. In May 2013, I transferred to Human Resources into my current position of Compensation and Executive Benefits Consultant. In this position, I am responsible for assisting with the development and maintenance of effective and cost efficient employee compensation programs for AEP, its subsidiaries and customers.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony responds to the direct testimony of Consumer Protection and Advocate Division (CPAD) witness Ralph C. Smith regarding his recommendation to reduce the going level amount of Kingsport and AEPSC employee compensation and benefit expenses to be reflected in the Company's rate year revenue requirement, in disregard of the cost of service included in the Company's filing. I show that these employee compensation and benefits expenses are a reasonable and customary cost of providing service to KgPCo's customers, and should be included in the revenue requirement without reduction.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following exhibit:

- Rebuttal Exhibit No. 1 (CLS): Kingsport and AEPSC Employee Comp. vs. Market for Exempt Positions

Q. WERE THE EXHIBITS THAT YOU ARE SPONSORING PREPARED OR ASSEMBLED BY YOU OR UNDER YOUR DIRECTION?

A. Yes.

Q. WHAT TYPES OF COMPENSATION DOES THE COMPANY GENERALLY PROVIDE TO EMPLOYEES?

A. The Company compensates all employees with both base pay and an annual incentive compensation opportunity. I use the term "annual incentive compensation" in this testimony rather than the term "variable incentive compensation" used by witness Smith, unless quoting witness Smith, to distinguish annual incentive compensation from long-term incentive compensation, since they are both variable compensation.

In addition to base pay and annual incentive compensation, approximately 1,000 positions in the AEP system are provided with a long-term incentive compensation opportunity. In this testimony "Total Compensation" is used to refer to the definition of compensation that includes all applicable forms of incentive compensation for the positions in question, including annual incentive compensation and long-term incentive compensation, as appropriate.

In this testimony "Total Rewards" is used to refer to Total Compensation and Benefits.

EMPLOYEE TOTAL COMPENSATION COSTS INCLUDED IN THE TEST YEAR COST OF SERVICE

Q. WHAT ADJUSTMENTS HAS CPAD WITNESS SMITH PROPOSED WITH RESPECT TO THE COMPANY'S REQUESTED LEVEL OF EMPLOYEE TOTAL REWARDS EXPENSE?

A. CPAD witness Smith proposes to disregard test year expenses reflecting Kingsport's and AEPSC's employee total rewards, and instead project a going level of employee total rewards costs that do not reflect actual total rewards expense at any point in time. For his recommendation, which amounts to approximately a $1 million disallowance, or about 1/12th of the revenue requirement in the Company's filing, Mr. Smith would exclude from his Cost of Service calculation for 2015 a dollar amount arbitrarily corresponding to a large portion of the actual employee total rewards expense incurred by the Company in

2015, plus a dollar amount corresponding to a small portion of total employee compensation expense allocated to KgPCo in 2014. This arbitrary reduction corresponds to the following components of total employee total rewards expense:

a) $242,119 attributed to 100 percent of the annual incentive component of Kingsport's employee compensation expenses in 2015 (Smith page 27, lines 3-5);

b) $460,503 attributed to 100 percent of the annual incentive component of employee compensation expenses in 2015 allocated to KgPCo by AEPSC (Smith page 27, lines 3-6);

c) $4,163 attributed to 100 percent of the long-term incentive component of Kingsport's employee compensation expenses in 2014 (N.B., not 2015) (Smith page 28, lines 3-9);

d) $228,509 attributed to 100 percent of the long-term incentive component of AEPSC's employee compensation expenses in 2015 (Smith page 27, line 25- page 28, line 9);

e) $9,416 attributed to approximately 50% of the retirement benefits component of employee compensation expenses for highly skilled personnel (executives and managers) under Kingsport's Supplemental Executive Retirement Plan (SERP) (Smith page 30, lines 12-16).

The arbitrariness of Mr. Smith's recommendation is highlighted by the fact that he recommends reducing the Company's revenue requirement by the amount paid for long-term incentive compensation directly charged to Kingsport in 2014 because there was no directly charged long-term incentive compensation expense in 2015. While this adjustment is a small dollar value, it shows that Mr. Smith is willing to make recommendations that suit his cause without regard to actual costs or rationale. It is ironic that in a year in which there was no direct long-term incentive expense for Kingsport employees (in other words, the year a greater portion of the market competitive total compensation was paid in the form of base pay), Mr. Smith looks elsewhere than in 2015 to find a basis for a recommended reduction. This clearly illustrates that his testimony does not appropriately consider employee total rewards expense, and instead makes arbitrary distinctions divorced from the real world.

<u>ANNUAL INCENTIVE COMPENSATION</u>

Q. WHAT ADJUSTMENTS HAVE BEEN PROPOSED WITH RESPECT TO THE COMPANY'S REQUESTED LEVEL OF INCENTIVE COMPENSATION EXPENSE?

A. CPAD witness Smith proposes denying rate recovery of the employee total compensation that the Company and AEPSC pay their employees, by excluding the annual incentive portion of Kingsport's employee compensation expenses, as well as the annual incentive portion of the employee compensation expenses allocated to KgPCo by AEPSC (Smith page 27, lines 3-7).

Q. DO YOU AGREE WITH THIS RECOMMENDATION?

A. No. There is no valid reason to exclude the employee total rewards expenses attacked by Mr. Smith. These are reasonable and customary costs of providing service to KgPCo's customers, and should be included in the revenue requirement without reduction. Mr. Smith's recommendation should be rejected because it is premised on the fundamental misconception that the base pay and annual incentive portions of an employee's total compensation are fundamentally different and, therefore, the annual incentive expense should be entirely borne by shareholders and not ratepayers. CPAD witness Smith provides no rationale or evidence to suggest that annual incentive compensation is in anyway detrimental to customers or that this necessary expense might somehow be recouped by shareholders.

At the core, both components together (along with the other employee total rewards that may be applicable) constitute an employee's total compensation package. Arbitrarily truncating a large portion of this package would simply not recognize the necessary employee compensation expense that the Company incurs, which is required to efficiently and effectively provide service to its customers. It would send the wrong signal to the Company and its employees to encourage a 100 percent fixed compensation package, and this would be to the detriment of customers and the Company alike in the long run.

Q. IS THE ANNUAL INCENTIVE COMPENSATION COMPONENT OF AN EMPLOYEE'S COMPENSATION SOMETHING OVER AND ABOVE, OR IN ADDITION TO, THE EMPLOYEE'S REASONABLE AND MARKET COMPETITIVE COMPENSATION?

A. No, not at all. Kingsport and AEPSC compensate all their employees with a pay package that is composed of a fixed base pay component and annual incentive compensation. These components, in total, comprise the employees' total compensation. Kingsport and AEPSC regularly compare total compensation to market survey information, and make adjustments as needed to maintain reasonable and market competitive total compensation levels, which are needed to maintain an efficient and effective workforce at a reasonable cost. As such, the annual incentive compensation opportunities that Kingsport and AEPSC provide to employees do not constitute a "bonus" above or in addition to already market competitive compensation, which sets it apart from many other incentive compensation programs. Rather it is an integral component of a reasonable and market competitive compensation package.

The annual incentive component of an employee's compensation package is an important tool for bolstering employee efficiency and effectiveness, and eliminating it by, for example, providing a market competitive compensation package through base pay alone, would gradually impair Kingsport's and AEPSC's ability to efficiency and effectively use its resources and minimize its costs.

Q. IS THE TOTAL COMPENSATION OPPORTUNITY EARNED BY EMPLOYEES MARKET COMPETITIVE?

A. Yes. The total compensation paid to these employees is compared to the marketplace on a regular basis, to determine that it is reasonable and competitive to maintain an efficient and effective workforce at a reasonable cost. Rebuttal Exhibit No. 1 (CLS): (Kingsport and AEPSC Employee Comp. vs. Market for Exempt Positions) shows that the total compensation opportunity that Kingsport's and AEPSC's provides to employees is market-competitive and not excessive. Comparing a sample of 21 exempt positions representative of the Company's distribution function, and using +/- 15 percent of the market midpoint as the market-competitive range, which is typical for the exempt positions, this exhibit indicates that, on average, target total compensation for these positions was 0.4 percent above the market median. This is as close to the middle of the market competitive range as is likely to be achieved. Notably, no positions are paid above the market competitive range.

The error in Mr. Smith's recommendation is clearly illustrated by the fact that if annual incentive compensation were to be excluded, then target total compensation for these positions would fall to ***9.7 percent below the market median*** on average. In fact, if one were to truncate employee compensation, as Mr. Smith recommends, then 4 of 21 individual positions (19.0 percent or essentially one of every five exempt positions) would fall ***below*** the market competitive range. Such compensation levels would not be market competitive, and would result in a significant impairment of Kingsport's and AEPSC's ability to attract and retain the suitably skilled and qualified employees needed to efficiently, effectively and safely provide electric service to customers. The annual incentive compensation opportunity component of the pay package for these positions is necessary to maintaining the competitiveness of their total compensation. This total compensation is a reasonable cost of doing business. This cost cannot be eliminated without a corresponding increase in base pay and such a change would still impair the Company's ability to efficiently and effectively provide electric service to customers over time by eliminating the many benefits that incentive compensation provides to the Company and its customers. These benefits include bolstering the development of a high performance corporate culture that enables the Company to provide electric service to customers more efficiently and effectively.

Q. HAVE ANY PARTIES TO THIS PROCEEDING RAISED CONCERNS THAT THE TOTAL COMPENSATION OF KGPCO'S OR AEPSC'S EMPLOYEES IS

EXCESSIVE, NOT JUST OR REASONABLE, OR OUT OF SYNC WITH THE MARKET?

A. No. No party has made that argument, and no witness could do so with any credibility. The average total compensation level for these employees is approximately at the market median. In other words, the employee compensation levels reflected in the Company's filing are in line with the market.

Q. HOW WOULD CUSTOMERS AND EMPLOYEES BE AFFECTED IF KINGSPORT WERE TO COMPENSATE EMPLOYEES AT THE LEVEL RECOMMENDED BY MR. SMITH, USING FIXED BASE PAY ONLY?

A. That is not a realistic option, since Mr. Smith's recommendations, if adopted, would result in a total employee compensation level that would fall well below market competitive ranges. This would harm employees and customers by causing: 1) high-turnover, 2) additional training time and expenses, and 3) difficulty in attracting and retaining the suitably skilled and experience employees need to provide service to customers efficiently and effectively. Additionally, using only a fixed compensation package would gradually: 1) reduce work efficiency due to elimination of pay for performance incentive, 2) increase safety concerns by eliminating safety performance as a factor to determine compensation levels, and 3) generally reduce the quality of customer service and efficiency. All of this would ultimately increase costs to customers.

Q. WOULD ADOPTING MR. SMITH'S RECOMMENDATIONS BE OUT-OF-LINE WITH WHAT IS CUSTOMARILY INCLUDED IN THE APPROVED COST OF SERVICE IN OTHER JURISDICTIONS?

A. Yes, particularly in recent APCo cases. In Appalachian Power Company Case No. PUE-2014-00026, the Virginia State Corporate Commission allowed recovery of the target amount of annual and long-term incentive compensation in the utility's cost of service (Final Order pp. 5-6). Similarly, the Public Service Commission of West Virginia approved the annual incentive plan costs proposed by two electric utilities (affiliates of Kingsport) for both the utilities' employees and employees of AEPSC in Case No. 14-1152-E-42T. (Final Order p. 143)

LONG-TERM INCENTIVE COMPENSATION

Q. MR. SMITH ALSO RECOMMENDS AN ADJUSTMENT TO THE COMPANY'S STOCK-BASED COMPENSATION EXPENSE (SMITH PAGE 29, LINES 1-4). HOW DO YOU RESPOND?

A. I disagree with Mr. Smith's recommendation to exclude expenses for stock-based (long-term incentive) compensation allocated to KgPCo from AEPSC. The long-term incentive portion of employee compensation is, again, simply a component of a market competitive total compensation program. Without long-term incentive compensation, or some other form of compensation with the same value to employees, AEPSC would not be able to attract and retain the suitably skilled and experienced leaders it needs to efficiently and effectively provide electric service to customers.

Long-term incentive compensation also better ensures that AEP leaders make sound long-term decisions, encourages a long-term view of customer benefit and the health of the company and its work environment, and better ensures management continuity by encouraging management retention, all of which provide long-term benefits for Company stakeholders, including current and future customers. The long-term incentive program also serves as a way of compensating employees in AEP's currency for extraordinary performance that often has significant benefits to customers, for example, by developing new equipment and procedures in-house. It would be short-sighted to ignore these long-term benefits, and penalize the Company for providing its leaders with a portion of their market competitive total compensation package in a form that encourages their pursuit of long-term objectives.

As with annual incentive compensation generally, the Company cannot successfully compete for appropriately skilled and experienced personnel without providing a market competitive total compensation opportunity to its employees. For many AEPSC employees, this includes both long-term and annual incentive compensation. Providing market competitive total compensation to employees at all levels of the organization is a necessary and basic cost of providing utility service to our customers. This is particularly true at the leadership levels that generally participate in AEPSC long-term incentive program where sound long-term decision making and management continuity is critical. Simply put, no organization can provide electric service reliably and cost effectively without highly skilled people to lead it.

Q. PLEASE EXPLAIN WHY THE REASONS MR. SMITH CITES FOR REMOVING LONG-TERM INCENTIVE EXPENSE ARE NOT VALID.

A. CPAD witness Smith provides only his opinion without any supporting rationale or evidence that customers should not pay for long-term incentive compensation "based on the performance of the Company's (or its parent company's) stock price." Secondly, the value of AEPSC's long-term incentive compensation is not largely based on the performance of the Company's stock. The performance of AEP's stock only affects the investment return during the vesting period, not the value of the principal amount of long-term compensation granted to employees. Additionally, Mr. Smith misconstrues the primary purpose of AEPSC's long-term incentive compensation. The primary purpose of long-term incentive compensation is to provide the compensation needed to attract and retain the suitably skilled and experienced employees needed to efficiently and effectively provide AEPSC's services to KgPCo's and its customers as part of a market competitive compensation package. Mr. Smith misconstrues this purpose as to benefit "the parent company's stockholders and aligning the interests of participants with those of such stockholders."

Furthermore, witness Smith indicates that changes in the accounting practices for stock options do "not provide a reason for shifting the cost responsibility for stock-based compensation from shareholders to utility ratepayers." This, however, is irrelevant because AEP did not grant stock options at any time prior to the last KgPCo rate case so no long-term incentive expense has been shifted as Mr. Smith describes.

<u>FAIRNESS OF EMPLOYEE INCENTIVE COMPENSATION</u>

Q. PLEASE DESCRIBE WHY IT WOULD BE UNREASONABLE FOR SHAREHOLDERS TO PAY FOR THE ENTIRE COST OF ANNUAL AND LONG-TERM INCENTIVE COMPENSATION.

A. The annual incentive compensation and long-term incentive programs have been in place for many years, so their accumulated ongoing benefits are already reflected in the Company's expense for the test year. It would not be appropriate for shareholders to pay the entire cost of maintaining these programs from which customers will capture the financial benefits through a cost of service that is lower than it otherwise would have been and will be without these programs. Mr. Smith has not suggested any mechanism by which shareholders might recoup the expense of these programs because no such mechanism exists. These programs ultimately benefit customers by being a part of a market competitive compensation program that attracts and retains suitably skilled and experienced employees.

SUPPLEMENTAL EMPLOYEE RETIREMENT PLANS (SERP)

Q. PLEASE EXPLAIN SERP BENEFITS.

A. Supplemental Employee Retirement Plans or "SERPs" are a tool that enables companies to offer the same retirement benefits formulas to all employees, including those for whom current Internal Revenue Service rules limit contribution amounts to a certain cap.

AEP primarily utilizes SERPs to provide the same retirement benefits to employees as are provided under AEP's qualified retirement plans if such benefits cannot be provided under these qualified plans. AEP's SERPs use the same benefit formulas as are used under AEP's qualified retirement plan, except that SERP benefits are reduced by the amount of qualified benefits. Therefore, the total benefit provided under AEP's SERPs is equal to the benefit that would be produced by the formulas utilized under the qualified retirement plan.

In my experience, most companies that provide defined benefit pension plans to employees also provide SERPs. SERPs also are a prevalent component of total rewards (compensation + employee benefits) among large U.S. utility and industrial companies.

SERP benefits are part of the market competitive total rewards package the Company provides to talented employees, not an additional benefit above and beyond what is needed to provide market competitive total rewards. As such, customers benefit from the provision of SERP benefits as part of a market competitive total rewards package in the same way as they benefit from the provision of base pay as part of the same market competitive package.

Q. PLEASE EXPLAIN THE RATIONALE WITNESSES SMITH CITES FOR DISALLOWING NON-QUALIFIED POST-RETIREMENT BENEFIT COSTS.

A. Smith states that "Participation in a SERP is typically limited to very high income executives and management who have annual compensation in excess of compensation limits set by the Internal Revenue Service for normal retirement benefits, such as pensions." (Smith page 29, lines 14-17). He also states that "typically, SERPs provide for retirement benefits in excess of the limits placed by IRS regulations on pension plan calculations for salaries in excess of specified amounts," and argues that SERPs should be removed from the Cost of Service. (Smith page 30, lines 12-16)

Q. DO YOU AGREE AND, IF NOT, PLEASE EXPLAIN WHY?

A. No. First, Mr. Smith is incorrect to the extent he implies SERPs are anything different from a normal retirement benefit plan. Whether qualified or unqualified, retirement plans like AEP's SERP are common among utilities and in other industries for large companies who offer pension plans. Second, the limits provided under IRS rules (which, incidentally, change from time to time, and sometimes significantly) do not typically affect only "very high income executives and management," but rather any employee whose position is compensated at a particular level, such as highly skilled specialist positions that are neither executive nor management positions.

Third, and most importantly, the Company needs employees with the experience, knowledge, capabilities and skills necessary to efficiently and effectively provide our electric service to customers. Therefore, it is reasonable, prudent and in customers' interests for the Company to attract and retain such employees, and the cost associated with attracting and retaining such employees is necessary and prudent if the Company is to provide its utility service to customers as efficiently and effectively as possible. Whether it be providing a compensation package that includes SERP benefits, or providing a compensation package that provides equivalent value to employees, the Company must offer market-competitive compensation to its employees.

Eliminating SERP benefits would have significant negative consequences on the Company's ability to attract and retain these highly talented employees – particularly those with more experience and who are more likely to be particularly interested in retirement benefits. The attributes such employees bring to the Company make them highly sought after and enable many of them to command compensation that exceeds IRS qualified plan compensation limits. Not being able to retain such employees would have negative impacts on the cost and quality of the service the Company is able to provide to customers. The Company's SERP is a very cost-effective method to provide value to employees, and an important component of the Company's total employee compensation package.

Q. ARE IRS QUALIFIED PLAN COMPENSATION LIMITS AN APPROPRIATE LIMIT ON THE AMOUNT OF RETIREMENT BENEFIT EXPENSE THAT SHOULD BE INCLUDED IN A PUBLIC UTILITIES COST OF SERVICE?

A. No. IRS qualified plan compensation limits are established based on many factors, including the need for government tax revenue. It is arbitrary to use these limits for other purposes, such as determining the maximum pension expense that is necessary and prudent for the provision of electric services. Consider, for example, whether it would be reasonable for the Commission to use this approach if these limits were substantially increased or decreased as has happened in the past. In fact, using any fixed limit for such a determination is biased against larger utility companies even if economies of scale enable such companies to be more efficient and, thereby, provide lower cost and higher quality electric service to customers. This is so because more capable managers are needed to effectively manage larger companies, and these managers command higher compensation that is more likely to exceed a fixed limit.

Instead, the appropriate standard for including or excluding compensation and supplemental benefit expenses should be based on whether such costs are part of a market-competitive total rewards package, and whether such costs are otherwise prudently incurred and provide benefits to customers. As the Company has fully supported that this is the case, the SERP expense should be included in the Company's cost of service.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Rebuttal Exhibit No. 1 (CLS): Kingsport Employee Comp. vs. Market for Exempt Positions

Kingsport Employee Comp. vs. Market for Exempt Positions	# Employees	AEP Data			Survey Results (2)			% Difference AEP Employees Total Cash Comp (TCC) vs.	% Difference AEP Employees Base vs. Survey
Survey Job*		Avg Base (3)	Incentive (3)	Employee Comp	Base	Incentive	Total Comp	Survey Total Cash Comp	Total Cash Comp (TCC)
Kingsport Positions (4)									
Position 1	1	$114,100	$17,115	$131,215	$121,000	$20,200	$141,200	-7.61%	-23.75%
Position 2	1	$77,850	$7,785	$85,635	$86,500	$15,900	$102,400	-19.58%	-31.54%
Position 3	1	$102,501	$10,250	$112,751	$97,800	$13,700	$111,500	1.11%	-8.78%
Position 4	1	$101,349	$10,135	$111,484	$96,400	$7,700	$104,100	6.62%	-2.71%
Position 5	1	$79,249	$7,132	$86,381	$78,700	$6,800	$85,500	1.02%	-7.89%
Position 6	1	$104,204	$15,631	$119,835	$107,400	$15,400	$122,800	-2.47%	-17.85%
Position 7	1	$63,037	$5,043	$68,080	$66,000	$3,900	$69,900	-2.67%	-10.89%
AEPSC Human Resources (5)									
Position 8	2	$103,144	$15,472	$118,616	$107,500	$9,000	$116,500	1.78%	-12.95%
HR Consultant	22	$90,773	$9,077	$99,851	$84,600	$4,000	$88,600	11.27%	2.39%
Position 9	3	$81,938	$8,194	$90,132	$86,600	$4,500	$91,100	-1.07%	-11.18%
AEPSC Business Logistics (5)									
Position 10	3	$72,640	$6,538	$79,178	$78,900	$2,300	$81,200	-2.55%	-11.78%
AEPSC Information Technology (5)									
Position 11	1	$86,540	$8,654	$95,194	$100,800	$4,600	$105,400	-10.72%	-21.79%
Position 12	2	$72,876	$6,559	$79,435	$74,900	$1,400	$76,300	3.95%	-4.70%
IT Software Developer Lead	42	$106,431	$10,643	$117,074	$114,000	$7,300	$121,300	-3.61%	-13.97%
IT Software Developer Sr	57	$93,369	$9,337	$102,706	$95,700	$4,500	$100,200	2.44%	-7.32%
IT System Administrator	20	$75,660	$6,809	$82,469	$74,900	$3,700	$78,600	4.69%	-3.89%
IT Business Syst Anlyst Sr	10	$96,332	$9,633	$105,965	$90,600	$4,100	$94,700	10.63%	1.69%
IT Systems Analyst Sr	19	$91,889	$9,189	$101,078	$89,100	$2,900	$92,000	8.98%	-0.12%
AEPSC Accounting/Finance/Audit 5)									
Accountant Sr	21	$74,600	$6,714	$81,314	$76,700	$3,100	$79,800	1.86%	-6.97%
Accountant Assc	19	$51,525	$3,092	$54,617	$53,400	$1,300	$54,700	-0.15%	-6.16%
Accountant	25	$62,820	$5,026	$67,846	$62,900	$2,400	$65,300	3.75%	-3.95%
Incumbent Count	**253**								
							Average	**0.4%**	**-9.7%**
					% of Jobs Above +15% Market Competitive Range			**0.0%**	**0.0%**
					% of Jobs Below -15% Market Competitive Range			**4.8%**	**19.0%**

Notes:
(1) Sparcely Filled Positions retitled for confidentiality
(2) All survey data age adjusted from March 2015 to December 2015 at 3.0% annual rate
(3) Average Base Salary as of December 2015; reflects annual target incentive payout
(4) Survey Data from March 2015 Towers Watson Energy Services Middle Management & Professional Survey
(5) Survey Data from March 2015 Towers Watson General Industry Middle Management & Professional Survey

Bartsch

REBUTTAL TESTIMONY OF
JEFFREY B. BARTSCH
ON BEHALF OF KINGSPORT POWER COMPANY
D/B/A AEP APPALACHIAN POWER
BEFORE THE TENNESSEE REGULATORY AUTHORITY
DOCKET NO. 16-00001

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

A. My name is Jeffrey B. Bartsch. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by the American Electric Power Service Corporation (AEPSC) as the Director of Tax Accounting and Regulatory Support. AEPSC supplies engineering, financing, accounting, and planning and advisory services to the subsidiaries of the American Electric Power (AEP) System, one of which is Kingsport Power Company (KgPCo or the Company).

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

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

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY AS A WITNESS BEFORE ANY REGULATORY COMMISSION?

A. Yes. I have filed testimony before the Public Utilities Commission of Ohio on behalf of Columbus Southern Power Company and Ohio Power Company; with the Michigan

Public Service Commission on behalf of Indiana Michigan Power Company; with the Louisiana Public Service Commission on behalf of Southwestern Electric Power Company; and with the Federal Energy Regulatory Commission in a transmission rate case for the eastern AEP Operating Companies. I have also filed testimony with and testified before the Public Utility Commission of Texas on behalf of AEP Texas Central Company, AEP Texas North Company, Southwestern Electric Power Company and Electric Transmission Texas, LLC. In addition, I have filed testimony with and testified before the Indiana Utility Regulatory Commission on behalf of Indiana Michigan Power Company and the Virginia State Corporation Commission on behalf of Appalachian Power Company and the Public Service Commission of West Virginia on behalf of Appalachian Power Company and Wheeling Power Company and the Kentucky Public Service Commission on behalf of Kentucky Power Company. Like Kingsport, all of these companies, except Electric Transmission Texas, LLC, are AEP operating companies.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony responds to the direct testimony of Consumer Protection and Advocate Division (CPAD) witness Mr. Ralph C. Smith related to his calculation of the property tax adjustment and CPAD witness William H. Novak related to his calculation of the amount of ADIT to be included in rate base.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following exhibits:

- Rebuttal Exhibit No. 1 (JBB): Corrected Property Tax Adjustment
- Rebuttal Exhibit No. 2 (JBB): Taxes Other Than Income Allocation Factors

- Rebuttal Exhibit No. 3 (JBB): Alternate Property Tax Adjustment
- Rebuttal Exhibit No. 4 (JBB): Forecast ADIT Balances to include in Rate Base
- Rebuttal Exhibit No. 5 (JBB): Property ADIT Balance Proration Calculation
- Rebuttal Exhibit No. 6 (JBB): Property Related ADIT Activity for 2016 / 2017
- Rebuttal Exhibit No. 7 (JBB): Tax Depreciation on 2016 / 2017 Additions

Q. WERE THE EXHIBITS THAT YOU ARE SPONSORING PREPARED OR ASSEMBLED BY YOU OR UNDER YOUR DIRECTION?

A. Yes.

CALCULATION OF PROPERTY TAX ADJUSTMENT

Q. DO YOU AGREE WITH CPAD WITNESS SMITH'S RECOMMENDED ADJUSTMENT TO PROPERTY TAX EXPENSE (SMITH PAGE 34, STARTING AT LINE 12)?

A. In general, I agree with his approach; however, while performing the calculation he made one error. Mr. Smith used a Distribution Allocation Factor for all "Taxes Other Than Income" where he should have used an allocation factor for only Property Taxes.

Q. WHAT IS THE MAGNITUDE OF CHANGING THE ALLOCATION FACTOR TO INCORPORATE ONLY PROPERTY TAXES?

A. In Rebuttal Exhibit No. 1 (JBB), I have recalculated his adjustment using the property tax allocation factor (the ratio of Distribution property taxes to Total Company property taxes). This correction changes his adjustment from an increase of $52,398 to an increase of $189,749 to property tax expense.

Q. WHY IS THERE SUCH A LARGE DIFFERENCE BETWEEN MR. SMITH'S ALLOCATION FACTOR AND THE ALLOCATION FACTOR THAT YOU ARE RECOMMENDING?

A. As shown in Rebuttal Exhibit No. 2 (JBB), the primary reason for the difference is that by using the overall Taxes Other Than Income allocation factor, Mr. Smith has included nearly $4,000,000 of State Gross Receipts Tax that are 100% allocated to Distribution. It is clear that for purposes of calculating the property tax adjustment, it would be appropriate to use a property allocation factor rather than a Total Taxes Other than Income allocation factor.

Q. IS THERE AN ALTERNATIVE METHOD TO COMPUTING THE PROPERTY TAX EXPENSE ADJUSTMENT?

A. Yes. As shown in Rebuttal Exhibit No. 3 (JBB), I have computed the property tax adjustment similar to Mr. Smith, but instead compared the annual calculated distribution property tax expense to that which was recorded on the Distribution books for 2015. This method would indicate that an adjustment to increase property taxes should be $208,360.

<u>CALCULATION OF ADIT</u>

Q. CAN YOU DESCRIBE THE APPROACH THAT MR. NOVAK HAS TAKEN IN DETERMINING THE AMOUNT OF ACCUMULATED DEFERRED INCOME TAXES (ADIT) THAT SHOULD BE INCLUDED IN RATE BASE (NOVAK PAGE 12, LINES 1–9)?

A. Mr. Novak states in his testimony that "to compute ADIT, I calculated a linear regression of historical distribution ADIT against historical distribution Plant in Service. I then applied the results of this regression (with a 94% correlation) to the attrition period Distribution Plant in Service". Mr. Novak started with the ADIT balances as of December 31, 2015 for Total Company as allocated to Distribution. Included in his analysis were the forecasted distribution property additions for 2016 and 2017.

Q. DID MR. NOVAK INCLUDE ADIT BALANCES OTHER THAN PROPERTY RELATED ADIT IN HIS CALCULATIONS?

A. Yes. Even though he used property balances for purposes of his ADIT regression analysis, he included ADIT balances in Account 190 and Account 283 that are not related to utility property but instead are related to other temporary book / tax differences that have not been forecast.

Q. DO THE ADIT BALANCES IN ACCOUNT 190 AND ACCOUNT 283 FOLLOW A TREND TO INCREASE AS DOES THE PROPERTY RELATED ADIT IN ACCOUNT 282?

A. No. The ADIT balances in these accounts are based on non-property book / tax temporary differences that increase or decrease due to specific book transactions and any kind of trending would not properly forecast these balances.

Q. ARE YOU AWARE OF THIS APPROACH BEING APPROVED BY A COMMISSION IN YOUR 30 YEARS OF ELECTRIC UTILITY EXPERIENCE WORKING ON RATE CASES?

A. No, I am not aware of any Commission approving this type of approach. As I indicated, one cannot simply trend ADIT. The ADIT balance has no independent existence of its own. It is the result of comparing specific book accounting to tax return differences, primarily book depreciation to tax depreciation each year, and is not trendable.

Q. HAVE YOU CALCULATED ADIT FOR RATE BASE PURPOSES IN RATE CASES INVOLVING FORECAST PERIODS OR WHEN PROPERTY ADDITIONS ARE FORECAST?

A. Yes. Normally I would include the historical ADIT balance at the date certain and then forecast the ADIT going forward based on projected or forecast information.

Q. DOES THE INTERNAL REVENUE CODE (IRC) PLACE ANY RESTRICTIONS ON HOW MUCH ADIT CAN BE INCLUDED AS A RATE BASE REDUCTION WHEN USING A FORECAST OR WHEN FORECASTING PLANT ADDITIONS?

A. Yes. The IRC has specific computations related to projected test years as to the determination of the maximum amount of ADIT that can be treated as a rate base reduction as it relates to utility property. These computations only apply to property since only the deferred taxes on property are governed by the Internal Revenue Service (IRS) normalization rules.

Q. CAN YOU DESCRIBE THE NORMALIZATION RULES FOR PROJECTED TEST YEARS?

A. Yes. The IRC rules are set forth in Treasury Regulation Section 1.167(l)-1(h)(6)(ii) which discuss forecasted test periods and the appropriate amount of ADIT used to reduce rate base for a forecast test period. Specifically, these regulations require that:

> *for the purpose of determining the maximum amount of the reserve to be excluded from the rate base (or to be included as no-cost capital) under the subdivision (i) of this subparagraph, if solely an historical period is used to determine depreciation for Federal income tax expense for ratemaking purposes, then the amount of the reserve account for the period is the amount of*

> *the reserve (determined under subparagraph (2) of this paragraph) at the end of the historical period. If solely a future period is used for such determination, the amount of the reserve account for the period is the amount of the reserve at the beginning of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during such period. If such determination is made by reference both to an historical portion and to a future portion of a period, the amount of the reserve account for the period is the amount of the reserve at the end of the historical portion of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during the future portion of the period. The pro rata portion of any increase to be credited or decrease to be charged during a future period (or the future portion of a part-historical and part-future period) shall be determined by multiplying any such increase or decrease by a fraction, the numerator of which is the number of days remaining in the period at the time such increase or decrease is to be accrued, and the denominator of which is the total number of days in the period (or future portion).*

As ADIT are often referred to as an "interest free loan from the U.S. Treasury", proration takes into account that the interest free loan obtained in the first month of the projected test period will be available for virtually the entire test period. The interest free loan obtained in month two of the forecast period will be available for a little less time. Eventually, the interest free loan obtained in the final month of the forecast test period will hardly be available at all. Proration recognizes this concept. To calculate deferred taxes otherwise, according to the treasury regulation, would be a form of flowing through an interest free loan to ratepayers that had not yet been obtained by the utility.

Q. DO THE IRS NORMALIZATION RULES APPLY TO ALL ADIT BALANCES?

A. No. The IRS normalization rules only apply to depreciation related ADIT balances included in account 282 and not to other ADIT balances included in accounts 190 or 283 (with the exception being 190 ADIT accounts related to net operating losses).

Q. WHAT TYPE OF TEST YEAR HAS MR. NOVAK PROPOSED IN HIS THIS RATE CASE?

A. Mr. Novak has proposed that the Company use a 2015 calendar test year with rate base as of December 2015 being updated to reflect forecast plant additions and retirements for 2016 and 2017. He has then calculated the utility plant to be included in rate base using a 13 month average using December 2016 through December 2017 projected balances.

Q. WHEN ARE THE NEW RATES IN THIS RATE PROCEEDING EXPECTED TO GO INTO EFFECT?

A. It is my understanding that the new rates are expected to take effect October 1, 2016.

Q. BASED ON THE RECOMMENDED TEST YEAR, RATE BASE, THE IMPLEMENTATION DATE OF NEW RATES AND IRC SECTION 1.167(l)-1(h)(6)(ii) DISCUSSED ABOVE, DO YOU BELIEVE THAT A PRORATION ADJUSTMENT IS REQUIRED FOR THE ADIT THAT MR. NOVAK HAS INCLUDED IN RATE BASE?

A. Yes.

Q. WHAT SPECIFIC IRC GUIDELINES OR INTERPRETATIONS SUPPORT YOUR POSITION?

A. There have been numerous private letter rulings (PLRs) issued over the years that have fact patterns similar to the situation in this case. PLRs are issued to specific taxpayers as an advisory service of the IRS National Office. Although PLRs are issued to specific taxpayers and are not to be cited as precedent, they reflect IRS thinking on an issue and are consistently followed by the IRS. PLR 9029040 states the following:

> *If rates go into effect before the end of the test period, and the rate base reduction is not prorated, the utility commission is denying a current return for accelerated depreciation benefits the utility is only projected to have. This procedure is a form of flow-through, for current rates are reduced to reflect the capital cost savings of accelerated depreciation deductions not yet claimed or accrued by the utility. Yet projected data is often necessary in determining rates, since historical data by itself is rarely an accurate indication of future utility operating results. Thus, the regulations provide that as long as the portion of the deferred tax reserve based on truly projected (future estimated) data is prorated according to the formula in section 1.167(l)(h)(6)(ii), a regulator may deduct this reserve from rate base in determining a utility's allowable return. In other words, a utility regulator using projected data in computing ratemaking tax expense and rate base exclusion must account for the passage of time if it is to avoid flow-through.*

The IRS issued a number of similar PLRs on this issue consistent with the excerpt above in the early 1990's. More recently, in the last year, a number of similar PLRs have been issued in connection with formula rate requests where a projected test period was used. The IRS's recent guidance mirrors the previous PLRs.

Q. HAS THE IRS DEFINED "HISTORICAL" VERSUS "FUTURE" TEST PERIODS AS IT RELATES TO THE PRO RATA ADIT CALCULATION?

A. Yes. In PLR 9202029, the IRS provided the following guidance:

> *Critical to the interpretation of section 1.167(l)-1(h)(6)(ii) of the regulation is the meaning of the terms "historical" and "future" in relation to the period for determining depreciation for ratemaking tax expense (this test period might not be coextensive with the taxpayer's test year; see, e.g. section 1.167(l)-1(h)(6)(iv) Example (2)). The meaning of these terms does not depend on the type or quality of the data used in the ratemaking process -- whether the data used is actual or estimated -- but on when the utility's rates become effective. The historical period is that portion of the test period before rates go into effect, while the portion of the test period after the effective date of the rate order is the future period.*
>
> *These date-based definitions of the terms "historical" and "future" are consistent with the purpose of normalization, which is to preserve for regulated utilities the benefit of accelerated depreciation as a source of cost-free capital. This cost-free capital is made available by prohibiting flow-through. But whether or not flow-through can be accomplished by means of a rate base exclusion depends primarily on whether, at the time rates become effective, the amounts originally projected to accrue to the deferred tax reserve have actually accrued.*

Q. BASED ON THE IRC REGULATIONS AND THE PLR'S DISCUSSED ABOVE, IS IT YOUR POSITION THAT MR. NOVAK'S APPROACH VIOLATES THE IRS NORMALIZATION RULES?

A. Yes. Not only is it inappropriate to trend an ADIT balance, but no proration was applied.

Q. WHAT ARE THE CONSEQUENCES OF VIOLATING THE IRS NORMALIZATION RULES?

A. The consequences are severe. KgPCo would no longer be able to claim accelerated depreciation (including bonus depreciation) on its tax returns. This would result in a significant loss of interest-free loans from the government which would significantly reduce the amount of ADIT that is recorded on its books. Without this interest-free loan, the Company would have to replace it with new loans as the ADIT balance unwinds and the current taxes are paid to the government. More importantly, the higher financing costs and the reduction in ADIT (which would result in a much higher rate base) would result in higher electric utility rates for customers. In other words, KgPCo's customers would no longer receive the reduction in rate base benefit of the ADIT interest free loan, resulting in increased revenue requirements.

Q. CAN A COMPANY SUCH AS KGPCO SIMPLY IGNORE THE NORMALIZATION RULES?

A. No. Once the utility becomes aware of a normalization violation, it could no longer claim accelerated tax depreciation on its federal tax returns. Since federal income tax returns are filed under penalties of perjury, no corporate officer would knowingly sign the federal income tax return in which accelerated depreciation was claimed. In addition, knowledge of a normalization violation would have to be communicated to the IRS and to the utility's outside auditor, and, at the very least, an uncertain tax position would then have to be disclosed on their financial statements and on Schedule UTP of their federal tax return.

Q. HAVE YOU PROVIDED A COMPUTATION OF THE ADIT BALANCE THAT SHOULD BE USED WITH MR. NOVAK'S RATE BASE THAT IN YOUR OPINION WOULD AVOID ANY IRS NORMALIZATION CONCERNS?

A. Yes. As discussed above, I have provided a calculation that incorporates the necessary proration calculation that imputes the maximum amount of property related ADIT that can be included in rate base without violating the normalization rules.

Q. PLEASE DESCRIBE THE STEPS THAT YOU WENT THROUGH TO COMPUTE THE PROPERTY RELATED ADIT FOR 2016 AND 2017 LEADING UP TO THE PRORATION CALCULATION.

A. The first step was to compute the tax depreciation that the Company would be able to claim on the Forecast property additions for 2016 and 2017 that Mr. Novak included in the property balance portion of rate base. This tax depreciation calculation is shown on Rebuttal Exhibit No. 7 (JBB) and includes the available bonus tax depreciation that could be claimed.

On Rebuttal Exhibit No. 6 (JBB), I accumulated the tax depreciation that would be able to be claimed for 2016 and 2017 (from Rebuttal Exhibit No. 7 (JBB)) and included the tax depreciation that would be available on the 2015 and prior vintage year additions (as obtained from the Company's PowerTax Depreciation System). The total Tax Depreciation for each year was then compared to the Forecast Book Depreciation as calculated by Mr. Novak in his workpapers (as adjusted for the forecast flow-through book depreciation). The difference between tax and book depreciation represents the depreciation Schedule M on which deferred income taxes would be calculated. ADIT activity for each respective year equals 35% of the Schedule M adjustment.

Q. PLEASE DESCRIBE THE PRORATION CALCULATION THAT YOU HAVE PROVIDED ON REBUTTAL EXHIBIT NO. 5 (JBB).

A. The starting point for the property related ADIT is the balance in Account 282 as of December 31, 2015. I then included the incremental monthly ADIT amounts for each year (from Rebuttal Exhibit No. 6 (JBB)) into the proration example contained in IRC section 1.167(l)-1(h)(6)(iv) Example (2). Since the electric rates are anticipated to go into effect on October 1, 2016, no proration adjustment is required for the forecast ADIT balance as of September 30, 2016 (the "historical" portion of the test period as defined by the IRS). Since the projected test year rate base is 2017 (using a 13 month average) the incremental ADIT from October 1, 2016 through December 31, 2017 is subject to the proration rules and that same averaging convention for the "future" portion of the test period. Thus, the denominator in the proration calculation is 458 days (the number of days from the effective date of the rate change to the end of the forecast test period). Following the consistency normalization rules, the pro-rated ADIT amounts were averaged using 13 months, the same as the projected utility property balances included in rate base.

Q. WHAT WAS THE RESULT OF YOUR CALCULATION?

A. Using the proration calculation, the maximum amount of property related ADIT that can be included as a rate base reduction is $19,713,599 (the property related ADIT balance is forecasted to be $20,988,562 as of December 31, 2017). As shown on Rebuttal Exhibit No. 4 (JBB), I then added this amount to the Distribution ADIT balances in Account 190 and 283 as of December 31, 2015. As explained above, the ADIT in Accounts 190 and 283 are not related to property, but are related to other temporary book / tax differences which have not been adjusted in the forecast period. The total amount of ADIT that should be included as a reduction to rate base is $21,279,141 as compared to the $25,140,046 that Mr. Novak included in his rate base calculation. This would result in an increase to rate base of $3,860,905.

Q. IF THE AUTHORITY IS NOT CONVINCED THAT ADOPTION OF MR. NOVAK'S POSITION WOULD RESULT IN A NORMALIZATION VIOLATION, WHAT STEPS CAN IT AND THE COMPANY TAKE?

A. The Company along with the Authority could file a Private Letter Ruling Request with the IRS in order to get guidance based on the specific facts and circumstances of the case at hand. It is important that any Authority decision in this matter that may violate the normalization requirements be resolved through the PLR process due to the severe consequences described above.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

KINGSPORT POWER COMPANY
DISTRIBUTION FUNCTION
Calculation of Property Tax Expense Adjustment
For the Update of Net Utility Plant Through the 2017 Attrition Period

Line No.	Description	Per CPAD (A)	Corrected CPAD (A)	Difference
	Adjusted Utility Plant Balances for 2017 Attrition Period (CPAD)			
1	Utility Plant in Service	$ 161,469,371	$ 161,469,371	
2	Property Held for Future Use			
3	Accumulated Depreciation	$ (60,051,552)	$ (60,051,552)	
4	**Utility Plant Property Tax Base**	$ 101,417,819	$ 101,417,819	
5				
6	**Calculation of Property Tax Expense Adjustment**			
7	**Utility Plant Property Tax Base**	$ 101,417,819	$ 101,417,819	
8	Effective Property Tax Rate	1.2469%	1.2469%	
9				
10	Property Tax Expense on Attrition Period Net Plant	$ 1,264,543	$ 1,264,543	
11	Distribution Allocation for Taxes Other Than Income	0.938834	0.822907	
12	Equivalent per Book Property Tax Expense	$ 1,346,929	$ 1,536,678	
13				
14	2015 Test Year Recorded Property Tax Expense	$ 1,294,531	$ 1,294,531	
15				
16	Increase to 2015 Test Year Recorded Property Tax Expense	$ 52,398	$ 242,147	$ 189,749

Line No.	**Calculated Allocation Factors Removing Transmission**	Taxes Other Than Income Taxes	Property Tax Expense	Taxes Other Than Income Taxes (Excluding Property Tax)
1	Total 2014 Amounts Per KgPCo Before Adjustment	$ 6,117,775	$ 1,165,280	$ 4,952,495
2	PJM Transmission Owner Allocation	$ 374,199	$ 206,363	$ 167,836
3	Remaining Amounts for Electric Distribution Utility Function	$ 5,743,576	$ 958,917	$ 4,784,659
4	Distribution Allocation	**0.93883**	**0.82291**	0.96611

KINGSPORT POWER COMPANY
TAXES OTHER THAN INCOME TAX
FOR THE TEST YEAR ENDED DECEMBER 31, 2014

TAXES OTHER THAN INCOME TAX	Operating Total Company Per Books	Transmission PJM Allocation Per Rate Dept	Distribution Before Rate Case Adjustments	Distribution Allocation Factor
FICA	171,291	19,707	151,584	88.4950%
Federal Unemployment Tax	1,031	119	912	88.4578%
Real / Personal Property Taxes	1,165,280	206,363	958,917	82.2907%
State Gross Receipts Tax	3,972,742	0	3,972,742	100.0000%
State Unemployment Tax	(1,642)	(189)	(1,453)	88.4896%
State Franchise Taxes	149,286	27,403	121,883	81.6440%
State Public Service Commission Tax / Fees	654,642	120,164	534,478	81.6443%
State Sales & Use Tax	1,702	0	1,702	100.0000%
State License / Registration Tax / Fees	3,442	632	2,810	81.6386%
Total Taxes Other Than Income --- Operating	6,117,774	374,199	5,743,575	93.8834%

KINGSPORT POWER COMPANY
DISTRIBUTION FUNCTION
Alternate Calculation of Property Tax Expense Adjustment
For the Update of Net Utility Plant Through the 2017 Attrition Period

Line No.	Description	Alternate Method
		(A)
	Adjusted Utility Plant Balances for 2017 Attrition Period (CPAD)	
1	Utility Plant in Service	$ 161,469,371
2	Property Held for Future Use	
3	Accumulated Depreciation	$ (60,051,552)
4	**Utility Plant Property Tax Base**	$ 101,417,819
5		
6	**Calculation of Property Tax Expense Adjustment**	
7	**Utility Plant Property Tax Base**	$ 101,417,819
8	Effective Property Tax Rate	1.2469%
9		
10	Property Tax Expense on Attrition Period Net Plant	$ 1,264,543
11	2015 Property Tax Expense recorded on Distribution Books	$ 1,056,183
12		
13	Increase to 2015 Test Year Recorded Property Tax Expense	$ 208,360

KINGSPORT DISTRIBUTION COMPANY
FORECAST ADIT BALANCES

Case No. 16-00001
Rebuttal Exhibit No. 4 (JBB)

Accumulated ADIT Account	Total Company Actual ADIT @ 12-31-2015	DISTRIBUTION Actual ADIT @ 12-31-2015	DISTRIBUTION Prorated ADIT @ 12-31-2017
Account 1901001 - Accum Deferred FIT - Other	(620,464)	(526,687)	(526,687)
Account 2821001 - Accum Deferred FIT - Property	(22,448,028)	(17,774,374)	(19,713,599)
Account 2831001 - Accum Deferred FIT - Other	(1,189,467)	(1,038,855)	(1,038,855)
Total Accumulated Deferred FIT	(24,257,959)	(19,339,916)	(21,279,141)

Kingsport Power Company
Calculation of Property Related ADIT
Pro Ration Calculation

Case No. 16-00001
Rebuttal Exhibit No. 5 (JBB)

Future Test Period	Deferred Tax Additions	Deferred Tax Balance	Days in Month	Number of Days Left in Period	Proration Amount	Prorated Item	Prorated Balance
Beginning Balance @ 12/31/2015		$ (17,774,374)	N/A	N/A	100.00%	$ (17,774,374)	$ (17,774,374)
January	$ (132,910)	$ (17,907,284)	N/A	N/A	100.00%	$ (132,910)	$ (17,907,284)
February	$ (132,910)	$ (18,040,194)	N/A	N/A	100.00%	$ (132,910)	$ (18,040,194)
March	$ (132,910)	$ (18,173,104)	N/A	N/A	100.00%	$ (132,910)	$ (18,173,104)
April	$ (132,910)	$ (18,306,014)	N/A	N/A	100.00%	$ (132,910)	$ (18,306,014)
May	$ (132,910)	$ (18,438,924)	N/A	N/A	100.00%	$ (132,910)	$ (18,438,924)
June	$ (132,910)	$ (18,571,834)	N/A	N/A	100.00%	$ (132,910)	$ (18,571,834)
July	$ (132,910)	$ (18,704,744)	N/A	N/A	100.00%	$ (132,910)	$ (18,704,744)
August	$ (132,910)	$ (18,837,654)	N/A	N/A	100.00%	$ (132,910)	$ (18,837,654)
September	$ (132,910)	$ (18,970,564)	N/A	458	100.00%	$ (132,910)	$ (18,970,564)
October	$ (132,910)	$ (19,103,474)	31	427	93.23%	$ (123,914)	$ (19,094,478)
November	$ (132,910)	$ (19,236,384)	30	397	86.68%	$ (115,208)	$ (19,209,686)
December @ 12/31/2016	$ (132,910)	$ (19,369,294)	31	366	79.91%	$ (106,212)	$ (19,315,898)
2016 ADIT Additions	$ (1,594,920)						
January	$ (134,939)	$ (19,504,233)	31	335	73.14%	$ (98,700)	$ (19,414,598)
February	$ (134,939)	$ (19,639,172)	28	307	67.03%	$ (90,450)	$ (19,505,048)
March	$ (134,939)	$ (19,774,111)	31	276	60.26%	$ (81,317)	$ (19,586,365)
April	$ (134,939)	$ (19,909,050)	30	246	53.71%	$ (72,478)	$ (19,658,843)
May	$ (134,939)	$ (20,043,989)	31	215	46.94%	$ (63,345)	$ (19,722,188)
June	$ (134,939)	$ (20,178,928)	30	185	40.39%	$ (54,506)	$ (19,776,694)
July	$ (134,939)	$ (20,313,867)	31	154	33.62%	$ (45,373)	$ (19,822,067)
August	$ (134,939)	$ (20,448,806)	31	123	26.86%	$ (36,239)	$ (19,858,306)
September	$ (134,939)	$ (20,583,745)	30	93	20.31%	$ (27,400)	$ (19,885,706)
October	$ (134,939)	$ (20,718,684)	31	62	13.54%	$ (18,267)	$ (19,903,973)
November	$ (134,939)	$ (20,853,623)	30	32	6.99%	$ (9,428)	$ (19,913,401)
December @ 12/31/2017	$ (134,939)	$ (20,988,562)	31	1	0.22%	$ (295)	$ (19,913,696)
2017 ADIT Additions	$ (1,619,268)						
13 Month Average (December 2016 thru December 2017)							**$ (19,713,599)**

Kingsport Power Company
Forecasted ADIT Related to Property
2016 / 2017

Case No. 16-00001
Rebuttal Exhibit No. 6 (JBB)

DISTRIBUTION PLANT

2016 FORECASTED ADIT

Description	2016 Activity	2017 Activity
Tax Depreciation - Plant @ 12/31/2015	3,498,350	3,163,039
Tax Depreciation - 2016 Additions	5,986,663	529,353
Tax Depreciation - 2017 Additions	-	6,522,772
Total Forecast Tax Depreciation	9,485,013	10,215,164
Forecast Book Depreciation	5,600,096	6,260,675
Less: Flow-Thru Book Depreciation	(672,000)	(672,000)
Forecast S/L Depreciation	4,928,096	5,588,675
Tax vs. Book Depreciation Normalized	4,556,917	4,626,489
Estimated ADIT @ 35%	**$ (1,594,921)**	**$ (1,619,271)**
Monthly ADIT Activity	**$ (132,910)**	**$ (134,939)**

Kingsport Power Company
2016 and 2017 Forecasted Capital Additions
Calculation of Tax Depreciation

DISTRIBUTION PLANT

2016 FORECASTED ADDITIONS

FERC Account	FERC Description	Plant Additions	MACRS Tax Life (Yrs)	MACRS Tax Life (Yrs)	Bonus Depreciation	MACRS Depr Rates (Adjusted to Include Bonus) 2016	2017	Tax Depreciation 2016	2017
30300	Miscellaneous Intangible Plant	573,247	5	20.000%	0%	20.000%	20.000%	114,649	114,649
36200	Station Equipment	2,163,483	20	3.750%	50%	51.875%	3.610%	1,122,307	78,102
36400	Poles, Towers and Fixtures	895,107	20	3.750%	50%	51.875%	3.610%	464,337	32,313
36500	Overhead Conductors, Device	6,451,655	20	3.750%	50%	51.875%	3.610%	3,346,796	232,905
36700	Underground conductors and devices	20,315	20	3.750%	50%	51.875%	3.610%	10,538	733
36800	Line Transformers	320,884	20	3.750%	50%	51.875%	3.610%	166,459	11,584
36900	Services	1,277,997	20	3.750%	50%	51.875%	3.610%	662,961	46,136
37000	Meters	109,257	20	3.750%	50%	51.875%	3.610%	56,677	3,944
39000	Gen Plt Structures and Improvements	60,998	7	14.290%	50%	57.145%	12.245%	34,857	7,469
39100	Gen Plt Office Furniture & Equipment	2,366	7	14.290%	50%	57.145%	12.245%	1,352	290
39700	Communication Equipment	10,027	7	14.290%	50%	57.145%	12.245%	5,730	1,228
	Total:	**11,885,336**						**5,986,663**	**529,353**

2017 FORECASTED ADDITIONS

FERC Account	FERC Description	Plant Additions	Book Depr Rate	MACRS Tax Life (Yrs)	Bonus Depreciation	MACRS Depr Rates (Adjusted to Include Bonus) 2016	2017	Tax Depreciation 2016	2017
30300	Miscellaneous Intangible Plant	925,707	5	20.000%	0%	N/A	20.000%	N/A	185,141
36200	Station Equipment	234,664	20	3.750%	50%	N/A	51.875%	N/A	121,732
36400	Poles, Towers and Fixtures	4,400,600	20	3.750%	50%	N/A	51.875%	N/A	2,282,811
36500	Overhead Conductors, Device	5,104,425	20	3.750%	50%	N/A	51.875%	N/A	2,647,920
36700	Underground conductors and devices	20,768	20	3.750%	50%	N/A	51.875%	N/A	10,773
36800	Line Transformers	332,665	20	3.750%	50%	N/A	51.875%	N/A	172,570
36900	Services	1,315,239	20	3.750%	50%	N/A	51.875%	N/A	682,280
37000	Meters	112,105	20	3.750%	50%	N/A	51.875%	N/A	58,154
39000	Gen Plt Structures and Improvements	622,469	7	14.290%	50%	N/A	57.145%	N/A	355,710
39100	Gen Plt Office Furniture & Equipment	-	7	14.290%	50%	N/A	57.145%	N/A	-
39700	Communication Equipment	9,942	7	14.290%	50%	N/A	57.145%	N/A	5,681
	Total:	**13,078,584**							**6,522,772**

Allen

REBUTTAL TESTIMONY OF
A. WAYNE ALLEN
ON BEHALF OF KINGSPORT POWER COMPANY
D/B/A AEP APPALACHIAN POWER
BEFORE THE TENNESSEE REGULATORY AUTHORITY
DOCKET NO. 16-00001

Q. PLEASE STATE YOUR NAME.

A. My name is A. Wayne Allen.

Q. ARE YOU THE SAME A. WAYNE ALLEN WHO SUBMITTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony responds to various recommendations and adjustments presented in the direct testimony of the Tennessee Attorney General's Office, Consumer Protection and Advocate Division (CPAD) witnesses William H. Novak and Ralph C. Smith related to the following subjects:

1. Accounts Receivable Factoring-Bad Debt Expense
2. Prepaid Pension and Other Postretirement Benefits (OPEB) Assets
3. Pension and OPEB Expenses
4. Customer Deposits Rate Base Issues
5. Customer Advance Receipts

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following exhibits:

- Rebuttal Exhibit No. 1 (AWA): Reduction in Pension Cost from Cash Contributions

- Rebuttal Exhibit No. 2 (AWA): Customer Deposits 2013-2015

Q. WERE THE EXHIBITS THAT YOU ARE SPONSORING PREPARED OR ASSEMBLED BY YOU OR UNDER YOUR DIRECTION?

A. Yes.

ACCOUNTS RECEIVABLE FACTORING-BAD DEBT EXPENSE (Smith, p.18, line 12-p.22, line 15)

Q. DO YOU AGREE WITH CPAD WITNESS SMITH'S RECOMMENDATION TO EXCLUDE ALL ACCOUNTS RECEIVABLE FACTORING EXPENSE FROM THE COMPANY'S COST OF SERVICE FOR RATEMAKING PURPOSES?

A. No. Mr. Smith's recommendation, if adopted by the TRA, would provide no recovery in base rates of electric customer uncollectible accounts expense (also known as bad debt expense) as well as certain other costs associated with factoring KgPCo's accounts receivable.

Q. MR. SMITH MENTIONS TWO ACCOUNTS RELATED TO ACCOUNTS RECEIVABLE FACTORING THAT KGPCO INCLUDED IN ITS REQUESTED COST OF SERVICE. CAN YOU PLEASE DESCRIBE THESE TWO ACCOUNTS?

A. Yes. KgPCo charges Account 4265009, Factored Customer Accounts Receivable Expense-Affiliated, with expenses for carrying costs and certain other costs associated with AEP Credit's purchase of the Company's customer accounts receivable balances but does not include bad debt expense which is recorded separately in Account 4265010, Factored Customer Accounts Receivable-Bad Debt-Affiliated. The cost in Account

4265010 includes only bad debt expense associated with the Company's accounts receivable factored by AEP Credit related to non-payments from KgPCo's customers. AEP Credit is a wholly owned subsidiary of American Electric Power Company, Inc. (AEP) and a non-utility affiliate of KgPCo.

Q. IS ANOTHER COMPANY WITNESS ALSO ADDRESSING CPAD WITNESS SMITH'S RECOMMENDATION TO DISALLOW THE RECOVERY OF ACCOUNTS RECEIVABLE FACTORING EXPENSE?

A. Yes, Company witness Hawkins in her rebuttal testimony will present an overview of the Company's participation in the factoring of customer accounts receivable including the benefits to KgPCo and its customers from such factoring. Ms. Hawkins also addresses Mr. Smith's recommended exclusion of factoring expense recorded in Account 4265009 from recovery in base rates.

Q. WHAT PORTION OF CPAD WITNESS SMITH'S RECOMMENDATION REGARDING FACTORING EXPENSE ARE YOU ADDRESSING?

A. My rebuttal testimony explains why CPAD witness Smith's recommendation to disallow bad debt expense, which is recorded in Account 4265010, from the Company's cost of service is inappropriate and inconsistent with his testimony in other regulatory jurisdictions involving AEP electric operating subsidiaries. I will also address Mr. Smith's comments regarding the Virginia State Corporation Commission's (VA SCC) treatment of accounts receivable factoring expense in the base rates of Appalachian Power Company (APCo). Like KgPCo, APCo is an electric operating subsidiary of AEP.

Q. PLEASE EXPLAIN HOW MR. SMITH'S RECOMMENDATION, IF ADOPTED, WOULD PROVIDE KGPCO WITH NO RECOVERY OF ITS CUSTOMER UNCOLLECTIBLE ACCOUNTS EXPENSE.

A. CPAD witness Smith has removed the entire amount of 2015 bad debt expenses recorded in Account 4265010 of $367,265 from the CPAD's updated 2015 test year level of operations and maintenance (O&M) expense. Since KgPCo factors its customer accounts receivable, all electric customer uncollectible accounts expense is charged to Account 4265010. In addition, Mr. Smith removed the $302,054 of factoring costs recorded in Account 4265009 for 2015 from his recommended level of O&M expenses, thus resulting in the CPAD's removal of all of KgPCo's actual 2015 factoring expenses of $669,319 from its recommended cost of service.

Q. WHAT LEVEL OF CUSTOMER UNCOLLECTIBLE ACCOUNTS EXPENSE DID THE COMPANY INCLUDE IN ITS COST OF SERVICE USED TO DETERMINE KGPCO'S REVENUE REQUIREMENT?

A. The Company included $418,205 of bad debt expense on customer accounts receivable recorded in Account 4265010 for the 2014 test year in its cost of service study. KgPCo also included an additional $55,830 of uncollectible accounts expense as part of the gross revenue conversion factor used to calculate the $12.1 million requested revenue increase.

Q. IN ADDITION TO THE $367,265 ACTUAL BAD DEBT EXPENSE RECORDED IN ACCOUNT 4265010 THAT MR. SMITH EXCLUDED FROM O&M EXPENSES, DID THE CPAD ALSO EXCLUDE ANY UNCOLLECTIBLE ACCOUNTS EXPENSE FROM ITS' RECOMMENDED REVENUE INCREASE?

A. Yes. As shown on CPAD Exhibit Schedule 11, the CPAD included a zero uncollectible expense rate in their revenue conversion factor used to calculate the CPAD's $6.952 million revenue deficiency for KgPCo.

Q. DO YOU AGREE WITH THE CPAD'S EXCLUSION OF AN UNCOLLECTIBLE COMPONENT IN THE REVENUE CONVERSION FACTOR?

A. No. The CPAD's exclusion of an uncollectible expense rate in the development of their revenue conversion factor ignores the anticipated increase in KgPCo's bad debt expense resulting from the additional base rate revenues that the CPAD recommends be approved in this proceeding.

Q. HAS THE COMPANY PROVIDED BAD DEBT EXPENSE AMOUNTS RELATED TO CUSTOMER UNCOLLECTIBLE ACCOUNTS FOR YEARS OTHER THAN 2014 AND 2015?

A. Yes. The Company provided annual bad debt expense, which was recorded in Account 4265010, for 2012 through 2015 in response to the CPAD First Discovery Request 1-100. KgPCo's annual bad debt expense over the most recent four year period has ranged from $349,434 to $473,025 and the four-year average over this period is $401,982.

Q. ON PAGE 18 OF HIS TESTIMONY, CPAD WITNESS SMITH ASSERTS THAT "KINGSPORT HAS ATTEMPTED TO INCLUDE IN ITS 2014 TEST YEAR OPERATING EXPENSES $730,469 FOR TWO ACCOUNTS THAT ARE NOT NORMALLY CONSIDERED TO BE O&M EXPENSE" INCLUDING ACCOUNT 4265010. IN YOUR EXPERIENCE, IS BAD DEBT EXPENSE A NORMAL O&M EXPENSE TYPICALLY RECOVERED IN BASE RATES FOR ELECTRIC UTILITIES?

A. Absolutely. The bad debt expense recorded by KgPCo in Account 4265010 is the same type of customer uncollectible accounts expense that the Company previously recorded in Account 9040000, Uncollectible Accounts, before KgPCo and the other AEP electric operating subsidiaries began factoring their accounts receivable balances.

Q. DID THE COMPANY OR THE CPAD INCLUDE ANY ACCOUNT 9040000 ELECTRIC CUSTOMER UNCOLLECTIBLE ACCOUNTS EXPENSE IN THEIR RESPECTIVE REVENUE DEFICIENCY DETERMINATIONS FOR KGPCO?

A. No. Because KgPCo factors its customer accounts receivable, the Company recorded no uncollectible accounts expense in Account 9040000 n 2014, which is the test year used in the Company's petition, or 2015, which is the test year used by the CPAD. The Company and the CPAD did include $1,734 and $12, respectively, in their respective revenue requirement calculations for costs recorded in Account 9040007, Uncollectible Accounts-Misc. Receivables. However, the costs charged to Account 9040007 consist solely of bad debt expense associated with miscellaneous receivables that are unrelated to electric customer accounts receivable.

Q. DOES CPAD WITNESS SMITH PROVIDE A REASON FOR HIS RECOMMENDATION THAT THE COMPANY NOT RECOVER ITS BAD DEBT EXPENSE ON CUSTOMER ACCOUNTS RECEIVABLE IN BASE RATES ON A GOING-FORWARD BASIS?

A. Not directly. Mr. Smith's main objection seems to be related to the account number that KgPCo uses to record its bad debt expense. For example, on page 19 of his testimony, Mr. Smith asserts that "account 426 and related subaccounts, which cover items such as donations and lobbying, are typically not included in utility O&M expenses."

Q. WHY DID THE COMPANY USE ACCOUNTS 4265009 AND 4265010 TO RECORD ITS ACCOUNTS RECEIVABLE FACTORING EXPENSES INCLUDING BAD DEBT EXPENSE?

A. The Company's decision to record accounts receivable factoring expenses in subaccounts of FERC Account 426.5, Other Deductions, was influenced, in part, by the portion of the factoring expense that relates to carrying costs and also to the affiliate relationship between AEP Credit, a non-utility company, and KgPCo, a regulated utility.

Q. SHOULD THE COMPANY'S USE OF ACCOUNT426.5 TO RECORD BAD DEBT EXPENSE INSTEAD OF ACCOUNT 904 CHANGE THE RECOVERABILITY OF SUCH COSTS IN BASE RATES?

A. No, not at all. The account classification of bad debt expense between accounts 426.5 and 904 should have no bearing on the TRA's determination that such costs are a normal and ordinary utility business cost that should be recovered from KgPCo's customers through base rates. Regardless of whether or not the Company factors its accounts receivable, it will incur bad debt expense related to customer accounts. The nature of customer uncollectible accounts expense does not change due to the account classification. KgPCo's affiliated electric utility, APCo, provides a good illustration of this last point.

APCo provides electric service to customers across significant portions of both Virginia and West Virginia. APCo factors its Virginia customers' accounts receivable balances to AEP Credit in a manner very similar to KgPCo, but does not factor its West Virginia customers' accounts receivable per direction from the Public Service Commission of West Virginia (WVPSC). As a result, APCo records bad debt expense related to its Virginia customers' accounts receivable in Account 4265010 and records bad debt expense related to its West Virginia customers' accounts receivable in Account 9040000. Even though bad debt expense related to the two states is recorded in different accounts, the type of expense is the same and both the VA SCC and the WVPSC have consistently allowed recovery of APCo's customer uncollectible accounts expense (whether recorded in Account 4265010 or Account 9040000) in base rates for their respective state jurisdictions.

Q. DOES THE FERC UNIFORM SYSTEM OF ACCOUNTS (USofA) INSTRUCTIONS PRESCRIBE THE TREATMENT OF COSTS RECORDED IN ACCOUNT 426, INCLUDING ACCOUNT 426.5, FOR RATEMAKING PURPOSES?

A. No. The FERC USofA instructions for Account 426 include the following notation:

> *The classification of expenses as nonoperating and their inclusion in these accounts is for accounting purposes. It does not preclude Commission consideration of proof to the contrary for ratemaking or other purposes.*

Q. ON PAGE 21 OF HIS TESTIMONY, CPAD WITNESS SMITH REFERENCES A VA SCC ORDER IN 2011 FOR APCO THAT INVOLVED FACTORING OF REGULATED UTILITY ACCOUNTS RECEIVABLE. ARE YOU FAMILIAR WITH THE REFERENCED VA SCC ORDER AND IN GENERAL WITH THE VA SCC'S TREATMENT OF FACTORING EXPENSE?

A. Yes. I testified on behalf of APCo in VA SCC Case No. PUE-2011-00037, which was a biennial review base rate case, and I also testified in the other four APCo base rate cases filed in Virginia between 2006 and 2014. VA SCC Case No. PUE-2006-00065 was the first APCo base rate case in which the ratemaking treatment of accounts receivable factoring expense was considered.

Q. IS THE EXAMPLE GIVEN BY MR. SMITH FROM APCO'S 2011 VA SCC BIENNIAL REVIEW RELEVANT TO THE ISSUE OF CPAD'S RECOMMENDED EXCLUSION OF KGPCO'S ACCOUNTS RECEIVABLE FACTORING EXPENSE FROM BASE RATES?

A. No, it is not relevant. The "illustrative example" discussed by Mr. Smith related to a one-time proposed increase to the working capital component of rate base to reflect a temporary decline in the credit quality of APCo's accounts receivable thus resulting in AEP Credit incurring additional costs to finance a larger percentage of receivables that did not qualify for securitized financing from banks. This proposed adjustment from APCo's 2011 VA biennial review related to rate base only and had no impact on the level of accounts receivable factoring expense recovered in base rates. KgPCo is proposing no similar increase to working capital in this current proceeding but instead is simply requesting to recover its actually incurred accounts receivable factoring expense. Therefore, the CPAD's example of a proposed rate base adjustment in another state jurisdiction is both unrelated and uninformative to the issue of CPAD's recommended disallowance of KgPCo's factoring expenses.

Q. HAS THE VA SCC APPROVED BASE RATE RECOVERY OF ACCOUNTS RECEIVABLE FACTORING EXPENSE FOR APCO?

A. Yes. The VA SCC has consistently approved recovery of APCo's accounts receivable factoring expense recorded in both Accounts 4265009 and 4265010 in every base rate case since APCo first requested recovery of factoring expense in 2006. For example, on page 35 of the Final Order in Case No. PUE-2011-00037, the VA SCC made the following determination:

> *We find that all of APCo's factoring costs should be included as part of base rates…*

Q. HAS CPAD WITNESS SMITH FILED TESTIMONY IN ANY APCO BASE RATE CASE BEFORE EITHER THE VA SCC OR THE WVPSC?

A. Yes. Mr. Smith has filed testimony in four out of the last five APCo base rate cases before the VA SCC and the last three APCo base rate cases before the WVPSC.

Q. ARE YOU AWARE OF ANY TESTIMONY PREPARED BY MR. SMITH THAT WAS FILED IN AN APCO BASE RATE CASE IN WHICH HE RECOMMENDED THE DISALLOWANCE OF ALL CUSTOMER UNCOLLECTIBLE ACCOUNTS EXPENSE?

A. No. Based on my research of APCo base rate cases back to 2005, I only found one instance in which Mr. Smith filed testimony addressing APCo's customer uncollectible accounts expense. In VA SCC Case No. PUE-2011-00037, Mr. Smith (representing the Virginia Office of the Attorney General, Division of Consumer Counsel) filed testimony that proposed an adjustment to the uncollectible component of APCo's factoring costs from AEP Credit to reflect a three-year average uncollectible rate. On page 66 of Mr. Smith's direct testimony in VA SCC Case No. PUE-2011-00037 filed on August 5, 2011, Mr. Smith includes the following question and answer:

> *Q. HOW HAS APCO REFLECTED UNCOLLECTIBLES IN ITS FILING?*

A. APCO has reflected uncollectibles as a component of the AEP Credit factoring cost.

Q. WHAT IS YOUR RECOMMENDED LEVEL OF CUSTOMER UNCOLLECTIBLE ACCOUNTS EXPENSE IN THIS PROCEEDING?

A. Given that the Company is not opposed to the CPAD's use of an updated 2015 test year with certain adjustments (see Company witness Castle's rebuttal testimony), I recommend that the Authority approve the 2012-2015 four year average of bad debt expense of $401,982 recorded in Account 4265010 as the appropriate normalized level of expense for inclusion in the Company's cost of service used to set going-forward rates. Also, an uncollectible expense rate of .004599 as supported in the Company's petition should be a component of the gross revenue conversion factor used to calculate KgPCo's approved revenue increase in this proceeding.

PREPAID PENSION AND OTHER POSTRETIREMENT BENEFITS (OPEB) ASSETS (Novak, p.11, lines 1-8)

Q. DID THE COMPANY INCLUDE PREPAID PENSION AND OPEB ASSETS AS A COMPONENT OF ITS REQUESTED RATE BASE OF $71.5 MILLION EXCLUSIVE OF THE STREET LIGHTING JURISDICTION?

A. Yes. KgPCo included $4,197,544 in its requested Distribution rate base for the Company's December 31, 2014 end of test year prepaid pension asset after allocating portions of the total Company prepaid pension asset balance of $4,922,326 (recorded in Account 1650010) to the Transmission function ($566,322) and Street Lighting jurisdiction ($158,460). Also, KgPCo included $258,755 in its Distribution rate base for the December 31, 2014 end of test year prepaid OPEB asset after allocating portions of the total Company prepaid OPEB asset balance of $303,434 (recorded in Accounts 1650035 and 1650036) to the Transmission function ($34,911) and Street Lighting jurisdiction ($9,768).

Q. DOES THE CPAD ALSO INCLUDE KGPCO'S PREPAID PENSION AND OPEB ASSETS IN ITS RECOMMENDED RATE BASE FOR THE COMPANY?

A. No. On page 11 of CPAD witness Novak's testimony, Mr. Novak recommends $1,900,772 in total prepayments be included in rate base used to determine KgPCo's distribution function revenue requirement. The $1,900,772 reflects a three-year average of certain prepayments for the period 2013-2015 after the CPAD's adjustments to remove the Transmission function portion as well as various other attrition year adjustments. The CPAD recommended level of prepayments in rate base consists almost entirely of prepaid taxes and prepaid insurance and contains no amount for prepaid pension or OPEB assets.

Q. DOES CPAD WITNESS NOVAK EXPLAIN WHY HE EXCLUDED KGPCO'S PREPAID PENSION AND OPEB ASSETS FROM HIS RECOMMENDED RATE BASE?

A. No. In fact, neither Mr. Novak nor any other CPAD witness specifically mentions the Company's prepaid pension or OPEB assets in their testimony.

Q. IS THE CPAD'S EXCLUSION OF KGPCO'S PREPAID PENSION AND OPEB ASSETS FROM RATE BASE APPROPRIATE?

A. No. These additional cash contributions to the pension and OPEB trust funds should be included in rate base since they benefit customers by substantially reducing pension and OPEB expenses included in KgPCo's cost of service.

Q. PLEASE DESCRIBE THE COMPANY'S PREPAID PENSION AND OPEB ASSETS.

A. The Company has recorded prepaid pension and OPEB assets for additional cash investments in the pension and OPEB trust funds in accordance with generally accepted accounting principles (GAAP). Under the provisions of FASB Statement of Financial Accounting Standards (FAS) No. 87, *Employers' Accounting for Pensions* (now referred to as FASB Accounting Standards Codification (ASC) No. 715-30 Compensation – Postretirement Benefits - Defined Benefit Plans – Pension), KgPCo recorded as a prepaid pension asset additional cash contributions in excess of FAS 87 pension cost in the amount of $4,798,712 on a total Company basis as of December 31, 2015. In a similar manner, under the provisions of FAS 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions* (now referred to as ASC 715-60 Compensation – Postretirement Benefits - Defined Benefit Plans – Other Postretirement), KgPCo recorded as a prepaid OPEB asset cash contributions in excess of FAS 106 OPEB cost in the amount of $613,631 on a total Company basis as of December 31, 2015.

Q. HOW DO KGPCO'S CUSTOMERS BENEFIT FROM THE ADDITIONAL CONTRIBUTIONS TO THE PENSION AND OPEB PLANS?

A. KgPCo's customers benefit from the investment earnings on the additional fund assets. This has the effect of reducing future pension and OPEB costs under GAAP in an amount that grows over time through compounding. For example, the additional pension contributions recorded as a prepaid asset reduced the 2015 test year pension cost by approximately $552,000 on a total Company basis, as computed on Rebuttal Exhibit No.

1 (AWA), thus significantly reducing Kingsport's requested pension costs in this proceeding.

Q. CAN YOU PLEASE PROVIDE AN EXPLANATION FOR REBUTTAL EXHIBIT NO. 1 (AWA)?

A. Yes. Rebuttal Exhibit No. 1 (AWA) computes the effect that the additional pension contributions have in reducing pension cost for KgPCo's customers. The additional pension contributions recorded as a prepaid pension asset, which are shown in the third column, are equal to the pension plan contributions shown in the first column less the FAS 87 pension cost shown in the second column. The fourth column shows each year's assumed rate of return that was used in determining that year's FAS 87 cost as recorded on the Company's books, while the fifth column shows the investment return on the additional contributions, or the amount of pension cost savings resulting from the prepaid pension asset. The final column shows the cumulative effect on the balance of pension plan assets resulting from the additional contributions and the investment return thereon. The pension cost savings amount in the fifth column grows over time through compounding.

Q. WHY HAS THE COMPANY MADE ADDITIONAL PENSION CONTRIBUTIONS THAT RESULTED IN A PREPAID PENSION ASSET?

A. Pension cost included in KgPCo's cost of service for ratemaking purposes has historically been based on GAAP as set forth in FAS 87. However, pension contributions are based on separate ERISA requirements, so the amount of pension cost and the amount of pension cash contribution can often vary. FAS 87 requires that this difference be recorded on the balance sheet as a prepayment if contributions exceed cost or as a liability if cost exceeds contributions.

The Company experienced a pension funding shortfall under FAS 87 over the period 2000 through 2003 because of a combination of factors that increased the difference between the accumulated pension benefit obligation and the pension fund assets. By 2005, the amount of underfunding had reached the point that it was neither prudent nor reasonable for the Company to rely on the shortfall reversing over time through normal market activity and ERISA required cash contributions. Accordingly, the Company made a significant additional cash pension contribution in 2005 of $3,194,975, as shown in Supplemental Attachment 2 to the response to CPAD 1-079, to lessen the gap between the pension fund assets and the accumulated pension benefit obligation.

The market decline of 2008 and the decline in interest rates in 2009 through 2012 again caused the difference between the benefit obligation and the pension fund assets to grow. As a result, the Company made additional pension contributions in 2010, 2011 and 2012 to reduce the funding shortfall and to bring the pension assets closer into alignment with the benefit obligation.

Q. WHAT IS THE COMPANY'S CURRENT POLICY REGARDING CASH PENSION CONTRIBUTIONS?

A. As noted in the response to CPAD 1-079, the Company's current policy is generally to contribute at least any amount required under ERISA or the annual service cost of the pension plan (i.e. pension service cost), whichever is greater. The pension service cost refers to the present value of the projected retirement benefits earned by plan participants in the current period. A company's pension service cost is the amount it must set aside in the current period to match the retirement benefits accrued by plan participants.

Q. ARE THE PREPAID PENSION AND OPEB ASSETS THAT THE COMPANY IS REQUESTING IN RATE BASE ENTIRELY SUPPORTED BY CASH CONTRIBUTIONS?

A. Yes, the prepaid pension and OPEB amounts included in rate base are entirely supported by actual cash contributions in excess of pension and OPEB costs, respectively. The inclusion of these cash investment amounts in rate base will allow ratemaking recognition of the Company's cost of funds on the additional cash contributions. KgPCo's requested rate base does not include non-cash accrual adjustments made under FAS 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*, and recorded in Accounts 1650014, FAS 158 Qualified Pension Contra Asset, and Account 1650037, FAS 158 Contra-Post Retirement Welfare Excluding Medicare Part D, since such adjustments have no effect on the amount of the Company's cash pension and OPEB contributions or its FAS 87 pension and FAS 106 OPEB costs.

Q. DOES THE CPAD INCLUDE THE NON-CASH ACCRUAL ADJUSTMENTS RECORDED IN ACCORDANCE WITH FAS 158 IN THE CALCULATION OF ITS RECOMMENDED RATE BASE?

A. Yes. The starting point for the CPAD's calculation of prepayments to include in rate base was the total for all subaccounts for Account 165, Prepayments, on KgPCo's balance sheet for each month from 2013 through 2015. Included in these Account 165 subaccounts on KgPCo's books are Accounts 1650014 and 1650037, which as explained above are used to record non-cash accrual adjustments made under FAS 158 that have no effect on the amount of the Company's cash pension and OPEB contributions or its FAS 87 pension and FAS 106 OPEB costs. In accordance with FAS 158, the balance sheet is adjusted each year to the funded position (either underfunded or overfunded) of defined benefit pension and postretirement benefit plans. The Company uses Accounts 1650014 and 1650037 to offset, dollar-for-dollar, the prepaid pension and OPEB assets recorded in Accounts 1650010 and 1650035 (and also Account 1650036 in 2014 and prior years) so that there is not a prepaid pension or OPEB asset balance reported under GAAP. Instead, the cash contributions to the pension and OPEB trust funds made in excess of the FAS 87 pension and FAS 106 OPEB costs, respectively, are recorded under GAAP as regulatory assets in Account 1823.

Q. WOULD THE COMPANY AGREE WITH THE CPAD'S RECOMMENDED THREE-YEAR AVERAGE OF PREPAYMENTS IN RATE BASE IF THE CPAD EXCLUDED THE NON-CASH ACCRUAL ADJUSTMENT ACCOUNTS 1650014 AND 1650037?

A. Yes. The exclusion of Accounts 1650014 and 1650037 from the determination of rate base would allow the Company to earn a return on a representative level of additional cash contributions recorded as prepaid pension and OPEB assets that were prudently made and benefit customers as described above.

<u>PENSION AND OPEB EXPENSES (Novak, p.19, line 1-p.21, line 6)</u>

Q. DOES THE CPAD TAKE EXCEPTION TO THE COMPANY'S INCLUSION OF PENSION AND OPEB EXPENSES AS RECORDED ON KGPCO'S BOOKS IN THE COMPANY'S COST OF SERVICE?

A. Yes. Mr. Novak recommends that the Company's recorded amounts of pension and OPEB expense be ignored for ratemaking purposes and instead he recommends a zero amount of pension and OPEB expenses be included in KgPCo's cost of service.

Q. IS THE CPAD'S EXCLUSION OF PENSION AND OPEB EXPENSES FROM KGPCO'S COST OF SERVICE APPROPRIATE AND REASONABLE?

A. No, it is neither appropriate nor reasonable to exclude the prudently incurred and recorded pension and OPEB expenses from the Company's cost of service.

Q. WHAT REASON DOES MR. NOVAK GIVE FOR INCLUDING A ZERO LEVEL OF PENSION AND OPEB EXPENSES IN THE COMPANY'S COST OF SERVICE?

A. Mr. Novak's primary reason for excluding the Company's recorded amounts of pension and OPEB expenses seems to be his assertion that "the TRA has a long-established policy of only allowing rate recovery of the minimum required contribution for pension and other post-employee benefits ("OPEB") expenses." He goes on to assert that "for 2013, 2014 and 2015, the Company made no contribution to its pension and OPEB plans." Mr. Novak then concludes that "therefore, I included zero ($0) as the appropriate attrition period expense for pension and OPEB expense." (Novak, page 19)

Q. WHAT SUPPORT DOES MR. NOVAK PROVIDE FOR HIS ASSERTION THAT THE TRA HAS A POLICY OF ONLY ALLOWING RATE RECOVERY OF MINIMUM REQUIRED CONTRIBUTIONS FOR PENSION AND OPEB EXPENSES?

A. The only support that Mr. Novak provides is a footnote on page 19 of his testimony referencing TRA Docket No. 92-14631, Investigation of Proper Regulatory Treatment of

Other Post-Employment Benefits for Utilities Regulated by the Tennessee Public Service Commission.

Q. DOES THE REFERNCED TRA DOCKET 92-14631 ACTUALLY SUPPORT MR. NOVAK'S POSITION?

A. No. In fact, the Order in the referenced docket clearly supports the Company's request for pension and OPEB expenses as recorded on KgPCo's books and makes no mention of a minimum required contribution.

Q. PLEASE EXPLAIN HOW THE ORDER IN TRA DOCKET 92-14631 SUPPORTS THE COMPANY'S REQUEST INSTEAD OF THE CPAD'S RECOMMENDATION FOR PENSION AND OPEB EXPENSES.

A. The Order issued June 14, 1993 by the Tennessee Public Service Commission (TPSC), the predecessor of the TRA, in Docket No. 92-14631 approved the Administrative Judge's Initial Order dated May 27, 1993 and provided that "the accounting and ratemaking treatment of Post-Retirement Benefits Other than Pensions (FAS 106 costs) for Kingsport Power Company shall be consistent with this order." The Initial Order in this docket approved a Settlement Agreement between KgPCo and the TPSC Staff related only to the ratemaking treatment of FAS 106 costs (i.e. OPEB costs). In Item 1 of this approved Settlement Agreement dated May 12, 1993, the participants agreed to the following: "accrual accounting for Kingsport Power's postretirement benefits cost determined and recorded in accordance with SFAS No. 106, is proper for accounting and ratemaking purposes…" Also, Item 4 of the approved Settlement provides that "Kingsport Power will increase its rates by $187,120, annually to recover the incremental costs associated with SFAS No. 106…by means of a …surcharge to customers' bills effective June 1, 1993…(t)he surcharge will be discontinued and the cost reflected in base rates in Kingsport Power's next rate case".

Q. IS THE RATEMAKING TREATMENT OF PENSION EXPENSE ALSO ADDRESSED IN TRA DOCKET 92-14631?

A. While Docket 92-14631 only directly addresses the ratemaking treatment of OPEB expenses for the first time, the approved Settlement Agreement does note the similar accrual accounting treatment under GAAP for pension and OPEB costs when it states "(t)he FASB based the new rule on its decision that postretirement benefits are a form of deferred compensation which should be recorded on an accrual basis as the benefits are earned, much like pensions". At the time of Docket 92-14631, KgPCo was already recovering its pension costs in base rates approved by the TPSC based on FAS 87 accruals recorded on the Company's books.

Q. DOES THE TRA HAVE A "LONG-ESTABLISHED POLICY" RELATED TO THE INCLUSION OF PENSION AND OPEB EXPENSES IN KGPCO'S RATES?

A. Yes, the TRA has approved recovery of KgPCo's pension costs based on FAS 87 accruals and OPEB expenses based on FAS 106 accruals as recorded on the Company's books in accordance with GAAP.

Q. DOES CPAD WITNESS NOVAK DISAGREE WITH THE COMPANY'S ACCOUNTING FOR PENSION AND OPEB EXPENSES?

A. No. Mr. Novak acknowledges on page 19 of his testimony that "KPC records the accrued calculation of its pension and OPEB expense that is provided by its actuary in accordance with specific Financial Accounting Standards Board ("FASB") requirements."

Q. IS MR. NOVAK'S ASSERTION THAT "FOR 2013, 2014 AND 2015, THE COMPANY MADE NO CONRIBUTION TO ITS PENSION AND OPEB PLANS" CORRECT?

A. No. As shown in the Company's response to CPAD 1-079, KgPCo made cash contributions to its pension trust fund of $252,000 and $264,000 in 2014 and 2015, respectively. In 2013, ERISA credits were applied for the pension plan so a cash contribution was not made for that year. For the OPEB plan, the Company is currently in an overfunded position and has recorded credits on its books for OPEB expenses for the last 3 years, and consequently, no Company contributions to the OPEB plan have been made since 2013.

Q. BESIDES THE ASSERTION THAT THE TRA'S POLICY IS TO ONLY ALLOW KGPCO'S MINIMUM REQUIRED CONTRIBUTIONS FOR PENSION AND OPEB EXPENSES IN RATES, DOES THE CPAD OFFER ANY OTHER REASONS FOR ITS RECOMMEDED LEVEL (ZERO) OF PENSION AND OPEB EXPENSES?

A. Yes. CPAD witness Novak argues that the TRA should adopt the Company's minimum required contribution for setting base rates because the minimum required contribution: (1) "most closely matches today's cost with today's customer", (2) "is also generally not subject to the same changes in assumptions for market conditions as the actuary's recommended contribution" and (3) "is typically a more stable and consistent amount" (Novak, pp. 20-21).

Q. DOES MR. NOVAK 'S PROVIDE ANY SUPPORT FOR HIS REASONS THE TRA SHOULD ADOPT THE CPAD'S MINIMUM REQUIRED CONTRIBUTION RECOMMENDATION FOR KGPCO'S PENSION AND OPEB EXPENSES?

A. No, he does not.

Q. WHAT IS YOUR RECOMMENDATION FOR THE LEVEL OF PENSION AND OPEB EXPENSES TO INCLUDE IN BASE RATES IN THIS PROCEEDING?

A. Consistent with other costs that the CPAD updated to 2015 actual expenses, I recommend that CPAD witness Smith's adjustments (based on Mr. Novak's recommendation) to zero-out pension and OPEB expenses be rejected and that the 2015 actual net pension expense and OPEB credit to expense for the Distribution function recorded on KgPCo' s books of $118,595 and ($139,732), respectively, be included in the cost of service used to set base rates. The CPAD has presented no evidence in this case that should change the TRA's past treatment of allowing KgPCo to recover its actually incurred and recorded pension and OPEB expenses.

<u>CUSTOMER DEPOSITS RATE BASE ISSUES (Novak, p.13, line 5-p.14, line 4)</u>

Q. DO YOU AGREE WITH THE CPAD'S RECOMMENDED RATE BASE REDUCTIONS RELATED TO CUSTOMER DEPOSITS?

A. No. I disagree with CPAD witness Novak's inclusion of a rate base deduction of $1.3 million for Accumulated or Accrued Interest on Customer Deposits and I also do not agree with Mr. Novak's calculation of his rate base deduction of $5.3 million for Customer Deposit balances.

Q. WHAT REASON DOES MR. NOVAK GIVE FOR HIS INCLUSION OF ACCRUED INTEREST ON CUSTOMER DEPOSITS AS A RATE BASE REDUCTION?

A. On page 13 of his testimony, Mr. Novak asserts that "(s)ince this accumulated interest is owed to the customer, it represents a source of non-investor supplied funds which the Company has available to finance a portion of its utility investment and should therefore be included as a deduction in computing Rate Base".

Q. DOES MR. NOVAK EXPLAIN IN HIS TESTIMONY HOW ACCRUED INTEREST ON CUSTOMER DEPOSITS IS A SOURCE OF FUNDS FOR THE COMPANY?

A. No. Additionally, the Company asked the CPAD in discovery to "explain how accrued interest on customer deposits provides the Company with a source of non-investor supplied funds" referencing page 13 of Mr. Novak's testimony. In its response to KgPCo Request No. 32, the CPAD simply restated Mr. Novak's testimony on the subject without offering any explanation.

Q. DOES ACCRUED INTEREST ON CUSTOMER DEPOSITS PROVIDE THE COMPANY WITH FUNDS THAT ARE AVAILABLE TO FINANCE ITS UTILITY INVESTMENT?

A. No. Unlike deposits made by KgPCo's customers that do provide the Company with an inflow or source of funds, Accrued Interest on Customer Deposits is a liability recorded in Account 2370007 for future interest expected to be paid to customers upon refund of customer deposits. As such, Accrued Interest on Customer Deposits represents an outflow of funds from the Company to the customer in accordance with TRA rules and regulations. I understand that the TRA requires the Company to pay interest on its customer deposits.

Q. WOULD CUSTOMERS RECEIVE A RETURN ON THEIR SECURITY DEPOSITS MADE WITH THE COMPANY WITHOUT THE CPAD'S RECOMMENDED INCLUSION OF A RATE BASE DEDUCTION FOR ACCRUED INTEREST ON CUSTOMER DEPOSITS?

A. Yes. The Company has included in its requested cost of service a rate base deduction of $4.1 million for the end of 2014 test year balance of Customer Deposits recorded in Account 2350001. Thus, this rate base deduction for Customer Deposits provides KgPCo's customers with a return on their security deposits at the TRA authorized interest rate.

Q. DOES THE CPAD ALSO RECOMMEND INCLUDING A RATE BASE DEDUCTION FOR KGPCO'S CUSTOMER DEPOSIT BALANCES IN ADDITION TO A DEDUCTION FOR THE ACCRUED INTEREST ON SUCH DEPOSITS?

A. Yes. CPAD witness Novak recommends a rate base deduction of $5,265,608 for Customer Deposits in addition to his recommended $1,312,985 for Accrued Interest on Customer Deposits.

Q. ARE YOU AWARE OF ANY OTHER JURISDICTION THAT REGULATES AEP OPERATING SUBSIDIARIES APPROVING RATE BASE DEDUCTIONS FOR BOTH CUSTOMER DEPOSITS AND THE RELATED ACCRUED INTEREST?

A. No. For example, the VA SCC and WVPSC do not include a rate base deduction for Accrued Interest on Customer Deposits for APCo.

Q. SHOULD THE TRA APPROVE A RATE BASE DEDUCTION FOR ACCRUED INTEREST ON CUSTOMER DEPOSITS AS RECOMMENDED BY THE CPAD?

A. No. KgPCo's customers receive a return on their Customer Deposit balances through a rate base deduction for those balances and it would be inappropriate to include an additional deduction for Accrued Interest on Customer Deposits that was not provided by customers to the Company.

Q. DO YOU AGREE WITH MR. NOVAK'S CALCULATION OF THE CUSTOMER DEPOSIT BALANCES INCLUDED IN HIS RECOMMENDED RATE BASE?

A. No, his recommended rate base deduction of $5,265,608 overstates a reasonably expected rate year level of Customer Deposits for the Company.

Q. HOW DOES MR. NOVAK CALCULATE HIS RECOMMENDED LEVEL OF CUSTOMER DEPOSITS TO INCLUDE IN KGPCO'S RATE BASE?

A. Mr. Novak explains his calculation of a rate base deduction for Customer Deposits as follows: "(t)o compute Customer Deposits, I calculated a linear regression of historical Customer Deposits against historical distribution Plant in Service. I then applied the results of this regression (with an 89% correlation) to attrition period distribution Plant in Service…" (Novak, p. 13)

Q. DOES MR. NOVAK'S METHODOLOGY FOR CALCULATING A GOING-FORWARD LEVEL OF CUSTOMER DEPOSITS FOR THE COMPANY PRODUCE A REASONABLE RESULT?

A. No. Mr. Novak's recommended rate base deduction of $5,265,608 is 23% higher than the 2015 actual Customer Deposit balance recorded on KgPCo's books of $4,275,913, and as such, it is not a reasonable going-forward level of Customer Deposits to use for setting base rates.

Q. IS THERE ANY RECENT HISTORICAL EVIDENCE THAT SUPPORTS MR. NOVAK'S PREDICTED 23% INCREASE IN KGPCO'S CUSTOMER DEPOSITS OVER THE 18-MONTH PERIOD FROM DECEMBER 2015 TO JUNE 2017?

A. No. As shown on Company witness Buck's KgPCo Exhibit No. 2-a (DRB) page 4 of 10, the Company included the 2014 end of test year Customer Deposits of $4,085,238 as a rate base reduction in its requested cost of service. An updated 2015 test year for purposes of developing base rates in this proceeding would include the 2015 end of year Customer Deposits of $4,275,913, which was an increase of $190,676 from the end of 2014 balance. At the time of preparing this rebuttal testimony, the most current balance of KgPCo's Customer Deposits as of June 30, 2016 was $4,327,313, which is $51,400 more than the December 31, 2015 balance, but almost $1 million less than the amount forecasted by Mr. Novak for KgPCo's Customer Deposits at June 30, 2017.

Q. HAVE YOU PREPARED AN EXHIBIT TO SHOW WHAT A REASONABLE ESTIMATE OF KGPCO'S CUSTOMER DEPOSITS AT JUNE 30, 2017 WOULD BE USING RECENT HISTORICAL INFORMATION?

A. Yes. Rebuttal Exhibit No. 2 (AWA) shows the derivation of an estimated Customer Deposits balance of $4,566,488 as of June 30, 2017 using the average annual increase in actual Customer Deposits recorded on KgPCo's books over the period 2013-2015 of $193,717. If the test year level of Customer Deposits is adjusted to determine the going-forward level to include in KgPCo's rate base, the Company recommends that the rate base deduction for Customer Deposits be no more than the $4,566,488 computed on Rebuttal Exhibit No. 2 (AWA).

<u>CUSTOMER ADVANCE RECEIPTS (Novak, p.12, line 21-p.13, line 4)</u>

Q. CPAD WITNESS NOVAK RECOMMENDS A RATE BASE DEDUCTION OF $546,604 FOR CUSTOMER ADVANCES RECORDED AS A LIABILITY ON KGPCO'S BALANCE SHEET. DO YOU AGREE WITH THIS RECOMMENDATION?

A. I disagree with $435,954 of the $546,604 recommended amount of Customer Advances related to activity in Account 2530022, Customer Advance Receipts.

Q. WHAT REASON DOES MR. NOVAK PROVIDE FOR INCLUDING CUSTOMER ADVANCES AS A RATE BASE DEDUCTION?

A. Mr. Novak asserts that the $546,604 of Customer Advances "represents non-investor supplied funds from customers for extending utility service that the Company has used to finance a portion of its utility investment…"

Q. IS MR. NOVAK'S DESCRIPTION OF CUSTOMER ADVANCES ACCURATE FOR THE ENTIRE $546,604 RECOMMENDED RATE BASE DEDUCTION?

A. No, it is not accurate for most of this amount. The $546,604 consists of historical averages for the following two accounts recorded on KgPCo's books: Account 2530022 in the amount of $435,954 and Account 2530124, Contribution in Aid of Construction (CIAC) Advance, in the amount of $110,650. The activity in Account 2530022 is not related to payments from customers for extending utility service but instead represents any negative electric customer accounts receivable balances temporarily reclassified from

Account 1420001, Customer Accounts Receivable-Electric, to Account 2530022. Mr. Novak's description for Customer Advances does accurately describe Account 2530124, which the Company also included as a rate base deduction in its requested rate base.

Q. SHOULD CUSTOMER ADVANCE RECEIPTS RELAED TO NEGATIVE ELECTRIC CUSTOMER ACCOUNT BALANCES BE INCLUDED AS A RATE BASE DEDUCTION AS RECOMMENDED BY MR. NOVAK?

A. No. These temporary overpayments by customers recorded in Account 2530022 should not be included in rate base in the same manner that electric customer receivables recorded in Account 1420001 are not included in the Company's rate base. KgPCo does not object to the inclusion of $110,650 of Customer Advances recorded in Account 2530124 as a rate base deduction as calculated by Mr. Novak.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Effect of Additional Pension Contributions Recorded As Prepaid Pension Asset in Reducing Pension Cost

Total Company Amounts

Kingsport Power Company

	Plan Contributions	Less Qualified FAS 87 Cost	Additional Contributions	Investment Return Rate	Investment Return Amount	Balance of Plan Assets
					FAS 87 Savings	
2005 Pension Balance @ 12/31						4,449,169
2006 Return on 2005 Balance				8.50%	**378,179**	4,827,348
2006 Contribution	-	136,816	(136,816)			4,690,532
2007 Return on 2006 Balance				8.50%	**410,325**	5,100,857
2007 Contribution	-	64,384	(64,384)			5,036,473
2008 Return on 2007 Balance				8.00%	**408,069**	5,444,542
2008 Contribution	-	52,492	(52,492)			5,392,050
2009 Return on 2008 Balance				8.00%	**435,563**	5,827,613
2009 Contribution	-	238,906	(238,906)			5,588,707
2010 Return on 2009 Balance				8.00%	**466,209**	6,054,916
2010 Contribution	595,076	343,908	251,168			6,306,084
2011 Return on 2010 Balance				7.75%	**488,722**	6,794,805
2011 Contribution	1,582,000	369,000	1,213,000			8,007,805
2012 Return on 2011 Balance				7.25%	**580,566**	8,588,371
2012 Contribution	767,000	419,827	347,173			8,935,544
2013 Return on 2012 Balance				6.50%	**580,810**	9,516,355
2013 Contribution	-	560,949	(560,949)			8,955,406
2014 Return on 2013 Balance				6.00%	**537,324**	9,492,730
2014 Contribution	252,000	536,638	(284,638)			9,208,092
2015 Return on 2014 Balance				6.00%	**552,486**	9,760,578
2015 Contribution	264,000	387,614	(123,614)			9,636,964
Total Additional Contributions Above	3,460,076	3,110,534	349,542			
Cumulative Prior Years			4,449,170			
Prepaid Pension Balance at December 2015			4,798,712			

	2015
Actual Pension Cost (Qualified)	387,614
Prepaid Contribution Savings Above	552,486
Pension Cost Without Contribution Savings	940,100

Note: This schedule computes the pension cost savings from the additional pension contributions since 2005 that were recorded as prepaid pension asset based on additional trust fund investment earnings on the additional contributions.

KINGSPORT POWER COMPANY
CUSTOMER DEPOSITS
ACCOUNT 2350001

		12/31/2015	12/31/2014	12/31/2013	Average
Customer Deposit Balances		$ 4,275,913	$ 4,085,237	$ 3,888,480	
Increase from Prior Year		$ 190,676	$ 196,757		$ 193,717
Estimated 12/31/16 Balance based on Average Increase from 2013-2015 applied to end of 2015 balance	$ 4,469,630				
Estimated 6/30/17 Balance based on Average Annual Increase from 2013-2015 applied to estimated 12/31/16 balance (Avg Rate Year Rate Base)	$ 4,566,488				

Buck

KgPCo Rebuttal Exhibit No. ____
Witness: DRB

REBUTTAL TESTIMONY OF
DOUGLAS R. BUCK
ON BEHALF OF KINGSPORT POWER COMPANY
D/B/A AEP APPALACHIAN POWER
BEFORE THE TENNESSEE REGULATORY AUTHORITY
DOCKET NO. 16-00001

Q. PLEASE STATE YOUR NAME.

A. My name is Douglas R. Buck.

Q. ARE YOU THE SAME DOUGLAS R. BUCK WHO SUBMITTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony responds to the direct testimony of Consumer Protection and Advocate Division (CPAD) witness Novak regarding his proposal on recovering the revenue deficiency for the various customer classes, his use of allocation factors and the class cost-of-service study, his calculation of the gross revenue conversion factor, and the Company's proposed Rate Realignment Rider.

<u>**WEATHER NORMALIZATION ADJUSTMENT**</u>

Q. CPAD WITNESS NOVAK STATES THAT "TO MY KNOWLEDGE, THE COMPANY HAS NEVER PROPOSED A WEATHER NORMALIZATION ADJUSTMENT IN A RATE CASE PRIOR TO THIS DOCKET" (NOVAK PAGE 16, LINES 3-4). HAS KINGSPORT POWER EVER PROPOSED A WEATHER NORMALIZATION ADJUSTMENT?

A. Yes. In the last base rate proceeding (Docket No. 92-04425), the Company included a weather adjustment. Company witness Burnett provides rebuttal testimony explaining the weather adjustment used in this case.

CLASS COST-OF-SERVICE STUDY

Q. MR. NOVAK STATES THAT TO HIS KNOWLEDGE, THE TRA HAS NEVER ADOPTED A CLASS COST-OF-SERVICE STUDY (CCOSS) FOR ANY OF THE UTILITIES THAT IT REGULATES (NOVAK PAGE 24, LINES 6-7). PLEASE COMMENT.

A. In Kingsport's last base rate case filed before the Tennessee Public Service Commission, case No. 92-04425, the Company included a CCOSS for a basis of its proposed rate design. While this was a settled case, nothing in the Final Order established any precedent for how rate design for electric utilities should be performed. Simply put, that is not a valid reason to oppose the Company's proposed rate design.

Q. WHAT IS THE PURPOSE OF THE CLASS COST-OF-SERVICE STUDY?

A. The cost-of-service studies are a basic and nearly universally accepted tool used in electric utility ratemaking based on the principle that the cost to provide service should be the basis on which costs are collected. These studies assure rates are reasonably set and do not discriminate between rate classes. The purpose of a class cost-of-service study is to fully allocate the test year revenues, expenses, and rate base to each customer class based on how those customers cause costs to be incurred. By conducting a CCOSS, cost-based rates are developed and each customer class is responsible for the costs they impose on the system. Different classes of customers use electricity differently and that difference is the basis for the disparity in the cost to provide them service. A residential customer may use very little electricity at night in the fall but considerable electricity on a hot summer day or cold winter morning. Contrast that with an industrial customer who may use electricity in a nearly uninterrupted way day and night, all year. On a per-unit basis, that residential customer is more expensive to serve because the Company must design its system to deliver electricity on the peak hour, but must collect the revenues over the year at times when consumption is often considerably less than the peak. Known as cost causality, this principle should be applied by the TRA to set rates in this case.

<u>REVENUE ALLOCATION</u>

Q. DOES THE COMPANY SUPPORT MR. NOVAK'S PROPOSAL TO RECOVER THE REVENUE DEFICIENCY FOR ALL CUSTOMER CLASSES BASED ON THE CURRENT MARGIN PROVIDED BY EACH CUSTOMER CLASS (NOVAK PAGE 24, LINES 12-15)?

A. No. In each of the other regulatory jurisdictions in which American Electric Power (AEP) operates the principle of cost causation is applied to rate development. The same principle should be applied by the TRA in this case. Mr. Novak proposes a method that socializes the cost of electricity for Kingsport Power Company customers by perpetuating and, in some cases, exacerbating existing subsidies among the classes. With Mr. Novak's proposed allocation method, certain classes of customers will continue to over-pay and others under-pay for their service from Kingsport Power Company. For economic reasons, discussed in the rebuttal testimony of Company witness Castle, subsidies among classes should be eliminated in order to communicate accurate economic signals. The Company has proposed a process to move Kingsport's rates gradually toward cost causation and recommends the TRA approve an objective method of reducing and eventually eliminating these subsidies.

In fact, Mr. Novak provides testimony conceptually supporting the principle of cost causation when he (incorrectly) states that the Company's proposed demand side management (DSM) program will, "require all of the Company's 47,000 customers to pay for the benefits received by as few as 300 customers" (Novak Page 32, Lines 9-10). Mr. Novak does not support the Company's proposed cost recovery for the DSM program, referring to it as an "involuntary tax on electric consumers' (Novak Page 32, Lines 4-5). It is completely incongruent to ignore a subsidy perpetuated by rate design based solely on pro rata increases and then use a version of that same logic to oppose demand-side management programs. Company witness Castle's rebuttal addresses the fallacy of Mr. Novak's assertions regarding the proposed DSM programs.

PURCHASED POWER COSTS

Q. MR. NOVAK CALCULATES HIS REVENUE INCREASE BASED ON THE CURRENT MARGIN, WHICH HE STATES EXCLUDES

PURCHASED POWER COSTS. (NOVAK PAGE 25, TABLE 6; NOVAK RESPONSE TO DATA REQUEST 1-9). DO YOU AGREE?

A. No. Mr. Novak's margin Exhibit 6 is not accurate because his calculations still include embedded purchased power costs. It is therefore not correct if the intent is to recognize Kingsport's local, or distribution, revenues which exclude all of the wholesale power purchased from Appalachian Power Company. The Company continues to stand behind its cost-of-service method to determine the allocation of the proposed revenue increase. However, if Mr. Novak's concept were adopted, the properly computed margin for each class should be used.

<u>ALLOCATION FACTORS</u>

Q. MR. NOVAK STATES CONCERNS OVER THE NUMBER OF ALLOCATION FACTORS THE COMPANY USES IN ITS COST STUDIES. WHY ARE THESE ALLOCATORS NECESSARY?

A. To accurately determine cost causation, costs must be assigned to the source, or class, that causes them to be incurred. As described under its respective section in my direct testimony, this is the purpose of both the jurisdictional and class cost-of-service studies. As is the industry standard, each line item in these studies is reviewed, an appropriate allocation method is determined based on cost causation, and numerous forms of Company data are used to allocate costs to the various classes. Allocators applied to this study are similar to those used and approved in rate cases across the AEP system as well as for numerous other electric utilities. For Mr. Novak to state that he could easily allocate plant accounts (which apply a demand allocator) using an energy allocator (Novak Page 23, Lines 12-15) ignores the fact that generating facilities are built and sized based on peak usage, or the demand requirements of the system, not annual consumption of electricity. Demand allocators are necessary to allocate demand related costs among the various rate classes based on their respective contribution to that peak demand. Additional examples of the use of specific allocators include: Company data on customer deposits to allocate the interest on customer deposits; pre-tax operating income to allocate taxes; retail sales to allocate the gross receipts tax; electric utility plant (gross utility plant) to allocate property taxes; detailed Company meter data to allocate investment in meters; detailed Company data on overhead and underground lines, as well as transformers and poles, between the primary and secondary distribution system to allocate investments associated with this distribution equipment. As these examples demonstrate, extensive efforts are made to fairly, and with objective bases as possible, determine the costs of serving each customer class and the return earned from each class. Numerous allocation factors are necessary to properly determine and assign costs.

Finally, while it is unclear how Mr. Novak would allocate the items listed previously, he states “factors beyond just the cost of service need to also be considered in allocating costs. These other factors include value of service, product marketability, encouragement of efficient use of facilities, broad availability of service functions, and a fair distribution of charges among users” (Novak page 23, lines 18-21). He provides no explanation as to how these subjective and unquantifiable factors would be determined.

Q. MR. NOVAK STATES THAT THE COMPANY'S CLASS COST-OF-SERVICE STUDY ALLOCATES 0.3% OF ITS PROPOSED $12.1 MILLION REVENUE INCREASE TO INDUSTRIAL CUSTOMERS AND THE REMAINING AMOUNT TO ALL OTHER CUSTOMERS (NOVAK PAGE 22, LINES 22-23, PAGE 23, LINES 1-2). DO YOU HAVE CONCERNS ABOUT THIS STATEMENT?

A. Yes. The Company's proposed revenue increase for the IP class is approximately 20% of the proposed overall $12.1 million increase. The Company cannot determine how Mr. Novak calculated the 0.3%.

<u>**GROSS REVENUE CONVERSION FACTOR**</u>

Q. IN CALCULATING THE PROPOSED REVENUE INCREASE, MR. NOVAK USES A GROSS REVENUE CONVERSION FACTOR (GRCF) THAT EXCLUDES ADJUSTMENTS FOR THE TRA INSPECTION FEE AND UNCOLLECTIBLES. IS IT APPROPRIATE TO EXCLUDE THESE ITEMS FROM THE GRCF?

No. Both the TRA Inspection Fee and Uncollectibles need to be included in the calculation of the proposed revenue increase in order for the Company to earn its approved return.

PROPOSED RATE REALIGNMENT RIDER

Q. PLEASE ADDRESS MR. NOVAK'S OPPOSITION TO THE COMPANY'S PROPOSED RATE REALIGNMENT RIDER TO REDUCE RATE CLASS SUBSIDIES OVER THE NEXT 5 YEARS.

A. Over the remaining five years of the rider, he recommends using the Company's proposed criteria to determine rate adjustments, by class, to gradually shift rates to a cost-of-service based rate structure.

The Company continues to support its proposed Rate Realignment Rider as a reasonable method to gradually move toward a cost-of-service based rate structure. Detailed cost-of-service studies, as have been used and approved in each of AEP's other state jurisdictions and are similarly used by other electric utilities across the country, are the correct methodology to determine the costs each customer class imposes on the Company. It is also appropriate to strive to recover from each customer class their respective costs. It is difficult to understand why Mr. Novak belittles this attempt by the Company to align rates with cost causation principles, the electric industry standard.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Vaughan

REBUTTAL TESTIMONY OF
ALEX E. VAUGHAN
ON BEHALF OF KINGSPORT POWER COMPANY
D/B/A AEP APPALACHIAN POWER
BEFORE THE TENNESSEE REGULATORY AUTHORITY
DOCKET NO. 16-00001

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

A. My name is Alex E. Vaughan. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by the American Electric Power Service Corporation (AEPSC) as Manager of Regulated Pricing and Analysis. AEPSC supplies engineering, financing, accounting, and planning and advisory services to the subsidiaries of the American Electric Power (AEP) System, one of which is Kingsport Power Company (KgPCo or the Company).

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I graduated from Bowling Green State University with a Bachelor of Science degree in Finance in 2005. Prior to joining AEP, I worked for a retail bank and a holding company where I held various underwriting, finance and accounting positions. In 2007 I joined AEPSC as a Settlement Analyst in the Regional Transmission Organization (RTO) Settlements Group. I later became the PJM Settlements Lead Analyst where I was responsible for reconciling AEP's settlement of its activities in the PJM market with the monthly PJM invoices and for resolving issues with PJM. In 2010, I transferred to Regulatory Services as a Regulatory Analyst and was later promoted to the position of Regulatory Consultant. My responsibilities included supporting regulatory filings across AEP's eleven state jurisdictions and at the Federal Energy

Regulatory Commission (FERC). I also performed financial analyses related to AEP's generation resources and loads, power pools and PJM. In September of 2012, I was promoted to my current position where my responsibilities include the oversight of cost of service analyses, rate design and special contracts for the AEP System operating companies. I am directly responsible for assisting KgPCo in its regulatory filings in the Tennessee jurisdiction, and proposed Rider NMS-2 and Tariffs RS-D and SGS-D were designed under my supervision.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY AS A WITNESS BEFORE ANY REGULATORY COMMISSION?

A. Yes. I presented testimony on behalf of the AEP Operating Companies numerous times before the regulatory bodies in Virginia, West Virginia, Kentucky and Indiana.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony responds to the direct testimony of The Alliance for Solar Choice (TASC) witness Sanders and Consumer Protection and Advocate Division (CPAD) witness Novak regarding the Company's proposed rider NMS-2, which requires new NMS customers to take service under Tariffs RS-D or SGS-D (the NMS Proposal).

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following exhibits:

- Rebuttal Exhibit No. 1 (AEV): NMS Related Data and Analysis
- Rebuttal Exhibit No. 2 (AEV): NMS Fixed Cost Contribution
- Rebuttal Exhibit No. 3 (AEV): RS-D Rate Design
- Rebuttal Exhibit No. 4 (AEV): Residential Rate Comparison

Q. WERE THE EXHIBITS THAT YOU ARE SPONSORING PREPARED OR ASSEMBLED BY YOU OR UNDER YOUR DIRECTION?

A. Yes.

<u>THE PREVALENCE OF DEMAND CHARGES</u>

Q. HOW DO YOU RESPOND TO TASC WITNESS SANDERS'S STATEMENT ON LINE 1 OF PAGE 4 OF HER TESTIMONY THAT DEMAND CHARGES IN RESIDENTIAL RATE DESIGN ARE NOT COMMON ACROSS THE COUNTRY?

A. This statement is inaccurate, as this rate design is ubiquitous for both commercial and industrial customers and has been in existence for more than a century. Moreover, residential demand rates are not a new phenomenon - Arizona Public Service offered a mandatory residential demand rate as early as 1981 for new homes with central air conditioning. Currently, demand rates for residential customers are offered by 25 utilities across 15 different states.

More and more utilities are turning to rate design, including demand charges, to address the inequities in the traditional net metering model. In the first quarter of 2015, there were 46 instances of policy and regulatory action related to net metering and community solar as well as rate design changes that included increasing fixed charges for all customers and/or the introduction of demand charges for solar net metered customers; in 2015 there were 77 instances of policy and action related to distributed solar and rate design (a 167% increase). I would also like to clarify that the proposed residential demand rate (Tariff RS-D) is optional for standard residential customers, to address Ms. Sanders's apparent uncertainty. (Sanders at 4:6-7)

Q. DO YOU HAVE FURTHER COMMENTS TO ADDRESS TASC WITNESS SANDERS'S STATEMENT ON LINE 1 OF PAGE 4 THAT DEMAND CHARGES IN RESIDENTIAL RATE DESIGN ARE NOT COMMON ACROSS THE COUNTRY?

A. Yes. As discussed in more detail later, the NMS Proposal is cost-based in nature and is therefore firmly rooted in the well-known and basic principles of rate design, as memorialized in Dr. James C. Bonbright's *Principles of Public Utility Rates*. Public utility commissions all across the United States and abroad have been setting rates based on these basic principles for the better part of 55 years. Regarding cost causation and equity in rates, Dr. Bonbright highlights several rationales in favor of the cost-based standard. (1st ed., Chapt. 4) Dr. Bonbright leads with the notion of "consumer sovereignty." That is,

> potential consumers should be free to enjoy whatever kinds of service, whatever amounts they desire as long as they are ready to indemnify the producers, and hence society in general, for the cost of rendition.

This simple principle of economic efficiency is an important aspect of cost causation in ratemaking: the consumer should pay the producer for the amount of goods or services it has consumed.

Dr. Bonbright also supports cost-based ratemaking because it is fundamentally fair: "an individual with a given income who decides to draw upon the producer, and hence on society, for a supply of public utility services should be made to 'account' for this draft by the surrender of a cost-equivalent opportunity respectively."

Q. HOW DID THESE RULES GUIDE THE DEVELOPMENT OF THE NMS PROPOSAL?

A. These notions of personal responsibility and fairness are the main reason behind the changes proposed in this proceeding for the NMS Proposal. Regardless of the rate design used to achieve equitable treatment, the concept of customers paying for their fair share of the costs they cause to be incurred by the Company is not a revolutionary concept, as Ms. Sanders would like the Authority to believe. Quite to the contrary, it is one of the most well-established rules of ratemaking.

Q. HOW DO YOU RESPOND TO MS SANDERS'S STATEMENT ON LINE 5 OF PAGE 3 THAT 0.02% OF KINGSPORT CUSTOMERS ENGAGE IN NET METERING?

A. Although the Company does not have a significant amount of residential customers engaging in net metering tariff, waiting to address widely known issues regarding net metering can prove to be problematic for customers, the utility and regulators. For example, in 2005, Hawaii had 1.8 MWs of installed solar capacity and 104 photovoltaic installations. In 2014 Hawaii that number had grown to 346 MWs of installed solar capacity and 46,279 photovoltaic installations, representing an astronomical 19,122% increase of installed solar capacity and a 44,399% increase in photovoltaic installations in less than a decade. If Kingsport saw a comparable amount of growth, its customers would have 3,551 photovoltaic installations and non-net metered customers in Kingsport would end up paying a subsidy to net metered customers of $3,835,080 per year ($90 subsidy per customer x 12 months x 3,551 net metered customers). In 2015, the Hawaii Public Utilities Commission approved requests by the Hawaiian Electric Company to terminate its net metering program and to introduce other options that would allow the utility to use distributed energy resources in a way that benefits all utility customers, noting the challenge of ensuring that the installation of customer- sited generation resources by some customers will benefit all customers.[1]

Other states that have faced challenges addressing the inequities of net metering include California, Nevada and Arizona.

Q. HAVE ANY STATE COMMISSIONS SOUGHT TO ADDRESS THE INEQUITIES IN THE TRADITIONAL NET METERING MODEL BEFORE NET METERING'S POPULARITY REACHED LEVELS SIMILAR TO THOSE IN HAWAII?

A. Yes. There is precedent for a state commission addressing a potential cross-subsidization issue before it becomes problematic. For example, the Public Service Commission of Wisconsin in its Final Order of Docket 5-UR-107[2] wrote:

> Some intervenors also argued that making the proposed tariff changes now is premature and not necessary because DG only makes up a small fraction of WEPCO's current system. However, it is precisely for that reason that it is reasonable to restructure WEPCO's DG tariff offerings now. The Commission finds, ***based upon the facts and as a matter of public policy, that there are utility fixed costs that are not being borne by DG customers and a change should be made now before those costs grow with increased adoption of DG***. The use of distributed generation is expected to continue to increase and it is important for those making such investments to understand the real costs and benefits of those investments and make informed choices. Subject to the

[1] *In the Matter of the Hawaii Public Utilities Commission Instituting a Proceeding to Investigate Distributed Energy Resource Policies*, Docket No. 2014-0192, Order No. 53258 at 4 (Oct 12, 2015).

[2] Final Decision, *Joint Application of Wisconsin Electric Power Company and Wisconsin Gas LLC, both d/b/a We Energies, for Authority to Adjust Electric, Natural Gas, and Steam Rates*, Public Service Commission of Wisconsin, Case No. 5-UR-107 (Dec. 23, 2014).

> conditions described below, ***the Commission finds that it is reasonable to authorize the tariff changes requested by WEPCO, as this will move WEPCO in the direction of better aligning its rates with its costs***. (emphasis added)

In the Final Order issued by the Public Service Commission of Wisconsin, buyback rates for excess generation were set (marginal cost of energy plus the avoided cost of transmission), monthly net-metering was upheld in lieu of annual net-metering, and demand charges for its Customer Owned Generation System tariffs were found to be reasonable.

Q. WHAT WOULD BE THE RESULT IF THE AUTHORITY FOLLOWS MS. SANDERS'S RECOMMENDATION AND DENIES THE NMS PROPOSAL?

A. Kingsport, like other utilities across the nation, must be fair and equitable towards its customers and must ensure that rates reflect utility cost as emerging technologies become more affordable and commonplace. Simply put, if the Company's rates are not aligned with costs, then the savings realized by net-metering customers are spread amongst non-net metered customers as a cost.

<u>THE NMS PROPOSAL</u>

Q. HOW DO YOU RESPOND TO MS. SANDERS'S ASSERTION THAT THE COMPANY PROVIDED NO DATA, QUANTITATIVE ANALYSIS OR OTHER SUBSTANTIVE FINDING TO SUPPORT ITS NMS PROPOSAL? (SANDERS AT 2)

A. The Company's filing, workpapers and subsequent data request responses to the parties contain vast amounts of data, quantitative analysis and justifications for the NMS

Proposal. I will further demonstrate the existence and magnitude of the subsidy described in the direct testimony of Company witness Castle, and will explain how the NMS Proposal better aligns costs with rates.

Q. PLEASE ELABORATE.

A. Through the filing materials and subsequent data requests, the Company provided detailed cost of service information by customer class which allows interested parties to examine the Company's requested revenues by class at the functional level (Generation, Distribution and Transmission). This information was provided to interested parties to the case as "Staff Informal 1-24 – TAC- Attachment 3 – KgPCo Rate Design.xlsx, which I will refer to generically as the rate design workpapers. Also included the Company's filing are class load research studies, the Company's cost of service studies, and the monthly Kingsport power bills from its affiliate Appalachian Power Company for transmission and generation service, among other items. A listing of the relevant data and analysis provided in this filing is included in Rebuttal Exhibit No. 1 (AEV): NMS Related Data and Analysis.

Q. HOW IS THIS INFORMATION GERMANE TO MS. SANDERS'S ASSERTION THAT THERE IS NO DATA OR ANALYSIS REGARDING THE NMS PROPOSAL?

A. This shows that the Company did in fact provide a great deal of relevant information and also supports the NMS Proposal that Ms. Sanders recommends that the Authority reject.

Q. PLEASE DESCRIBE HOW THE INFORMATION ALREADY PROVIDED BY THE COMPANY SUPPORTS ITS POSITION REGARDING THE NMS

PROPOSAL, WHICH IS CONTRARY TO MS. SANDERS'S POSITION. (SANDERS AT 6:10)

A. At its core, the Company's proposal to close Rider NMS to new participants and introduce Rider NMS-2 for net metering customers who begin taking service after January 1, 2017 is being made to close an intraclass subsidy being provided to current net metering customers by non-net metering customers. The NMS Proposal accomplishes this goal, for example, by requiring new residential NMS-2 customers to take service under the Company's proposed Tariff RS-D, which includes a three part rate structure that will recover an appropriate amount of fixed costs from residential NMS-2 customers, something that does not occur under the current Rider NMS. The Company's current Rider NMS does not provide for an appropriate amount of fixed cost recovery from residential customers taking service under the rider because it uses the two part rate structure of the Company's standard residential service tariff which collects the majority of fixed costs through the energy (kWh) rate. NMS customers avoid paying the kWh rate when they net their usage to zero or their customer sited generation resource produces in excess of their load requirements in a given billing period.

That excess is carried forward and used to net future billing period usage to zero, which can result in, for example, residential NMS customers only paying the residential tariff's current monthly fixed service charge of $7. In fact, the data and analysis included in the Company's cost of service studies, load research and rate design workpapers show that NMS customers cause much higher costs than $7 per month because they do use the Company's electric delivery system and electric supply resources every day of the year whether their monthly bill reflects that usage or not. The inequity inherent in the current rate structure is the difference between $7 and the actual costs incurred to serve residential NMS customers which must be paid for by non-NMS customers.

Q. PLEASE DISCUSS THE AVERAGE MONTHLY COST TO SERVE A RESIDENTIAL NMS CUSTOMER. (SANDERS AT 2:17)

A. Pursuant to the well-established principles of rate-making I discussed above, it cannot be rationally argued that net metering customers are not responsible for their appropriately allocated share of fixed costs associated with the Company's distribution and transmission infrastructure. The Company's distribution system is sized primarily based on the typical customer's requirements. Therefore dividing the residential class distribution revenue requirement by the number of customers in the class is a reasonable proxy for each customer's cost responsibility. This amounts to about $19 per residential customer per month. As the Company's transmission system is sized to meet the peak demands of the end use distribution systems connected to it, peak demand is the rational way to allocate transmission infrastructure costs to the customer classes and end use customers. Based on the residential class's transmission revenue requirement and its annual peak demand in kW, transmission service for the Company's residential class costs $1.53 /kW of max billing demand. The average monthly max billing demand for the Company's nine residential net metering customers is 14 kW, which results in an average transmission cost of $21.43 per customer per month.

Q. HOW SHOULD THE COMPANY CALCULATE THE NET METERING CUSTOMERS' RESPONSIBILITY FOR FIXED GENERATION COSTS?

A. Proponents of net metering program structures that subsidize net metering participants argue that net metering customers should contribute less than the class average amount of fixed generation costs because they self-supply, during some hours, some portion of their electrical requirements from their own generation resources. But unless they also have incorporated an elaborate battery and control array to complement their distributed generator so that they can store energy generated by their units to serve their needs when the sun does not shine, they do in fact use the Company's generation, or electrical supply, resources every day. Thus, a reasonable contribution to generation fixed costs is warranted. As discussed later in this testimony, seven of the 12 Kingsport monthly peaks that cause its test year generation fixed costs occurred in the morning between 7:00 and 8:00. Making a conservative and generous assumption that the other five monthly peaks were avoided entirely, a reasonable proxy for NMS generation fixed cost contribution for this exercise would be 7/12 of the residential class average generation fixed cost per kW. This share of generation fixed costs is equal to $4.03/kW of max billing demand and $56.38 per average residential net metering customer per month based on that same 14 kW of monthly billing demand. To put that 14 kW average monthly billing demand for NMS customers into perspective, it is three and a half times larger than the typical non-net metered residential customer's monthly billing demand of approximately 4 kW.

Q. GIVEN THE ABOVE CALCULATIONS, WHAT IS THE CURRENT SUBSIDY PAID TO THE COMPANY'S RESIDENTIAL NET METERING CUSTOMERS BY ITS NON-NET METERING CUSTOMERS?

A. As the average cost to serve a residential net metering customer has been calculated to be roughly $97 per month, and the Company's current fixed service charge for residential customers is $7 per month, the current subsidy being paid to net metering customers from all other customers in the residential class is as high as $90 per month or $1,077 ((96.74-

7)*12 = 1,077) per year per net metering customer. Note that the calculation of total monthly amount of fixed cost to serve the average residential net metering customer can be found in Rebuttal Exhibit No. 2 (AEV): NMS Fixed Cost Contribution with references to the Company's filing schedules from which the data used was sourced. It should also be noted that this $97 figure does not include any commodity cost (fuel or electric supply), which would be based on actual kWh of service used.

Q. IN FURTHER RESPONSE TO TASC WITNESS SANDERS'S DIRECT TESTIMONY ON PAGE 2 AT LINE 17, WHAT OTHER RELEVANT QUANTITATIVE ANALYSIS HAS BEEN PROVIDED?

A. The Company provided a class by class load research study as "Staff Informal 1-24 DRB&TAC Attachment3.pdf" in response to a Staff data request. This study contains a wealth of load information pertaining to the residential class such as Kingsport Power's monthly peak days and hours. This information is germane to the NMS Proposal and further supports that the NMS Proposal facilitates an equitable amount of fixed cost recovery from NMS customers.

This information shows, among other things, that NMS customers are relying on the Company's electric supply and delivery infrastructure at the time of its peak usage. The listing of Kingsport Power's monthly peaks during the test year demonstrates that seven of the Company's twelve test year monthly peak demands occurred between 7:00 and 8:00 in the morning and that the residential class is at or near its monthly peak load at the same time as the Company's overall peak load. These peaks are important because they are the billing determinant for which the Company is billed by its affiliate

Appalachian Power Company for generation service and also drive the allocation of PJM transmission costs amongst the AEP East Companies.

These seven early morning monthly peaks are a result of the Company's residential customers primarily using electric to heat their homes in the morning, when the sun has not yet risen. Therefore NMS customers are relying on the Company's electric supply and delivery infrastructure at the time of its peak usage. Because NMS customers are in fact causing peak electric supply and delivery costs to be incurred, they should pay an equitable share of those costs which they currently do not do under the current Rider NMS and Tariff RS. The NMS Proposal would correct this for new NMS customers beginning January 1, 2017.

Q. DO YOU HAVE AN OVERALL RESPONSE TO THE CONCERNS RAISED IN MS. SANDERS'S DIRECT TESTIMONY, ESPECIALLY HER RECOMMENDATION ON PAGE 10 AT LINE 6?

A. Although the Company stands behind its originally filed NMS Proposal, to address the concerns of TASC and those of public comments, the Company is willing to offer a compromise rate design for residential net metering customers that should reasonably address those concerns. The proposed compromise RS-D rate design can be found on Rebuttal Exhibit No. 3 (AEV): RS-D Rate Design and contains a time of use energy charge, a customer charge and a smaller peak demand charge. The on-peak energy charge is very similar to the standard RS tariff energy charge of approximately nine and a half cents per kWh while the off-peak energy charge is much lower (approximately four and cents per kWh). The peak demand charge would then be $4.0 per kW, down from the originally proposed full cost demand charge of $9.44 per kW. Tariff RS-D would still be mandatory for new NMS customers taking service under NMS-2. The compromise rate design of RS-D through the time of use kWh charge allows customer generators to sell their output on-peak at a higher kWh rate and then pay for their off-peak energy usage at a much lower rate. The Company is comfortable with this compromise because it will still receive fixed cost contribution from NMS customers through the lower kW demand charge and the customer charge. This proposal will also insulate all other residential customers from a shifting of fixed infrastructure costs from NMS customers to non-NMS customers.

ALLEGATIONS THAT THE NMS PROPOSAL IS DISCRIMINATORY

Q. HOW DO YOU RESPOND TO CPAD WITNESS NOVAK'S QUESTION AND ANSWER NUMBER 40 ON PAGE 29 OF HIS DIRECT TESTIMONY?

A. Mr. Novak suggests that no policy decisions should be made by the Authority until the associated "legal threshold issues" are adequately addressed and is clearly referring to the legal issue raised by the TASC motion to dismiss that accuses the NMS Proposal of being discriminatory under the language of T.C.A. § 65-4-105(d), which states:

> When any public utility regulated by the authority supplies its services to consumers who use solar or wind-powered equipment as a source of energy, such public utility shall not discriminate against such consumers by its rates, fees or charges or by altering the availability or quality of energy. Any consumer who uses solar, wind power, or other auxiliary source of energy shall install and operate the equipment, property, or appliance for such energy source in compliance with any state or local code or regulation applicable to the safe operation of such equipment, property, or appliance.

The Company vehemently disagrees with Mr. Novak: the Authority should not put off the decisions in question, as this rate case contains all of the necessary information, data and analysis to prove that the NMS Proposal is not discriminatory and does not violate T.C.A. § 65-4-105(d).

Q. FROM A RATE-MAKING PERSPECTIVE, WHAT IS GENERALLY UNDERSTOOD TO BE A DISCRIMINATORY RATE?

A. In my experience, state regulatory commissions, FERC and courts will conclude, after a fact-based inquiry, that a rate is discriminatory if it treats similarly situated customers differently. In contrast, a rate is not considered to be discriminatory if it reasonably distinguishes between two different classes of customers due to the differences between those customers.

Q. UNDER THIS STANDARD, DOES THE NMS PROPOSAL DISCRIMINATE IN ANY WAY AGAINST SOLAR OR WIND POWERED CUSTOMER SITED GENERATION?

A. No. The NMS Proposal, which requires new NMS customers to take service under Tariff RS-D, for example, facilitates an equitable fixed cost contribution from NMS customers using the same residential class cost components and billing units used to calculate the Company's standard Tariff RS rates as can be seen in Rebuttal Exhibit No. 4 (AEV): Residential Rate Comparison. The only difference is the inclusion of a kW demand charge to recover an equitable portion of fixed costs related to the Company's infrastructure that NMS customers use every day. The fact that the rate structures contain differing rates and components does not make RS-D discriminatory. The resulting equitable cost recovery or lack thereof should be the measure the Authority uses to assess whether or not the Company's proposal is in fact discriminatory.

Under the well-established precedents regarding discrimination in rates, discrimination can only exist if the Company unreasonably charges the NMS customers more than their equitable share of fixed infrastructure costs. Simply because a new NMS customer would likely pay a higher bill under the NMS Proposal than they would have under the current NMS rider does not make the NMS Proposal discriminatory. As proven in this testimony using the Company's filing information, the NMS Proposal does not discriminate against NMS customers or solar and wind power. Rather, it simply removes the forced, regressive subsidy that would be provided to new NMS customers by all other residential customers in Kingsport's service territory.

I struggle to find any definition, interpretation or precedent that would deem "discriminatory" the NMS Proposal's requirement that all customers pay an equitable share of the infrastructure costs incurred to serve them. To the contrary, the NMS Proposal alleviates the issue of discrimination currently in rates because it would in fact set rates that would place NMS customers and all other customers on a level playing field where both groups would be making equitable fixed cost contributions related to the Company's utility infrastructure that they both use every day. Nowhere in the language of T.C.A. § 65-4-105(d) does it state that solar or wind powered equipment are being discriminated against unless they are subsidized by all other customers.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Exhibit No. 1 AEV, NMS Related Data and Analysis

	Filing Document	Witness	Provided As
1	Cost of Service Studies and Revenue Allocation	Buck	Exhibits DRB No. 1-4
2	Functional Revenue Targets	Buck/Caudill	Staff Informal 1-24 – TAC- Attachment 3 – KgPCo Rate Design.xlsx
3	Rate Design Workpapers	Caudill	Staff Informal 1-24 – TAC- Attachment 3 – KgPCo Rate Design.xlsx
4	Load Research Study	Buck/Caudill	Staff Informal 1-24 DRB&TAC Attachment3.pdf

Exhibit No. 2 AEV, NMS Fixed Cost Contribution

Test Year 2014 Residential Class Information

			Calculation	Source
RS Distribution Revenue Requirement	$	9,371,286	a	Staff Informal 1-24 – TAC- Attachment 3 – KgPCo Rate Design.xlsx
RS Transmission Revenue Requirement	$	5,989,657	b	Exhibits DRB No. 1-4
RS Generation Revenue Requirement	$	27,012,809	c	Staff Informal 1-24 – TAC- Attachment 3 – KgPCo Rate Design.xlsx
RS Total Bills		494,855	d	Staff Informal 1-24 – TAC- Attachment 3 – KgPCo Rate Design.xlsx
RS Total Annual Max Billing Demand kW		3,913,023	e	Staff Informal 1-24 – TAC- Attachment 3 – KgPCo Rate Design.xlsx
Average NMS Monthly Max Billing Demand kW		14	f	Calculated from CPAD 1-159 Supplemental Attachment 2
Average Distribution Fixed Cost per Customer per Month	$	19	g = a/d	Calculation
Average Transmission Fixed Cost per kW	$	1.53	h = b/e	Calculation
Average Generation Fixed Cost per kW	$	6.90	i= c/e	Calculation
Average Generation Fixed Cost for NMS per kW*	$	4.03	j = i*(7/12)	Calculation
NMS Average Monthly Distribution Fixed Cost Contribution	$	19	= g	Calculation
NMS Average Monthly Transmission Fixed Cost Contribution	$	21.43	k = h*f	Calculation
NMS Average Monthly Generation Fixed Cost Contribution	$	56.38	l = j*f	Calculation
Monthly Total	$	96.74	m = g+k+l	Calculation
Annual Total	$	1,161	n = m*12	Calculation
Current Min Annual Fixed Cost Contribution Under Tariff RS	$	84	o =7*12	Calculation
Difference (Subsidy Paid By Other Residential Customers)	$	1,077	= n-o	Calculation

Exhibit No. 3 AEV, RS-D Rate Design

Rebuttal Compromise RS-D Rate Design

Demand Charge	$4.00	per monthly max billing kW
On-Peak Energy Charge	$ 0.09432	per on-peak kWh
Off Peak Energy Charge	$ 0.04161	per off-peak kWh
Customer Charge	$ 16.00	per customer per month

Originally Filed RS-D Rate Design

Demand Charge	$9.44	per monthly max billing kW
kWh Charge	$0.03826	per all kWh
Customer Charge	$ 11.00	per customer per month

Exhibit No. 4 AEV,Residential Rate Comparison

Rate Design Revenue Components and Targets		
From CCOS	Total Retail	Residential
Demand	72,198,336	33,002,466
Energy	77,165,570	26,068,106
Dist Primary	9,906,510	4,187,942
Dist Secondary	5,333,281	2,773,729
Customer	6,238,753	2,409,615
Total	170,842,449	68,441,858

Standard Residential Tariffs

RS Revenue Verification	Units		Rate		Revenue
All Standard kWh	681,189,623	kWh	$0.09248	/kWh	$ 62,996,416
Storage Water Heating	55,811	kWh	$0.05827	/kWh	$ 3,252
Customer	494,807	Bills	$11.00	/mo.	$ 5,442,877
					$ 68,442,545

RS-TOD / RS-LM-TOD Verification	Units		Rate		Revenue
On-Peak kWh	21,898	kWh	$0.13257	/kWh	$2,903
Off-Peak kWh	36,510	kWh	$0.05827	/kWh	$2,127
Customer - Std TOD	48	Bills	$13.25	/Mo.	$636
Total Residential kWh	681,303,842				$5,666

Total Residential Revenue Verification	
Standard RS	$ 68,442,545
RS-TOD	$ 5,666
Employeed Discount	$ (11,867)
Total Residential Revenue Verification	$ 68,436,345
Revenue Target	$ 68,441,858
Difference	$ (5,513)

RS-D as Originally Filed

	Units	Rate	Revenue
Bills - Standard	494,807	$11.00	$ 5,442,877
Bills - TOD	48	$13.25	$ 636
Total kWh	681,303,842	$0.03826	$ 26,066,685
kW	3,913,023	$9.44	$ 36,938,937
Employee Discount			$ (11,867)
Total			$ 68,437,268
Revenue Target			$ 68,441,858
Difference			$ (4,590)

RS-D AEV Rebuttal Compromise Rate Design

	Units	Rate	Revenue
Bills - Standard	494,807	$16.00	$ 7,916,912
Bills - TOD	48	$13.25	$ 636
On-Peak kWh	313,709,436	0.09432	$ 29,589,074
Off-Peak kWh	367,594,406	0.04161	$ 15,295,603
Total kWh	681,303,842		
kW	3,913,023	$4.00	$ 15,652,092
Employee Discount			$ (11,867)
Total			$ 68,442,450
Revenue Target			$ 68,441,858
Difference			$ 592