COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application Of Kentucky Power Company For:	)	
(1) A General Adjustment Of Its Rates;	)	
(2) Approval of Its 2014 Environmental Compliance	)	Case No. 2014-00396
Plan; (3) Approval of Tariffs And Riders; and (4)	)	
An Order Granting All Other Required Approvals	)	
and Relief	)	

ATTORNEY GENERAL'S POST-HEARING BRIEF and EXHIBITS

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ATTORNEY GENERAL'S POST-HEARING BRIEF

Comes now the intervenor, the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention, and states as follows for his post-hearing brief in the above-styled matter.

I. STATEMENT OF THE CASE

On November 14, 2014, Kentucky Power Company ("KPCo" or "the company") filed its notice of intent to seek permission to raise its base rates. The instant case thus marks KPCo's first base rate case since acquiring an undivided 50% ownership in the Mitchell Generating Station, located in Moundsville, West Virginia.[1] The company's application, utilizing a historic test year ending September 30, 2014 was filed on December 23, 2014. The following entities were granted intervention: The Office of the Attorney General; Kentucky Industrial Utility Customers, Inc. ("KIUC"); Wal-Mart Stores East, LP, and Sams East, Inc. ("Wal-Mart"); and the Kentucky School

[1] *See generally* Case No. 2012-00578 (hereinafter the "Mitchell Transfer Case"), Final Order dated Oct. 7, 2013.

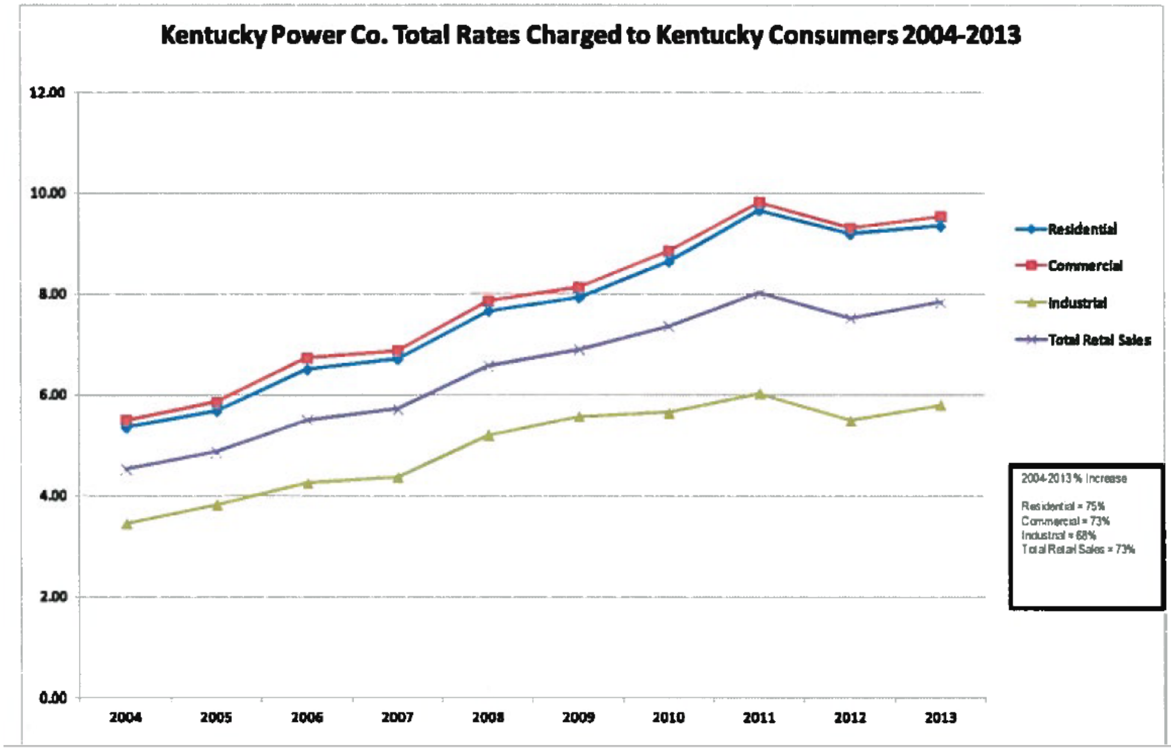
Boards Association ("KSBA"). Following several rounds of discovery, all intervenors filed testimony, which included revenue requirements and rate of return testimony from both the Attorney General and KIUC. Public hearings to accept comments from affected ratepayers were held on March 24-25, and on April 16, 2015. The parties to the case met in informal conferences on April 9 and April 14, 2015, for the purposes of discussing whether settlement could be reached. Another settlement conference was held on April 23, 2015, in which the Office of the Attorney General participated via telephonic conference, and during which it advised Commission staff and the other parties that it would not be a signatory to the partial settlement which the other parties had reached with KPCo.[2] On April 30, 2015, KPCo filed a motion asking the Kentucky Public Service Commission ("PSC" or "Commission") to approve the terms of a settlement stipulation which it had reached with the parties ("non-unanimous partial settlement stipulation") except for the Office of the Attorney General, as well as other documents supporting the non-unanimous partial settlement stipulation. The final evidentiary hearing was held on May 5, 2015.

II. <u>ARGUMENT</u>

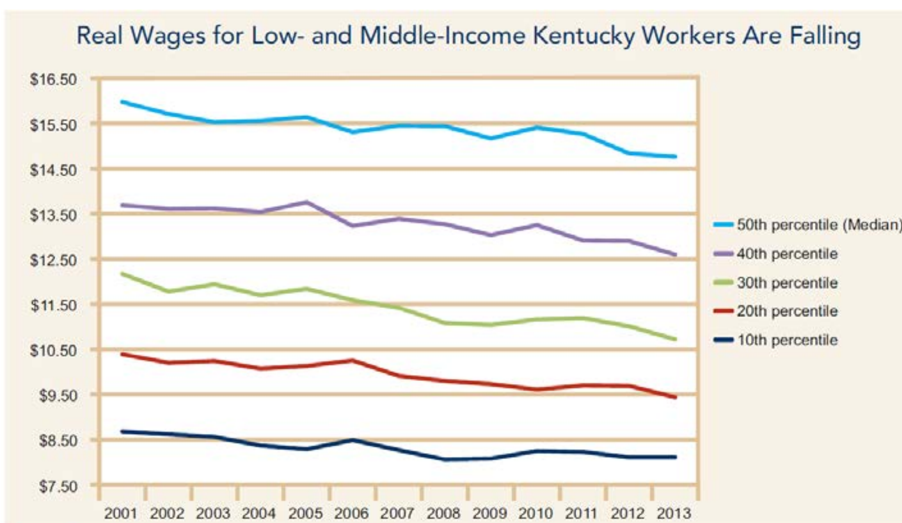
A. Ratepayer Impact

KPCo's rates have increased steadily over the past ten (10) years, averaging 73% over all customer classes during that time frame. The following chart, as depicted in the Direct Testimony of Lane Kollen,[3] graphically depicts this increase:

[2] The Attorney General participated in the initial portion of the April 23, 2015 settlement conference solely to discuss procedural issues, and then ended its participation in settlement negotiations.
[3] Kollen Direct, p. 9.



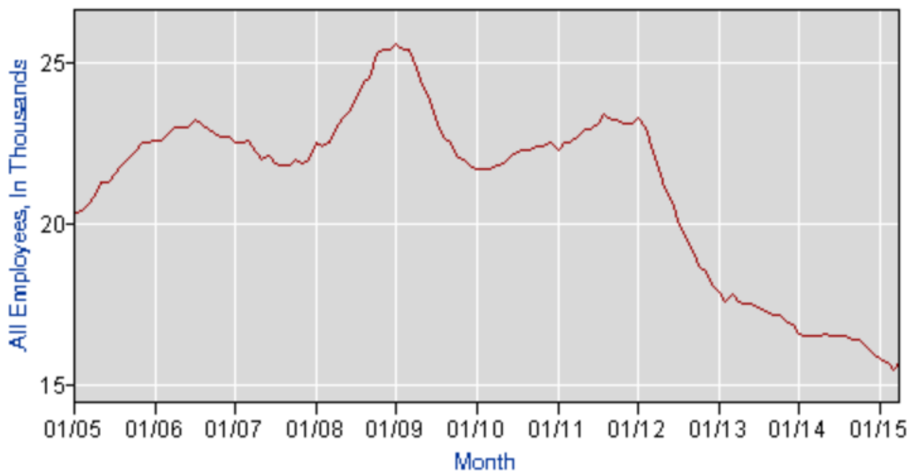
However, during this same time frame, real wages for Kentuckians as a whole declined over the past ten years, which stands in stark juxtaposition to KPCo's steadily increasing rates during the same time frame:[4]



Source: Economic Policy Institute analysis of Current Population Survey data.

[4] Kentucky Center for Economic Policy, August 2014, p. 13, available at: http://kypolicy.org/dash/wp-content/uploads/2014/08/State-of-Working-KY-2014-final.pdf

As can be seen in the U.S. Department of Labor's statistics, the Commonwealth's mining and logging industries have declined an average of 5.08% during the period Nov. 2014 – April 2015. [5] That decline is even more stark when viewed over the past ten (10) years, in the following U.S. Department of Labor chart: [6]

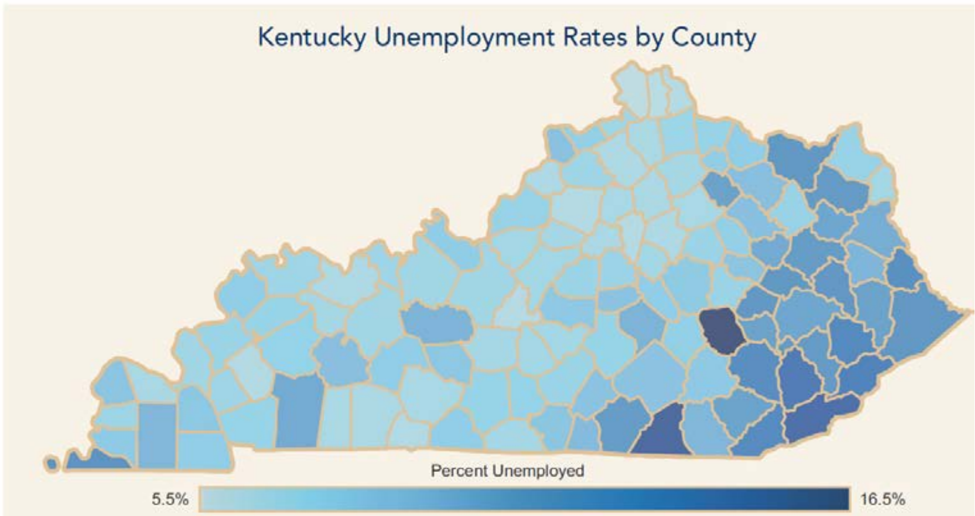


Thousands of employees

When the data is isolated to far eastern Kentucky, an even more dismal image of the economy in that part of the Commonwealth emerges. Nearly one-fourth (25%) of all eastern Kentucky coal mining jobs were lost in 2013 alone.[7] Non-farm wage and salary employment has been nearly stagnant over the past six (6) months, increasing an average of only 0.57% over the period.[8]

[5] http://www.bls.gov/regions/southeast/kentucky.htm#eag
[6] http://data.bls.gov/timeseries/SMS21000001000000001?data_tool=XGtable; depicts State and Area Employment, Hours, and Earnings, as seasonally adjusted for the state as a whole, in the mining and logging industry, by thousands of employees.
[7] "People at the End of the Line," a film discussing the Eastern Kentucky Economy, produced by East Kentucky Power Cooperative, at 0:15; accessible at: https://www.youtube.com/watch?v=JvtdgQwQf2A
[8] http://www.bls.gov/regions/mid-atlantic/wv_huntington_msa.htm#eag_wv_huntington_msa.f.P

As indicated in the chart below, as depicted in the report, "The State of Working Kentucky,"[9] the greatest unemployment rates in the Commonwealth are found in eastern Kentucky, many of whose counties comprise the KPCo service territory:



If the Commission approves the non-unanimous partial settlement stipulation, the average residential ratepayer will experience a monthly rate increase of $13.72, or 9.89%.[10] However, due to prevailing economic conditions throughout KPCo's service territory, its ratepayers will be bearing a disproportionate burden due to their loss in real wages and unusually high unemployment rates.

It was against this back drop that KPCo ratepayers submitted public comments concerning the company's proposed rate increase:

> ". . . [A] lot of those people are still not working. Then you've got a lot of people on low income that they make, I don't know exactly, probably between $450 and $600 a month. They can't afford the power bill they got now. And I mean it's like nobody cares about us back here in East

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[9] Kentucky Center for Economic Policy, August 2014, p. 11, available at: http://kypolicy.org/dash/wp-content/uploads/2014/08/State-of-Working-KY-2014-final.pdf

[10] KPCo Responses to Post-Hearing Data Requests, Item no. 3.

> Kentucky." City of Hazard Mayor Jimmy Ray Landon, March 24, 2015 public meeting in Hazard, Kentucky.[11]
>
> "We've just had so many hundreds and hundreds of people that cannot right now pay their power bill, and to you all $20 may not sound like a lot, but you take $20 dollars when all they do is draw $400, you can't exist like that." Perry County Clerk Haven King, March 24, 2015 public meeting, Hazard, Kentucky.[12]
>
> "When they have to decide between their medicine, and their power bill, and their food, something is not right." Letcher County Judge Executive Jim Ward, March 24, 2015 public meeting, Hazard, Kentucky.[13]

Clearly, KPCo ratepayers are among the most poorly-positioned to absorb any additional rate increase. KPCo's failure to provide in the context of the instant case any studies on the price elasticity of demand is also quite telling. It appears that KPCo's service territory is approaching the point where electricity, for many, will become a luxury that an increasing number of people cannot afford. The Commission should do everything it can within its powers to mitigate the amount and impact of any rate increase for KPCo's ratepayers.

B. Return on Equity

> *"Low interest rates are not a short-term aberration, but part of a long-term trend."*
> --*Ben Bernanke*, March 30, 2015[14]

One of the primary factors in determining a utility's return on equity ("ROE") is the company's cost of capital, which in turn is based in large part upon interest rates.[15]

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[11] Hazard Public Meeting, video transcript at 11:07 – 11:32.
[12] Hazard Public Meeting, video transcript at 15:30-15:45.
[13] Hazard Public Meeting, video transcript at 22:42-23:00.
[14] http://www.brookings.edu/blogs/ben-bernanke/posts/2015/03/30-why-interest-rates-so-low.
[15] Woolridge Direct, p. 6, lines 1-4. Throughout this brief, the following abbreviations will be used to delineate between the various testimony in this case: "Direct," "Rebuttal," or "Hearing Testimony." Other

As noted in the testimony of the Attorney General's ROE expert, Dr. J. Randall Woolridge, ". . . interest rates remain at historically low levels and are likely to stay there for some time,"[16] primarily because inflationary expectations in the U.S. remain very low and global economic growth remains stagnant.[17] Although KPCo's rate of return experts Dr. Avera and Mr. McKenzie ("Avera/McKenzie") acknowledge the continued prevalence of historic low interest rates, nonetheless they urge the Commission to approve an ROE for KPCo significantly higher than these national averages based in large part upon ". . . [w]idespread *expectations* for higher interest rates."[18]

Dr. Woolridge's testimony carefully notes that since 2009, economists have been forecasting the return of inflation, yet those forecasts have been *universally* proven wrong:

> ". . . [A]ll the economists in Bloomberg's interest rate survey forecasted interest rates would increase in 2014, and 100% of economists were wrong. According to the Market Watch article: 'The survey of economists' yield projections is generally skewed toward rising rates — only a few times since early 2009 have a majority of respondents to the Bloomberg survey thought rates would fall. But the unanimity of the rising rate forecasts in the spring was a stark reminder of how one-sided market views can become. I**t also teaches us that economists can be universally wrong.**'"[19] [Emphasis added]

Indeed, the notoriety of these errant forecasts has become so prevalent that the

company testimony such as KPCo Witness Wohnhas' "Testimony in Support of Partial Settlement Stipulation," will be referred to by their entire name.

[16] Woolridge Direct, p. 14 lines 2-3.

[17] *Id.* at 14, lines 4-6.

[18] Avera/McKenzie Direct, p. 4 [emphasis added].

[19] Woolridge Direct, pp. 15-16, *quoting* Ben Eisen, "Yes, 100% of economists were dead wrong about yields," MARKET WATCH, October 22, 2014.

Federal Reserve Bank of New York has ceased relying upon the interest rate estimates of professional forecasters in the Bank's interest rate model.[20]

Throughout the nation, public utility commissions at increasing frequency are heeding the veracity of ex-Federal Reserve Board Chairman Ben Bernanke's statement cited at the beginning of this section. As described in the First Quarter 2015 Regulatory Research Associates Report,[21] the national average ROE awarded to utility companies was 9.67%,[22] which is 11 basis points *lower* than the first quarter average for 2014. As Dr. Woolridge noted, this national trend is "headed in my direction."[23] Additionally, while the 2015 first quarter average level is still greater than his recommended ROE of 8.65% for KPCo,[24] nonetheless utility commissions are increasingly recognizing that capital cost rates are indeed low, and there is a notable paucity of reliable evidence to indicate that they will increase in the immediate future.[25] Notwithstanding the New York Fed's leeriness of relying upon inflation forecasts, Dr. Avera would have the Commission do just that by overtly disagreeing with Chairman Bernanke's statement, when he stated that the nation is currently in an "abnormal interest rate regime."[26] As Dr. Woolridge

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[20] *Id*. at 16, *citing* Susanne Walker & Liz Capo McCormick, "Unstoppable $100 Trillion Bond Market Renders Models Useless," BLOOMBERG.COM (June 2, 2014), http://www.bloomberg.com/news/2014-06-01/the-unstoppable-100-trillionbond-market-renders-models-useless.html.
[21] KPCo Hearing Exhibit 1, "Regulatory Research Associates, Regulatory Focus," dated April 13, 2015.
[22] As noted on p. 1 of this report, the 9.67% figure excludes a Feb. 20, 2014 ruling of the New York Public Service Commission which approved a 9.3% ROE for Consolidated Edison Co. of New York.
[23] Woolridge Hearing Testimony, Video Transcript of Evidence ["VTE"] at 15:14:38 – 15:15:13.
[24] Woolridge Hearing Testimony, VTE at 15:14:18 – 15:15:01, the West Virginia Public Service Commission
[25] In Case Nos. 14- 1152-E-42T and 14- 1151 -E-D, Final Order dated May 26, 2015, p. 21, the West Virginia Public Service Commission awarded KPCo affiliates, Appalachian Power Co. and Wheeling Power Co., an ROE of 9.75% in those companies' just-completed rate cases.
[26] Avera Hearing Testimony, VTE at 14:46:25 – 14:47:32.

testified, "It's impossible to forecast interest rates . . . you're really speculating. The services that forecast interest rates tend to be continually wrong."[27]

While ROEs approved by utility commissions are on a decidedly downward trend, nonetheless it appears Avera/McKenzie defy that trend by continuing to argue for ultra-high levels of return. As recently as 2013, Dr. Avera argued for an ROE of 10.65% for KPCo,[28] which is almost exactly the same as in the instant case. In that last case, Dr. Avera projected that the 30-year Treasury bond would have an average yield of 4.40%,[29] whereas the yield on the day before the hearing in the instant case was 2.85%. Additionally, in that case he projected that the long-term BBB utility bond yield would be 6.11%,[30] whereas today's yield is slightly less than 5%, as Dr. Avera correctly identified in his direct testimony in the instant case.[31] These facts illustrate once again that the sources Dr. Avera adopts for his projected interest rates have a pattern of weighing-in on the high side.[32]

Additionally, Avera/McKenzie's arguments for a high-end ROE for KPCo stand in stark opposition to Moody's Investors Service March 10, 2015 guidance for regulated utilities entitled, "Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles."[33] In this guidance, Moody's analysts state that they expect regulators will ". . . continue to trim the sector's profitability by lowering its authorized returns on equity,"

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[27] Woolridge Hearing Testimony, VTE at 15:16:32 – 15:16:43.
[28] Case No. 2013-00197, Direct Testimony of Dr. William Avera, p. 7.
[29] *Id*., Exhibit WEA-8, p. 2 of 2, included in AG Hearing Exhibit 3 in the instant case.
[30] *Id*., Exhibit WEA-7.
[31] Case No. 2014-00396, Direct Testimony of Avera/McKenzie, p. 13, Figure 1.
[32] Woolridge Hearing Testimony, VTE at 15:16:30 – 15:16:59.
[33] Copy attached hereto as AG Brief Exhibit A.

but this will not harm utilities' credit profiles. Among the reasons they cite are: (i) persistently low interest rates; and (ii) a comprehensive suite of cost recovery mechanisms. Quite significantly, Moody's states:

> We view cash flow measures as a more important rating driver than authorized ROEs, and we note that regulators can lower authorized ROEs without hurting cash flow, for instance by targeting depreciation, or through special rate structures. Regulators can also adjust a utility's equity capitalization in its rate base. . . . Robust cost recovery mechanisms will help ensure that US regulated utilities' credit quality remains intact over the next few years. As a result, falling authorized ROEs are not a material credit driver at this time, but rather reflect regulators' struggle to justify the cost of capital gap between the industry's authorized ROEs and persistently low interest rates. We also see utilities struggling to defend this gap, while at the same time recovering the vast majority of their costs and investments through a variety of rate mechanisms.[34]

KPCo has for years enjoyed the use of "special rate structures," as the Moody's analysts noted, including the Environmental Surcharge (ECR),[35] the Demand Side Management Surcharge (DSM)[36] and the Fuel Adjustment Charge (FAC).[37] Additionally, KPCo's ECR Surcharge has its own, guaranteed ROE collection mechanism, while the company's DSM Surcharge allows recovery of all program costs through a DSM factor, as well as any net revenues lost due to reduced sales resulting from DSM programs.[38] Moreover, as a result of the Commission's Final Order in Case No. 2012-00578,[39] KPCo has also utilized another direct tracker, the "Asset Transfer Rider" (ATR) that allowed it to immediately begin recovery of the costs associated with

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[34] *Id.* at pp. 1-2.
[35] KRS 278.183.
[36] KRS 278.285.
[37] 807 KAR 5:056.
[38] *See, e.g.,* Case No. 2014-00271, Final Order issued Feb. 13, 2015, p. 15.
[39] The "Mitchell Transfer Case," Final Order dated Oct. 7, 2013.

the purchase of its 50% undivided interest in the Mitchell plants. Additionally, as a potential outcome of the instant case, the company may, if the Commission so approves, be able to directly track, through two new trackers: (a) the costs of the retirement of Big Sandy Unit 2 and the coal-related retirement costs of Big Sandy Unit 1 (BSRR) which will replace the ATR; and (b) the operating costs of the re-fueled Big Sandy Unit 1 once it begins operations next year (BS1OR). Both of these new trackers, if approved, would also carry their own ROE recovery mechanisms.

Based on Moody's analysis, KPCo's comprehensive suite of cost recovery mechanisms / surcharges – the ECR, FAC, DSM, BSRR and BS1OR -- will almost certainly shield the company from any potential adverse consequences that could result from lowering the company's approved ROE, and certainly remove much, if not most, of the financial risks the company faces.

The Attorney General believes that while the non-unanimous partial settlement stipulation in this case states an ROE of 10.25% for the ECR, BSRR, BS1OR, AFUDC and WACC, nonetheless this level still greatly exceeds the 8.65% that Dr. Woolridge recommended, as well as the 8.75% recommended by KIUC's ROE expert Richard Baudino.[40] Furthermore, the non-unanimous partial settlement stipulation's stated ROE also falls well-outside of the range of the national average as reported in the Regulatory Research Associates' Report for the First Quarter of 2015 (9.67%). If the Commission approves the 10.25% stated ROE figure set forth in the non-unanimous partial

[40] Baudino Direct, p. 3.

settlement stipulation, this will represent one of the highest -- if not ***the*** highest -- ROEs in the nation.

Additionally, the Attorney General notes that Avera/McKenzie have called for an upward adjustment of KPCo's ROE based upon flotation costs[41] associated with the sale of common stock issued by KPCo's parent company, AEP. In Case No. 2009-00548, Kentucky Utilities Co. sought an award of flotation costs associated with the sale of common stock of its then-parent, E.ON. The Attorney General opposed any such upward adjustment of ROE based on flotation costs, and the Commission agreed, noting that denying any such upward adjustment is consistent with past Commission practice.[42] The Attorney General urges the Commission to continue to adhere to its established precedent in this regard, and deny KPCo's request for an upward adjustment of ROE based on flotation costs in the instant case.

Finally, setting the appropriate ROE in the current KPCo proceeding is not only important for the company's base rates, but doing so will also directly impact costs included in several riders that KPCo uses to collect costs that include a return on investment, including the BSRR and the ECR. Under the terms of the non-unanimous partial settlement stipulation, a stated ROE of 10.25% would be applied to various KPCo Riders including the BSRR and the ECR. The AG respectfully submits that a 10.25% ROE is too high for purposes of determining KPCo's base rate revenue requirement and for applying to such Riders. The West Virginia Public Service

[41] Avera/McKenzie Direct, p. 56.
[42] Case No. 2009-00548, Final Order dated July 30, 2010, p. 31.

Commission in Case Nos. 14- 1152-E-42T and 14- 1151 -E-D,[43] recently authorized a **9.7% ROE** for Appalachian Power/Wheeling Power, which are the neighboring utilities and affiliates of KPCo that ended up owning the other 50% interest in the Mitchell Plant. This 9.7% ROE thus represents the high end of what would be reasonable for KPCo in this case, which is being driven primarily by issues relating to KPCo's ownership of Mitchell, the related retirement of Big Sandy Unit 1, and the retirement and repowering of Big Sandy Unit 2. While 9.7% is an important frame of reference and would represent the high side of a reasonable ROE, the AG continues to recommend that the Commission adopt an ROE of 8.65% as recommended by AG witness Woolridge in this case for base rates and for the purpose of determining the cost of capital in the applicable KPCo riders. The Commission should direct KPCo to make a compliance filing updating the base rate revenue requirement and each of the riders that includes a return component, based on the Commission's finding of the authorized ROE for KPCo in the current case.

Therefore, the Attorney General urges the Commission to approve an ROE of 8.65%, as Dr. Woolridge testified.[44]

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[43] Final Order dated May 26, 2015, p. 21, copy attached hereto as AG Brief Exhibit B.
[44] Woolridge Direct, p. 2.

C. Revenue Requirements

1. Capitalization

KPCo's capital structure as reflected in its application in the instant case contained a *negative* short-term debt of $30.9 million.[45] But as set forth in the pre-filed written direct testimony of Attorney General revenue requirements expert Ralph C. Smith, there are only two options as to short-term debt: either the balance is positive, or it is zero.[46] Any purported negative short-term debt balance would overstate the cost of capital, thus unjustly increasing the revenue requirement. Mr. Smith's adjustment to KPCo's capital structure removes the negative short-term debt balance and resets it to zero. [47]

The Attorney General urges the Commission to adopt Mr. Smith's adjusted capital structure, which contains three (3) rate base adjustments, as discussed below. For that reason, the Attorney General disagrees with the capital structure set forth in the proposed non-unanimous partial settlement stipulation, [48] which does not contain Mr. Smith's rate base adjustments.

2. Rate Base Adjustments

a. Bonus Depreciation

In December of last year, President Obama signed into law the Tax Increase Prevention Act of 2014 (TIPA), which extended 50% bonus depreciation to property acquired and placed into service during 2014. KPCo's response to KIUC 1-29 indicates

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[45] Section V, Exhibit 1, Schedule 3 from the Company's application.
[46] Smith Direct, p. 27.
[47] *Id. See also* Smith Exh. RCS-1, Sch. D, pp. 2-3.
[48] *See* non-unanimous partial settlement stipulation Exhibit 2.

that the company would have recorded an additional $23.6 in accumulated deferred income taxes (ADIT) through September 2014 had TIPA been enacted during the test year. Additionally, KPCo has agreed that its test year ADIT should be increased by $23.6 million to reflect the impact of TIPA's extension of bonus depreciation.[49] Mr. Smith reflects the $23.6 million in additional ADIT on Exhibit RCS-1, Sch. B-1, which results in a reduction in KPCo's rate base of $23.3 million, which he allocated ratably between long-term debt and common equity, as reflected in Exhibit RCS-1, Schedule D, page 3. [50]

Although KPCo has acknowledged it would have included bonus depreciation in its application but for the difference in time between the date that the company filed its application and the date the TIPA extension became effective,[51] nonetheless Company witness Wohnhas would have the Commission believe that the adjustment to ADIT did not affect capitalization for ratemaking purposes:[52]

> **Q. DO YOU AGREE WITH THE RECOMMENDED REDUCTIONS TO CAPITALIZATION BASED ON BONUS TAX DEPRECIATION PROPOSED BY MESSRS. SMITH AND KOLLEN?**
>
> A. No. As Company Witness Bartsch describes in his rebuttal testimony, the accounting entries that would have been included in the Company's income statement and balance sheet if the 50% bonus tax deprecation were included would have produced equal and off-setting entries. These adjustments would have had no effect on the Company's capitalization for rate making purposes.

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[49] *See* KPCo response to AG 2-79.
[50] Smith Direct, pp. 28-30.
[51] Company response to KIUC 1-30, and Bartsch Rebuttal, p. 9.
[52] Wohnhas Rebuttal, p. 3.

Mr. Wohnas, however, is absolutely wrong about this. ADIT represents a long-term source of non-investor supplied cost-free capital, and does indeed affect not only rate base, but also capitalization. Failing to reflect the impact of this source of non-investor supplied cost free capital in KPCo's adjusted capitalization would effectively provide KPCo with a return on rate base that is supported with cost-free capital, **thus giving KPCo an excessive return.** As shown on Smith Exhibit RCS-1, pp. 13-14 of 31, Sch. D, KPCo's capitalization is adjusted by any and all adjustments to rate base that impact any component of rate base other than working capital. ADIT affects rate base by providing a long-term source of non-investor supplied zero-cost capital that is provided to KPCo by the accounting for deferred income taxes under normalization rules, and by ratepayer payments for the cost of service which includes deferred income taxes. ADIT supports the utility's investment in plant. ADIT is not considered a component of working capital. Adjustments to ADIT for known and measurable changes, such as bonus tax depreciation that occurred within the test year, is thus a proper adjustment to rate base and to KPCo's adjusted capitalization. KPCo's adjusted capitalization should be adjusted for the known and measurable change to ADIT resulting from 2014 bonus tax depreciation as recommended by AG witness Smith [53] and KIUC witness Kollen.[54]

b. Contributions in Aid of Construction

As Mr. Smith’s testimony discusses, KPCo acknowledged an error in its filing

[53] Smith Direct, p. 28.
[54] Kollen Direct, p. 48.

regarding Contributions in Aid of Construction (CIAC). As a result, the company has agreed that rate base should be reduced by $38,321. [55] The company has not opposed this adjustment.

c. Cash Working Capital

Mr. Smith proposes an adjustment to the O & M expenses to KPCo's Cash Working Capital (CWC) requirement which would reduce this level by $726,000, to $42.8 million as opposed to the company's as-filed amount of $43.6 million. However, unlike the ADIT item addressed above, this adjustment to working capital does not change KPCo's jurisdictional capitalization. [56]

3. Operating Income Adjustments

a. Commercial & Industrial Revenues

In response to data requests, KPCo acknowledged that after September 30, 2014 commercial and industrial customers had informed the company that they will be expanding operations or increasing purchases of electricity. In response to AG 1-331, the company provided a list of 14 customers that announced anticipated expansions, reductions, or closures. In further follow-up on this issue, the company in response to AG 2-112 provided an updated list of expansions, reductions, or closures, which included tariff codes and estimated monthly revenue changes associated with each such project. For those projects in which the effective date had already occurred, the net new monthly revenues totaled $88,636, which when annualized totals $1.063 million. When

[55] *Id.* at 30-31.
[56] Smith Direct, pp. 32-33.

KPCo's jurisdictional factor is applied, this yielded new jurisdictional revenues of approximately $1.052 million. Mr. Smith's adjustment in this regard is set forth in Exhibit RCS-1, Sch. C-1.

KPCo witness Rogness, however, opined at the hearing [57] that if new revenues are recognized, KPCo would have to net out any closures such as coal mines. The Attorney General's adjustment, however, already has incorporated the *net* margins from adding industrial and commercial customers and significant closures, as shown on Exhibit RCS-1, p. 19 of 31 to AG witness Smith's testimony. As shown there, the known net increase in net revenue of $88,636 per month reflects the net impact of known expansions and closures that have already occurred. KPCo witness Rogness also mentioned that the increased O & M for new customers to generate the increased kWh would also have to be recognized; however, that is a false issue because the amounts of revenue that have been added are base revenues and fuel costs are not included. Additionally, the impact on uncollectibles related to changes in base rate revenues has been reflected, as shown on Exhibit RCS-1, page 4 of 31, Schedule A-1, lines 2 and 12. [58] If the Commission does not reflect this <u>known and measurable</u> adjustment for known expansions and closures, the result would be to misstate KPCo's revenue requirement. In the current case, because the net impact of closures and expansions is a net increase in revenues, KPCo's revenue requirement would be overstated by at least $1.052 million if this adjustment is not reflected. The AG recommends that the Commission adopt this

[57] VTE at 15:32:00 – 15:34:50.

[58] The amount on Schedule A-1, line 12 reflects the net change in uncollectibles based on the overall net decrease to KPCo's base rate revenues, and is effectively the net impact on uncollectibles of all of the AG's adjustments that affect KPCo's base rate revenue requirement.

adjustment for the net increase in KPCo base rate revenues of $1,051,938. This adjustment has the impact of reducing KPCo's base rate revenue requirement by $1.052 million.

b. Parent Company Loss Adjustment

KPCo's application reflected a parent company loss allocation (PCLA), which is based on the tax savings benefit of the parent company, American Electric Power (AEP). However, the PCLA was only reflected on a total company basis, and did not flow through as a reduction to KPCo's jurisdictional federal income tax expense.[59] In response to an initial data request, KPCo stated that its prior precedent was to *not* use its share of the PCLA to reduce its jurisdictional federal income tax expense.[60] However, the company modified its position in response to a supplemental data request, conceding that it *should have* included a PCLA as a reduction to income tax expense in its filing.[61]

In Case. No. 9061, the Commission noted that KPCo's parent company has historically generated tax losses which KPCo has used to reduce its cost of service.[62] In that case, KPCo argued that it was reversing its prior position, and decided that its share of AEP's tax loss should be used for the shareholder's benefit rather than for the ratepayer's benefit by reducing cost of service.[63] The Commission disagreed, finding that since ratepayers would be proportionally responsible for any potential parent

[59] Smith Direct, p. 45.
[60] KPCo Response to KIUC 1-21 (c).
[61] KPCo response to KIUC 2-2.
[62] Case No. 9061, 1984 WL 1022598 (Ky. P.S.C.), Final Order dated Dec. 4, 1984, p. 16 [emphasis added].
[63] *Id.*

company tax expense, conversely, they should receive the benefit of any tax losses. Accordingly, the Commission made a downward adjustment to KPCo's federal income tax expense. [64]

The Commission should also take notice that KPCo witness Bartsch filed testimony in the pending base rate case of KPCo affiliates Appalachian Power Co. and Wheeling Power Co., in which he advocated for the PCLA to be applied to the benefit of those companies' ratepayers in West Virginia.[65]

Mr. Smith's adjustment appearing in Exhibit RCS-1, Sch. C-6 sets forth a reduction in current federal income tax expense of $314,997.

c. Incentive Compensation

KPCo has a long-term annual incentive compensation plan ("AIP") available to its employees. Copies of the 2013 [66] and 2014 [67]AIP plans were provided in response to KIUC 1-31. The AIP Plan's stated objectives are to:

> (i) Attract, retain and motivate employees to further the objectives of the company, its customers and the communities it serves; (ii) Enable high performance by establishing, communicating and aligning employee efforts with the Plans performance objectives; and (iii) Foster the creation of sustainable **shareholder value** through achievement of AEP's goals.[68] [Emphasis added.]

Significantly, **75%** of the AIP Plan's funding measures are tied to AEP's ***operating***

[64] *Id.*
[65] West Virginia Case No. 14-1152-E-42T, copy of that testimony attached hereto as AG Brief Exhibit C.
[66] Response to KIUC 1-31 Attach. 1.
[67] Response to KIUC 1-31 Attach. 2.
[68] Response to KIUC 1-31, Attach. 1, p. 1. The wording is identical with the 2014 AIP Plan, set forth in Attachment 2.

earnings per share, while safety and strategic initiatives receive weights of only 10% and 15%, respectively.

Furthermore, the AIP Plan provides the following rationale for the 75% weight value geared toward operating earnings per share:

> AEP is committed to generating sustainable **value for its shareholders** through its earnings and growth. Therefore 75% of annual incentive funding is tied to AEP's Operating Earnings Per Share. This ensures that funding is commensurate with the Company's earnings and the extent to which the company can afford to pay annual incentive compensation while also serving the interests of its shareholders, customers and other stakeholders. It also: (i) Further aligns the financial interests of all AEP employees **with those of AEP's shareholders**; (ii) Ensures adequate earnings are generated for AEP's shareholders and continued investment in AEP's business before employees are rewarded with annual incentive compensation; and (iii) Aligns employee interests with those of regulated and other customers by strongly encouraging expense discipline.[69] [Emphasis added]

In response to AG 1-369, KPCo admitted that it has included incentive compensation expense in its test year cost of service. [70]

KPCo's own documents thus irrefutably establish that the primary beneficiaries of the AIP Plan are AEP shareholders. Although ratepayers receive no demonstrable benefit from the AIP Plan, nonetheless KPCo seems content with requiring its ratepayers to pay for it. More to the point, the issue transcends a mere lack of benefit because ratepayers actually suffer *detriment* as they are required to pay value in the

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[69] *Id.* at 19-20.

[70] The following sums of O & M incentive compensation were included in the test year: (a) **$3.579 million** in direct-charges O & M incentive compensation [Response to AG 1-369]; (b) **$99,763** billed to KPCo from affiliates other than AEPSC [Response to AG 2-112 Attach. 5]; and (c) **$3.510 million** billed to KPCo by AEPSC [Response to AG 2-112 Attach. 6].

form of higher utility rates which is then transferred directly to the shareholders' pocketbooks.

In well-established precedents, the Commission has ruled that expenses, even those having a minimal effect on operating income, must be borne by shareholders unless such expenses are proven to be beneficial to ratepayers in furnishing utility service.[71] This precedent applies even to long-term incentive plans such as the AIP.

In Case No. 2010-00036,[72] the Commission adjusted the revenues of Kentucky-American Water Co. to prevent ratepayers from having to pay for an incentive plan, finding:

> In prior proceedings, the Commission has refused to permit Kentucky-American's recovery of AIP costs through rates and has placed the utility on notice that "[t]he mere existence of such [incentive compensation] plans is insufficient to demonstrate that they benefit ratepayers and that their costs should be recovered through rates" and that the utility must demonstrate why shareholders should not bear the costs associated with such plans." [73]

In that same case, Kentucky-American argued that it had produced a study which purportedly quantified benefits that had inured to ratepayers' benefit as a result of the incentive compensation plan. [74] However, the Commission found that the results of that study were inconclusive, at best, and that the study: (a) failed to demonstrate any correlation between the rate of increase in its O & M expense per customer and its use of incentive compensation plans; (b) provided no comparison between its

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[71] *See, e.g.,* Case No. 9482, *In the Matter of Notice of Adjustment of Rates of Kentucky-American Water Company*, Order dated July 8, 1986, p. 22.
[72] *In re: Application of Kentucky-American Water Company for an Adjustment of Rates Supported By a Fully Forecasted Test Year.*
[73] *Id.,* Final Order dated Dec. 10, 2010 at p. 31, *quoting* Case No. 2004-00103, Order of Feb. 28, 2005 at 49.
[74] *Id*. at 31.

performance during the study period and that of firms that offer no incentive compensation plan to their employees; (c) made no effort to eliminate or isolate the effects of other factors, such as the parent company's reorganization efforts, on Kentucky-American's O & M costs per customer.[75] The Commission in that case concluded:

> We remain unconvinced that Kentucky-American's ratepayers receive any benefit from the AIP program to support the recovery of AIP's costs through rates. While some consideration is given to non-financial criteria, the AIP appears weighted to financial goals that primarily benefit shareholders.[76]

The Commission has continued to follow this long-lasting and well-established precedent as recently as 2013, when it removed the entire amount of incentive-based compensation from test period operating expenses in Atmos-Kentucky's most recent base rate case, despite that company's assertions that its long-term incentive plan provided benefits to ratepayers. [77]

In the instant case, KPCo repeatedly states in unsubstantiated direct and rebuttal testimony that the AIP plan provides numerous benefits for ratepayers. Quite tellingly, however, the company has failed to produce *any study at all* to back-up its naked assertions. The record is utterly devoid of any evidence in this regard. KPCo witness Carlin makes repeated assertions that the company's AIP Plan is reasonable, and is a

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[75] *Id.* at 32.
[76] *Id.* at 32.
[77] *In re:* Application of Atmos Energy Corp. for an Adjustment of Rates and Tariff Modifications, Case No. 2013-00148, Final Order dated April 22, 2014, pp. 19-20.

critical component of market-based total compensation.[78] However, he fails to back up these claims with hard data showing any true benefit to ratepayers.

Having failed to offer any quantitative support for its claims that the AIP benefits ratepayers, KPCo has thus failed to meet its burden to demonstrate the reasonableness of the AIP Plan expenses. Accordingly, the Commission should disallow 75% of the total AIP expenses, in the sum of $4,607,841, as was recommended in Mr. Smith's adjustment set forth in RCS-1, Sch. C-7. [79] However, the Attorney General is willing to accept[80] the revised amount for this adjustment set forth in KPCo witness Yoder's rebuttal testimony.[81] There, Mr. Yoder indicates that his calculation of the incentive compensation adjustment would produce an adjustment to reduce operating expenses by $2.9 million, which is $1.7 million less than the Attorney General's calculation of $4.6 million.

d. Stock-Based Compensation

KPCo makes two types of stock-based compensation available to employees: Restricted Stock Units ("RSUs," common stock issued subject to restrictions on transfer, with no voting rights or dividends), and Performance Units ("PUs," no voting dividend or any other common stock rights, but which accrues dividend credits generally equal

[78] Carlin Rebuttal, pp. 2-4.
[79] Smith Direct, pp. 51-52.
[80] The Attorney General nonetheless finds it somewhat disturbing that KPCo refused to provide adequate quantifications of the adjustment impacts in response to discovery, but is allowed to wait until rebuttal in order to present such quantifications.
[81] Yoder Rebuttal, pp. 3-5.

to the value of dividends).[82] KPCo has included stock-based compensation expense in the test year cost of service.[83]

Just as was the case with KPCo's AIP Plan, the metrics for the funding of the company's stock-based compensation (or long-term incentive plan, or "LTIP") are all clearly derived from shareholder value, as is shown in KPCo's response to KIUC 1-33:

> The LTIP metrics for the 2013 test year are calculated based on of the **Company Total Shareholder Return** and **Earnings Per Share** scores (TSR and EPS, respectively). These benchmarks have an important long-term effect on the Company's cost of service and cost of raising equity and debt capital. Each of the two components makes up 50% of the score. The TSR score is calculated by comparing the Company's stock return during a 3 year period to the return of a peer group and multiplying that result by a payout curve. The peer list and payout curve is provided by the Human Resources department annually for the new LTIP compensation. . . . The Corporate Consolidation and Governance, Planning, Analysis Reporting group provides the EPS score which is a score based on the Company's earnings per share. [Emphasis added]

Clearly, KPCo's stock-based compensation expenses incentivize financial performance to achieve shareholder goals. There is no indication anywhere in the record that ratepayers benefit from these expenses.

While KPCo believes it is appropriate for ratepayers to foot the bill for stock-based compensation, the Commission has a well-established precedent that excludes stock-based compensation from rate base. "In the absence of clear and definitive

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[82] *See* KPCo's response to AG 1-86.

[83] The following sums of O & M related stock-based compensation expense were included in the test year: (a) **$215,336** (RSUs) and **$37,806** (PUs)[KPCo response to KIUC 1-32]; (b) **$15,939** in amounts billed from affiliates other than AEPSC [KPCo response to PSC 2-112 Attach. 5]; and (c) **$2,372,183** billed to KPCo by AEPSC [KPCo response to PSC 2-112 Attach. 6].

quantitative evidence demonstrating a benefit to the utility's ratepayers, the ratepayers should not be required to bear the program's costs."[84]

KPCo, just as it argued in the case of the AIP, contends that its stock-based compensation plan is reasonable and market-competitive. But this argument fails to address the Commission's long-standing precedent that ratepayer value must be irrefutably established in order to allow recovery of such expenses. The company has failed to do so.

Therefore, the Attorney General urges the Commission to remove stock-based expenses from rate base, as illustrated in Mr. Smith's Direct Testimony, Exhibit RCS-1, Sch. C-8, which decreases test year expense by $2,614,851. The AG is willing to accept [85] the revised amount for this adjustment based on KPCo witness Yoder's rebuttal. At page R7 of his rebuttal, Mr. Yoder indicates that his calculation of the incentive compensation adjustment would produce an adjustment to reduce operating expenses by $1.7 million, which is $0.9 million less than the Attorney General's calculation of $2.6 million.

e. Engage to Gain Program Costs

KPCo's Engage to Gain Program, which ended at the end of the 2013 calendar

[84] *In re Application of Kentucky-American Water Company for an Adjustment of Rates Supported by a Fully Forecasted Test Year*, Case No. 2010-00036, Final Order dated Dec. 14, 2010, p. 34. *See also, In re An Adjustment of the Gas Rates of the Union Light, Heat & Power Company*, Case. No. 2005-00042, Order on Rehearing dated Feb. 2, 2006, pp. 3-4.
[85] Just as was the case in the incentive compensation issue, *supra* at n. 80, KPCo once again failed to provide the correct calculations in discovery responses, and waited until the time to file rebuttal to provide the correct information.

year, was essentially an employee suggestion program for submission of cost-saving and revenue enhancement ideas.[86] Employees submitting ideas chosen by management would receive cash rewards. Given that the program was in existence for only three (3) months during the historic test year, and has not been in existence for approximately 18 months, the Attorney General believes that the $145,421 of program costs KPCo included in its test year are appropriately excluded.[87]

f. Adjusted Mitchell Plant Maintenance Expense

KPCo's application utilizes a three-year normalization period to adjust maintenance expenses for the Mitchell Plant. [88] The company's proposed normalization period uses the 12 months ended September 30, 2012, 2013 and an annualized amount for 2014, resulting in maintenance expenses of approximately $15.774 million, which resulted in an increase to O & M expenses of approximately $3.223 million on a Kentucky jurisdictional basis.

The Attorney General disagrees with the three year normalization period, and instead proposes a five (5) year period.[89] The company's choice of a three year period gives disproportionate effect to any unusual maintenance expenses that occurred in that time frame, thus the proposed five-year period smoothes out that unusual expense. Mr. Smith's adjustment set forth in Exhibit RCS-1, Sch. C-12 reduces the level of Mitchell maintenance expenses by $998,577 on a Kentucky jurisdictional basis. The Attorney General recommends that the Commission adopt Mr. Smith's adjustment.

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[86] See KPCo response to AG 2-32, Attach. 1.
[87] Smith Direct, p. 56, and Exhibit RCS-1, Sch. C-9.
[88] KPCo Application, Section V, Exhibit 2, page 34.
[89] Smith Direct, pp. 57-59.

KPCo witness LaFleur's rebuttal testimony describes Mr. LaFleur's experience as an engineer, and with the Mitchell Plant. However, the $15.774 million that KPCo has claimed for Mitchell Plant maintenance expense is excessive not only with respect to the historical average Mitchell maintenance expense information listed on Exhibit RCS-1, Schedule C-12, but also with respect to AEP's own 2014 actual, 2014 budgeted and 2015 budgeted Mitchell Plant O&M expense. On March 2, 2015, KPCo filed an Annual Status Report regarding the Mitchell generating station. Table 1 on page 4 shows Mitchell Plant O&M Expense.[90] Fifty percent of the amounts listed for Mitchell Plant O&M on Table 1 of that report would be Mitchell O&M expense of $12.5 million for actual 2014 (which is in line with the $12.474 million Mitchell Plant maintenance expense listed in KPCo's response to AG 1-20 for the 12 months ending September 30, 2014, as shown on Exhibit RCS-1, Schedule C-12, line 10); $10.24 million for budgeted 2014; and $15.2 million for budgeted 2015. The $15.744 million claimed by KPCo is excessive in comparison to any of these amounts, including the $15.2 million 2015 budget. The AG therefore respectfully submits that the $15.744 million of Mitchell plant maintenance expense is excessively high and requests that the Commission reduce the amount of KPCo's claimed Mitchell maintenance expense in determining KPCo's base rate revenue requirement.

g. Interest Synchronization

Mr. Smith has proposed an adjustment to reflect: (a) the Attorney General's

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[90] There is a note on that page stating that the "Totals reflect the 50% of Mitchell Plant owned by KPCO;" however, those amounts are more than double the Mitchell O&M expense listed in response to AG 1-20.

recommended capitalization; and (b) including the tax-deductible interest for the company's accounts receivable financing, which the Company had omitted from its calculation.[91] At the hearing, company witness Wohnhas acknowledged that the company is now including an interest calculation for accounts receivable financing, as reflected in Wohnhas Rebuttal Exhibit RKW-R1.[92]

h. Amortization of Certain Deferred Costs

KPCo's application sought to amortize costs related to the following projects which the company never completed: IGCC, CCS FEED Study, CARRS Site, and the Big Sandy FGD preliminary engineering costs.[93] As stated by company witness Wohnhas during the hearing, if the Commission approves the non-unanimous partial settlement stipulation, KPCo will not seek any cost recovery for any of these items in any future proceeding.[94] The Attorney General supports removal of all of these costs from this, and any future rate proceedings.

4. Other Revenue-Related Issues

a. Big Sandy-1 Operations Rider (Tariff B.S.1.O.R.)

KPCo's filing seeks permission to establish a rider to recover the non-fuel costs of operating Big Sandy Unit 1 (BS-1) until the conversion to gas fueling is completed; the non-fuel costs of operating BS-1 after the gas conversion is completed; and a return on and of investment required for the conversion. Under the terms of the proposed partial settlement, the BS1OR will continue in operation until rates in the company's next base

[91] *Id.* at 59; see also Exhibit RCS-1, Sch. C-13.
[92] Wohnhas Hearing Testimony beginning at approximately 11:25:30.
[93] See Smith Direct, pp. 36-45, Exhibit RCS-1, Schedules C-2 through C-5.
[94] Wohnhas Hearing Testimony, beginning at approximately 11:27:18 – 11:27:54.

rate case are set (after the gas conversion has been completed), at which time they will be placed back into base rates. [95]

The Attorney General has no objection with the terms of Tariff B.S.1.O.R. as set forth in the partial settlement, with two exceptions: (a) the stated ROE should be at the level to which Dr. Woolridge testified, 8.65%; and (b) PJM actual costs that would be recovered under this rider [96] should be removed and instead placed into base rates. When those costs are removed from the BS1OR and placed into base rates, it yields an increase in O & M expense of $4.221 million.[97]

b. <u>Big Sandy Retirement Rider (Tariff B.S.R.R.)</u>

In the Mitchell Transfer Case, the Attorney General opposed the retirement of the Big Sandy plant. The Attorney General continues to appeal this matter, currently in the Kentucky Court of Appeals.[98] The parties to the non-unanimous partial settlement stipulation have recommended that the Commission approve a new rider designed to address the costs of retiring the Big Sandy plant. Notwithstanding the Attorney General's pending appeal of the retirement of the Big Sandy plant, and without waiving any arguments set forth therein, he offers in the alternative the following comments regarding this rider.

KPCo's filing, and the non-unanimous partial settlement stipulation, seek

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[95] Wohnhas Hearing Testimony, beginning at 11:16:30 – 11:17:45.
[96] *See* Wohnhas Hearing Testimony, beginning at 10:57:23. These costs, which were incurred from Jan. – Sept. 2014, total approximately $4.3 million. *See* Smith Direct, p. 56.
[97] Smith Direct, pp. 56-57, and Exhibit RCS-1, Sch. C-10.
[98] Court of Appeals Docket No. 2015-CA-00708 (Notice of Appeal filed on May 8, 2015).

permission to establish a rider which would track costs incurred for the purpose of retiring Big Sandy Unit 1, the Big Sandy Retirement Rider (BSRR), which was initially authorized in the partial settlement which the Commission approved in the Mitchell Transfer case.[99] If approved, the tracker would recover all Big Sandy Unit 1 coal-related costs as well as the Big Sandy Unit 2 retirement costs on a levelized basis, which includes carrying costs based on the weighted average cost of capital (WACC) and which are subject to an accumulated deferred income tax (ADIT) offset, over a 25-year period. [100]

As originally proposed, the BSRR revenue components were comprised of estimated balances as well as estimated future costs. However, the partial settlement states that no estimated costs would be placed into this rider, which was a key concern of the Attorney General. [101] Instead, as proposed in the partial settlement, actual Big Sandy retirement-related costs incurred subsequent to June 30, 2015 would be deferred as they are incurred and added to the unamortized balance of the BSRR regulatory asset.[102]

Additionally, the as-filed version of the BSRR would have employed carrying costs of over $314 million, which the Attorney General believed to be excessive.[103] The non-unanimous partial settlement stipulation, however, addresses the Attorney

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[99] Case No. 2012-00578, Final Order dated October 7, 2013.
[100] Wohnhas Testimony in Support of Partial Settlement, p. 14; *see also* Smith Direct, p. 60.
[101] Wohnhas Testimony in Support of Partial Settlement, p. 15.
[102] *Id.* at 16.
[103] *See, e.g.*, Smith Direct, p. 62.

General's concerns in this limited regard by utilizing WACC-based carrying costs.[104] The Attorney General recommends that the BSRR be adjusted to reflect the Commission-authorized WACC, which should reflect a lower ROE, as described above, than was reflected in the non-unanimous partial settlement stipulation, and that KPCo be required to make a compliance filing reflecting the impact of the Commission's decision on the BSRR.

Finally, under the terms of the non-unanimous partial settlement stipulation, revenues to be recovered in the BSRR will total approximately $16.7 million annually over a 25-year period, [105] which, if approved would be $5.2 million less than the $21.9 million figure provided under the as-filed version of the BSRR. [106] Additionally, rates will be reviewed annually under the non-unanimous partial settlement stipulation, rather than only at every base rate case filing, as they would have been under the as-filed version. [107]

The Attorney General continues to believe that the retirement of the Big Sandy plant itself was unlawful and unreasonable. However, and without waiving any arguments to be set forth in his appeal of the retirement of the Big Sandy plant, the Attorney General states that he has no objection with most of the basic structure of the BSRR as set forth in the non-unanimous partial settlement stipulation. However, he believes utilizing the stated ROE of 10.25% for the BSRR would result in rates that are not fair, just and reasonable. As argued in greater detail in the section of this brief

[104] Wohnhas Testimony in Support of Partial Settlement, pp. 15-16.
[105] Wohnhas Hearing Testimony, VTE at approximately 11:12:35.
[106] Wohnhas Testimony in Support of Partial Settlement at 15.
[107] *Id.* at 17.

entitled "Return on Equity," the Attorney General believes the Commission should utilize the 8.65% ROE figure to which Dr. Woolridge testified, which would yield substantial savings to ratepayers over the multi-year life of this proposed tracking mechanism.

c. PJM Cost Deferral Mechanism

As set forth in numerical paragraph 13 of the non-unanimous partial settlement stipulation, the settling parties seek Commission approval of a mechanism for the purpose of deferring portions of certain PJM costs, subject to the conditions set forth therein. This mechanism would essentially take the place of the PJM Rider which KPCo had included in its original application.

The Attorney General has no objection with the terms of the proposed PJM Cost Deferral Mechanism, and urges the Commission to approve it.

d. Vegetation Management

The Attorney General has no objection with the terms of the non-unanimous partial settlement stipulation's provisions regarding vegetation management, as set forth in numerical paragraph 8 of that document.

e. Environmental Compliance Plan (Tariff E.S.)

As stated in numerical paragraph 2 of the non-unanimous partial settlement stipulation, an ROE of 10.25% would be applied to the company's environmental surcharge. The Attorney General believes that an ROE of this amount would not yield fair, just and reasonable rates. Therefore, he argues that the Commission should apply the 8.65% ROE level which Dr. Woolridge testified to in his direct testimony as to

KPCo's Environmental Compliance Plan.[108] As Mr. Smith testified, application of an 8.65% ROE would reduce the Mitchell FGD revenue requirement by $3.280 million from KPCo's as-filed amount of $34.391 million. [109]

f. Off-System Sales (Tariff S.S.C.)

The non-unanimous partial settlement stipulation at numerical paragraph 5 provides for a revision to KPCo's Tariff S.S.C. which provides, *inter alia*: (a) any over or under difference between each month's actual off-system sales margins and the monthly baseline would be shared between the customers and Kentucky Power on a 75% (customer)/25% (KPCo) basis; and (b) on the date new rates are put into effect, the sharing of off-system sales margins shall be calculated using an annual baseline of $15,136,000.

The Attorney General has no objection with the proposed revisions to Tariff S.S.C. as set forth in the non-unanimous partial settlement stipulation.

g. Biomass Energy Rider (Tariff B.E.R.)

The non-unanimous partial settlement stipulation at numerical paragraph 12 provides a Biomass Energy Rider that will come into effect if and when KPCo begins purchasing power under the Renewable Energy Purchase Agreement which the Commission approved in Case No. 2013-0144.

The Attorney General has no objection with the terms of the non-unanimous partial settlement stipulation in this regard.

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[108] S*ee* Woolridge Direct.
[109] Smith Direct pp. 67-70, and Exhibit RCS-4, and Exhibit RCS-1, Sch. D p. 1; *see also* Elliott Direct p. 17.

h. Economic Development Surcharge ("K.E.D.S.")

The non-unanimous partial settlement stipulation contains a provision which urges the Commission to authorize a new surcharge on ratepayers for economic development projects in the Company's service territory. The surcharge would impose a $0.15 cents monthly fee on each meter. Funds raised under the proposed K.E.D.S. surcharge would be matched dollar-for-dollar with AEP shareholder funds.

The Office of the Attorney General recognizes that the counties comprising KPCo's service territory have some of the highest unemployment rates in the Commonwealth, and indeed some of the highest rates in the nation. Economic development can only help ratepayers by spreading the costs of service among a greater number of customers.

While the Attorney General supports the overall concept of economic development, his preference in this particular case is that the approximate $600,000 in funds to be devoted for this purpose should come exclusively from KPCo's shareholders. Alternatively, he has no objection to the terms of the proposed non-unanimous partial settlement stipulation in this regard, as set forth in numerical paragraph 10 of that document.

i. NERC Compliance and Cybersecurity Deferral

As originally filed, KPCo sought a separate NERC Compliance cost tracking mechanism. However, the parties to the non-unanimous partial settlement stipulation modified this provision so that it would not be an automatic cost tracking mechanism, and instead would allow the Commission to review and approve these costs over five years, and would allow KPCo to begin recovery of approved costs beginning in its next base rate case.[110]

The Attorney General has no objection to the terms of the non-unanimous partial settlement stipulation in this regard. However, he believes that when KPCo brings any such costs before the Commission for review and possible approval, the Commission should carefully consider the concerns set forth in the direct testimony of KIUC Witness Kollen in this regard. [111]

j. Transmission Adjustment

KPCo's application includes a transmission adjustment wherein it proposes to remove $126,908 in transmission costs from base rates, and instead recover them in a transmission rider. As set forth in Mr. Smith's testimony,[112] the Attorney General opposes any such proposal, and prefers that transmission costs continue to be recovered in base rates.

k. The Attorney General has no objection to numerical paragraphs 15 (School Energy Manager Program) and 16 (Tariff K-12 School) of the non-unanimous partial settlement stipulation.

D. Rate Design

a. Residential Class Customer Charge ("Tariff RS").

The Attorney General objects to the non-unanimous partial settlement

110 Non-unanimous partial settlement stipulation, § 14.
111 Kollen Direct, pp. 68-72.
112 Smith Direct p. 72. *See also* Sch. RCS-1, Sch. A.

stipulation's proposal to increase the residential class customer charge from the current $8 per month to $14 because such an increase does not comport with the principle of gradualism, and would lead to rates that are not fair, just and reasonable. Instead, the Attorney General points to a unanimous settlement reached among the parties to Case Nos. 2014-00371 [113] and 2014-00372,[114] in which those companies agreed to not raise their monthly electric service charge. [115] The Attorney General sees no reason why KPCo could not accommodate this change, and urges the Commission to adopt this position. Alternatively, in the event the Commission believes some level of increase in the monthly customer charge is warranted, the Attorney General believes that $11 per month would much more closely comport with gradualism than the $14 figure set forth in the non-unanimous partial settlement stipulation.

b. Rate of Return

The Attorney General has no objection to the non-unanimous partial settlement stipulation's provision regarding rate of return, as set forth in Settlement Exhibit 1 to that document.

III. CONCLUSION

WHEREFORE, the Attorney General respectfully requests that the Public Service Commission adopt the entirety of the adjustments and modifications he proposes in the

[113] *In re* Application of Kentucky Utilities for an Adjustment of Rates.
[114] *In re* Application of Louisville Gas & Electric Co. for an Adjustment of Rates.
[115] *See e.g.,* Testimony and Settlement Agreement at http://psc.ky.gov/pscecf/2014-00371/robert.conroy@lge-ku.com/04202015062015/3-Blake_Testimony_and_Settlement_Agreement.pdf. It should be noted that the unanimous settlement stipulation in those cases is still awaiting Commission approval.

instant brief, in lieu of accepting the totality of the non-unanimous partial settlement stipulation as it currently stands.

Respectfully submitted,
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Certificate of Service and Filing

Counsel certifies that the responses set forth herein are true and accurate to the best of his knowledge, information, and belief formed after a reasonable inquiry. Counsel further certifies that: (a) the foregoing is a true and accurate copy of the same document being filed in paper medium; (b) pursuant to 807 KAR 5:001 § 8(7)(c), there are currently no parties that the Commission has excused from participation by electronic means in this proceeding; and (c) the original and copy in paper medium is being filed with the Commission on March 25, 2015.

I further certify that in accordance with 807 KAR 5:001 § 4 (8), the foregoing is being contemporaneously provided via electronic mail to:

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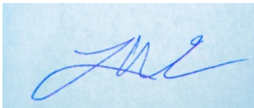

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Attorney General's Brief Exhibit A

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US Regulated Utilities

Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles

The credit profiles of US regulated utilities will remain intact over the next few years despite our expectation that regulators will continue to trim the sector's profitability by lowering its authorized returns on equity (ROE). Persistently low interest rates and a comprehensive suite of cost recovery mechanisms ensure a low business risk profile for utilities, prompting regulators to scrutinise their profitability, which is defined as the ratio of net income to book equity. We view cash flow measures as a more important rating driver than authorized ROEs, and we note that regulators can lower authorized ROEs without hurting cash flow, for instance by targeting depreciation, or through special rate structures. Regulators can also adjust a utility's equity capitalization in its rate base. All else being equal, we think most utilities would prefer a thicker equity base and a lower authorized ROE over a small equity layer and a high authorized ROE.

» **More timely cost recovery helps offset falling ROEs**. Regulators continue to permit a robust suite of mechanisms that enable utilities to recoup prudently incurred operating costs, including capital investments such as environment related or infrastructure hardening expenditures. Strong cost recovery is credit positive because it ensures a stable financial profile. Despite lower authorized ROEs, we see the sector maintaining a ratio of Funds From Operations (FFO) to debt near 20%, a level that continues to support strong investment-grade ratings.

» **Utilities' cash flow is somewhat insulated from lower ROEs**. Net income represents about 30% - 40% of utilities' cash flow, so lower authorized returns won't necessarily affect cash flow or key financial credit ratios, especially when the denominator (equity) is rising. Regulators set the equity layer when capitalizing rate base, and the equity layer multiplied by the authorized ROE drives the annual revenue requirements. Across the sector, the ratio of equity to total assets has remained flat in the 30% range since 2007.

» **Utilities' actual financial performance remains stable**. Earned ROEs, which typically lag authorized ROEs, have not fallen as much as authorized returns in recent years. Since 2007, vertically integrated utilities, transmission and distribution only utilities, and natural gas local distribution companies have maintained steady earned ROE's in the 9% - 10% range. Holding companies with primarily regulated businesses also earned ROEs of around 9% - 10%, while returns for holding companies with diversified operations, namely unregulated generation, have fallen from 11% (over the past seven year average) to around 9% today.

Robust Suite of Cost Recovery Mechanisms Is Credit Positive

Over the past few years, the US regulatory environment has been very supportive of utilities. We think this is partly because regulators acknowledge that utility infrastructure needs a material amount of ongoing investment for maintenance, refurbishment and renovation. Utilities have also been able to garner support from both politicians and regulators for prudent investment in these critical assets because it helps create jobs, spurring economic growth. We also think regulators prefer to regulate financially healthy utilities.

Across the US, we continue to see regulators approving mechanisms that allow for more timely recovery of costs, a material credit positive. These mechanisms, which keep utilities' business risk profile low compared to most industrial corporate sectors, include: formulaic rate structures; special purpose trackers or riders; decoupling programs (which delink volumes from revenue); the use of future test years or other pre-approval arrangements. We also see a sustained increase in the frequency of rate case filings.

A supportive regulatory environment translates into a more transparent and stable financial profile, which in turn results in reasonably unfettered access to capital markets - for both debt and equity. Today, we think utilities enjoy an attractive set of market conditions that will remain in place over the next few years. By themselves, neither a slow (but steady) decline in authorized profitability, nor a material revision in equity market valuation multiples, will derail the stable credit profile of US regulated utilities.

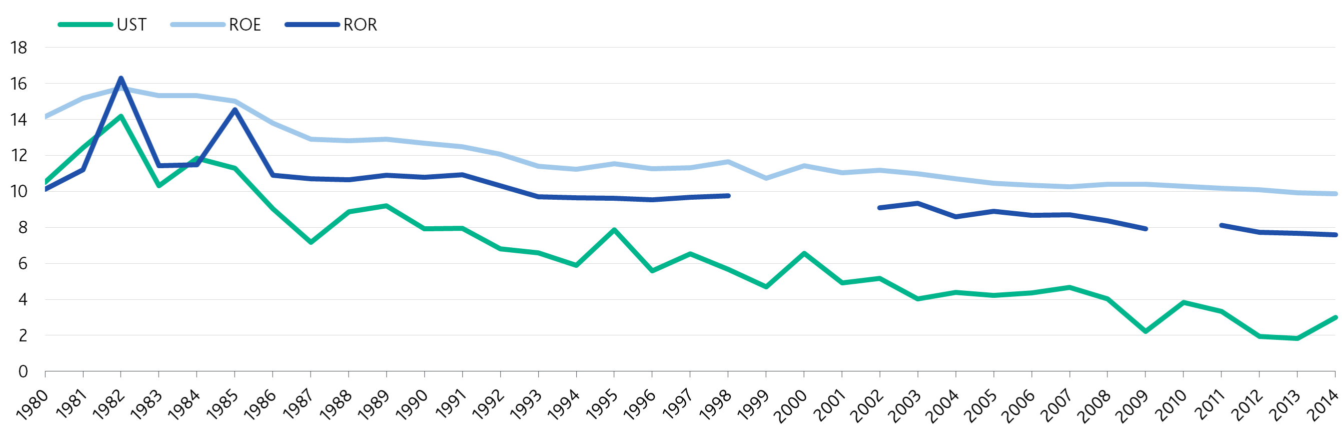
Cost recovery will help offset falling ROEs

Robust cost recovery mechanisms will help ensure that US regulated utilities' credit quality remains intact over the next few years. As a result, falling authorized ROEs are not a material credit driver at this time, but rather reflect regulators' struggle to justify the cost of capital gap between the industry's authorized ROEs and persistently low interest rates. We also see utilities struggling to defend this gap, while at the same time recovering the vast majority of their costs and investments through a variety of rate mechanisms.

In the table below, we show the US Treasury 10-year yield, which has steadily fallen from the 5% range in the summer of 2007 to the 2% range today. US utilities benefit from these lower interest rates because they borrow approximately $50 billion a year. For some utilities, a lower cost of debt translates directly into a higher return on equity, as long as their rate structure includes an embedded weighted average cost of capital (and the utilities can stay out of a general rate case proceeding).

Exhibit 1

Regulators hold up their end of the bargain by limiting reduction in return on equity (ROE) and overall rate of return (ROR) when compared with the decline in US Treasury 10-year yields



SOURCE: SNL Financial, LP, Moody's

As utilities increasingly secure more up-front assurance for cost recovery in their rate proceedings, we think regulators will increasingly view the sector as less risky. The combination of low capital costs, high equity market valuation multiples (which are better than or on par with the broader market despite the regulated utilities' low risk profile), and a transparent assurance of cost recovery tend to support the case for lower authorized returns, although because utilities will argue they should rise, or at least stay unchanged.

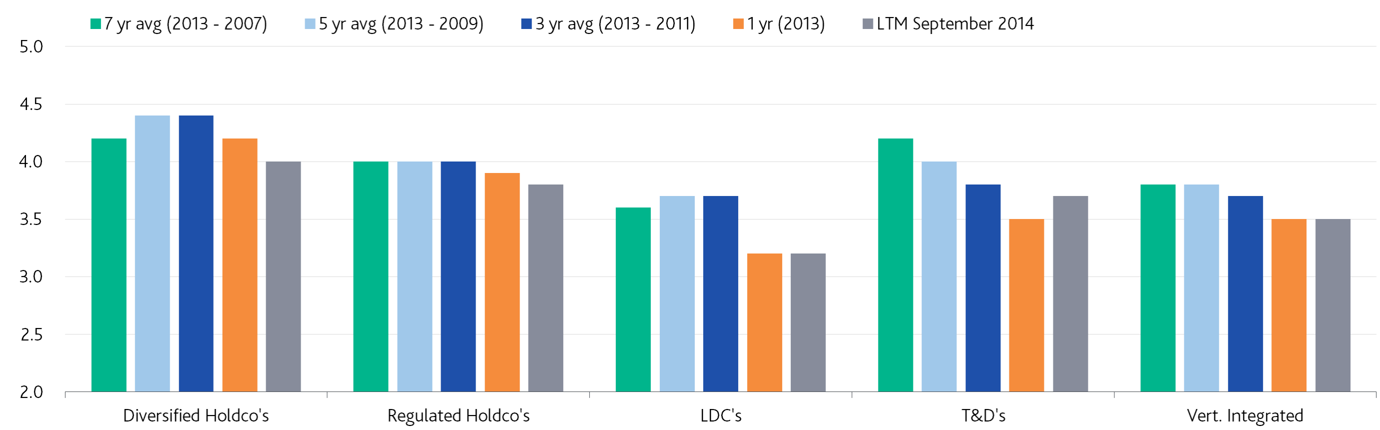
One of the arguments for keeping authorized ROEs steady is that lowering them would make utilities less attractive to providers of capital. Utility holding companies assert that they would rather invest in higher risk-adjusted opportunities than in a regulated utility with sub-par return prospects. We see a risk that this argument could lead to a more contentious regulatory environment, a material credit negative. We do not think this scenario will develop over the next few years.

Our default and recovery data provides strong evidence that regulated utilities are indeed less risky (from the perspective of a probability of default and expected loss given default, as defined by Moody's) than their non-financial corporate peers. On a global basis, we nonetheless see a material amount of capital looking for regulated utility investment opportunities, and the same is true in the US despite, despite a lower authorized return. This is partly because investors can use holding company leverage to increase their actual equity returns, by borrowing capital at today's low interest rates and investing in the equity of a regulated utility.

Despite the reduction in authorized ROEs, US utilities are thankful to their regulators for the robust suite of timely cost recovery mechanisms which allow them to recoup prudently incurred operating costs such as fuel, as well as some investment expenses. These recovery mechanisms drive a stable and transparent dividend policy, which translates into historically very high equity multiples. Moreover, cost recovery helps keep the sector's overall financial profile stable, thereby supporting strong investment-grade ratings.

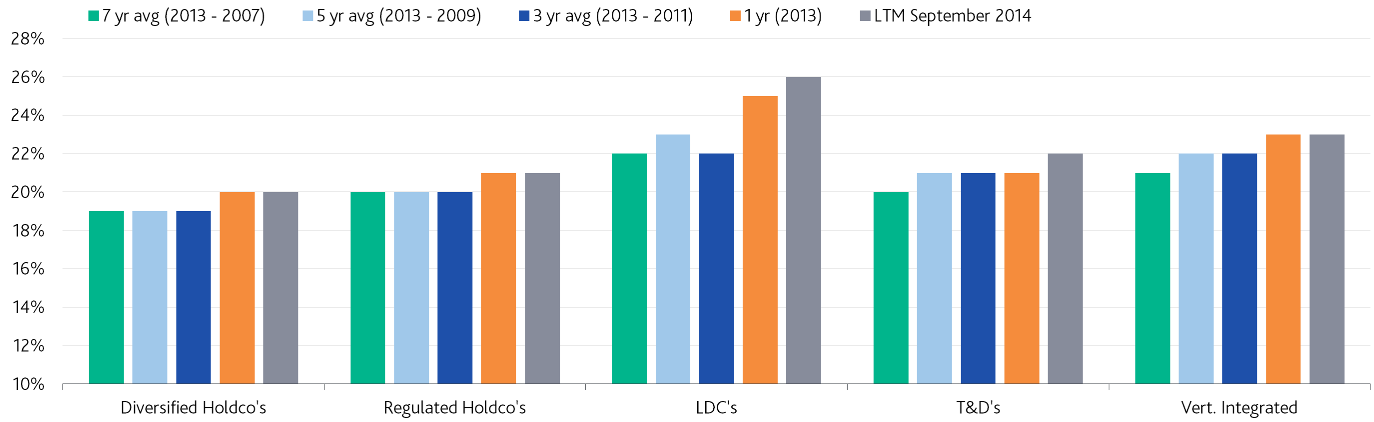
Exhibit 2

With better recovery mechanisms, the ratio of debt-to-EBITDA can rise, modestly, without negatively impacting credit profiles



SOURCE: Company filings; Moody's

Exhibit 3
The ratio of Funds From Operations to debt is rising, a material credit positive,
but the rise is partly funded by bonus depreciation and deferred taxes, which will eventually reverse



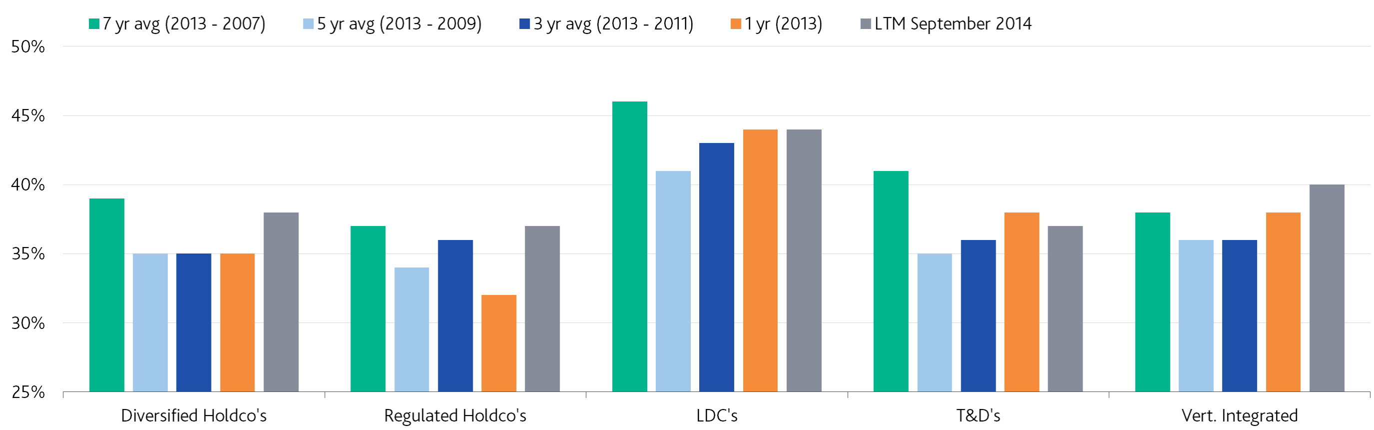
SOURCE: Company filings; Moody's

Utilities' cash flow is somewhat insulated from declining ROEs

Across all our utility group sub-sectors (see Appendix), net income - the numerator in the calculation of ROE – accounts for between 30% - 40% of cash flow. While net income is important, cash flow exerts a much greater influence over creditworthiness. This is primarily because cash flow takes into account depreciation and amortization expenses, along with other deferred tax adjustments. We note that deferred taxes have risen over the past few years, in part due to bonus depreciation elections, which will eventually reverse. From a credit perspective, there is a difference between the nominal amount of net income, which goes into cash flow, and the relationship of net income to book equity (a measure of profitability).

In the chart below, we highlight the ratio of net income to cash flow from operations (CFO) for our selected peer groups. Across all of the sectors, the longer term historical average of net income to CFO has fallen compared with the late 2000s, but has been rising over the more recent past. This is partly a function of deferred taxes, which have become a larger component of CFO over the past decade.

Exhibit 4
Net income as a % of cash flow from operations has been steadily rising (since 2011)

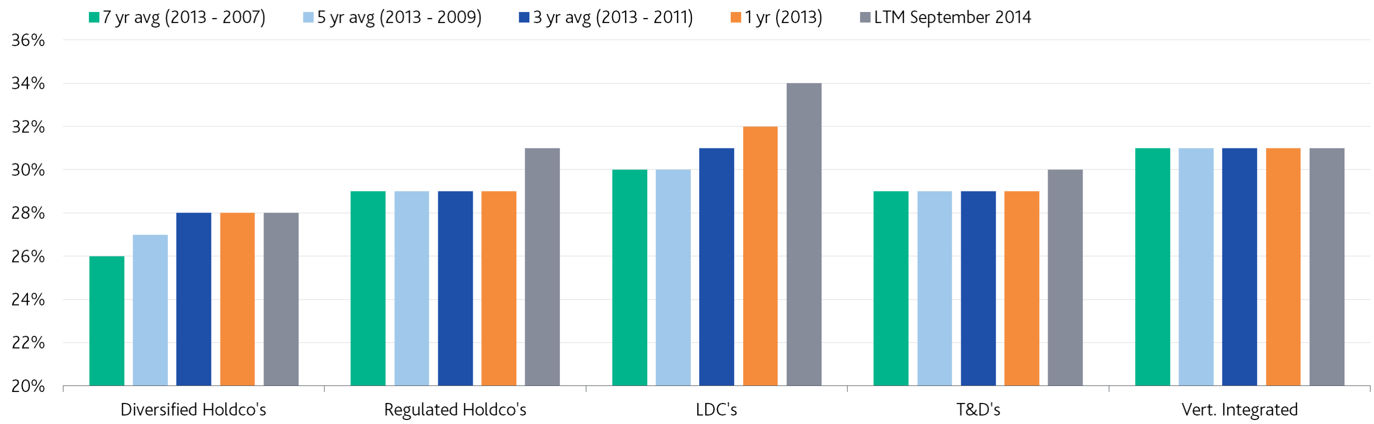


SOURCE: Company filings, Moody's

We can also envisage scenarios where regulators seek to achieve a reduction in authorized ROEs without harming credit profiles by focusing on utilities' equity layer. In the chart below, we illustrate median equity as a percentage of total assets for our selected peer groups. In our illustration, utilities will benefit from acquisition related goodwill on one hand, and impairments on the other.

Exhibit 5

Equity as a % of total assets, not capitalization, includes both goodwill and impairments



SOURCE: Company filings; Moody's

Utilities' actual financial performance remains stable

Earned ROE's, as reported by utilities and adjusted by Moody's, have been relatively flat over the past few years, despite the decline in authorized ROEs. This means utilities are closer to earning their authorized equity returns, which is positive from an equity market valuation perspective.

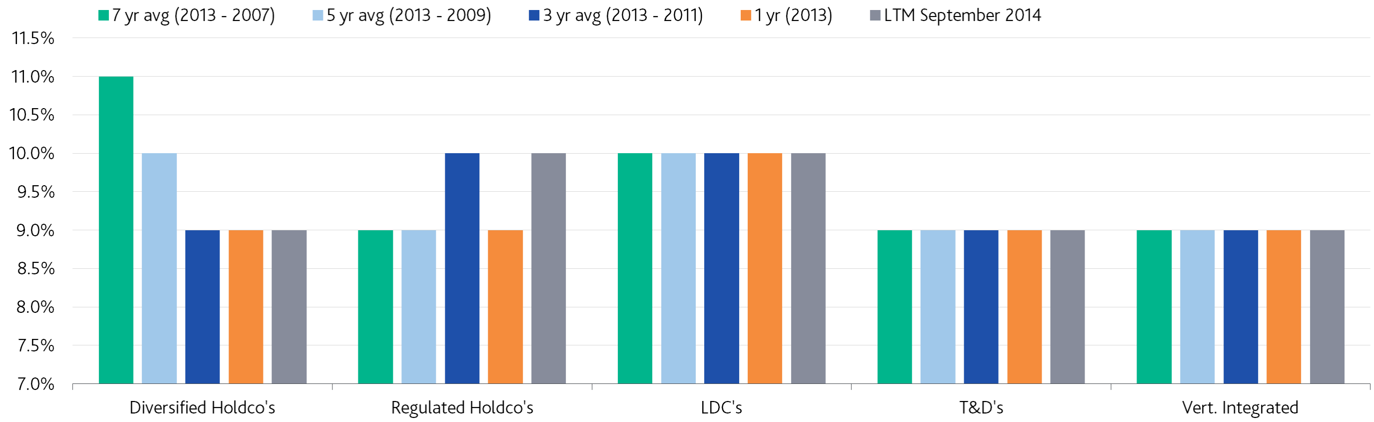
The authorized ROE is a popular focal point in many regulatory rate case proceedings. In addition, many regulatory jurisdictions look to established precedents that rely on various methodologies to determine an appropriate ROE, such as the capital asset pricing model or discounted cash flow analysis. In some jurisdictions where formulaic based rate structures point to lower ROEs for a longer projected period of time, regulators are incorporating a view that today's interest rate environment is "artificially" being held low.

Regardless, we think interest rates will go up, eventually. When they do, we also think authorized ROEs will trend up as well. However, just as authorized ROEs declined in a lagging fashion when compared to falling interest rates, we expect authorized ROEs to rise in a lagging fashion when interest rates rise.

Depending on alternative sources of risk-adjusted capital investment opportunities, this could spell trouble for utilities. For now, utilities can enjoy their (historically) high equity valuations, in terms of dividend yield and price-earnings ratios.

Exhibit 6

GAAP adjusted earned ROE's are relatively flat across all sub-sectors except Holding Companies with Diversified Operations, while the lower-risk LDC sector is outperforming



NOTE: GAAP adjusted ROE, not regulated ROE, does not adjust for goodwill or impairments.

Source: Company filings; Moody's

Appendix

Exhibit 7

Utilities with the highest earned ROEs (ranked by 7-year average)

Company Name	Sector	Rating	1-year average (2013) ROE	3-year average (2013 - 2011) ROE	5-year average (2013 - 2009) ROE	7-year average (2013 - 2007) ROE
CenterPoint Energy Houston Electric, LLC	T&D	A3	33%	32%	25%	23%
Questar Corporation	Holdco - Primarily Regulated	A2	14%	18%	20%	20%
AEP Texas Central Company	T&D	Baa1	14%	28%	22%	20%
Exelon Corporation	Holdco - Diversified	Baa2	7%	10%	14%	17%
CenterPoint Energy, Inc.	Holdco - Primarily Regulated	Baa1	7%	16%	15%	17%
Ohio Edison Company	T&D	Baa1	23%	18%	17%	16%
Public Service Enterprise Group	Holdco - Diversified	Baa2	11%	12%	14%	15%
Dayton Power & Light Company	T&D	Baa3	7%	9%	13%	15%
Dominion Resources Inc.	Holdco - Diversified	Baa2	13%	9%	12%	15%
Southern California Gas Company	LDC	A1	14%	13%	14%	15%
PECO Energy Company	T&D	A2	12%	12%	12%	14%
PPL Corporation	Holdco - Diversified	Baa3	9%	12%	11%	14%
UGI Utilities, Inc.	LDC	A2	15%	13%	13%	13%
Entergy Corporation	Holdco - Diversified	Baa3	7%	11%	12%	13%
Cleco Corporation	Holdco - Primarily Regulated	Baa1	10%	12%	13%	13%
Alabama Gas Corporation	LDC	A2	4%	11%	12%	13%
Entergy New Orleans, Inc.	Vertically Integrated Utility	Ba2	5%	10%	11%	12%
Entergy Gulf States Louisiana, LLC	Vertically Integrated Utility	Baa1	11%	13%	12%	12%
Piedmont Natural Gas Company, Inc.	LDC	A2	11%	11%	12%	12%
Ohio Power Company	T&D	Baa1	25%	14%	13%	12%
Southern Company (The)	Holdco - Primarily Regulated	Baa1	9%	11%	11%	12%
Georgia Power Company	Vertically Integrated Utility	A3	12%	12%	12%	12%
Alabama Power Company	Vertically Integrated Utility	A1	12%	12%	12%	12%
Southern California Edison Company	Vertically Integrated Utility	A2	8%	12%	12%	12%
NextEra Energy, Inc.	Holdco - Diversified	Baa1	10%	11%	11%	12%
Wisconsin Energy Corporation	Holdco - Primarily Regulated	A2	13%	13%	12%	12%
West Penn Power Company	T&D	Baa1	17%	13%	12%	12%
San Diego Gas & Electric Company	Vertically Integrated Utility	A1	9%	10%	11%	12%
Interstate Power and Light Company	Vertically Integrated Utility	A3	10%	9%	9%	12%

NOTE: GAAP adjusted ROE, not regulated ROE, does not adjust for goodwill or impairments.

SOURCE: Moody's; company filings

Exhibit 8

Highest (over 30%) and lowest (less than 20%) equity level as a % of total assets (ranked by 7-year average) [NOTE: Book equity is not adjusted for goodwill or impairments]

Company Name	Sector	Rating	1-year average (2013)	3-year average (2013 - 2011)	5-year average (2013 - 2009)	7-year average (2013 - 2007)
Duke Energy Ohio, Inc.	T&D	Baa1	48%	47%	48%	50%
Yankee Gas Services Company	LDC	Baa1	41%	42%	43%	43%
Texas-New Mexico Power Company	T&D	Baa1	43%	43%	43%	43%
Oncor Electric Delivery Company LLC	T&D	Baa1	40%	41%	41%	43%
Dayton Power & Light Company	T&D	Baa3	37%	38%	39%	40%
Pennsylvania Power Company	T&D	Baa1	25%	30%	34%	40%
Black Hills Power, Inc.	Vertically Integrated Utility	A3	38%	38%	37%	38%
ALLETE, Inc.	Vertically Integrated Utility	A3	38%	37%	37%	38%
Central Maine Power Company	T&D	A3	39%	38%	38%	38%
MGE Energy, Inc.	Holdco - Primarily Regulated	NR	39%	37%	38%	38%
Duke Energy Corporation	Holdco - Primarily Regulated	A3	36%	36%	37%	38%
Jersey Central Power & Light Company	T&D	Baa2	32%	33%	36%	38%
Oklahoma Gas & Electric Company	Vertically Integrated Utility	A1	36%	37%	37%	37%
Public Service Company of Colorado	Vertically Integrated Utility	A3	37%	37%	37%	37%
Virginia Electric and Power Company	Vertically Integrated Utility	A2	37%	37%	37%	35%
Wisconsin Public Service Corporation	Vertically Integrated Utility	A1	34%	34%	34%	35%
PacifiCorp	Vertically Integrated Utility	A3	36%	35%	35%	35%
UGI Utilities, Inc.	LDC	A2	35%	34%	34%	34%
Cleco Corporation	Holdco - Primarily Regulated	Baa1	37%	36%	34%	34%
Empire District Electric Company (The)	Vertically Integrated Utility	Baa1	35%	34%	34%	34%
Great Plains Energy Incorporated	Holdco - Primarily Regulated	Baa2	35%	35%	34%	34%
Nevada Power Company	Vertically Integrated Utility	Baa1	32%	33%	33%	33%
Tampa Electric Company	Vertically Integrated Utility	A2	34%	33%	33%	33%
Wisconsin Power and Light Company	Vertically Integrated Utility	A1	34%	33%	32%	33%
Questar Corporation	Holdco - Primarily Regulated	A2	29%	28%	31%	33%
Duke Energy Kentucky, Inc.	Vertically Integrated Utility	Baa1	31%	30%	33%	33%
Florida Power & Light Company	Vertically Integrated Utility	A1	36%	35%	34%	33%
Alabama Gas Corporation	LDC	A2	59%	40%	35%	33%
El Paso Electric Company	Vertically Integrated Utility	Baa1	34%	32%	32%	33%
IDACORP, Inc.	Holdco - Primarily Regulated	Baa1	34%	33%	33%	33%
PPL Electric Utilities Corporation	Vertically Integrated Utility	Baa1	34%	34%	34%	33%
Commonwealth Edison Company	T&D	Baa1	31%	32%	32%	33%
Georgia Power Company	Vertically Integrated Utility	A3	33%	33%	33%	33%
CMS Energy Corporation	Holdco - Primarily Regulated	Baa2	20%	19%	18%	18%
Hawaiian Electric Industries, Inc.	Holdco - Diversified		17%	16%	16%	16%
CenterPoint Energy, Inc.	Holdco - Primarily Regulated	Baa1	20%	19%	17%	15%
CenterPoint Energy Houston Electric, LLC	T&D	A3	9%	15%	15%	15%
AEP Texas Central Company	T&D	Baa1	13%	15%	14%	13%

SOURCE: Moody's; company filings

Exhibit 9

Highest (over 30%) and lowest (less than 15%) ratio of FFO to debt (ranked by 7-year average)

Company Name	Sector	Rating	1-year average (2013)	3-year average (2013 - 2011)	5-year average (2013 - 2009)	7-year average (2013 - 2007)
Dayton Power & Light Company	T&D	Baa3	32%	34%	42%	42%
Questar Corporation	Holdco - Primarily Regulated	A2	29%	30%	31%	42%
Pennsylvania Power Company	T&D	Baa1	30%	34%	32%	37%
Exelon Corporation	Holdco - Diversified	Baa2	28%	34%	37%	37%
Alabama Gas Corporation	LDC	A2	23%	27%	32%	36%
Florida Power & Light Company	Vertically Integrated Utility	A1	34%	35%	35%	35%
Southern California Gas Company	LDC	A1	42%	37%	35%	34%
Southern California Edison Company	Vertically Integrated Utility	A2	32%	33%	35%	32%
Madison Gas and Electric Company	Vertically Integrated Utility	A1	39%	35%	34%	31%
PECO Energy Company	T&D	A2	29%	31%	33%	31%
Dominion Resources Inc.	Holdco - Diversified	Baa2	16%	17%	16%	14%
Entergy Texas, Inc.	Vertically Integrated Utility	Baa3	15%	14%	12%	14%
Monongahela Power Company	T&D	Baa2	13%	16%	15%	14%
CMS Energy Corporation	Holdco - Primarily Regulated	Baa2	18%	16%	15%	14%
Appalachian Power Company	Vertically Integrated Utility	Baa1	15%	13%	14%	14%
Pennsylvania Electric Company	T&D	Baa2	15%	14%	12%	13%
NiSource Inc.	Holdco - Diversified	Baa2	15%	14%	14%	13%
Puget Energy, Inc.	Vertically Integrated Utility	Baa3	14%	12%	12%	13%
Toledo Edison Company	T&D	Baa3	10%	10%	8%	13%
Cleveland Electric Illuminating Company	T&D	Baa3	11%	11%	12%	13%
AEP Texas Central Company	T&D	Baa1	14%	15%	13%	12%

SOURCE: Moody's; company filings

Exhibit 10

Highest (over 4.5x) and lowest (less than 3.0x) ratio of debt to EBITDA (ranked by 1-year average, 2013, to focus on more recent performance)

Company Name	Sector	Rating	1-year average (2013)	3-year average (2013 - 2011)	5-year average (2013 - 2009)	7-year average (2013 - 2007)
Berkshire Hathaway Energy Company	Holdco - Diversified	A3	7.1	5.8	5.6	5.3
FirstEnergy Corp.	Holdco - Diversified	Baa3	6.0	5.2	4.8	4.4
Wisconsin Electric Power Company	Vertically Integrated Utility	A1	5.9	6.1	5.6	5.0
Entergy Texas, Inc.	Vertically Integrated Utility	Baa3	5.8	6.1	6.2	6.1
Monongahela Power Company	T&D	Baa2	5.6	5.2	5.7	6.0
NiSource Inc.	Holdco - Diversified	Baa2	5.2	5.5	5.4	5.5
PPL Corporation	Holdco - Diversified	Baa3	5.1	4.9	5.1	4.6
Appalachian Power Company	Vertically Integrated Utility	Baa1	5.0	5.0	5.2	5.4
Progress Energy, Inc.	Holdco - Primarily Regulated	Baa1	4.9	5.6	5.1	4.9
Puget Energy, Inc.	Vertically Integrated Utility	Baa3	4.9	5.6	5.9	5.6
Cleveland Electric Illuminating Company	T&D	Baa3	4.9	5.2	4.7	4.2
Northwest Natural Gas Company	LDC	A3	4.8	4.8	4.5	4.2
Jersey Central Power & Light Company	T&D	Baa2	4.7	5.5	4.2	3.6
NorthWestern Corporation	Vertically Integrated Utility	A3	4.7	4.5	4.4	4.3
Pepco Holdings, Inc.	Holdco - Primarily Regulated	Baa3	4.7	5.1	5.2	5.2
Laclede Gas Company	LDC	A3	4.7	5.5	5.3	5.6
Atlantic City Electric Company	T&D	Baa2	4.7	4.9	4.8	4.7
Nevada Power Company	Vertically Integrated Utility	Baa1	4.6	4.6	4.9	5.0
Black Hills Power, Inc.	Vertically Integrated Utility	A3	2.9	3.2	3.8	3.6
Virginia Electric and Power Company	Vertically Integrated Utility	A2	2.9	3.1	3.4	3.4
Duke Energy Kentucky, Inc.	Vertically Integrated Utility	Baa1	2.9	3.3	3.3	3.4
Texas-New Mexico Power Company	T&D	Baa1	2.9	2.9	3.2	3.3
Oklahoma Gas & Electric Company	Vertically Integrated Utility	A1	2.9	2.9	2.9	3.0
Cleco Power LLC	Vertically Integrated Utility	A3	2.9	3.2	3.6	3.7
Consumers Energy Company	Vertically Integrated Utility	A1	2.9	3.1	3.3	3.5
Alabama Power Company	Vertically Integrated Utility	A1	2.8	2.9	3.0	3.1
Public Service Electric and Gas Company	T&D	A2	2.8	3.0	3.2	3.3
Alabama Gas Corporation	LDC	A2	2.8	2.7	2.5	2.4
Pinnacle West Capital Corporation	Holdco - Primarily Regulated	Baa1	2.8	3.1	3.3	3.6
Cleco Corporation	Holdco - Primarily Regulated	Baa1	2.8	2.9	3.4	3.6
PECO Energy Company	T&D	A2	2.8	3.0	2.6	2.6
Northern States Power Company (Wisconsin)	Vertically Integrated Utility	A2	2.8	2.9	2.8	2.8
Duke Energy Carolinas, LLC	Vertically Integrated Utility	A1	2.8	3.1	3.2	3.1
UGI Utilities, Inc.	LDC	A2	2.7	3.0	3.1	3.3
Exelon Corporation	Holdco - Diversified	Baa2	2.7	2.8	2.5	2.5
West Penn Power Company	T&D	Baa1	2.7	3.3	3.3	3.4
Questar Corporation	Holdco - Primarily Regulated	A2	2.7	2.8	2.7	2.3
Tampa Electric Company	Vertically Integrated Utility	A2	2.6	2.7	2.8	2.9
Arizona Public Service Company	Vertically Integrated Utility	A3	2.6	2.9	3.1	3.3
New York State Electric and Gas Corporation	T&D	A3	2.6	2.9	3.2	4.3
Dayton Power & Light Company	T&D	Baa3	2.5	2.2	2.0	1.9
Florida Power & Light Company	Vertically Integrated Utility	A1	2.4	2.7	2.6	2.6
Ohio Power Company	T&D	Baa1	2.4	2.8	3.1	3.3
Madison Gas and Electric Company	Vertically Integrated Utility	A1	2.4	2.8	2.8	2.9
Pennsylvania Power Company	T&D	Baa1	2.4	2.3	2.4	2.2
MGE Energy, Inc.	Holdco - Primarily Regulated	NR	2.3	2.7	2.9	3.1
Rochester Gas & Electric Corporation	T&D	Baa1	2.3	2.9	3.0	3.5
Public Service Enterprise Group Incorporated	Holdco - Diversified	Baa2	2.3	2.3	2.3	2.4
NSTAR Electric Company	T&D	A2	2.2	2.6	2.7	2.8
Southern California Gas Company	LDC	A1	2.2	2.5	2.4	2.5
Mississippi Power Company	Vertically Integrated Utility	Baa1	(3.2)	3.5	3.4	3.1

Exhibit 11

List of Companies (NOTE: in our appendix tables, we exclude utilities with private ratings)

Company Name	Sector	Rating
Berkshire Hathaway Energy Company	Holdco - Diversified	A3
Black Hills Corporation	Holdco - Diversified	Baa1
Dominion Resources Inc.	Holdco - Diversified	Baa2
DTE Energy Company	Holdco - Diversified	A3
Entergy Corporation	Holdco - Diversified	Baa3
Exelon Corporation	Holdco - Diversified	Baa2
FirstEnergy Corp.	Holdco - Diversified	Baa3
Hawaiian Electric Industries, Inc.	Holdco - Diversified	NR
Integrys Energy Group, Inc.	Holdco - Diversified	A3
NextEra Energy, Inc.	Holdco - Diversified	Baa1
NiSource Inc.	Holdco - Diversified	Baa2
PPL Corporation	Holdco - Diversified	Baa3
Public Service Enterprise Group Incorporated	Holdco - Diversified	Baa2
Sempra Energy	Holdco - Diversified	Baa1
Alliant Energy Corporation	Holdco - Primarily Regulated	A3
Ameren Corporation	Holdco - Primarily Regulated	Baa2
American Electric Power Company, Inc.	Holdco - Primarily Regulated	Baa1
CenterPoint Energy, Inc.	Holdco - Primarily Regulated	Baa1
Cleco Corporation	Holdco - Primarily Regulated	Baa1
CMS Energy Corporation	Holdco - Primarily Regulated	Baa2
Consolidated Edison, Inc.	Holdco - Primarily Regulated	A3
Duke Energy Corporation	Holdco - Primarily Regulated	A3
Edison International	Holdco - Primarily Regulated	A3
Great Plains Energy Incorporated	Holdco - Primarily Regulated	Baa2
IDACORP, Inc.	Holdco - Primarily Regulated	Baa1
MGE Energy, Inc.	Holdco - Primarily Regulated	NR
Northeast Utilities	Holdco - Primarily Regulated	Baa1
Pepco Holdings, Inc.	Holdco - Primarily Regulated	Baa3
PG&E Corporation	Holdco - Primarily Regulated	Baa1
Pinnacle West Capital Corporation	Holdco - Primarily Regulated	Baa1
PNM Resources, Inc.	Holdco - Primarily Regulated	Baa3
Progress Energy, Inc.	Holdco - Primarily Regulated	Baa1
Questar Corporation	Holdco - Primarily Regulated	A2
SCANA Corporation	Holdco - Primarily Regulated	Baa3
Southern Company (The)	Holdco - Primarily Regulated	Baa1
Wisconsin Energy Corporation	Holdco - Primarily Regulated	A2
Xcel Energy Inc.	Holdco - Primarily Regulated	A3
Alabama Gas Corporation	LDC	A2
Atmos Energy Corporation	LDC	A2
DTE Gas Company	LDC	Aa3
Laclede Gas Company	LDC	A3
New Jersey Natural Gas Company	LDC	Aa2
Northern Natural Gas Company [Private]	LDC	A2
Northwest Natural Gas Company	LDC	A3
Piedmont Natural Gas Company, Inc.	LDC	A2
South Jersey Gas Company	LDC	A2
Southern California Gas Company	LDC	A1
Southwest Gas Corporation	LDC	A3
UGI Utilities, Inc.	LDC	A2
Washington Gas Light Company	LDC	A1
Wisconsin Gas LLC [Private]	LDC	A1
Yankee Gas Services Company	LDC	Baa1
AEP Texas Central Company	T&D	Baa1
AEP Texas North Company	T&D	Baa1
Atlantic City Electric Company	T&D	Baa2

Baltimore Gas and Electric Company	T&D	A3
CenterPoint Energy Houston Electric, LLC	T&D	A3
Central Hudson Gas & Electric Corporation	T&D	A2
Central Maine Power Company	T&D	A3
Cleveland Electric Illuminating Company (The)	T&D	Baa3
Commonwealth Edison Company	T&D	Baa1
Connecticut Light and Power Company	T&D	Baa1
Consolidated Edison Company of New York, Inc.	T&D	A2
Dayton Power & Light Company	T&D	Baa3
Delmarva Power & Light Company	T&D	Baa1
Duke Energy Ohio, Inc.	T&D	Baa1
Jersey Central Power & Light Company	T&D	Baa2
Metropolitan Edison Company	T&D	Baa1
Monongahela Power Company	T&D	Baa2
New York State Electric and Gas Corporation	T&D	A3
NSTAR Electric Company	T&D	A2
Ohio Edison Company	T&D	Baa1
Ohio Power Company	T&D	Baa1
Oncor Electric Delivery Company LLC	T&D	Baa1
Orange and Rockland Utilities, Inc.	T&D	A3
PECO Energy Company	T&D	A2
Pennsylvania Electric Company	T&D	Baa2
Pennsylvania Power Company	T&D	Baa1
Potomac Edison Company (The)	T&D	Baa2
Potomac Electric Power Company	T&D	Baa1
Public Service Electric and Gas Company	T&D	A2
Rochester Gas & Electric Corporation	T&D	Baa1
Texas-New Mexico Power Company	T&D	Baa1
Toledo Edison Company	T&D	Baa3
West Penn Power Company	T&D	Baa1
Western Massachusetts Electric Company	T&D	A3
Alabama Power Company	Vertically Integrated Utility	A1
ALLETE, Inc.	Vertically Integrated Utility	A3
Appalachian Power Company	Vertically Integrated Utility	Baa1
Arizona Public Service Company	Vertically Integrated Utility	A3
Avista Corp.	Vertically Integrated Utility	Baa1
Black Hills Power, Inc.	Vertically Integrated Utility	A3
Cleco Power LLC	Vertically Integrated Utility	A3
Consumers Energy Company	Vertically Integrated Utility	A1
DTE Electric Company	Vertically Integrated Utility	A2
Duke Energy Carolinas, LLC	Vertically Integrated Utility	A1
Duke Energy Florida, Inc.	Vertically Integrated Utility	A3
Duke Energy Kentucky, Inc.	Vertically Integrated Utility	Baa1
Duke Energy Progress, Inc.	Vertically Integrated Utility	A1
El Paso Electric Company	Vertically Integrated Utility	Baa1
Empire District Electric Company (The)	Vertically Integrated Utility	Baa1
Entergy Arkansas, Inc.	Vertically Integrated Utility	Baa2
Entergy Gulf States Louisiana, LLC	Vertically Integrated Utility	Baa1
Entergy Louisiana, LLC	Vertically Integrated Utility	Baa1
Entergy Mississippi, Inc.	Vertically Integrated Utility	Baa2
Entergy New Orleans, Inc.	Vertically Integrated Utility	Ba2
Entergy Texas, Inc.	Vertically Integrated Utility	Baa3
Florida Power & Light Company	Vertically Integrated Utility	A1
Georgia Power Company	Vertically Integrated Utility	A3
Gulf Power Company	Vertically Integrated Utility	A2
Hawaiian Electric Company, Inc.	Vertically Integrated Utility	Baa1
Idaho Power Company	Vertically Integrated Utility	A3
Indiana Michigan Power Company	Vertically Integrated Utility	Baa1
Interstate Power and Light Company	Vertically Integrated Utility	A3
Kansas City Power & Light Company	Vertically Integrated Utility	Baa1
Kentucky Power Company	Vertically Integrated Utility	Baa2

Madison Gas and Electric Company	Vertically Integrated Utility	A1
MidAmerican Energy Company	Vertically Integrated Utility	A1
Mississippi Power Company	Vertically Integrated Utility	Baa1
Nevada Power Company	Vertically Integrated Utility	Baa1
Northern States Power Company (Minnesota)	Vertically Integrated Utility	A2
Northern States Power Company (Wisconsin)	Vertically Integrated Utility	A2
NorthWestern Corporation	Vertically Integrated Utility	A3
Oklahoma Gas & Electric Company	Vertically Integrated Utility	A1
Pacific Gas & Electric Company	Vertically Integrated Utility	A3
PacifiCorp	Vertically Integrated Utility	A3
Portland General Electric Company	Vertically Integrated Utility	A3
PPL Electric Utilities Corporation	Vertically Integrated Utility	Baa1
Public Service Company of Colorado	Vertically Integrated Utility	A3
Public Service Company of New Hampshire	Vertically Integrated Utility	Baa1
Public Service Company of New Mexico	Vertically Integrated Utility	Baa2
Public Service Company of Oklahoma	Vertically Integrated Utility	A3
Puget Energy, Inc.	Vertically Integrated Utility	Baa3
Puget Sound Energy, Inc.	Vertically Integrated Utility	Baa1
San Diego Gas & Electric Company	Vertically Integrated Utility	A1
Sierra Pacific Power Company	Vertically Integrated Utility	Baa1
South Carolina Electric & Gas Company	Vertically Integrated Utility	Baa2
Southern California Edison Company	Vertically Integrated Utility	A2
Southwestern Electric Power Company	Vertically Integrated Utility	Baa2
Southwestern Public Service Company	Vertically Integrated Utility	Baa1
Tampa Electric Company	Vertically Integrated Utility	A2
Tucson Electric Power Company	Vertically Integrated Utility	Baa1
Union Electric Company	Vertically Integrated Utility	Baa1
Virginia Electric and Power Company	Vertically Integrated Utility	A2
Wisconsin Electric Power Company	Vertically Integrated Utility	A1
Wisconsin Power and Light Company	Vertically Integrated Utility	A1
Wisconsin Public Service Corporation	Vertically Integrated Utility	A1

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MOODY'S
INVESTORS SERVICE

Attorney General's Brief Exhibit B

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

Case Nos. 14-1152-E-42T and 14-1151-E-D

APPALACHIAN POWER COMPANY
and WHEELING POWER COMPANY

COMMISSION ORDER ON THE TARIFF FILING
OF APPALACHIAN POWER COMPANY and
WHEELING POWER COMPANY TO INCREASE RATES,
and PETITION TO CHANGE DEPRECIATION RATES.

May 26, 2015

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PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

At a session of the PUBLIC SERVICE COMMISSION OF WEST VIRGINIA in the City of Charleston on the 26th day of May 2015.

Case No. 14-1152-E-42T

APPALACHIAN POWER COMPANY and
WHEELING POWER COMPANY, both dba
AMERICAN ELECTRIC POWER
Rule 42T tariff filing to increase electric rates and charges.

and

Case No. 14-1151-E-D
APPALACHIAN POWER COMPANY and
WHEELING POWER COMPANY, both dba
AMERICAN ELECTRIC POWER
Petition to change depreciation rates.

COMMISSION ORDER

I. INTRODUCTION

A. Preliminary Discussion

This Commission Order rules on a general base rate case (2014 Rate Case) of Appalachian Power Company (APCo) and Wheeling Power Company (WPCo) (collectively APCo/WPCo or the Companies) that is significant to the customers and other stakeholders of the Companies. This 2014 Rate Case is significant not only for the amount of the requested revenue increase but also because the Commission has before it in this case a number of important ratemaking issues addressed by good witnesses in a case that was well presented, well argued and well briefed.[1] It is a case in which the parties have taken strong and divergent views and ratemaking approaches to the resolution of contested ratemaking issues.

[1] The record in this proceeding consists of over 1,056 pages of live testimony and 5,191 pages of prefiled testimony and exhibits, plus exhibits admitted at the hearing. In addition, the parties tendered 464 pages of briefs.

In establishing rates for utilities, the Commission, of course, is guided by the general instruction and admonitions of the United States Supreme Court and the West Virginia Supreme Court regarding the adequacy of public utility rates. We have recited that guidance in numerous prior cases, including, among others Mountaineer Gas Company, Case No. 11-1627-G-42T (Order of October 31, 2012, at 7) and West Virginia-American Water Company, Case No. 10-0920-W-42T (Order of April 18, 2011, at 15):

> The United States Supreme Court and the West Virginia Supreme Court of Appeals have held that utility rates should allow a public utility the opportunity to earn a level of revenue sufficient to attract capital in the competitive capital market, balanced with the interests of the consuming public in receiving fair and reasonable rates. Bluefield Water Works v. Public Service Commission, 320 U.S. 679 (1923); Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 64S. Ct. 281 (1944); Permian Basin Area Rate Cases, 390 U.S. 747, 88 S. Ct. 1344 (1968); Monongahela Power Company v. Public Service Commission, 276 S.E.2d 179 (W.Va. 1981).

That guidance is generally helpful, but the best way to assess and calculate whether that level of revenue is adequate in the first instance is often just to labor through those rate issues on an issue by issue basis in a general rate case. That is precisely what the Commission has done in this case as can be seen from the length and complexity of this Order.

Although APCo/WPCo have had various Expanded Net Energy Cost (ENEC) proceedings that "pass through" rate increases based generally on the costs of the fuel and purchased power experienced over a period of time, the last major APCo/WPCo base rate case, Appalachian Power Company and Wheeling Power Company, Commission Case No. 10-0699-E-42T (2010 Rate Case), filed on May 14, 2010, was based on a 2009 test year and was decided March 30, 2011. In that 2010 Rate Case, the Companies requested a 13.8 percent rate increase, consisting of a $223,778,770 base rate increase offset by a $68,315,471 decrease in the Construction Surcharge and ARS Surcharge (a net requested total rate increase of $155.4 million). As a part of the proceedings in the 2010 Rate Case, the parties submitted a Joint Stipulation and Agreement for Settlement (2010 Joint Stipulation) and recommended a rate increase of approximately $60 million to the Commission, rather than the $155.4 million request filed by the Companies.

In the 2010 Rate Case, the Commission examined the 2010 Joint Stipulation, extensively reviewed the record in the proceeding, and based to some extent on (i) the dismal "Current Economic Climate" (2010 Rate Case Order at 5) existing at the time of the 2010 Order (referred to at the time in the 2010 Rate Case Order as the "Great Recession"), (ii) the additional burden imposed on ratepayers by the 2010 Order, and (iii) other rulings in the case, entered a lengthy order, modifying the 2010 Joint

Stipulation and awarding the Companies $51.12 million, an amount approximately $9 million less than the recommendation of the parties in the 2010 Joint Stipulation.

In this 2014 Rate Case, the Commission again has before it a request by the Companies for a base rate increase of approximately $225 million which includes a request to increase depreciation rates (Case No. 14-1151-E-D) (2014 Depreciation Case).[2] There has been a substantial number of public comments filed in this case,[3] with those comments generally opposing the 2014 Rate Case because of the dollar impact on fixed or low-income customers or because of the perception that the Companies file too many rate cases.[4] The Companies addressed those customer complaints early in their Initial Brief in this case:

> The Companies are seeking their requested base rate increase because "the costs of fulfilling their on-going obligation to provide their customers with safe and reliable electrical service made it imperative that they file for a base rate increase. The costs of providing electric service have increased and revenues have not increased commensurately." Companies Exh. CRP-D at 6. The Companies have read each protest and communication that their customers have sent to the Commission. Many of those customers complain of the high cost of many items, including food, housing, and medicine. But the cost of all of these things is determined by the market. The cost of their utility services is one of the few things that is set by governmental decision-making. And so this case before this regulatory body presents one of the few opportunities for them to vent their dissatisfaction.
>
> The Companies, like their customers, are confronted with rising costs. The costs of virtually everything the Companies need to fulfill their public service obligation – from the cost of trucks, meters, building materials, and wire to the compensation paid to employees and the cost of needed investment capital – is similarly determined by the market. One of the few things that is set by governmental decision-making for the Companies are the rates that they are permitted to charge and, hence, the revenues that they receive.

Appalachian Power Company and Wheeling Power, Initial Brief at 2 (the briefs of the parties will be referenced by party identification, nature of brief, and page number, such

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[2] The procedural histories of the 2014 Rate Case and 2014 Depreciation Case are set forth as Appendix D to this Order.

[3] There were more than 200 protest letters signed by nearly 2,500 customers.

[4] In fact, the last major APCo base rate case prior to the 2010 Rate Case was Appalachian Power Company and Wheeling Power Company, Case No. 05-1278-E-PC-PW-42T, decided July 26, 2006.

as "APCo Init. Br. at __." References to prefiled testimony will be by Exhibit identification and page number, such as "Companies Exh. MJM-D at __.").[5]

Many of the public comments and protests also suggest that the Commission is insensitive to the customers, but nothing could be further from the truth. The Commission continues to be sympathetic to the plight of all customers of the Companies, including the residential customers and has, in extraordinary circumstances, such as the Great Recession referenced in the 2010 Rate Case, given consideration to adjusting rates for the singular impact of a significant economic event or other dire financial circumstances.[6] We knew when we heard and deliberated this case that it would be a case with a significant revenue impact, but it was not until we deliberated over the record and the issues while preparing this Order that we appreciated the magnitude of the revenue requirement that APCo/WPCo had demonstrated.

While we are sensitive to the rate impact of this case, and particularly the potential impact of the case on all residential customers, we are also mindful of the Commission's overriding general statutory charge "to exercise the legislative powers" granted to it under W.Va. Code §24-1-1 and to appraise and balance the general interests of current and future utility service customers, the general interests of the State's economy and the interests of the utilities subject to its jurisdiction, deliberations and decisions, including:

- [Ensuring] the fair and prompt regulation of public utilities in the interests of the consuming public;

---

5 For this Order, the other parties to this proceeding will be referred to as: "Staff" (Staff of the Commission); "CAD" (Consumer Advocate Division of the Commission); "Kroger" (The Kroger Company); "SWVA" (Steel of West Virginia, Inc.) "WVEUG" (West Virginia Energy Users Group); and; "Walmart" (Wal-Mart Stores, Inc.).

6 Residential customers do receive the specific rate case protections afforded by the participation of the Commission CAD. In addition, low income residential customers are eligible for rate assistance from Dollar Energy or other specific low income energy or financial assistance programs. For instance, in calendar year 2014 and calendar year 2015 to date, residential customers of the Companies received the following rate assistance:

Grants to AEP Customers		
Program	CY 2014	CY 2015 YTD (as of 4/16/2015)
Dollar Energy	$ 435,646	$ 148,359
LIEAP*	6,684,151.82	6,738,961.50
ELIEAP**	837,677.22	83,854.09
Total LIEAP/ELIEAP	$ 7,521,829.04	$ 6,822,815.59
*Low Income Energy Assistance Program		
** Emergency Low Income Energy Assistance Program		

- [Providing] the availability of adequate, economical and reliable utility services throughout the state; and

- [Ensuring] that rates and charges for utility services are just, reasonable, applied without unjust discrimination or preference, applied in a manner consistent with the purposes and policies set forth in article two-a [W.Va. Code §§24-2A-1 et seq.] of this chapter, and based primarily on the costs of providing these services.

The Commissioners take an oath to uphold their statutory duties to insure that the interests of the utilities and all customers (current and future) and the general interests of the State's economy are properly and constitutionally protected, and that Commission orders are not contrary to the evidence, without evidence to support them, are not arbitrary or result from a misapplication of legal principles. United Fuel Gas Company v. Pub. Serv. Comm'n, 143 W. Va. 33, 99 S.E.2d 1 (1957); Boggs v. Pub. Serv. Comm'n, 154 W. Va. 146, 174 S.E.2d 331 (1970); Monongahela Power Co. v. Pub. Serv. Comm'n of W. Va., 166 W. Va. 423, 276 S.E.2d 179 (1981); Broadmoor/Timberline Apartments v. Pub. Serv. Comm'n, 180 W.Va. 387, 376 S.E.2d 593 (1988); Sexton v. Pub. Serv. Comm'n, 188 W. Va. 305, 423 S.E.2d 914 (1992); and most recently, Allied Waste Serv. of North Amer., LLC v. Pub. Serv. Comm'n, No. 14-1131 (West Virginia Supreme Court of Appeals Memorandum Decision filed March 11, 2015); W.Va. Code §24-1-1. Chesapeake & Potomac Telephone Company v. Public Service Commission, 1982 W.Va. LEXIS 687, 300 S.E.2d 607 (1982).

The Companies in their Initial Brief, apparently anticipating the substantial pressure that would be on the Commission to impose a "revenue haircut" on the Companies, urged the Commission to re-examine and to consider altering some of its existing regulatory treatments:

> In every base rate case the Commission determines, in addition to what a utility's operational costs are, what investment it has in rate base and what a reasonable return on that investment would be. The sad situation in which the Companies find themselves is twofold: (1) for some years they have not been able to earn anything approaching their authorized rate of return (Company Exh. CRP-R at 2); and (2) various ratemaking treatments have denied them even a fair opportunity to earn their authorized rate of return (Company Exh. CRP-D at 10-11; *see also* Tr. 1/20, at 91 (Patton)). This situation is of especial concern to the Companies because it has persisted despite the Companies' efforts to make prudent investments to serve their customers and to control the Companies' operational costs. Company Exh. CRP-D at 7-9.
>
> What the Companies need as the outcome of the instant proceedings is fair and reasonable rates that will allow them to cover their prudent

> operational costs and to have a fair opportunity of earning their authorized rate of return. An essential element of such a result is the reformation of regulatory policies that essentially deprive the Companies at the outset of that fair opportunity. With such a fair and reasonable result, and with future operational improvements like the operational improvements that the Companies have achieved in the past, the Companies hope that they will be able to delay as long as possible the next occasion on which they will have to apply to the Commission for base rate relief.

APCo Init. Br. at 3 (emphasis added).

The underscored language in the preceding quote concerning regulatory policies was apparently the Companies' effort to "sharpen the focus" of the Commission on the ratemaking treatments the Commission has granted or denied for certain key issues that the Companies view as critical to attaining an acceptable financial outcome in this case and to attempt to convince the Commission to either change its prior approach or at least to modify its prior rulings on some of the issues in this proceeding.

We have done that, and while some of the matters raised in this case for special consideration are issues of first impression before the Commission or issues that the Commission has had before it in prior cases and that one or more of the parties want us to revisit, most of those issues also have significant revenue impact. Although not an exhaustive list, those issues, addressed by the parties (and addressed by the Commission later in this Order), include among others:

- Consolidated tax savings;
- Cash working capital allowance, including particularly items such as service company and intercompany billings, property tax lead days, and depreciation and return (earnings) revenue lag;
- Annual incentive pay;
- Pension assets;
- Lost revenues from energy efficiency and demand response programs;
- Depreciation rates and cost of removal;
- Units of property and federal and state income tax impacts; and
- Treatment of tree trimming expense.

We completed our review and examination of the record, the comments of the witnesses, the financial analyses, and the briefs of the parties and to our dismay, but not necessarily to our surprise, we arrived at a revenue deficiency for APCo/WPCo of $123,457,711, an amount that is significant by any standard, and one of the larger revenue recommendations from any recent general rate case that we can recall.

We believe the revenue level we have established in this case is accurate. We also, however, appreciate the magnitude of that increase, and have as a result (and consistent with our obligation to fix rates that are just, reasonable, applied without unjust discrimination or preference), proposed a treatment for the recovery of that revenue from the customers, described below at "Revenue Recovery Proposal" at page 111, that may be slightly at variance with traditional utility rate recovery.

Although the fact is often lost in the intensity surrounding major rate cases, West Virginia's electric rates for residential customers are, by comparison on a national level, relatively low, and even after the implementation of the revenue recovery proposal (Revenue Recovery Proposal) in this case, will place the State's rates in the reasonable range.[7] The detail of the Revenue Recovery Proposal that we have advanced in this case is set forth later in this Order. See Order infra at 111.

Before beginning an examination of all of the issues in this case, however, we believe we must first address an issue that has played a significant role in the examination of this case, and particularly in the examination of the issues set forth as bullets on page six above.

B. The Commission's Legislative Function; Stare Decisis

It is not unusual, nor for that matter is it improper, for parties before the Commission to refer to the ratemaking treatment of a particular rate issue in prior Commission orders as support for the requested treatment of an issue in a current rate proceeding, particularly in instances in which no other argument or position is advanced.

All too frequently, however, in connection with requests for ratemaking consideration of cost of service items, the Commission is met in testimony and briefs with a response that a particular ratemaking item has been decided previously; that the decision is a matter of Commission policy; and that the Commission should not rule on that particular matter (or at least should not deviate markedly from the earlier expression of that policy).

There are such instances in this case where parties have cited prior Commission cases as support for their position in the face of other arguments. These instances frequently trigger discussions of res judicata, stare decisis and the "sanctity" of preserving consistent treatment of prior Commission ratemaking issues.

Some Commission policies are guided or shaped by controlling statutes (cost based rates; fair and reasonable rates; no undue discrimination) or Commission Rules (Rule 42 Exhibit and case filing requirements). Those policies deriving from

[7] Based on information sorted on September 2014, West Virginia's average residential retail prices placed West Virginia second lowest in the nation, behind on the State of Washington, and indicated that the average rate had actually declined in both September 2013 and 2014 from the level in 2012. This rate comparison is largely based on the West Virginia residential rates of APCo/WPCo and Mon Power/PE. While it is difficult to predict precisely what the ranking of those rates will be after this case, we believe it will be somewhere in the lowest eight to ten.

Commission Rules are typically not changed by rate cases, but can under a proper showing be waived. By the same token, not every prior decision on a ratemaking issue fixes an unalterable "policy," and the Commission is free to examine alternative ratemaking treatments within the exercise of legislative authority in a given rate case.

The discussion of some ratemaking issues deserves consideration in Commission orders. The parties who offer no testimony on these issues and treat them as a matter of Commission "policy" (as if discussion of the merits of the issue is neither necessary, appropriate nor permitted) do so at their peril. A prior pronouncement is not fixed, indeterminate or immutable. Nothing precludes reconsideration of an issue or makes evidence in the case unnecessary. It is not an appropriate response for a seriously contested issue. It is the Commission's right, if not its obligation, in fulfilling its legislative function, to examine issues, particularly those issues raised in good faith, supported by evidence and valid arguments and not contrary to statutes or Commission Rules. Those prior treatments are not dispositive of the issue before the Commission, and no party seriously urges that the Commission is bound by stare decisis.

In order to assess the propriety and manner of the Commission addressing these issues or modifying any prior decision on these issues, the Commission will review the nature of and the statutory authority for the regulation of rates and charges of public utilities by the Commission.

C. The Commission's Ratemaking Authority

No Commission order plumbed the depths of the Commission's ratemaking authority or the nature of the statutory powers conveyed to the Commission by the Legislature more extensively than Century Aluminum of West Virginia, Case No. 12-0613-E-PC (2012) (hyperlink to October 4, 2012 Commission Order in Century Aluminum: http://bit.ly/1xyvwDN) (Century Order). In Century Aluminum, the Commission reviewed and analyzed the historical development of the constitutional and statutory underpinnings of Commission regulation of the rates and charges of public utilities in the context of applying the difficult and elusive standard for special rates for qualified large energy intensive industrial customers under the provisions of W.Va. Code §24-2-1j.

Century Order at 8-18.

In Century, the Commission examined early challenges made to the delegation of legislative authority to the Commission:

> Among other things, the Court held that the Legislature's delegation of authority to the Commission was constitutional; that the rate orders of the Commission were akin to an act of the Legislature; that the Legislature intended the Commission to be the body in State government that would determine the public interest from the perspective of the regulated utilities,

current and future ratepayers and the State; and that, because of the legislative nature of the Commission orders, the Court's review (which was not reviewed upon appeal, but rather reviewed by original process under W.Va. Code §24-5-1) was limited so as not to give the Court the power to substitute its judgment for that of the Commission. United Fuel Gas Co. v. Public Serv. Comm'n, 73 W.Va. 571, 80 S.E. 931 (1914).

The Court, in United Fuel, recognized that the Legislature was directing the Commission to assume duties that were important, technical and complex. The Court observed

> [T]he salaries which the statute attaches to the office of commissioners, and the nature of the subjects to be dealt with by them, all imply that only persons of the requisite qualifications should be appointed, and that after appointment they should by investigation and study become further qualified by learning and experience, indeed should become experts upon all subjects and businesses coming within their jurisdiction.

Century Order at 581-582

In holding that the delegation of authority to the Commission was constitutional, the Court also held that the functions that the Commission fulfills are quasi-judicial and quasi-legislative. Public Serv. Comm'n v. Baltimore & Ohio Railroad Co., 76 W.Va. 399, 403, 85 S.E. 714 (1915). The Court recognized that the legislative function of establishing railroad rates could be constitutionally delegated to the Commission and that this concept was recognized and established as law throughout the country by both state and federal decisions. Id. at 407, 85 S.E. at 717-718.

Century Order at 11.

We mention these early cases (and the earlier specific reference to W.Va. Code §24-1-1 about the exercise of "legislative powers" granted to the Commission (Order, supra, at 4)) for a specific purpose. The grant of legislative power to the Commission is not window dressing – it is, in fact, the inherent legislative nature of the authority granted to the Commission that authorizes the Commission to examine the individual facts and circumstances of each case before it in order to decide cases without being absolutely bound by the doctrine of stare decisis.

The West Virginia Supreme Court has addressed stare decisis and its applicability to the Commission and has determined that generally the doctrine may be applied to a hearing body if the following conditions are met: (i) the body acts in a judicial capacity; (ii) whether parties are afforded a full and fair opportunity to litigate the matters in dispute; (iii) whether applying the doctrine is consistent with the implied policy in the legislation which created the body. Mellon-Stuart Co. v. Hall, 176 W.Va. 291, 359 S.E.2d 124 (1987).

Although the Commission acts in a quasi-judicial capacity, it is not a court. As discussed above in Century, the Commission was created by the Legislature and given specific legislative authority (supra at 8). The membership of the Commission is provided in W.Va. Code §24-1-3, with three Commissioners appointed by the Governor for six-year staggered terms, with the advice and consent of the Senate. Because no more than two of the Commissioners can be members of the same political party and because the Commission is expressly delegated legislative power, it is natural that the Commissioners may bring different insights and perspectives to the Commission. Commissioners reflect to some degree the financial, political, economic and philosophical views of the appointing authority and bring those views to ratemaking approaches.

Those insights and perspectives change; rate regulation is not static. The actions, activities, business and degree of oversight of public utilities change. The Commission must react to that change. The Commission must be free to adjust and to reflect changing concepts of utility regulation, altered economic conditions, changing environmental conditions and regulations, changing political realities reflected in changing laws, statutes and regulations, changing court decisions, changing mixes of fuel and generation, changing concepts of utility management, rate design and conservation and a host of other externalities that impact the utilities and the role of the Commissioners as regulators.

As a consequence, the Commission is free to review rate cases with some degree of flexibility, and without being absolutely bound in its decisions by stare decisis.

The issue of the extent to which the Commission, acting in its legislative capacity, can act in each case without the strictures of stare decisis has been addressed by the Courts, and no less authority than the United States Supreme Court has addressed this issue and left little doubt where it stands.

The United States Supreme Court, in St. Joseph Stock Yards Co. v. United States, 298 U.S. 38 (1936), held that ratemaking authority is a legislative function and the Legislature may exercise that authority directly, or through the agency it creates or appoints to act for that purpose in accordance with appropriate standards.

The West Virginia Supreme Court of Appeals cited this language with approval in Central West Virginia Refuse v. Public Serv. Comm'n, 438 S.E.2d 596, 600, 601:

> Our Legislature chose to exercise its rate-making authority through the PSC. *See* W.Va. Code, 24-1-1(a) (1986). The United States Supreme Court in *Tagg Brothers & Moorhead v. United States*, 280 U.S. 420, 445,

50 S.Ct. 220, 226, 74 L.Ed. 524, 537 (1930), stated: "A rate order is not *res judicata*. Every rate order may be superseded by another."

The West Virginia Supreme Court concluded in Central West Virginia Refuse:

> We, therefore, conclude that when the PSC is exercising its rate-making authority under W.Va. Code, 24-2-3, its decisions are not subject to the doctrines of stare decisis or res judicata simply because rate making is a legislative function.

Central West Virginia Refuse, 438 S.E. 2d 596, 601 (W. Va. 1993).

The West Virginia Supreme Court earlier held in The Chesapeake and Potomac Telephone Company of West Virginia v. Public Service Commission of West Virginia, 300 S.E.2d 607, 613 (1982):

> [I]t is generally recognized that the doctrine of *stare decisis* does not normally apply to administrative decisions. As Professor Davis states in his respected treatise:
>
> > When the purpose is one of regulatory action, as distinguished from merely applying law or policy to past facts, an agency must at all times be free to take such steps as may be proper in the circumstances, irrespective of the past decisions . . . . Even when conditions remain the same, the administrative understanding of those conditions may change, and the agency must be free to act . . . . 2 K. Davis, *Administrative Law* § 18.09 (1958) (footnotes omitted.)
>
> *Accord, State v. Alabama Public Service Commission,* 293 Ala. 553, 307 So.2d 521 (1975); *Rumney v. Public Utilities Commissioner*, 172 Colo. 314, 472 P.2d 149 (1970). The Commission's decisions in previous cases therefore do not preclude it from reaching an opposite result in this case.

The Commission will thus move forward to examine or revisit the issues in the 2014 Rate Case in a manner consistent with legislative authority granted to the Commission.

II. CAPITAL STRUCTURE AND COST OF CAPITAL

A. Overview

The capital structure of a utility is comprised of all of the sources of capital used by the utility and consists of various types of capital supporting its net utility assets (rate base). A utility capital structure will normally reflect the amount of capital acquired through borrowing (debt), the issuance of stock (common and preferred), retained earnings and other paid in capital contributions from stockholders. Other sources of utility capital, such as customer contributions, customer advances, and some deferred credits, are normally treated as a rate base offset, and therefore are not supported by the total capitalization of the utility. Capital structure detail for purposes of cost of capital calculations normally examines the component parts, such as short-term and long-term debt, and both common equity and preferred equity. The measurement of the ratio of individual capital components to the total capital establishes the relationship among the various capital sources for use in determining a composite weighted cost of capital. West Virginia-American Water Company, Case No. 10-0920-W-42T, Order at 10 (April 18, 2011).

In determining the cost of capital, the Commission typically calculates each type of capital as a percentage of the total capital. The cost rate for each type of capital (long-term debt, short-term debt, preferred equity, and common equity) is then multiplied by each type of capital's percentage of the total capital structure to derive a weighted cost of capital for each component. The weighted costs for each capital component are then added to reach a total cost of capital that under normal circumstances equals or serves as a proxy for the overall rate of return (RoR) a utility is authorized to earn on the cost of its investment.

The Commission uses a variety of techniques, and its judgment and experience, to determine a reasonable capital structure. Depending on economic or other circumstances, the Commission may review historic, projected and hypothetical capital structures. The Commission determines a capital structure that (i) is reasonable, (ii) fairly balances the interests of current and future customers, the general interests of the State's economy and the interests of the utilities and (iii) produces the lowest reasonable overall revenue requirement that maintains the financial integrity and flexibility of the utility. Mountaineer Gas Company, Case No. 11-1627-G-42T, Order at 3 (October 31, 2012), and W.Va. Code §24-1-1.

B. Capital Structure

Testimony and other evidence pertaining to capital structure and rate of return came primarily from five witness in this proceeding: Dr. William E. Avera and Renee V. Hawkins on behalf of the Companies, Dr. J. Randall Woolridge on behalf of SWVA, Ralph C. Smith on behalf of CAD, and Josh Allen on behalf of Staff. Walmart witness, Steven W. Chriss, presented testimony on return on equity (RoE), but did not perform an independent analysis of RoE. The respective parties advocated the following capital structures and cost rates:

Type of Capital	Companies % of Total	Companies Cost Rate	SWVA % of Total	SWVA Cost Rate	CAD % of Total	CAD Cost Rate	Staff % of Total	Staff Cost Rate
Common Equity	47.141	10.620	47.14	8.70	47.155	9.0 or 10.0	45.16	9.24
Long-Term Debt	51.339	5.408	51.34	5.48	51.325	5.408	51.86	5.118
Short-Term Debt	1.520	0.346	1.52	0.35	1.520	0.346	2.98	0.310

The Companies proposed a capital structure that adjusted the test-year balances to reflect post test-year changes to APCo's outstanding long-term debt, as well as the exclusion of the effects of the non-recurring events related to ENEC securitization in November 2013 and the transfer of Amos 3 to APCo on December 31, 2013. Those changes include a reduction to long-term debt outstanding of $500 million to reflect APCo's repayment of a Term Loan Agreement that was assumed by APCo when Ohio Power Company's two-thirds ownership in Amos 3 transferred to APCo on May 9, 2014, and its redemption of a series of Senior Notes (Series I) on May 22, 2014. On May 5, 2014, APCo issued $300 million of Senior Notes, Series U, with a cost rate of 4.40 percent. The net result of these adjustments reduced the Companies long-term debt from $3,845,854,787, as of December 31, 2013, to the $3,645,854,787 level of long-term debt incorporated in the proposed capital structure.

The Companies also adjusted the thirteen-month average outstanding balance of short-term debt for the 2013 test year to remove the effect of non-typical levels of short-term debt balances in August, September and October 2013 related to the timing of the ENEC Securitization. This adjustment removed $275 million of short-term debt from the August, September and October balances. The resulting requested thirteen-month average of short-term debt for the 2013 test year is $107,955,743. Additionally, the Companies adjusted the December 31, 2013 actual common stock balance to remove $1,901,500 of common equity related to the Appalachian Consumer Relief Funding, LLC (ACRRF), an entity established to complete the ENEC Securitization. The Companies Rule 42 Exhibit, Statement A at 4 included the ACRRF equity level; Companies witness Hawkins Direct Testimony included a corrected Statement A removing the ACRRF equity. Companies Exh. RVH-D at 5-9.

SWVA used the Companies proposed debt cost rates and capital structure. SWVA Exh. JRW-D at 2, attached Exh. JRW-1 at 1.[8] For purposes of determining a recommended overall revenue requirement, CAD used the Companies requested capital structure as reflected on the filed Statement A and applied both a 9.0 percent and 10.0 percent RoE to illustrate the overall cost of capital. CAD Exh. RCS-D at 5, attached Exh. LA-1, Schedule D at 1. Staff recommended a capital structure derived from the Companies actual combined capital structure at December 31, 2013, adjusted to exclude ACRRF capital, and the actual short-term debt balance adjusted to include the average balance of accounts receivable sold by the Virginia operations during the 2013 test year. Staff Exh. JA-D at 3, 4.

The Companies argued that the Staff use of the year-end capital structure did not incorporate known transactions that occurred in 2014. Additionally, the Companies disagreed with the Staff inclusion of the APCo Virginia sale of receivables as a form of financing. Although Staff and the Companies included nearly identical dollar levels of equity in their capital structures, the effects of Staff including higher dollar levels of both short-term and long-term debt in the calculation resulted in different debt and equity ratios from those proposed by the Companies.

The difference between Staff and the Companies level of short-term debt relates to the Staff inclusion of the average level of receivables sold by APCo Virginia as short-term debt during the 2013 test year. The different levels of short-term debt are the primary drivers of the disparity in the capital component ratios to total capital. That disparity has a significant impact on the overall weighted cost of capital calculation.

The Commission does not believe either party adequately addressed and supported their position about whether the sale of accounts receivable should be treated as short-term debt. The Commission is not persuaded that the cash obtained from the sale of those receivables is not embedded in the capital structure presented by the Companies that was based on the actual December 31, 2013 capital structure, adjusted for known post test year financing transactions. The Commission is, likewise, not convinced that the adjustment proposed by Staff to impute the average value of the receivables sold to an affiliate collection entity should be added to the actual average 2013 test year short-term debt balance included in the Companies' proposed capital structure. For purposes of determining the appropriate capital structure in the instant case, the level of short-term debt proposed by the Companies is reasonable, and the Commission will not impute the sale of receivables as short-term debt. The Commission, however, cautions the Companies that it expects a more thorough examination and explanation of the costs and benefits of the receivable sale arrangement before determining the appropriate capital structure in its next base rate filing.

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8 Although SWVA Exh. JRW-D at 2 adopted the Companies proposed debt cost rates, his attached Exhibit JRW-1 at 1 incorporates a cost rate for long-term debt of 5.48 percent, not the Companies requested cost rate for long-term debt of 5.408 percent. By request of SWVA, Dr. Woolridge was excused from the evidentiary hearing.

Capital structures can and do shift from time to time and any single snapshot of capital structure may or may not represent a reasonable expectation of the capital structure over an extended period of time. With regard to long-term debt, the Companies cited several changes that occurred during the test year, and refinancing and retirements of debt after the test year in the first half of 2014 that are now known and should be included in the calculation of the appropriate capital structure. The Commission agrees with the Companies that the incorporation of these known changes more accurately reflects the level of long-term debt likely to be in place during the time rates from this case will be in place. The Commission adopts the adjusted level of long-term debt requested by the Companies and reflected in the corrected Statement A attached to Companies Exh. RVH-D.

C. Cost of Short-Term Debt

SWVA and CAD agreed with the Companies that the cost rate for short-term debt of 0.346 percent reflects the weighted average daily borrowing rate for the AEP utility money pool for the months of January 2013 through December 2013. Staff recommended a cost of short-term debt of 0.310 percent that is based on the most recent cost of short-term debt during the test year. Staff Exh. JA-D at 4. Although the Commission usually prefers the more current actual cost rate, Staff did not establish the basis or source for its cost rate of 0.310 percent. The Commission adopts the average short-term debt cost rate during the test year of 0.346 percent recommended by the Companies.

D. Cost of Long-Term Debt

As with other components of the capital structure and cost rates, SWVA and CAD adopted the Companies calculation of the cost of long-term debt of 5.408 percent. That overall weighted cost rate for long-term debt reflects adjustments to the long-term balance at the end of the test year, December 31, 2013, and includes the effects of refinancing and retirement of long-term debt during the first half of 2014. Staff recommended a cost of long-term debt of 5.118 percent. The Staff cost rate is determined by weighting the effective cost rate for all debt issued by the Companies and finding the total effective long-term debt rate for the Companies. Staff Exh. JA-D at 4. The Staff weighted cost rate for long-term debt included debt the Companies subsequently retired in 2014 and excluded debt the Companies refinanced in 2014.

Consistent with the Commission adoption of the Companies known changes to long-term debt in determining the appropriate capital structure, the Commission will also adopt the cost rates associated with those known changes in determining the overall cost of long-term debt. The Commission adopts the Companies 5.408 percent recommendation for the cost of long-term debt.

E. Return on Equity and Resulting Rate of Return

As we indicated earlier, supra at 2, utility rates should allow a public utility the opportunity to earn a level of revenue sufficient to attract capital in the competitive capital market, balanced with the interests of the consuming public in receiving fair and reasonable rates. The Commission uses its best judgment to assess the record in order to determine a reasonable RoE that allows the utility a level of revenue sufficient to attract capital in the competitive market, while balancing the interests of ratepayers in receiving fair and reasonable rates. Black Diamond Power Company, Case No. 12-0064-E-42T, Order at 5 (August 10, 2012); West Virginia-American Water Company, Case No. 10-0920-W-42T, Order at 15 (April 18, 2011).

Although the goal of utility ratemaking is easy to state, the calculation of the appropriate cost of common equity is not as easy to determine. Witnesses presenting testimony on the cost of common equity capital frequently use the same or similar methodologies, but often end at significantly different results. The Commission has noted in the past that "all of these methods represent artful analyses rather than exact science, and none of them can be said to produce a finite 'correct' answer to the exclusion of the others. These studies are useful in providing data that is susceptible to interpretation, but the ultimate answer regarding investor expectations must rely heavily on the judgment of the Commission." Appalachian Power Company, Case No. 91-026-E-42T Order at 4 (November 1, 1991).

We recently stated that the data that underlie the recommendations of RoE witnesses must be evaluated and judged carefully and practically, based on our judgment of the methods used by expert witnesses, the data presented by those witnesses and the current market conditions. There is no absolute, correct answer with regard to RoE, even though the determination of a reasonable RoE involves calculations on a mass of data presented by expert witnesses. The fair RoE result lies within a zone of reasonableness that is framed by the evidence, including the testimony and exhibits of various witnesses. The final determination of RoE, however, rests with the Commission based on our judgment and the application of regulatory principles and policies that have been used by this Commission. West Virginia-American Water Company, Case No. 10-0920-W-42T, Order at 18.

The Companies recommended a RoE of 10.62 percent. The Companies witness on RoE, Dr. Avera, provided fundamental analyses of APCo and WPCo, their parent company, American Electric Power Company (AEP), the electric utility sector and projected capital market conditions. Companies Exh. WEA-D at 5-13. He then estimated the cost of equity capital by means of discounted cash flow (DCF) analysis, capital asset pricing model (CAPM) analysis, the risk premium method, a comparable risk model and an expected earnings approach. Id. at 23-60. Dr. Avera's RoE range was 9.5 percent to 11.5 percent, with a recommended point estimate of 10.5 percent. He added a flotation cost adjustment of twelve basis points to his point estimate of 10.5 percent to derive a RoE recommendation for the case of 10.62 percent.

SWVA witness Woolridge recommended a RoE of 8.70 percent. Dr. Woolridge also provided analyses of current capital costs and the credit markets. SWVA Exh. JRW-E at 7-14. Relying primarily on the results of his DCF analysis for a group of twenty-eight publicly-held electric utility companies and CAPM analysis of the same sample group, his recommended range for the cost of equity was 7.8 percent to 8.7 percent. He performed his same analysis on Dr. Avera's sample group of electric utility companies. His recommended cost of equity capital of 8.7 percent represented the upper range of his cost of equity range. Id. at 2. He also provided extensive critique of the Companies rate of return testimony.

Staff was the only other party in this proceeding to perform a cost of equity analysis. Staff witness Allen recommended a return on equity based on the application of the DCF and CAPM to a sample group of twenty-two electric utilities that produced average costs of equity of 8.63 percent and 9.86 percent, respectively. The average of those two measures resulted in the Staff-recommended RoE of 9.24 percent.

As indicated, Walmart witness, Steve W. Chriss, did not perform any independent analysis of RoE, but stated a concern that the Companies proposed RoE of 10.62 percent was excessive. In support of his claim, he produced a summary of authorized RoEs for AEP operating companies authorized in recent base rate cases and a chart of reported authorized RoEs for electric utility rate cases completed from 2012 to present. Walmart Exh. SWC-D at 5, attached Exh. SWC-5 at 3. Although CAD did not offer any specific rate of return testimony, it used two scenarios, the first a 9.0 percent RoE and the second a 10.0 percent RoE, to illustrate the impact on the overall weighted cost of capital at those levels of RoE. CAD Exh. RCS-D at 5.

The DCF model is based on the dividend discount model of financial theory that holds that the value (price) of any security is the discounted present value of all future cash flows. This financial theory assumes an investor buys a share of stock to receive a string of dividend payments plus capital appreciation when that stock is sold. The price of the stock is adjusted by the market until the investors receive their required return for the level of risk associated with that investment. The discount rate that makes the future anticipated dividends and future anticipated selling price equal to the current market price is the cost of common equity. The purpose of the DCF model is to capture that cost of equity based on the market data inputs used in the model.

Companies Witness Avera's DCF analysis incorporated a variety of projected earnings growth estimates added to the current yield for each of the companies in his sample electric group. Dr. Avera testified that it was reasonable to exclude the results for any company in the sample group when the calculated RoE failed to exceed the average bond yield by 100 basis points or more. The bond rate chosen by Dr. Avera to determine the outlier results was the forecasted BBB bond yield of approximately 6.7 percent for 2015-2018. Dr. Avera eliminated low-end DCF estimates ranging from 3.6 percent to 7.3 percent. Companies Exh. WEA-D at 33-36. The results of his DCF analysis, utilizing exclusively projected earnings growth rates and eliminating only outliers on the low side, produced average DCF results for his four groups of growth estimates between 9.4 percent and 9.9 percent. A separate sustainable growth rate br+sv DCF analysis (in which "b" is the expected retention ratio, "r" is the expected earned return on equity, "s" is the percent of common equity expected to be issued annually as new common stock and "v" is the equity accretion rate) produced an average RoE estimate for the electric sample group of 8.5 percent.

The CAPM is a type of risk premium analysis where a premium is added to the risk-free rate to estimate the cost of equity capital. The premium is the difference between the market return, estimated on either a historical basis, *ex poste*, or on a projected basis, *ex ante*, and the risk free rate. The CAPM model requires the determination of the risk for each sample company, called beta, that is a measurement of the relative movement (and relative risk) between a particular company's stock and the movement of the entire stock market. A company that experiences an exact correlation to the volatility of the market has a beta of 1.0, while a company that only changes by half of the total market volatility has a beta of 0.5. Multiplying the market return premium by the company specific beta and adding it to the risk-free rate produces a CAPM estimate of the RoE.

Dr. Avera utilized the empirical CAPM (eCAPM), a variant of the traditional CAPM, for his sample group and applied it on an *ex ante* basis. The eCAPM attempts to correct for understated returns for low beta stocks that would be produced by the standard CAPM. Companies Exh. WEA-D at 39. Dr. Avera calculated the market return as 12.7 percent by adding the weighted average dividend yield (2.3 percent) of the dividend paying firms in the S&P 500 with the weighted average IBES earnings growth rate (10.4 percent) of the dividend paying firms in the S&P 500. By subtracting the June 2014 average 30-year Treasury bond yield risk-free rate of 3.6 percent from the 12.7 percent market premium, multiplying the result by the company specific beta and then adding back the risk-free rate, produced an average sample group eCAPM RoE of 11.0 percent. Dr. Avera then made a size adjustment based on the relative market capitalization of the companies. His average size-adjusted eCAPM is a RoE of 11.8 percent. A similar analysis, using a projected 2015-2018 bond yield of 4.7 percent as the risk-free rate produced an unadjusted average RoE for the sample group of 11.2 percent and a size adjusted RoE estimate of 12.0 percent. As a check for reasonableness, Dr. Avera performed a traditional, or non-empirical CAPM analysis. Using the same data as his eCAPM, his traditional CAPM methodology produced an unadjusted RoE of 10.4 percent using current bond yields and a RoE of 10.7 percent using projected bond yields. Companies Exh. WEA-D, attached Exh. WEA-D9 at 1, 2.

For his third cost of equity estimation, Dr. Avera determined the additional risk that investors require to forgo the relative safety of bonds and to bear the greater risks associated with common stock. Dr. Avera calculated the average utility bond yield for the period 1974-2013 as 8.69 percent. He then subtracted that average bond yield from the average allowed RoE of 12.21 percent during that period to produce a risk premium for electric utilities of 3.53 percent. Adjusting that result by a factor to reflect the risk premium/interest rate relationship and adding it to the June 2014 average BBB utility bond yield produced a risk premium RoE of 10.19 percent. The same methodology using projected average 2015-2018 utility bond yields produced a risk premium RoE of 11.19 percent. Companies Exh. WEA-D at 42-47.

SWVA witness, Dr. Woolridge, performed DCF and CAPM analyses on his sample group of electric utility companies. For his DCF analysis, he examined a variety of growth rate indicators from Value Line for earnings per share (EPS), dividends per share (DPS) and book value per share (BVPS) on both a historical and projected basis. He also examined projected EPS growth rate estimates from Yahoo, Zacks and Reuters. Dr. Woolridge calculated a sustainable growth rate for his sample group. For his sample electric proxy group, the average growth estimates were 3.3 percent, 4.4 percent, 4.8/4.6 percent and 3.9 percent, respectively. He did not apply any screening of his growth rates to eliminate outliers or negative rates of growth. From those data points, he determined an appropriate growth rate of 4.75 percent for his sample group. That growth rate, added to his dividend yield of 3.8 percent produced a DCF derived RoE estimate of 8.6 percent. He applied this same methodology to Dr. Avera's sample group of electric utility companies and produced a RoE estimate of 8.7 percent. SWVA Exh. JRW-D at 39.

Dr. Woolridge's CAPM analysis relied on an examination of various estimates of market premiums from a variety of sources; from that he determined the data indicate a market risk premium in the 4.0 percent to 6.0 percent range. SWVA Exh. JRW-D at 47. Using the midpoint of 5.0 percent as the market risk premium, an average beta for his sample group of 0.75 and a risk free rate of 4.0 percent, derived from yields on 30-year treasury bonds in the 3.0 percent to 4.0 percent range over the 2013-2014 time period, Dr. Woolridge's CAPM analysis produced a RoE estimate of 7.8 percent. SWVA Exh. JRW-D at 48.

Staff witness, Josh Allen, calculated the cost of equity capital as 9.24 percent, derived from his application of the DCF (8.63 percent) and the CAPM (9.86 percent). For his DCF analysis, Allen examined a sample group of twenty-two electric utilities and calculated their dividend yields by dividing each sample company's projected dividend for the next twelve months by its recent average stock price. To estimate the appropriate growth rate, Staff examined various measures of growth, on both an historic and projected bases, for dividends per share and earnings per share. Staff added those individual growth rates to the individual dividend yields of the sample companies. Those steps produced multiple DCF results. In order to remove outliers, Staff applied a first screening test and eliminated any DCF result lower than the 4.4 percent cost for the Companies recent long-term debt issue. Additionally, Staff eliminated any results that exceeded 300 basis points above or below the average RoE result. After elimination of these thirty-two outliers, Staff calculated the average growth rate as 5.0 percent that, when added to the average dividend yield of 3.64 percent, produced a DCF cost of equity of 8.63 percent (arguably 8.64 percent). Staff Exh. JA-D at 7, 8.

Mr. Allen's application of the CAPM to his sample group produced a cost of equity estimate of 9.86 percent. The Staff CAPM calculation used an historical, or *ex poste*, approach to determine the market premium for equity, made adjustments for the Company specific beta and added the result to the historical U.S. Treasury bill return of 3.5 percent as the risk free component. The Staff CAPM calculation resulted in an estimate of RoE of 9.86 percent. Staff Exh. JA-D at 9-12.

The DCF method has long been one of the methods relied on by the Commission for determining a reasonable RoE. All three cost of equity experts presented various DCF analysis. The Companies average DCF results ranged between 8.5 percent and 9.9 percent, with four of the five average estimates clustered between 9.4 percent and 9.9 percent, Staff produced an average DCF result of 8.63 percent and SWVA produced a DCF equity cost estimate of 8.7 percent.

The Commission also considers CAPM a valuable tool in evaluating the range from which to determine a reasonable RoE. The CAPM compares the risk adjusted RoE result to alternative utility investments, and provides the Commission with a basis to compare the reasonableness of the DCF results. The three return witnesses all presented CAPM RoE estimates. Dr. Avera relied more heavily on his eCAPM results, determined from forecasted market premium and interest rate data, then adjusted for size, to produce an average eCAPM range between 11.0 and 12.0 percent. He also presented his unadjusted traditional CAPM that produced a RoE of 10.4 percent. The Commission in the past, however, has stated a preference for the traditional CAPM analysis. Hope Gas, Inc., Case No. 08-1783-G-42T, Order at 14 (November 20, 2009). The Commission believes Dr. Avera's eCAPM results tend to overstate the cost of equity, and we placed less reliance on those results and relied more heavily on Dr. Avera's unadjusted traditional CAPM RoE estimate of 10.4 percent in determining a reasonable range for RoE in this case.

The Staff CAPM analysis produced an average CAPM RoE estimate of 9.86 percent utilizing an *ex poste* approach that incorporated historical market premiums and the average historical risk-free rate for U.S. Treasury bills. In light of the ongoing actions by the Federal Reserve to keep short-term interest rates at record lows to stimulate the economy, it is not realistic to rely on short-term treasury rates as the risk-free rates. The current treasury market is more driven by government intervention than market bidding, and we find the Staff *ex poste* approach reasonable.

For the SWVA CAPM analysis, Dr. Woolridge presented a myriad of equity risk premium studies from multiple sources covering different time periods, both historical and projected. These studies were published at various times over the past two decades. Dr. Woolridge did not attempt to quantify which result he preferred but instead summarily concluded a market premium of 5.0 percent was appropriate to use in his CAPM model, ultimately producing a CAPM cost of equity of 7.8 percent. We will dismiss his result because his recommendation lacks specific market data support.

As is generally acknowledged, calculation of RoE is more art than science. The Commission has reviewed all of the evidence, testimony and arguments, considered cases cited by the Companies, and reviewed prior decisions of the Commission. We are also familiar with the tremendous upheaval and change in the electric utility industry, particularly as it relates to generation, fuel mix, alternative energy, and numerous other factors. The recommendations of expert witnesses on cost of common equity are useful as guides, but the determination of an appropriate cost of common equity for a utility must rest principally with the best judgment of the Commission. The recommendations of the experts in this case, like most rate cases, are based on identical or similar methodologies and similar market analyses, but result in an array of recommendations on the cost of equity capital.

Based on our review of the record presented in this case, and applying the Commission judgment and expertise in this area, the Commission determines a RoE of 9.75 percent is reasonable, falls within the range of reasonable RoEs presented by the parties, fairly balances the interests of the Companies and their customers, and meets the standards set forth by the United States Supreme Court and the Supreme Court of Appeals of West Virginia.

F. Summary of Capital Structure and Cost of Capital

Based on the discussion and determinations described above concerning the capital structure, cost of debt and RoE, the Commission determines that an overall weighted cost of capital of 7.379 percent is reasonable for establishing rates in this proceeding and fairly balances the interests of the Company and its customers. The capital structure and cost of capital determination of the Commission are provided in Appendix B attached to this Order.

III. RATE BASE

A. Amos 3 Generating Unit Utility Plant

No party took issue with including in rate base $411.3 million of utility plant for the acquisition of two-thirds of the Amos 3 generation unit. The Commission will adopt the inclusion of $411.3 million in the Companies utility plant accounts for Amos 3.

B. Mitchell Generating Unit

1. Mitchell Settlement Interest Adjustments

The Companies included the full utility plant value of $972.890 million for the acquisition of the fifty percent undivided interest in the Mitchell Plant as rate base in their June 30 2014 filing. Companies Rule 42 Exh., Statement B, Schedule 1, Statement G Adjustment 90-EPIS. Companies Exh. JDL-D at 8. At the time of the Companies' Petition, the ultimate resolution concerning acquisition of the Mitchell Plant by Wheeling

Power Company was still an issue in Case No. 14-0456-E-P (Mitchell Case). The Commission Order of December 30, 2014, in the Mitchell Case approved the transfer of an interest in the Mitchell Plant according to the terms of a Joint Stipulation. The Joint Stipulation recognized that 82.5 percent of the various components making up the Mitchell Settlement Interest, as defined in the Joint Stipulation in the Mitchell Case, would be recognized for rate recovery for up to the first five years from the date of acquisition.

In the 2014 Rate Case, Staff proposed to reduce the Mitchell Plant utility plant balance of $972.9 million to 82.5 percent of that value. Staff made one other adjustment to reclassify $20 million of the Mitchell Plant value related to the cost of the Conner's Run impoundment from utility plant to a regulatory asset. Staff recommended that the Conner's Run regulatory asset be amortized over twenty-six years, the estimated remaining life of the Mitchell Plant. Staff Exh. ELO-D at 18-19. CAD proposed that 82.5 percent of the $972.9 million Mitchell Plant value be recognized as utility plant with no adjustment to reclassify the $20 million related to the Conner's Run facility. The Companies did not contest the Staff or CAD adjustments related to the Mitchell Plant value to be recognized as rate base in this proceeding.

The position of Staff is reasonable and consistent with the terms of the Joint Stipulation approved by the Commission decision in the Mitchell Case. The Commission authorizes $782.634 million for the Mitchell utility plant value and an unamortized balance of $19.230 million for the Conner's Run regulatory asset be included in rate base for rate recovery in this proceeding. The Conner's Run regulatory asset will be amortized over twenty-six years as proposed by Staff.

2. Environmental CWIP - Mitchell

The Companies included the full $33.427 million of Mitchell Environmental Construction Work In Progress (CWIP) proposed for rate recovery in the Mitchell Case in this case. Staff proposed that the full value be limited to the 82.5 percent factor included in the Joint Stipulation in the Mitchell Case. Staff Exh. ELO-D at 8. CAD recommended that no Environmental CWIP at Mitchell be included as rate base in this proceeding, citing the Commission decision in the 2010 Rate Case regarding environmental CWIP as support. In rebuttal testimony, Mr. Ferguson argued that the Mitchell Settlement Interest described in the Joint Stipulation approved in the Mitchell Case included 82.5 percent of the $33.427 million of environmental CWIP included in the original description of the Mitchell Plant values. Companies Exh. SHF-R at 2-3.

The environmental CWIP in the Mitchell Case was part of the $577.973 million of rate base included in the surcharge calculation that produced a rate increase of $118.081 million as proposed in the original petition. March 27, 2014 Petition, Exh. D. The rate base amount included in Exhibit D was supported by the book values by account number supplied in Exhibit C to the March 27, 2014 petition and Mr. Ferguson's direct testimony. Companies Exh. SHF-D, Exh. SHF-D3. The rate base amount was amended to $566.964 million in the direct testimony of Mr. Martin. Companies Exh. JFM-D at 4.

The position proposed by Staff regarding the Mitchell environmental CWIP is adopted in this case. Because the recent order in the Mitchell Case approved the Mitchell Plant transfer (including the environmental CWIP) and associated surcharge, it is reasonable to include 82.5 percent of the $33.427 million of the Mitchell environmental CWIP as rate base in this proceeding. The Commission has on occasion included environmental CWIP related to large rate base additions for scrubbers and other environmental requirements in surcharges between base rate cases, but it has long been the Commission practice not to include CWIP in rate base and permit the recording of Allowance for Funds Used During Construction (AFUDC) on the CWIP until the plant additions are placed in service. The inclusion of the Mitchell environmental CWIP in rate base in this case reflects the intent of the parties to the Joint Stipulation in the recent Mitchell Case and does not reflect a change by the Commission to include CWIP in all future rate proceedings. The Companies will no longer record AFUDC on the Mitchell environmental CWIP of $33.427 million after the issuance of this Order.

C. Other CWIP

In addition to the Mitchell environmental CWIP, the Companies also included in their filing $17.253 million for the average test-year balance of environmental CWIP and $1.378 million of environmental CWIP related to the acquisition of the Amos 3 unit. Companies Exh. JLB-D at 19. Mr. Oxley argued against inclusion of both the $17.253 million of average test-year environmental CWIP and the $1.378 million of environmental CWIP for Amos 3. Mr. Oxley cited the Commission Order of March 30, 2011, in the Companies 2010 Rate Case as support for not including environmental CWIP in rate base for projects other than the Mitchell acquisition. Staff Exh. ELO-D at 17-18.

CAD did not eliminate the $17.253 million of average test-year CWIP proposed by the Companies, but did eliminate the adjustment for the $1.378 million of environmental CWIP for Amos 3. CAD Exh. RCS-D at 54. In rebuttal testimony, Mr. Ferguson indicated that the Companies agreed with either (i) the inclusion of $18.631 million of other environmental CWIP as rate base or (ii) allowing AFUDC on that CWIP until the project is placed in service. SHF-R at 3.

Unlike the environmental CWIP related to Mitchell, neither the average test-year environmental CWIP nor the Amos 3 environmental CWIP is included in an existing surcharge as was addressed in the recent Mitchell Case. The Commission will not authorize the $18.631 million of other environmental CWIP as rate base, but will authorize the Companies to record AFUDC on that environmental CWIP until the underlying projects are placed in service.

D. Pension Asset

The Companies proposed that a prepaid pension asset of $92.102 million be included in rate base. Companies Rule 42 Exh., Statement A, Schedule B-6. The Companies record pension expense in accordance with Financial Accounting Standard (FAS) 87, an accrual accounting format. The accrual accounting method for pensions under FAS 87 determines the appropriate current pension expense based on actuarial valuations that determine the future payment of pension obligations as employees reach retirement. FAS 87 addressed the accounting requirements for current pension expense on the income statement and the related assets and liabilities recorded on the balance sheet. Companies Exh. HEM-D at 3-4.

Funding for qualified pension plans is guided by federal law (ERISA)[9] that is administered through the United States Department of Labor. The amount of pension expense recorded on the financial statements under FAS 87 guidance and the level of funding required by ERISA standards may differ. Id. at 6. Mr. McCoy explained that the Companies have funded the pension obligation above the level of FAS 87 pension expense by $189.312 million as of December 31, 2013 ($92.102 million for the West Virginia jurisdiction). Companies Exh. HEM-D1. The contributions to the qualified pension fund above the level of FAS 87 expense, under FAS 87 guidelines, are recorded as a prepaid pension asset. Companies Exh. HEM-D at 3.

Mr. McCoy further explained that the prepaid pension asset has grown significantly since 2005, but the increased contributions were necessary to address a significant funding shortfall between the total pension obligation and the funding level of the qualified pension plan. Mr. McCoy asserted that without the additional contributions to the qualified pension plan, the pension plan obligation would have been funded at only 61 percent as of December 31, 2012, a dangerously low level that could trigger ERISA participant notification provisions and pension benefit payment restrictions. Combining the 2005-2012 contributions to the qualified pension plan along with favorable market returns in 2013 raised the pension obligation funding ratio to 95 percent at December 31, 2013. Id. at 6-8. According to Mr. McCoy, the return on the prepaid pension asset lowered the 2014 current pension expense by $15.7 million from the level of current pension expense absent the additional contributions. Id. at 8.

The contributions to the qualified pension plan that resulted in the prepaid pension asset were deducted for income tax purposes in the year the contributions were made. The tax deductibility of those additional pension contributions resulted in timing differences between book/tax accounting for pension expense. This book/tax timing

9 Employment Retirement Income Security Act of 1974 (ERISA), a federal law that establishes minimum standards for private industry pension plans. Private industries are not required by ERISA to establish pension plans but for those private companies that do, ERISA sets minimum standards for vesting in the plan, spousal participation, funding requirements for the future pension obligations, minimum annual contributions to the plan, fiduciary accountability, and notice to plan participants.

difference for pension expense resulted in the recording of an Accumulated Deferred Income Tax (ADIT) provision of $29.511 million that the Companies included as an offset to the prepaid pension asset in the determination of rate base. Companies Exh. JBB-D at 11.

Staff did not take exception to the inclusion of either the prepaid pension asset or the offsetting pension ADIT proposed by the Companies. Staff Exh. DLK-D at 4-5. CAD opposed the inclusion of both the prepaid pension asset and the associated offsetting pension ADIT in rate base, citing the Commission decision in the 2010 Rate Case as support for its position. CAD Exh. RCS-D at 30-31. CAD witness Smith proposed, however, to include $2.964 million of carrying cost on the net prepaid pension asset at the cost of long-term debt. Id. at 80. Mr. Smith claimed that inclusion of a carrying charge using only the cost of long-term debt (no cost of equity) more accurately addressed (i) the source of financing of the prepaid pension asset, (ii) the additional contributions to the qualified pension fund as being made solely at the discretion of the Companies management, and (iii) a better balancing of the interests of the ratepayer and shareholder than the full rate base approach proposed by the Companies. Id. at 32.

Mr. McCoy took exception with each of the reasons given by CAD for removal of the net prepaid pension amount from rate base. Mr. McCoy claimed that the CAD position is premised on two fundamental misconceptions: that the September 2010 AEP Board of Directors minutes mention of favorable short-term debt rates near the time of the additional 2010 contribution is the type of financing used to permanently finance the pension contributions and that because the pension funding exceeded the ERISA minimum funding requirements, they were discretionary. Companies Exh. HEM-R at 1-7, Tr. 1/21 at 66-70, 77-78 and 88-91. Mr. McCoy argued that the prepaid pension asset is a long-term investment and is financed with all sources of capital available to the Companies. Companies Exh. HEM-R at 5, Tr. 1/21 at 90-91. He also argued that the additional investments made by the Companies to adequately fund the qualified pension plan were prudent and necessary, reduced underfunding of the pension fund, and resulted in lower annual pension expense, lower cost of service, and thus lower rates, than if the additional contributions had not been made. Tr. 1/21 at 66-69.

The inclusion of the pension asset net of the associated pension ADIT in rate base is reasonable in this case as proposed by both the Companies and Staff. It would not be reasonable to allow a pension expense to be lowered by $15.7 million from the earnings on the investment of the additional contributions to the pension plan as proposed by the Companies in their filing, but ignore the carrying cost of the prepaid pension asset that generated those savings. The Commission is not persuaded by the CAD argument that the carrying cost related to the net prepaid pension asset should be limited to the cost rate of long-term debt. The Companies use short-term debt to temporarily finance cash requirements, including the prepaid pension asset, but the Companies refinance that short-term debt on a regular basis with long-term debt and additional equity to maintain acceptable debt to equity ratios. Given the longer-term nature of the pension asset, it is reasonable to include the net pension asset as rate base that will generate a return on that asset at the overall weighted cost of capital.

E. Cash Working Capital

1. Overview

The Companies seek a \$15.986 million cash working capital (CWC) allowance determined by a lead/lag study methodology[10] for determining the revenue lag and expense lead days that are applied to various cost of service elements included in their filing. Companies Rule 42, Statement B, Schedule 7, Companies Exh. JJJ-D at 19. There is no dispute among the parties about using the Lead/Lag Study methodology to determine the CWC rate base component; however, there are major areas of disagreement about (i) which cost of service elements should be included in the CWC calculation and (ii) the number of average lead days for certain operating expense elements.

Staff disagreed with the Companies CWC calculation regarding inclusion of the revenue lag on the cost of service elements of depreciation and net income, and disagreed with the average lead days for AEP Service Company (AEPSC) invoices, intercompany billings transactions and West Virginia property tax payments. Staff determined a CWC of negative \$63.645 million, or a reduction of \$79.631 million, from the Companies CWC request. Staff Exh. DLK-D at 1-3, Exh. DLK. CAD disagreed with Companies position on three of the same issues raised by Staff; however, CAD did not make an adjustment to the Companies proposed lead days for Operation & Maintenance (O&M) Expenses related to the AEPSC and intercompany billing lead days. CAD determined a CWC allowance of negative \$42.946 million, or a reduction of \$58.932 million, from the Companies CWC request.

The Commission will address each of these disagreements among the parties.

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[10] Lead/Lag studies review customer billing information to determine the average revenue lag between when the customer revenue is generated and when the Companies receive the cash from those billings. A review of representative invoices for each category of operating expense is used to determine the number of average lead days between the mid-point of the service period applicable to each invoice and the date when the invoice is actually paid. The revenue lead days are applied to the revenue to determine the positive rate base CWC component applicable to revenue lag and the expense lead days are applied to each applicable operating expense category to determine the negative rate base CWC components. The netting of the revenue lag and expense lead results determine the actual net (either positive or negative) CWC component for inclusion in rate base. The Lead/Lag study methodology has long been used by the Commission to determine the CWC rate base component in the rate setting process for most private utilities that are regulated on the rate base/rate of return methodology.

2. AEPSC Service Company Invoice Lead Days

The Companies Lead/Lag Study determined the average lead days for AEPSC charges from the mid-point of the month for which the service applies until the actual payment is made in the subsequent month. The Companies Lead/Lag study determined the lead days applicable to the AEPSC charges was approximately 19.9 days. Companies Exh. JJJ-R at 7. Staff argued that the AEPSC Agreement, an agreement between AEPSC and the Companies, requires payment of the AEPSC invoice within thirty days of the invoice date. The invoice is normally issued the first working day after the month for which the AEPSC charges apply, and the Companies pay the invoice within two to four days of the invoice date. Staff proposed to utilize hypothetical lead days for AEPSC invoices that would be thirty days after the invoice date. The Staff calculation produced 47.22 lead days for AEPSC invoices. Staff Exh. DLK-D at 1.

Mr. Joyce argued that the payment of the AEPSC invoice within two to four days of the invoice date does not violate the AEPSC Agreement, and if the Staff position of basing the payment on a hypothetical thirty-day lead from the invoice date was adopted, a corresponding increase would be required to the Companies requested AEPSC expense level to compensate for the impact the lengthened payment lead would have on financing costs billed to the Companies by AEPSC. Companies Exh. JJJ-R at 7-8.

The Commission agrees that the 19.9 lead days proposed by the Companies regarding payment of AEPSC invoices is reasonable and adopts that position for determination of the CWC in this case. The AEPSC Agreement only requires payment of the invoice within thirty days of the invoice date. The Companies payment history does not violate that provision of the AEPSC Agreement. The Commission agrees with the Companies that the CWC requirement for AEPSC invoices should be either built into the CWC of the Companies or the appropriate financing costs should be added to the AEPSC bill. It is not reasonable, however, to make the adjustment to the lead days for the AEPSC charges and not make a corresponding adjustment to the financing costs included in the AEPSC charges.

3. Intercompany Billing Lead Days

Intercompany billing involves invoicing by the Companies for services provided to other AEP subsidiaries (revenues), and the billing for services provided by other subsidiaries to the Companies (expense). Whether the Companies are billing for those services or being billed for those services, the payments are made on the day after receiving the invoice. Companies Exh. JJJ-R at 10. The best example of the intercompany billings occurs when one subsidiary is called to provide emergency service restoration assistance during major weather events. Customers of the Companies have benefited in recent times through faster service restoration following interruptions from the Derecho and super storm Sandy. In the test year, the net impact of the intercompany billings produced a net expense to the Companies. Staff argued that payment of intercompany invoices should be made on the same timeframe as the payment lead the

Companies would employ when paying independent third-party contractors. Staff therefore used hypothetical lead days for the intercompany billing equal to the other O&M expense category included in the CWC calculation. Staff Exh. DLK-D at 2.

The Commission does not in this instance endorse the Staff position of using hypothetical lead days related to intercompany billing. In any given year, the netting of the intercompany billing could result in either net revenue or net expenses for the Companies. Because one-day payments of invoices are applied equally to billings from the Companies and to the Companies regarding intercompany billings, it does not appear necessary or reasonable to disturb the AEP practice of paying those invoices on the first working day after receipt of the invoice. In years when the netting of the billings results in revenue to the Companies, the customers will benefit from a lower CWC at the same rate that applies when the netting results in an expense.

4. West Virginia Property Tax Lead Days

The Companies Lead/Lag Study produced an average of 220.7 lead days for the expense category - taxes other than income taxes. This expense category is divided into four distinct types of taxes other than income taxes: (i) payroll taxes, (ii) property taxes, (iii) B&O (business and occupation) taxes, and (iv) other miscellaneous general taxes. The Companies Lead/Lag Study produced 32.93 lead days for payroll taxes, 390.98 lead days for property taxes, 40.92 lead days for B&O taxes and 131.77 lead days for other miscellaneous general taxes. Companies Exh. JJJ-D at 16.

The property tax lead days were determined from the average lead days applicable to property taxes the Companies pay to the States of West Virginia, Virginia, Tennessee and Ohio. The only issue among the parties to this case regarding taxes other than income taxes related specifically to the lead days applicable to the West Virginia ad valorem property taxes.

The Companies proposed that the lead days for West Virginia property taxes be based on the mid-point of a service period in which the property tax return is filed and appealable assessments are issued by the Board of Public Works. The Companies indicated that the proposed service period is different from the service period used by the Commission in the 2010 Rate Case, but consistent with one alternative method of determining the lead days for West Virginia property taxes described in Black Diamond Power Company, Case No. 12-0064-E-42T, August 10, 2012 Order (Black Diamond Order). Companies Exh. JBB-D at 11-12.

Mr. Bartsch does not strictly rely on the alternative service period mentioned in the Black Diamond Order to support the service period for West Virginia property taxes. He claimed the alternative service period mentioned in the Black Diamond Order was applicable to public service companies as defined by W.Va. Code §11-5-3. Mr. Bartsch argued the tax year and assessment year coincide in the same calendar year (which is the year following the year covered by the return) and supported the alternative service period mentioned in the Black Diamond Order. Companies Exh. JBB-D at 15. The Companies claimed that the year following the year covered by the return is the assessment year as defined by W.Va. Code §11-3-1(f)(2) enacted in 2010 based on a decision of the Attorney General of West Virginia.[11] Companies Init. Br. at 20.

Using a service period that is the year following the year on which the property tax return is based produces 609 average lead days for West Virginia property tax payments. When the 609 average lead days for West Virginia property tax payments is blended with the lead days for the property taxes paid in other states where the Companies own property, the result is 390.98 lead days for all property tax payments included in the Companies Lead/Lag Study.

Staff based the service period on the year on which the property values were determined, the year before the actual property tax return was filed. Using this service period produced an average of 874 lead days for West Virginia property tax payments and 636.19 lead days when the lead days for all states where the Companies own property is blended. Staff Exh. DLK-D at 2.

CAD based the service period on the year on which property values were determined in a manner similar to Staff; however, the results of the CAD calculation produced 333.00 lead days for the category of taxes other than income taxes. CAD witness Smith primarily supported his recommendation by reference to the Commission decision in the 2010 Rate Case. CAD Exh. RCS-D at 19-20.

The Companies provided rebuttal to the Staff and CAD positions, also arguing that neither Staff nor CAD provided any justification for departure from the alternative methods addressed in the Black Diamond Order. Mr. Bartsch also commented on the lack of any meaningful argument based on fact or law to support the Staff and CAD positions and criticized them for not addressing the analysis of the West Virginia tax code provided in his direct testimony. Companies Exh. JBB-R at 9.

The Commission has struggled with the issue surrounding the appropriate lead days applicable to West Virginia property tax payments for some time. The Commission put forth a challenge in the Black Diamond Order to all utilities regulated by the Commission to conduct a proper analysis to support their claims that the service period for West Virginia property taxes should not be the year on which the property values are determined for the property tax return filed on the subsequent May 1. The Commission believes that the Companies have put forth a persuasive argument in this case that the

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[11] The West Virginia Attorney General has opined that the assessment year referred to in W.Va. Code §11-6-23 is the calendar year beginning on January 1 and ending the succeeding December 31, and that the dates referred to in W.Va. Code §§11-6-1 (the May 1 filing of the return), 11-6-9 (the September 15 tentative assessment by the Tax Commissioner), and 11-6-11 (the October 1 deadline for assessing and fixing the true and actual value by the BPW) all occur in the assessment year. 59 W. Va. Op. Att'y Gen. 94, 1981, WL 157185 (March 23, 1981)

appropriate service period for West Virginia property tax payments is the year in which the property tax report is filed and the year when the assessments of the property values are determined by the Board of Public Works. The Commission finds the average lead days for property taxes as determined by the Companies Lead/Lag Study and supported in the testimony and briefs filed in this case to be reasonable and to accurately reflect the lead days and level of CWC attributable to property tax payments. The Commission adopts 390.28 as the lead days for property tax payments as presented by the Companies in this proceeding.

5. Depreciation and Return on Equity

The Companies included both depreciation expense and return on equity in the CWC calculation by applying the revenue lag days, but included zero lead days because the revenue generated from both of those cost of service elements is immediately reinvested in the business, on receipt of the revenue. Companies Exh. JJJ-D at 17-18. Mr. Joyce argued that although depreciation expense is sometimes referred to as "non-cash" and excluded from the CWC determination, that label is misplaced. Id. at 18. Mr. Joyce argued that revenue related to the net income element of the cost of service should be subject to the revenue lag applicable to all revenue. Id. at 17.

Staff did not include depreciation expense or return on equity in the CWC calculation, claiming both depreciation expense and return on equity are "non-cash" items, citing the Order in the 2010 Rate Case as support for their position. Staff Exh. DLK-D at 3. CAD likewise did not include either depreciation expense or return on equity in the CWC calculation claiming they were "non-cash," also citing the 2010 Rate Case Order as support for that position. On questions from the Commission, Ms. Kellmeyer conceded that depreciation expense is the return of the cash expenditures made when utility plant was installed in some previous period. Tr. 1/23 at 51.

Mr. Joyce disputed the Staff and CAD positions and argued that all elements of the cost of service used to determine the total revenue collected from the customers should be subject to the revenue lag and should be included in the CWC calculation. Companies Exh. JJJ-R at 2-3. Mr. Joyce argued that the failure to include the depreciation expense and return on equity components of revenue in measuring CWC incorrectly assumes that the Companies collect this portion of the revenue requirement on the same day service is provided even though the revenue is not recovered for 36.5 days – a fact not contested as to the remainder of the Companies revenue. Id. at 3. Mr. Joyce testified that approximately twenty-two percent of every dollar of the revenue requirement is associated with recovery of depreciation and equity return.

The issue of whether the revenue lag days should be applied to depreciation expense in the Lead/Lag methodology of determining CWC was a contested issue in this case. Earlier in this Order (see supra, at 6), the Commission identified this issue as one that warranted a further review.

The Commission reviewed other regulatory decisions to assess whether other state regulators recognize depreciation expense in the CWC calculation. Although finding specific language from the vast array of orders on the Web page dockets is not an easy task, the Commission was able to find specific references for inclusion of the revenue lag for depreciation expense in the CWC calculation in cases filed in Virginia, Kentucky, Tennessee and New Jersey.[12] The review of the decisions from other jurisdictions was made to see how those other jurisdictions have addressed this issue.

The Commission has reviewed the evidence, testimony and arguments, considered cases cited by the Companies, and reviewed decisions by other state regulatory commissions. Based on that review and the record presented in this case, the Commission will allow depreciation expense to be included in the determination of CWC. Neither Staff nor CAD provided support for their position on depreciation expense (other than citing the 2010 Rate Case Order) nor did Staff or CAD address the testimony provided by the Companies about why depreciation expense should be included in the CWC calculation. The Companies' argument that all revenue billed to utility customers is subject to the revenue lag is persuasive and supports the inclusion of depreciation expense in the CWC calculation.

To characterize depreciation expense as "non-cash" (as do both Staff and CAD) is not entirely accurate. Depreciation expense is a return of the cash investment made by the utility for utility plant placed in service during some previous period, and the revenue provided to the Companies for the return of that investment is included in the revenues the Companies are permitted to recover from customers. Although it is true that recording depreciation expense does not require the expenditure of cash at the time the expense is recorded and charged to the customer, there is no doubt that cash was expended at the time the property was acquired, and the recorded depreciation is used to reduce the investment in that property (rate base). The Companies experience the same 36.5-day revenue lag in receiving the cash for depreciation expense from the time that expense is recorded as they do for any other cost of service element.

The Commission will not, however, authorize the inclusion of return on equity in the CWC calculation. Return on equity, like depreciation expense, is a cost of service element and is subject to the same revenue lag between the time the return on equity is recorded and the time the cash is received for that revenue. Unlike depreciation expense, however, return on equity is not reflected as an offset to rate base. The Companies may have the use of the cash collected for the return on equity for some short time to offset the need to finance ongoing cash requirements, but eventually some portion of the cash

[12] Commonwealth of Virginia, State Corporation Commission, Case No. PUE-2008-00001, December 16, 2008, Order at 26, Schedule 17; Kentucky Public Service Commission, Kentucky-American Water Co., Case No. 2004-00103, February 28, 2005 Order at 17: Tennessee Regulatory Authority, Tennessee-American Water Company, Docket No. 08-0039, January 13, 2009 Order at 39-41 (footnote 146 referencing Petition Exhibit No. 1, Schedule 2); New Jersey Board of Public Utilities, Jersey Central Power & Light Company, BPU Docket No. ER12111052, January 9, 2014 Initial Decision (ALJ Order) at 9-11, upheld by March 18, 2015 Order on Reconsideration.

collected for the return on equity component of revenue will be paid as dividends. The amount of revenue paid as dividends will depend on the dividend retention policy of the utility. Typically dividends are paid quarterly. If the Commission was to recognize the revenue lag for the return on equity component of revenues, there should be an offsetting lead time for when a portion of those revenues is paid as dividends. The Companies only addressed the revenue lag associated with the return on equity component of revenue, and neither the Companies nor any other party addressed the lead time associated with the payment of dividends. Because of the lack of a record in this proceeding about the Companies dividend retention policy or lead days for dividend payments, the Commission will not grant the request of the Companies to include return on equity in the CWC calculation.

As a result of the Commission review of the inclusion of depreciation expense in the CWC calculation, the Commission has developed some concern about how Allowance for Fund Used During Construction (AFUDC) is recorded on the Companies books. The Commission has generally authorized the utilities to record AFUDC during construction of new utility plant additions. The recording of AFUDC permits the Companies to record as non-cash income the carrying cost for the capital invested to fund the CWIP and increase the cost of the new utility plant constructed by the unrecovered carrying cost. After capital projects recorded in CWIP are completed, the cost of each asset plus AFUDC is transferred to the appropriate utility plant account and included in rate base in the next base rate case filing. Most utilities do not record AFUDC on purchases of equipment, routine utility plant replacements and other projects of short duration. Because it is the customers who supply the cash for depreciation expense and normalized current deferred income tax expense for accelerated depreciation through rates, the accumulated depreciation expense and deferred income tax expense offset net plant in the determination of rate base.

To address the Commission concern about recording AFUDC on the level of utility plant additions funded by depreciation expense and normalized current deferred income tax expense recovered in rates, the Companies must address in their next base rate case the issue of whether the Commission should limit AFUDC for rate recovery to only the AFUDC applicable to the level of annual utility plant additions that exceed the annual depreciation and normalized current deferred income tax expense included in current base rates. If the Commission determines that AFUDC has been overstated as a result of accruing AFUDC on construction funded by depreciation and deferred income tax cash flow, any adjustment will be limited to the time period from the effective date of rates in this case forward.

6. Summary of Cash Working Capital

Based on the Commission decisions described in the preceding sections concerning CWC that address the lead days for AEPSC billing, intercompany billing and West Virginia property taxes, and whether to include depreciation expense and return on equity in the CWC calculation, the Commission will approve a CWC allowance of

$2.982 million. This determination was made by applying the results described above to the cost of service elements determined in this case as shown on Appendix A attached to and incorporated in this Order.

F. Prepaid Rent and Other Prepayments

The Companies filing included a request that $3.306 million of prepaid rent and other prepaid expenses be included as rate base. Companies Rule 42, Statement B, Schedule 6. Statement B, Schedule 6 actually included an additional $7.784 million of prepaid rent for WPCo that should have been reflected as a prepaid pension asset. That reclassification is included in the Pension Asset amount authorized as rate base and discussed in Section III., D above.

Staff did not include the prepaid rent and other prepaid expenses as rate base. Staff cited Commission Tariff Rule 19.4.f. as support for its position. Staff claimed that Tariff Rule 19.4.f. requires that prepaid expenses be excluded from rate base if the CWC calculation produces a negative CWC allowance. Staff Exh. DLK-D at 5-6. CAD eliminated the entire prepaid expense balance of $95.408 million proposed by the Companies, except for the average test-year balance for prepaid rent of $128,046. CAD Exh. RCS-D at 28-34. It appears the prepaid pension asset classification error on Companies Rule 42 Exhibit, Statement B, Schedule 6 was not addressed by CAD. The reclassification issue, however, had little impact on Mr. Smith's recommendation because he excluded both the prepaid pension asset ($84,317,492) and all of the other prepaid expense items, including prepaid insurance ($1,874,961), prepaid taxes ($1,321,518) and other prepaid accounts ($52,350), leaving only the $128,046 of prepaid rent in his rate base recommendation.

Mr. Joyce argued that the prepaid expenses should not be excluded from rate base. He claimed that the Staff interpretation is not a reasonable reading of the Rule. Mr. Joyce argued that whether CWC is positive or negative should not be dispositive of the inclusion of prepaid items as long as the prepaid expenses are excluded from the CWC calculation and not double counted. He argued that including a negative CWC from a Lead/Lag methodology that excluded prepaid expenses as Staff proposed, but then also excluded a demonstrated prepaid expense from base rate, fails to recognize the working cash requirement for prepayments entirely, a result that he characterized as absurd. Companies Exh. JJJ-R at 13.

The Commission has addressed the prepaid pension asset previously. The Commission understands that Tariff Rule 19.4.f. could be clearer and that Staff could arrive at the interpretation of that Rule it presented, but the Commission does not agree with the interpretation proposed by Staff. The Commission believes the Rule is meant to exclude prepayments from rate base in the absence of a calculation of CWC. It is reasonable to include $3.306 million of prepaid rent and other prepaid expenses in the determination of rate base.

G. Material and Supplies

1. Mitchell - Coal Inventory

The Companies included $34.02 million of coal inventory for the Mitchell Plant in their filing. Companies Rule 42 Exh., Statement B, Schedule 5. At the time of the Companies rate filing, the decision about the acquisition of the Mitchell Plant by WPCo had not been decided in the Mitchell Case. The Commission Order of December 30, 2014, in the Mitchell Case, however, approved the transfer of an interest in the Mitchell Plant according to the terms of a Joint Stipulation in that case. The Joint Stipulation recognized that 82.5 percent of the various components making up the Mitchell Settlement Interest, as defined in the Joint Stipulation, would be recognized for rate recovery for up to the first five years after the date of acquisition. Staff recommended the Mitchell coal inventory be limited to 82.5 percent of the $34.02 million, or $28.067 million. Staff Exh. ELO-D at 16. No other party took exception to the Staff position. The Staff position is reasonable, consistent with the terms of the Joint Stipulation and will be adopted by the Commission.

2. Mitchell – Other Material and Supplies

The Companies included $13.691 million of Other Material and Supplies for the Mitchell Plant in their filing. Companies Rule 42 Exh., Statement B, Schedule 5. Staff recommended that the Other Material and Supplies for Mitchell be limited to 82.5 percent of the $13.691 million, or $11.295 million. Staff Exh. ELO-D at 16. No other party took exception to the Staff position. The Staff position is reasonable, consistent with the terms of the Joint Stipulation and will be adopted by the Commission.

3. 2013 Average Test-Year Coal Inventory

The Companies included $92.979 million of average coal inventory based on the 2013 test-year and proposed an adjustment to increase that amount by $13.662 million to reflect additional coal inventory needed to supply the two-thirds interest in the Amos 3 Generation Unit acquired on December 31, 2013. Companies Rule 42 Exh., Statement B, Schedule 5.

CAD proposed to reduce the coal inventory requested by the Companies by $63.454 million. Mr. Smith argued that the average test-year balance of the coal inventory, adjusted for the burn for the full Amos 3 Generating Unit, is high and that APCo had proposed to reduce the coal inventory to a normalized amount in a recent Virginia bi-annual review case (Case No. PUE-2014-00026). CAD Exh. RCS-D at 44. Mr. Smith made three adjustments to arrive at his proposed level of non-Mitchell coal inventory. He (i) reduced the coal inventory to the West Virginia jurisdictional allocation of the total APCo coal inventory proposed by APCo in the recent Virginia Case; (ii) reduced that inventory level further to reflect an inventory of 971,369 tons at a thirty-five day burn rate of 27,753 tons per day; and (iii) reduced the Companies average inventory price per ton of $76.78 to the average cost per ton of $71.26 for coal burned during the eighteen months from December 2013 through May 2014. Id. at 45-46. Mr. Smith argued that the coal inventory level based on a thirty-five day burn rate (determined from the data for the twelve months ending May 2014) reflected the most recent data, was representative of going level conditions and appeared to be representative of normal operating conditions, including some months with a very high burn rate. Id. at 48.

Staff did not address the non-Mitchell coal inventory in its direct testimony. Mr. Eads, however, did address that issue in rebuttal and claimed that prior to the 2010 Rate Case, APCo normally adjusted the test-year coal inventory to reflect either a thirty-five or forty-day burn rate. Staff Exh. TRE-R at 2. Mr. Eads argued that the average, normalized coal inventory should be 1,339,621 tons, a level based on a forty-day average burn rate of 33,491 tons per day. Id. at 3. Staff claimed that APCo's generation fleet operated at a low average capacity factor of less than thirty-eight percent during 2013, and these low levels of operation would contribute to the high level of coal inventory experienced in the test-year. The Staff higher burn rate of 33,491 tons per day was based on a seventy percent capacity factor, a capacity factor Staff believed was more reflective of normal operations after several coal fired units are retired in June 2015. Id. at 4. Staff claimed that after APCo retires the three coal-fired units and relies more heavily on the Amos and Mountaineer coal-fired generating units to meet their capacity and energy requirements, there will be less flexibility in coal supply in the event of supply disruption. Staff recommended that the higher forty-day burn rate be the basis for determining the normalized coal inventory level and recommended the inventory level be priced at the $71.26 per ton proposed by CAD to determine the coal inventory value. Id. at 5. During cross examination by the Companies, Mr. Eads stated that on a going-forward basis APCo would only be operating the Amos and Mitchell coal-fired units and the actual cost of coal burned at those plants during the 2013 test-year was around $68 per ton. He recommended, however, that the proposed CAD coal inventory cost of $71.28 be used because coal inventory from the generating units to be retired would be transferred to Amos and Mitchell. Tr. 1/23 at 107-108.

In rebuttal to the Staff and CAD position, the Companies argued that the average cost of coal burned of $71.26 per ton does not reflect the average cost per ton of coal in inventory because the inventory may have a different mix of high and low sulfur coal from the amount of coal burned. Mr. West asserted that the Companies do not base their operational or ratemaking decisions concerning the appropriate level of coal inventory on the average day burn rate. Companies Exh. CFW-R at 5. Mr. West claimed that inventory levels in recent years have been impacted by (i) international and domestic market conditions, (ii) higher demand in China, (iii) port issues in Australia, (iv) mine problems in South Africa, (v) strong worldwide demand for coal, (vi) many Central Appalachian and Northern Appalachian producers offering their incremental production to the international market to take advantage of that demand, (vii) the low price of natural gas, (viii) the coal-fired generation run times, and (ix) Cross-State Air Pollution Rule changes (CASPR). Id. at 5-8. Mr. West argued that these external factors have impacted the price, availability and contract length of coal contracts and the run rates of APCo's generation fleet during the 2013 test-year. He argued that both of these results impact the level and price of the coal inventory. Id. at 8-9. Mr. West also argued that if the Commission decides to establish the coal inventory on some targeted burn rate, the full-load burn rate should be used because it is easily understood, provides a consistent, stable comparison from year to year, and minimizes the risk of supply disruption. Mr. West claimed the 1,299,720 tons of coal inventory proposed by the Companies for the determination of the West Virginia jurisdiction coal inventory value is based on full-load burn days of ten days for the Glen Lyn Power Plant (Glen Lyn) and the Philip Sporn Power Plant (Sporn); fifteen days at Clinch River Power Plant (Clinch River); twenty-five days at Amos; and thirty days for Mountaineer. He argued that this forms the basis for the optimal inventory level determined by the Companies Fuel Supply Task Group. Id. at 11-12.

The coal inventory issues presented in this case are troubling. The Companies recover their actual cost of generation fuel through the annual ENEC Proceeding and the Companies bear little risk in not recovering the actual cost of the fuel used in generation through the approved ENEC rates. The issue in this case involves what reasonable, normalized level of coal inventory should be included as rate base that will minimize the risk of not operating those generation units efficiently and reliably in the event of a supply disruption. The Commission must balance the need for reliability of supply in the event of supply disruption with the need to include a normalized level of coal inventory that will be recovered in rates at a reasonable cost to the ratepayers. Although both the Companies and opposing parties have made arguments for their positions, the record confirms that there are a number of factors that cause uncertainty about the appropriate level of coal inventory. There is, for instance, a level of uncertainty about the potential impact from the retirement of three coal-fired generation units, ongoing environmental regulation changes, and the run rates for the remaining generating units will have on the coal inventory levels prospectively. All of these factors impact the determination of the appropriate normalized level of coal inventory.

The Commission will adopt the Staff level of coal inventory for the non-Mitchell generation units of 1,339,621 tons. That level of coal inventory is based on an average day burn rate of forty days and is reasonable, particularly given the average daily burn rate is determined using a seventy percent run rate, a run rate significantly higher than the actual run rate experienced during the 2013 test-year. The Commission understands the argument made by the Companies that the average price of coal in inventory can be different from the average cost of coal burned because of the mix of high and low sulfur coal, market conditions, contract terms, delivery options and many other issues. The Commission also understands that the inventory mix of coal present in the test-year will likely be different after the three coal-fired units are retired and that the current trend is lower coal prices in the market. The Commission will price the coal inventory tonnage at $71.26 per ton as proposed by CAD and supported by Staff. The Commission believes $71.26 per ton reasonably reflects the cost of coal inventory to be experienced after the three coal-fired generation units are retired, a time that closely approximates the time new rates from this case will become effective.

4. Amos – Other Material and Supplies

The Companies proposed an adjustment of $5.177 million to the average 2013 test-year Other Material and Supplies for the Amos Unit 3 because the Amos 3 material and supplies balances were only included in the test-year average for one month. Companies Rule 42 Exh., Statement B, Schedule 5. No other party took exception to the Company position. The Company position is reasonable and will be adopted by the Commission.

H. Putnam Coal Terminal

The Companies filing included the facility called the Putnam Coal Terminal in rate base under Account 105 – Plant Held for Future Use. A portion of the Putnam Coal Terminal located at the site of APCo's Amos Plant was formerly used to deliver coal to the Mountaineer Plant. Companies Exh. JLB-R at 8. Staff recommended that the Commission reject the Companies proposal to include $2.810 million in rate base related to the utility plant, net of accumulated depreciation for the Putnam Coal Terminal, arguing that it was no longer used and useful. Staff Exh. DLP-D at 6. CAD also recommended the utility plant, net of accumulated depreciation and ADITs, for the Putnam Coal Terminal not be included in rate base. CAD Exh. RCS-D at 21-28.

In rebuttal to the Staff and CAD positions, the Companies argued that a portion ($8.55 million of $35.6 million of Gross Plant on the books) was still used and useful. Companies Exh. JDL-R at 11-12, attached Exhibit JDL-R2; Tr. 1/22 at 219; JLB-R at 8-12. Mr. Brubaker explained that in March 2013 the Companies mistakenly transferred all of the Putnam Coal Terminal assets to Account 105 – Plant Held for Future Use. In fact, the facility assets belong in two categories: (1) conveyor and barge loader assets that the Companies have not used in recent years and that APCo transferred to Account 108 – Retired plant in December 2014; and (2) other assets, including an office building, land, rail assets, and runoff ponds, that APCo continued to use in operating the Amos Plant and that APCo transferred back into Account 101 in December 2014. Companies Exh. JLB-R at 10; citing Companies Exh. JDL-R at 11-12; Tr. 1/22 at 23-24, 42.

Mr. Brubaker further argued in rebuttal that when a utility retires an asset it moves the undepreciated balance of the asset from Account 101 to Account 108 and that transfer has no affect on rate base because both accounts are included in rate base. Tr. 1/22 at 41. Mr. Brubaker calculated that the reclassification of the Putnam Coal Terminal assets should result in only a $335,167 reduction to jurisdictional depreciation expense. He stated that this adjustment is the net of a $413,013 reduction to depreciation expense to remove the Putnam Coal Terminal depreciation expense included in the Companies' Rule 42 filing offset by an increase of $77,846 in depreciation expense related to the

$8.55 million of assets reclassified from Account 105 to Account 101 in December 2014. Id.

At the hearing, Mr. Smith and Mr. Pauley accepted Company witness LaFleur's testimony that some of the assets at the Putnam Coal Terminal are used and useful and some are not. Tr. 1/23 at 31-33; Tr. 1/22 at 68-70. CAD witness Smith testified, however, that standard accounting treatment notwithstanding, for ratemaking purposes, the retired portions of the Putnam Coal Terminal should no longer be in rate base. Tr. 1/22 at 69-71. He recommended a rate base reduction of $2.043 million on a West Virginia jurisdictional basis. CAD Exh. RCS-D, attached Exhibit LA-1, B-5.

Mr. Pauley agreed the reduction to net rate base should be approximately $2.1 million related to the Putnam Coal Terminal assets that are no longer used and useful. Tr. 1/23 at 32-33. He also agreed with Mr. Brubaker that the Staff adjustment to reduce depreciation expense by $411,000 (actually $413,013) should be lowered to the amount addressed in Mr. Brubaker's rebuttal testimony. Tr. 1/23 at 36

The Commission will reduce net rate base by $2.043 million for the West Virginia jurisdictional portion of the Putnam Coal Terminal that has been retired as agreed to by both Staff and CAD during cross examination at hearing. The Commission also accepts the revised depreciation expense for the Putnam Coal Terminal as proposed in Mr. Brubaker's rebuttal testimony.

I. Asset Retirement Obligation – Accretion Expense

The Companies record expenses related to Asset Retirement Obligations (AROs) on their financial statements as prescribed by accounting guidelines ASC-410-20 and ASC-410-25 (formerly known as SFAS 143 and FIN 47). According to Companies' witness Brubaker, these costs represent the expected net negative salvage (cost of removal) related to ash ponds, carbon capture and asbestos utility plant assets. The net negative salvage is different for ARO assets because the Companies have a legal obligation to remove these assets upon retirement; however, for most other utility plant assets, the Companies will have a future cost to retire those assets, but have no current legal, contractual or environmental obligation to do so. The Companies in their petition proposed to reduce the per books utility plant by $33.173 million (Statement G, Adj. 88-EPIS) and reduce accumulated depreciation by $15.102 million (Statement G, Adj. 95-AD) for the ARO property because those per books balances represent non-cash assets recorded under FAS 143/FIN 47 accounting guidelines. These assets should not be included in rate base. In addition, the Companies proposed to reduce rate base further by $5.235 million (Statement G, Adj. 104-ORB) for the after-tax effect of the 2013 test year depreciation and ARO accretion expenses because those amounts have been historically included in base rates, paid by customers and, therefore, should reduce rate base. Companies Exh. JLB-D at 17-21.

Neither Staff nor CAD opposed the $18.071 million net rate base reduction proposed by the Companies in Statement G, Adjustments 88-EPIS and 95-AD. Mr. Oxley urged that the Companies rate base reduction for ARO accretion expense (Statement G, Adj. 104-ORB) should not be limited to the 2013 test-year amount, but should be increased to include the total accumulated ARO accretion expense previously recovered through customer rates. Mr. Oxley testified that the Companies proposed rate base should be reduced by $35.640 million for the accumulated ARO accretion expenses recovered in rates through the end of the 2013 test year. Staff Exh. ELO-D at 19. Mr. Oxley also recommended that the depreciation expense proposed by the Companies be lowered by $3.105 million to eliminate the depreciation expense related to the ARO assets. Id. at 14.

In rebuttal to the Staff positions, Mr. Brubaker did not disagree with Staff's proposal to reduce rate base by the accumulated ARO accretion expense recovered in rates through the end of the test year, but did argue that the amount should be limited to the average test year balance of $33.715 million. Companies Exh. JLB-R at 18-19. Mr. Brubaker also disagreed with the Staff adjustment to reduce depreciation expense related to the ARO assets. He claimed that the Commission in previous base rate cases had authorized the recovery of ARO depreciation expense and that Mr. Oxley provided no basis for the change he proposed. Mr. Brubaker argued further that it is not necessary to provide a return on the ARO assets as indicated in his direct testimony, but SFAS 143 requires amortization of the ARO assets over its expected life. Id. at 15-16. He argued that if the depreciation or amortization of the ARO assets is not recovered in rates, as proposed by Staff, the Companies would never recover the full ARO liability in rates. Id. at 17.

No party objected to the adjustments proposed by the Companies to reduce rate base by the net ARO assets, and the Commission will adopt those adjustments. The Commission also adopts the Staff position to reduce rate base by the accumulated ARO accretion expense recovered in customer rates through the end of the 2013 test year. The Staff reduction of $35.640 million will be adjusted downward to $33.715 million to reflect the average test year balance as agreed to by the Companies at hearing. The Commission will not adopt the Staff position to lower depreciation expense by $3.105 million for depreciation of the ARO assets. While the net ARO assets should not be recognized for the purposes of return on rate base, the ARO assets should be depreciated over the expected life of the ARO assets to avoid intergenerational issues. That charge should be imposed on the ratepayers who benefit from the service provided by those assets.

J. Accumulated Depreciation

1. Amos Accumulated Depreciation Reserve Adjustment

CAD proposed to increase accumulated depreciation (reduce rate base) by $12.951 million for the West Virginia jurisdictional share of an accumulated depreciation reserve adjustment related to the acquisition of Amos Unit 3 that was recognized by the Virginia SCC in Case No. PUE-2014-00026. CAD Exh. RCS-D at 36. Mr. Smith claimed that the Amos Unit 3 asset, prior to acquisition by APCo, had not been subject to either the Virginia or West Virginia accounting rules. Mr. Smith asserted that except for minor differences in the manner CWIP and AFUDC are handled in each state, there is no reason the Commission should not reduce the West Virginia jurisdictional rate base for Amos Unit 3 in the same manner as the Virginia SCC. Id. at 38-43.

WVEUG witness Kollen took a position similar to the CAD position regarding the Amos Unit 3 depreciation reserve, claiming that the Amos Unit 3 net rate base value should be the same in West Virginia and Virginia. He argued that his review of the record in the Virginia Case indicated there was a depreciation reserve adjustment for Amos Unit 3, and that the Commission should recognize a similar adjustment in this case. WVEUG Exh. LK-D at 28-29.

In rebuttal to the CAD and WVEUG position, Mr. Ferguson argued that for many years the West Virginia and Virginia Commissions have implemented different depreciation rates for APCo in their respective jurisdictions and have recognized different plant balances, including different levels of accumulated depreciation. Mr. Ferguson argued that, in addition to the lack of a record in this case for such an adjustment, there is no reason why the regulatory treatment of Amos Unit 3 must be the same in both jurisdictions nor is there any compelling reason why this Commission should subordinate its regulatory judgment to the decisions arrived at by the Virginia SCC. Companies Exh. SHF-R at 1-2.

On cross examination, Mr. Smith indicated that the CAD's proposed depreciation rates would recoup the undepreciated balance over the remaining life of the Amos Unit 3 and claimed the $83 million Amos Unit 3 reserve deficiency was appropriately synchronized between the adjustment to reduce rate base proposed by Mr. Smith and the new depreciation rates recommended for Amos Unit 3 by Mr. Majoros. Tr. 1/22 at 92-93.

The Commission will not adopt the adjustment proposed by CAD and WVEUG to accumulated depreciation related to the claimed Amos Unit 3 depreciation reserve deficiency. Mr. Smith admitted during examination that if an adjustment to accumulated depreciation to correct the Amos Unit 3 reserve was made, as he proposed, that adjustment would have to be reflected in the depreciation reserve for Amos Unit 3 used to determine new depreciation rates. The Commission believes the opposite is also true. If the accumulated depreciation for Amos Unit 3 is not adjusted as proposed by Mr. Smith, any over/under accrual of depreciation will self-correct in the depreciation rate established for the remaining life of that asset. As described in Section VI of this Order, the Commission has authorized new depreciation rates based on the Staff recommendation. The Commission understands that if it had accepted the CAD-recommended depreciation rates there may be a need also to reflect the Amos Unit 3 depreciation reserve adjustment as proposed by Mr. Smith. Because the

Commission adopted the Staff-recommended depreciation rates (and there is nothing in the record to indicate they did not properly adjust the depreciation rate to correct any reserve deficiency over the remaining life for the Amos Unit 3), the Commission will not adopt the CAD and WVEUG proposed adjustment.

2. Adjustment to Reflect Composite Depreciation Rates

The CAD proposed an adjustment to the West Virginia jurisdictional accumulated depreciation level proposed by the Companies to increase accumulated depreciation (reduce rate base) by $37.068 million. Mr. Smith testified that APCo records depreciation expense on their financial statements using composite depreciation rates for each property classification that differs from the jurisdictional depreciation rates authorized in either Virginia or West Virginia, and the adjustment reflects lower depreciation rates for the West Virginia jurisdiction than the composite depreciation rates. CAD Exh. RCS-D at 11-12. Mr. Smith argued that in the Companies' filing (Statement G-1, Adjustment 5-AD) APCo restated per books West Virginia jurisdictional depreciation expense using the depreciation rates authorized by the Commission. Mr. Smith claimed the APCo adjustment is retroactive ratemaking because the resulting accumulated depreciation rate base reduction is different from what APCo reported on the financial statements. He claimed that APCo could have changed the recording of depreciation on the West Virginia jurisdictional utility plant at any time after completion of Case No. 05-1278-E-PC-PW-42T, but chose not to do so. Id. at 12.

In response to the CAD position, the Companies argued that a simple allocation of the per books accumulated depreciation to the West Virginia jurisdiction fails to recognize the different depreciation rates authorized in West Virginia. Companies Exh. JLB-R at 2. Mr. Brubaker asserted that APCo did adjust the composite depreciation rates to reflect the new depreciation rates authorized in the 2005 Rate Case. Id. at 5. Mr. Brubaker testified that the adjustment to restate APCo's accumulated depreciation to reflect the depreciation rates authorized in the 2005 Rate Case does not constitute retroactive ratemaking. He also argued that the adjustment reflects the proper allocation of APCo's total accumulated depreciation to the West Virginia jurisdiction and is appropriate because APCo made a similar adjustment in Virginia to increase jurisdictional accumulated depreciation to reflect the higher depreciation rates authorized by the Virginia SCC. Id. at 7. Mr. Brubaker claimed Mr. Smith did not oppose a similar adjustment to increase accumulated depreciation (reduce rate base) for the recently completed APCo bi-annual review filing before the Virginia SCC.

The Commission will not adopt the adjustment proposed by CAD to increase the West Virginia jurisdictional accumulated depreciation proposed by the Companies to reflect the per books accumulated depreciation using the composite depreciation rates. We do not believe it is reasonable to determine West Virginia jurisdictional rate base using depreciation rates different from those authorized by the Commission.

It is not unusual for regulated utilities to keep sub-ledgers for various cost of service elements when there are differences between GAAP accounting and regulatory accounting. The Commission believes it would be difficult to record depreciation expense for each jurisdiction independently. Because jurisdictional allocation factors change in each base rate case, it is hard to imagine that attempting to account for depreciation expense on a jurisdictional basis for financial reporting would not result in a tremendous accounting effort that would likely not be possible during a monthly accounting closing schedule. The Companies made a substantial effort to establish accumulated depreciation on a jurisdictional basis in the more expanded time frame needed to prepare a rate case. Accounting for jurisdictional depreciation differences through rate case adjustments is not a reasonable justification for the Commission to base accumulated depreciation on depreciation rates different from those previously authorized by the Commission.

The CAD proposal, if accepted, would create a situation where the Companies would have a stranded investment if, as the Companies asserted, they make an adjustment in Virginia to reflect the authorized depreciation rates in Virginia similar to the adjustment proposed by the Companies in this case. The Companies also argued that Mr. Smith did not oppose such an adjustment in the recent bi-annual APCo filing in Virginia, an assertion not challenged in this case.

3. Summary of Commission Decision on Accumulated Depreciation

After considering all Commission decisions regarding rate base elements and depreciation related issues that impact accumulated depreciation, as described in this Order, the Commission has determined the accumulated depreciation balance for establishing a fair and reasonable rate base on which to determine customer rates in this proceeding is $2.097 billion.

K. Accumulated Deferred Income Taxes

After considering all Commission decisions regarding rate base elements, depreciation related issues, prepaid items, regulatory assets, and tax issues that impact accumulated deferred income taxes, as described in this Order, the Commission has determined the accumulated deferred income tax balance for establishing a fair and reasonable rate base on which to determine customer rates in this proceeding is $828 million.

IV. REGULATORY ASSETS

A. Deferred 2012 Storm Recovery Expenses and Carrying Charges

The Companies proposed to recover the deferred costs of two major storms that occurred in 2012 over a five-year amortization period. Specifically, the Companies sought to recover the costs related to the straight-line windstorm that hit the service territories of the Companies on June 29, 2012 (Derecho) and Hurricane Sandy that hit the service territories of the Companies starting on October 29, 2012. The restoration costs at issue are approximately $68.6 million. Companies Exh. PAW-D at 14; Companies Exh. JJS-D at 3-4. Mr. Scalzo testified that the total restoration costs of the Derecho and Hurricane Sandy were approximately $84 million, $68.6 million of which were non-capital restoration costs. The Companies deferred the $68.6 million portion for future recovery. The $16 million of capital restoration costs are included in the thirteen-month average rate base filed in this case. Companies Exh. JJS-D at 3. Mr. Scalzo argued that the Companies should be allowed to recover carrying charges at the weighted cost of capital on the deferred $68.6 million amount because the Companies incurred financial costs by carrying this large amount for several years. Id; Companies Exh. JJS-R at 3.

Mr. Scalzo testified that a five-year amortization period is appropriate because it strikes a balance between the rate impact on customers and the financing costs of the Companies. If the Commission disallows the carrying charge, however, the Companies requested a more expedited recovery period. Id. at 4.

Staff witness Pauley objected to the request for carrying costs and recommended a longer recovery period. Mr. Pauley referenced the 2010 Rate Case, in which the Commission approved recovery, over seven years and without financing costs, of about $18.2 million in cost for the 2009/2010 major winter storm incurred by APCo. Staff Exh. DLP-D at 3. Mr. Pauley recommended a ten-year amortization period of storm costs in this case and no rate base treatment. Mr. Pauley agreed that the Companies should have the opportunity to recover the unexpected costs from customers, but that it is unreasonable to require customers to pay the Companies a return on the storm expenses. Id. at 4. The treatment proposed by Staff would reduce the annual recovery amount to $6,520,623 for APCo and $334,702 for WPCo. Id. at 5.

CAD witness Smith accepted the five-year amortization of 2012 deferred storm expenses but agreed with Staff that the Commission should not include those storm expenses in rate base because they were operating costs. Mr. Smith also objected to the fact that the rate filing showed the first year's amortization of $13.711 million with going level adjustment 43-SD, and also reflected the entire $68.6 million balance in rate base as opposed to the unamortized balance of $54.843 million ($68.6 million - $13.711 million). Mr. Smith stated that the Companies' response to discovery reflected the entire $68.6 million balance because that was the deferred balance on December 31, 2013. Mr. Smith removed from rate base the deferred 2012 incremental storm damage costs for APCo and WPCo in the amounts of $65.2 million and $3.347 million, respectively. Mr. Smith recommended that the Commission allow an expense amortization for deferred storm costs, but not a return on rate base. CAD Exh. RCS-D at 35-36 and attached Exh. LA-I, Schedule B-8.

WVEUG witness Kollen also objected to including the unrecovered 2012 storm cost deferrals as rate base. He noted that the Commission did not authorize deferrals to be included in rate base. He argued that rate base treatment is not appropriate because deferrals are temporary in nature and will decline to $0 as they amortize. Mr. Kollen also stated that deferrals are generally financed with short-term debt. Mr. Kollen referred to the Commission Order in the 2010 Rate Case rejecting the proposal of the Companies to include storm costs in rate base and authorizing the Companies to instead amortize the expenses over seven years. Mr. Kollen stated that the Companies did not offer any compelling arguments to support a change in that treatment. WVEUG Exh. LK-D at 31-34.

Mr. Kollen recommended that if the Commission was to allow storm expense deferrals in rate base, the Commission should set an amortization period of ten years and determine the appropriate return on the revised storm damage deferral amount, net of ADITs. Mr. Kollen stated a ten-year period would be reasonable to mitigate the effects on customers of extraordinary costs. The WVEUG position would reduce the Companies' revenue requirement by $6.856 million, or one-half of the Companies' requested amortization expense. Mr. Kollen testified that, instead of a return based on the weighted cost of capital, the Commission should use the cost of short-term borrowings from the AEP Money Pool because those costs, and financing of those costs, are temporary. He argued that allowing the deferred costs in rate base and using a 0.25 percent short-term interest rate would reduce the Companies' revenue requirement by $4.402 million. WVEUG Exh. LK-D at 33-35.

A five-year amortization period is reasonable for the 2012 storm recovery costs in view of the large dollar amount incurred. Because the Companies have carried these deferred expenses for over two years, allowing recovery over a shorter five-year period without rate base recognition achieves a reasonable sharing of the risk and cost between the customers and shareholders for the non-capital service restoration costs experienced during these extraordinary weather events. The Commission will not treat storm expenses that are non-capital in nature as rate base that generates a return on that deferred cost, but will permit amortization of those extraordinary costs over a reasonable period that provides an appropriate sharing of those costs between the customer and the shareholder. Accordingly, the request of the Companies to recover carrying costs is not granted.

B. IGCC Study

The Companies sought recovery of the costs of an Integrated Gasification Combined Cycle feasibility, engineering, design, and construction study (IGCC Study) of approximately $8.9 million, and the amortization of the cost over five years (at a rate of approximately $1.8 million per year). Mr. LaFleur argued that the IGCC Study costs were reasonable and prudently incurred in connection with its certificate filing with this Commission. Appalachian Power Company, dba American Electric Power, Case No. 06-0033-E-CN (Order entered March 6, 2008) (IGCC Order). Companies Exh. JDL-D at 16, Tr. 1/22 at 197. APCo undertook the Study as part of its development of its IGCC plant project and used the IGCC Study to consider the feasibility of the construction of an

IGCC plant that would have enabled APCo to ensure the availability of adequate capacity while complying with anticipated environmental regulations and consuming West Virginia coal. Id. at 15-17; Tr. 1/22 at 224.

Under cross-examination Mr. LaFleur testified that the Companies believed that the Commission expected the Companies to conduct and file a supporting study with its certificate application for construction of new generation. He stated, however, that there was no formal requirement from the Commission to perform that study. Tr. 1/22 at 198-199. In response to cross examination by WVEUG and the Commission, Mr. LaFleur described the benefits of the IGCC Study. Mr. LaFleur testified that the study informed the Companies and other parties of potential generation technology, the type of coal necessary for IGCC technology, and the capital costs and risks that vendors may be willing to assume in developing a project. He indicated that the IGCC Study will assist the Companies with future planning. Tr. 1/22 at 200-01, 223-25.

WVEUG witness Kollen argued that the IGCC plant is no longer under consideration or development after the Virginia State Corporation Commission (VSCC) denied rate recovery for the project. WVEUG Exh. LK-D at 17-18. Mr. Kollen supported his position by referencing the VSCC order in Case No. PUE-2007-00068. Following the VSCC decision, this Commission rescinded certification for the IGCC plant causing APCo to place the IGCC project on hold. Appalachian Power Co., dba American Electric Power, Case No. 06-0033-E-CN, Commission Order July 9, 2008.

Mr. Kollen stated that the Companies had no authority to defer the IGCC Study costs to this base rate case and no reason to expect that the costs would be recoverable. WVEUG Exh. LK-D at 19. Mr. Kollen quoted language from the Commission's March 6, 2008 Order in Case No. 06-0033-E-CN to support his argument that the Companies incurred the IGCC Study costs at their own risk and that the Commission did not contemplate any rate impact from the IGCC project on customers if the project was not constructed. Id. at 20. Mr. Kollen suggested that to allow amortized recovery of the IGCC Study costs would be retroactive ratemaking and impermissible. Id.

In response to questions from the Commission, Mr. Kollen conceded that the West Virginia Commission never agreed with the VSCC holding that the IGCC project was imprudent or unreasonable. Tr. 1/22 at 174.

CAD witness Smith testified that the Commission should not approve the IGCC Study adjustment. Mr. Smith stated that the VSCC rejected an attempt by APCo to charge IGCC costs to ratepayers in prior cases. Mr. Smith argued that the IGCC Study costs are not related to a used and useful asset for electric service to customers because APCo has not constructed an IGCC. Mr. Smith stated that APCo should write off the costs. CAD Exh. RCS-D at 79.

Staff witness Oxley agreed with the IGCC Study adjustment of the Companies. Mr. Oxley testified that front-end costs of a major project are normally capitalized as part of the project and then recovered over the life of the asset. In this case, consistent with Commission treatment of other abandoned utility projects, Staff recommended recovery of the deferred IGCC Study costs over five years. Staff Exh. ELO-D at 10-11, citing Blue Ridge Pumped Storage Project, Case No. 9091, Commission Order November 1, 1978, and Brumley Gap Pumped Storage Project, Case No. 83-697-E-42T, Commission Order September 28, 1984.

The Commission will allow an amortized recovery of the jurisdictional portion of the IGCC Study costs. The record of the IGCC case, Case No. 06-0033-E-CN shows that the study was undertaken in good faith and to support the certificate application. The timeline of the filings and Commission Orders first granting and then rescinding a certificate in the IGCC case are relevant when evaluating ratemaking treatment of the IGCC Study. The Commission concludes that the Companies' adjustment, supported by Commission Staff, is reasonable and should be allowed.

C. Carbon Capture and Sequestration Project

The Companies seek to recover costs incurred for the Carbon Capture and Sequestration (CCS) project and Front End Engineering Design (FEED) study for the commercial scale facility that the Companies intended to construct at the Mountaineer Plant. As proposed in Statement G-1 Adjustments 19-PE and 20-PE filed in this proceeding, the Companies are requesting to recover CCS operational costs of $10,835,475 over a five-year period ($2,167,095 annually) as shown in Adjustment 20-PE, and FEED study costs of $1,062,615 over a five-year period ($212,523 annually) as shown in Adjustment 19-PE. JDL-D at 18. Because no further carbon capture is occurring at the Mountaineer Plant, the operational portion is to pay for monitoring and maintenance of wells in which carbon is sequestered. Companies Exh. JDL-R at 5-6; Tr. 1/22 at 204, 220-222. The Companies seek only the West Virginia jurisdictional share of these costs consistent with the rate treatment ordered by the Commission for O&M costs relating to CCS in the Companies 2010 Rate Case. Companies Init. Br. at 29.

Mr. Oxley testified that the Commission's prior allowance of CCS annual operation expense of $1,933,140 in the 2010 rate case was based on the Companies' representation that the CCS project would operate for a total of five years or until September 2014. In fact, however, the Companies ceased operation of the CCS project on May 28, 2011, two months after the final Commission Order in the 2010 Rate Case, which was forty-one months earlier than represented. The Companies did not request recovery of the CCS project and FEED study costs in the 2010 rate case. Mr. Oxley testified that during the forty-one months that the project did not operate as expected, the Companies effectively recovered $6,604,895 in CCS operating revenues that it did not expend for the purpose intended. Mr. Oxley recommended that the Commission permit the Companies to recover the difference between the allocated APCo West Virginia operating costs of $10,760,469 and the $6,604,895 of unexpended CCS operating revenue, or a net amount of $4,155,574. Staff also agreed that the

Commission should allow the Companies to recover the FEED study costs of \$1,062,615 over a five-year period. Staff Exh. ELO-D at 12-13. Staff Exh. ELO-D at 12-13.

WVEUG Witness Kollen quoted language from the Commission Order issued in the 2010 Rate Case in which the Commission stated concern that APCo did not obtain Commission input or authorization before pursuing the CCS project. 2010 Rate Case, March 30, 2011 Commission Order at 45. When asked by the Commission about prior rate treatment of CCS costs, Mr. Kollen stated that the Commission did not include any rate base component or depreciation expense for the CCS project. The Commission, instead, authorized operating expenses. Tr. 1/22 at 175. Mr. Kollen testified that none of the Commission's concerns about the CCS project have been alleviated since the Order issued in the 2010 Rate Case, and that APCo has now abandoned the project altogether. The only CCS activities that occur today are limited to minimal monitoring of the CO_2 storage. In its brief, WVEUG stated that it believes the operating costs recovered to date should be more than sufficient to compensate the Companies for study costs relating to the CCS and that ratepayers should no longer be burdened with the costs of this failed project.

The Companies have justified the requested allowance for continuing operational costs to monitor the wells at the CCS project. The Commission should not engage in retroactive ratemaking by reassigning the prior CCS O&M expense rate recovery revenues to offset the ongoing monitoring and maintenance costs as suggested by Mr. Oxley. The FEED study costs for the CCS project were prudently incurred and will be allowed in rates. The Commission concludes that a seven-year amortization of the West Virginia jurisdictional share of the FEED study costs of \$1,062,615 is appropriate in lieu of the five-year period requested by the Companies. The Commission has recognized seven years as the customary period of time for amortization of deferred costs that were not afforded rate base treatment, and no persuasive argument has been made for a shorter period of time. 2010 Rate Case, March 30, 2011 Order at 38.

V. OPERATING INCOME AND OPERATION AND MAINTENANCE EXPENSES

A. Operating Income

1. EE/DR Lost Revenues

Companies witness Fawcett testified in support of the request of the Companies to recover "net lost revenues" from its Energy Efficiency and Demand Response (EE/DR) programs. The Companies offer customers four current EE/DR programs: 1) SMART Lighting; 2) Residential HomeSMART Energy Audit; 3) Commercial and Industrial Prescriptive Program; and 4) Residential Low Income Weatherization Program.

Mr. Fawcett stated that the Companies initiated the first three programs in 2011 and the fourth in April 2012. Companies Exh. JDF-D attached Exh. 1.

Mr. Fawcett stated that the term net lost revenues refers to revenues the Companies do not earn because of customer participation in EE/DR programs, offset by dollars that the Companies save on fuel and other variable costs as a result of implementing the EE/DR programs. Mr. Fawcett provided a table of quantified customer savings that have resulted from customer participation in EE/DR programs. The Commission-required Evaluation, Measurement and Verification (EM&V) Reports indicated that during the test year, customer usage declined by 50,000,000 kilowatt-hours (kWh) of energy because of savings from implementation of the EE/DR program, equivalent to the average annual usage of 4,350 homes. Companies Exh. JDF-D at 5-6.

Mr. Fawcett acknowledged that factors other than EE/DR, such as weather and the economy, could reduce yearly kWh sales. Those factors, however, may average out over the course of several years whereas EE/DR programs always result in lower kWh sales. Mr. Fawcett testified that full recovery for implementation of EE/DR by the Companies includes three components: 1) program costs; 2) net lost revenues; and 3) appropriate return on investment. Mr. Fawcett argued that there is an economic disincentive for a utility to pursue EE/DR programs if those programs reduce the ability of the utility to recover fixed costs associated with the EE/DR investment. He stated that recovery of the first two components, program costs and net lost revenues, will put the Companies in a break-even position as related to the level of reduced kWh consumption resulting from the EE/DR programs. Recovery of an appropriate return on investment through a shared savings mechanism, as the Companies have previously proposed, would constitute full recovery and place the Companies' EE/DR investment on an equal footing with supply-side investments. Companies Exh. JDF-D at 7-8.

The Companies hired an independent third-party EM&V contractor to quantify test year net lost revenues of $1,966,215 and to forecast losses for years 2014-2016. Companies Exh. JDF-D2. The quantification was based on megawatt-hours of energy saved, multiplied by the appropriate residential, commercial or industrial rate representing the fixed component of the energy cost. For each forecast year 2014-2016, the Companies added one-half of the projected lost revenue for that year as shown in Companies Exh. JDF-D2 to one-half of the test year net lost revenues, or $983,307. That addition reflects the assumption that implementation of the EE/DR programs is spread evenly throughout any given year. The Companies seek recovery in this case of approximately $5.19 million, the three-year average of anticipated annual lost revenues from the EE/DR programs during the post-test-year period of 2014-2016. As an alternative, Mr. Fawcett stated that the Commission could use the annual EE/DR report to compare each year's actual lost revenues to the forecasted amount, and then reconcile any over- or under-recovery in a running deferral until the average amount can be adjusted in a subsequent base rate filing. Companies Exh. JDF-D at 9-11.

Mr. Patton testified under cross examination by CAD that EE/DR programs impair the ability of the Companies to earn their authorized rate of return because the deployment of EE/DR programs reduce sales, and the loss in kilowatt hour sales means that certain fixed costs associated with the programs are not recovered. Mr. Patton did not agree with CAD that if sales during the test year do not fall below those the Commission deemed necessary for the Companies to recover its costs, the Companies cannot justify recovery of EE/DR related net lost revenues. Tr. 1/20 at 63-68.

CAD witness Smith objected to any adjustment for EE/DR net lost revenues because the Companies did not show a reduction in total electric sales due to EE/DR programs in the state. CAD Exh. RCS-D at 75. During years that EE/DR programs were offered, residential and commercial sales increased. Tr. 1/22 at 61-65. Mr. Smith also objected to use of estimates of future energy savings for 2014-2016 that are not known and measureable. CAD Exh. RCS-D at 72, Tr. 1/22 at 63. On cross examination, Mr. Smith stated that West Virginia customers will not enjoy the benefit of a reduced need for the Companies to make additional investment in generation plant, a benefit that is usually attributable to EE/DR programs, because the Companies have excess generation capacity. Tr. 1/22 at 64. Mr. Smith stated that if the Commission makes any adjustment for EE/DR lost revenue in this case the adjustment should only reflect test-year and 2014 results and not 2015 or 2016 estimates. This allowance would result in a $2.561 reduction in revenues instead of the $5.186 million reduction requested by the Companies. CAD Exh. RCS-D at 75, Tr. 1/22 at 58.

WVEUG witness Baron testified that the lost revenue adjustment of the Companies is speculative and not known and measurable. The quantification of the $5.186 million lost revenues is premised on estimates of EE/DR program savings that are projected for three years. Mr. Baron claimed the EM&V study relied on by the Companies is based only on field measurements, customer surveys, and unconfirmed calculations and does not account for other changes that may occur that would offset this revenue loss, such as customer growth or sales growth per customer. Mr. Baron also stated that the record does not include evidence that the Companies are unable to earn a fair return without recovery of lost revenues or that they will not or cannot pursue EE/DR programs without lost revenue recovery. WVEUG Exh. SJB-D at 25-26, Tr. 1/22 at 161.

Kroger witness Higgins stated that the Commission should allow some recovery of net lost revenues but modify the proposal of the Companies by limiting the lost revenue calculation to year 2014 and take into account any increases in non-fuel revenue attributable to load growth in 2014. Mr. Higgins stated that it would be reasonable to extend net lost revenue consideration twelve months beyond the historical test period but that consideration through 2016 would be overreaching and unduly speculative. Limiting the calculation to 2014 reduces the projected lost revenues from EE/DR from approximately $5.2 million to approximately $2.6 million. Kroger Exh. KCH-D at 5-6.

SWVA witness Daniel testified that the Companies did not adequately support the amount of claimed lost revenues or provide a sufficient rationale to allow recovery of the claimed lost revenue amounts. Mr. Daniel also stated that if the Commission decided to allow recovery of EE/DR lost revenues, a problem would arise with respect to allocation of net lost revenues among the customer classes. The Companies assigned $2,398,961 of the net lost revenues to the commercial and industrial (C&I) customer classes. The allocation to the individual customer classes within the C&I class is on the basis of total test year revenues. This results in an allocation of $301,615 to Special Contract customers. Mr. Daniel testified that there should be no allocation of lost revenues to C&I customers who have opted-out of the EE/DR programs and do not participate in EE/DR programs. Many of those customers have their own energy efficiency programs and are paying the associated costs. Any lost revenue amount allocated to the Special Contracts customer class should be assigned only to Special Contracts customers that have not opted out of EE/DR. SWVA Exh. JWD-D at 4-6.

Staff witness Eads testified that a revenue adjustment for EE/DR program net lost revenues is appropriate. He stated that the principal purpose of the approved EE/DR programs is to assist and encourage customers to take steps to reduce energy consumption and demand on the utility grid. The programs, therefore, reduce the billing units by which the Companies can recover the fixed costs of service. Mr. Eads stated that if it is reasonable and in the public interest for a utility to implement EE/DR programs, it would be disingenuous to ignore the erosive effects the programs have on the utilities' net revenues. Staff Exh. TRE-D at 13-14.

When asked about possible offsetting revenue factors such as customer growth and weather, Mr. Eads testified that customer growth is accompanied by increased capital investment, O&M expense and administrative cost to serve that growth. These additional costs must somehow be funded. If additional revenue from customer growth is considered to be an offset to the EE/DR customer lost revenue, then the Commission should consider how the cost incurred to serve the growth will be funded. Mr. Eads stated that new customer revenue can only be spent once; either for new facilities, or to cover the lost revenues.

Mr. Eads stated that weather varies from year to year and tends to average out over time. The impacts of EE/DR programs, however, consistently reduce revenues. Mr. Eads gave little weight to customer behavior, specifically the acquisition and use of more electronic devices in the home or business, as a factor to be considered because it is likely that customers would acquire additional devices whether or not the utility offers EE/DR programs. He argued that utility revenue erosion from cost effective EE/DR is real and should not be ignored in the ratemaking process. Staff Exh. TRE-D at 14-15.

Mr. Eads testified that Staff supported an adjustment for lost revenues in this case, but not at the level requested by the Companies. Recognizing that base rate filings generally occur at three-year intervals, and that the effect of lost revenues compounds over time, the use of a three-year average of lost revenues appears reasonable. Staff did not support the use of projected program results, and instead supported a downward revenue adjustment of $3,932,428 based on a three-year average of the test year lost revenues. Staff Exh. TRE-D at 15-17.

The Commission will allow recovery in this base rate case of net lost revenues associated with the EE/DR programs. In Case No. 13-0462-E-P, the Commission concluded that it would be reasonable for the Companies to request recovery of lost revenues associated with EE/DR programs through reasonable and verifiable post-test year going-level adjustments in this base rate case. December 20, 2013 Commission Order at 17. In this case, the Companies have shown that revenues will be reduced based on the twelve months of reduced sales post-test year attributable to EE/DR programs. The Commission has required annual EM&V reports to assess the results of the EE/DR programs by an independent third party contractor. Those reports provide reasonable and verifiable estimates of the reduced kWh customer usage savings as a result of implementing the EE/DR program elements based on industry standard savings from each EE/DR program element, customer surveys and verified customer participation levels. The net lost revenues are a known and reasonably measurable cost of providing service. The Commission will utilize the Staff-recommended level of lost revenues because that adjustment is limited to the EE/DR program results currently in place and do not incorporate projections that reach three additional years past the historical test-year, and two years past the year on which new rates from this case are to be effective. We do not believe the 2015/2016 estimates are yet reasonably known and measurable.

2. Large Customer Load Changes

CAD proposed to increase going-level revenue to reflect forecasted additional load of 402,508 MwH or $9.786 million, claiming this load growth was related to large customer information supplied in response to Discovery Request CAD D-4. CAD Exh. RCS-D at 65. Most of the rebuttal to revenue growth addressed the "lost revenue" issue related to the impact of EE/DR programs. The Companies argued in general that sales growth is not an offset to lost sales from EE/DR programs for the test-year, but contended that forecasted sales growth should not be used to determine the level of rate increase in this case because that sales growth may be accompanied by increased capital investment and operating expenses. Companies Exhibit JDF-R at 7.

The Commission will not adopt the increase in going level revenue for post historical test year estimates of large customer growth as proposed by CAD. The Commission has long indicated a preference for the use of an historical test-year approach to establishing fair and reasonable rates. On cross examination by the Staff attorney, Mr. Smith indicated that he was not familiar with the Commission free extension rules and had made no determination about whether increased sales were accompanied by additional capital investment or increased operating expenses. Tr. 1/21 at 58-61. The adjustment proposed by CAD, unlike the lost revenue from EE/DR described above, is not known and measurable, is limited to only a small segment of the customer base and did not include an analysis of whether additional capital investment and increased operating expenses accompanied that estimated sales increase.

3. Rate Treatment of Felman Production, LLC Revenues

The Companies requested that going-level base rates reflect a contribution of $500,000 by Felman Production, LLC (Felman) to fixed costs. Felman is a large, energy-intensive industrial customer of APCo. In Case No. 13-1325-E-PC, the Commission approved, under W.Va. Code §24-2-1j, a special contract rate for Felman to purchase electricity from APCo. Case No. 13-1325-E-PC, April 3, 2014 Commission Order. The Companies proposed that a certain amount of the Felman revenues should be included in the base rate calculation in order to credit APCo's other customers the fixed cost contributions of Felman. Companies witness Scalzo pointed out that when the Commission established the special contract rate, it required Felman to contribute a minimum of $500,000 to the Companies' fixed costs. Companies Exh. JJS-R at 18, citing Case No. 13-1325-E-PC, April 3, 2014, Commission Order at 20. The Companies stated that this requirement made it appropriate to include $500,000 in the Companies' base rate revenues. Companies Exh. JJS-R 18-19.

CAD witness Smith opposed the inclusion of only a minimal $500,000 when APCo anticipates $3.979 million of revenue from Felman. Mr. Smith testified that the Companies' proposal does not reflect the annual consumption from Felman of 526,812,544 kWh and, thus, does not appear to reflect a normal ongoing level of the expected non-fuel related revenues from Felman. Mr. Smith urged the Commission to apply the fundamental ratemaking principle that development of utility base rates should reflect normal operating conditions. Mr. Smith stated that $3.979 million of base rate revenues should be used, and all revenues above that level should be credited through the ENEC. CAD Exh. RCS-D, attached Exh. LA-1, Schedule C-5.

Staff witness Oxley recommended that the Commission eliminate from base rates all the Felman test year revenues of $3,979,292. Mr. Oxley testified that the Commission gave clear guidance on this issue in its Order in Case No. 13-1325-E-PC. Staff Exh. ELO-D at 4-5. In the Staff brief, Staff cited the specific Order language,

> The Commission also takes this opportunity to provide guidance to APCo on incorporating the Approved Rate into its overall rate design. If Felman elects to pursue an agreement with APCo based on the Approved Rate, the Commission anticipates that APCo will eliminate the Felman load and revenue at going level in its next general rate case. Thereafter, APCo would include any contribution Felman makes to fixed costs in each future ENEC to be used as a credit to other ratepayers as directed by the Commission.

Case No. 13-1325-E-PC, Felman Production, LLC, April 3, 2014 Commission Order at 25.

The Staff position is consistent with the Commission's Felman decision and will be adopted in this case. None of the Felman revenues will be included in the going-level revenues used to determine the revenue requirement increase applicable to this case. All Felman revenues, instead, will be credited in the pending ENEC case of the Companies.

4. Annualized Test-Year Revenues

The Companies proposed an adjustment to annualize 2013 test year revenue at current rates for ENEC revenues, construction surcharge and EE/DR revenues using the 2013 historical test year billing determinates to determine the adjustment. The adjustment increased revenues recorded in the test year by $35.746 million. Companies Exh. AEV-D at 5. Staff proposed a similar adjustment, but arrived at an increase over 2013 historical test-year revenues of $35.622 million. The Companies did not oppose the Staff adjustment, and the Commission will adopt the Staff position as reasonable.

5. Pole Attachment Rental Income

The Companies proposed an adjustment to increase 2013 test year revenues by $4.441 million to reflect the removal of pole attachment revenue recorded in the 2013 historical test year that related to prior accounting periods. Companies Exh. JLB-D at 9. No party contested this adjustment, and it will be adopted by the Commission.

6. West Virginia Transco Rental Payments

Staff proposed an adjustment to increase 2013 test year revenues by $350,000 to impute rental payments from West Virginia Transco that will be received during the period the rates from this case will be in effect. No party contested this adjustment, and the Commission will adopt the Staff position as reasonable.

B. Income Tax Expense

No issue before this Commission over the years has generated the high level of "utility concern" more than the efforts to calculate a fair and reasonable level of federal income tax expense for rate recovery purposes. It has been an issue that this Commission has treated in disparate ways for a number of reasons, not the least of which are (i) the tremendous impact that federal income tax expense usually has on revenue requirement and customer rates and (ii) the unfortunate, and sometimes mind-numbing, "complexity" of tax issues that has dampened the Commission's enthusiasm for confronting the federal income tax expense issue. The Commission has recognized this disparity and believes it is time to give the issue of federal income tax expense a full review and decision.

1. Federal Income Tax – Consolidated Tax Savings

a. Consolidated Tax Savings Adjustment

Most of the larger private utilities regulated by this Commission are part of a utility holding company corporate structure, and most, if not all, utility holding companies have elected to file their federal income tax returns on a consolidated filing basis as permitted by the Internal Revenue Service (IRS). Generally, the federal income tax expense applicable to each subsidiary of the consolidated tax filing group is based on a tax sharing policy outlined in a tax sharing agreement. Companies Exh. KAH-D at 7, 9, WVEUG Cross Examination Exh. 1.

The vast majority of state commissions establish federal income tax expense on a standalone basis for utilities that are members of a consolidated tax filing group. Companies Exh. KAH-D at 9, Tr. 1/20 at 104. Under the standalone approach, the jurisdictional taxable income of the utility subsidiary is determined based on its individual cost of service elements, and the statutory federal income tax rate is applied to arrive at current federal income tax expense to be included in the cost of service. A smaller number of state commissions has historically determined current federal income tax expense for rate recovery by using a consolidated tax adjustment (CTA). Companies Exh. KAH-D at 11; Tr. 1/20 at 34; Tr. 1/22 at 109-127.

The CTA calculation captures a portion of the taxable losses that are netted against positive taxable income at the consolidated tax return level. This netting of tax losses at the consolidated level results in the consolidated group paying a lower tax to the IRS than it would have paid based on the combined positive taxable income of the group on a standalone basis. Companies Exh. KAH-R at 2. The amount by which the tax payments determined by applying the statutory tax rate to the total positive taxable income of the consolidated group exceeds the net tax liability of the consolidated group payable to the IRS is often referred to as the "tax savings." Id. at 2. The IRS permits this tax savings to be refunded to the taxable loss subsidiaries by the consolidated group, instead of requiring each loss subsidiary to carry forward those losses as a credit to future tax liabilities.

The "tax savings" has been captured through different approaches in the state jurisdictions that have used a CTA approach, such as (i) a rate base reduction (New Jersey method), (ii) an interest credit (Texas method), (iii) a dollar reduction to standalone taxable income (Pennsylvania method), and (iv) an effective tax rate (West Virginia method). This Commission has for many years used the "effective tax rate" method commonly referred to as the "consolidated tax savings or CTS approach" (CTS). The CTS calculation has varied in West Virginia based on the type of taxable losses (parent company only or all subsidiary losses) and the amount of taxable losses (adjustments for book/tax normalization issues or trending of historical losses) used in the calculation. The numerous variations used by the Commission to apply the CTS will be addressed further in this Order

b. Review of CTS in the 2014 Rate Case

The Commission has been concerned for some time with the potential negative impact on utility earnings, as reported on audited financial statements, created by the use of the CTS methodology. West Virginia utilities, subject to the CTS, have for years argued that the use of a CTS placed West Virginia utilities at a disadvantage when compared to other regulated subsidiaries in the holding company family whose rates are established on their standalone income tax position. Monongahela Power Co., Case No. 06-0960-E-42T (2006 Mon Power Case), May 22, 2007 Order at 30; West Virginia-American Water Co., Case No. 08-0900-W-42T, March 25 2009 Order at 19; Hope Gas, Inc., Case No. 08-1783-G-42T, November 20, 2009 Order at 32. The Companies' inability to achieve an earnings level near the authorized return on investment has again been raised as a central point of Mr. Patton's testimony in this case, and the application of a CTS in the manner applied in the 2010 Rate Case was given as one of the primary reasons for the lower West Virginia jurisdictional earnings. Companies Exh. CRP-D at 9-11, Companies Exh. CRP-R at 1-4, Tr. 1/20 at 31-38.

The issues of whether to apply a CTS approach, which tax losses to include, and what adjustments to make to those tax losses are not new to the Commission. The West Virginia utilities have complained, among other things, that the CTS (i) created an automatic erosion of their ability to achieve the authorized return on equity (RoE), (ii) restricted access to capital from parent-holding companies when compared to regulated subsidiaries not subject to CTA regulation, (iii) negatively impacted bond credit ratings, (iv) inappropriately diverted the tax benefit of revenues and expenses of other operating subsidiaries to the West Virginia customers, (v) created potential IRS normalization accounting violations, and (vi) resulted in cross subsidization of rates between regulated jurisdictions. West Virginia-American Water Co., Case No. 03-0353-W-42T, January 2, 2004 Order at 81; Monongahela Power Co., Case No. 06-0960-E-42T, May 22, 2007 Order at 29-32; West Virginia-American Water Co., Case No. 08-0900-W-42T, March 25, 2009 Order at 64-68; Hope Gas, Inc., Case No. 08-1783-G-42T, November 20, 2009 Order at 32-33. In each of those cases the Companies presented experts in the field of taxation who consistently argued against the CTS approach in general and about the various elements specific to the CTS listed in (i)-(vi) above. The orders just cited included reference to that expert testimony that has served to educate the Commission on complicated income tax matters and had a direct bearing on the various modifications the Commission made to the application of CTS after the 2006 Mon Power Case.

The Commission has also been concerned about the confusion created by the oft-repeated use of the term "actual taxes paid" (to the IRS) to describe or support the application of the CTS in determining federal income tax expense for rate recovery.[13] As described later in this Order, that term has caused confusion about the application of the CTS and does not accurately reflect the Commission position regarding CTS. This is particularly so in the income tax circumstances present in Virginia Electric and Power Co., Case No. 8410, 66 ARPSCWV[14] 446-448, (1977) (VEPCO Case), a case often cited to describe and support the CTS as an "actual taxes paid" approach.

The number of state regulatory jurisdictions utilizing the CTA approach is dwindling. The Texas and Oregon legislatures have recently eliminated the CTA approach through new legislation, leaving only West Virginia, Pennsylvania and New Jersey as CTA states. The Commission is aware that the New Jersey Board of Public Utilities has modified their historical approach to CTA in a manner that significantly mitigates the impact of taxable losses of the consolidated filing group on the CTA calculation.[15] Because of our concern with the CTS approach, the CTS methodology utilized by the Commission "evolved" (meaning it was modified or adjusted from case to case) over the years to attempt to deal somewhat with its unfair result. This included the 2010 Rate Case.

Because of the Commission's ongoing concerns about the impact of CTS, the record presented in this case and the continuing decline in the support for CTS in other

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13 West Virginia-American Water Co., Case No. 08-0900-W-42T, The March 25, 2009 Order at 64 states, "Mr. Warren referred to the "actual taxes paid" as a myth. He asserted that because of the provision that must be made for taxes payable in the future (deferred taxes) the tax expense allowed for rate making is often different, and usually greater, than the current taxes due to be paid immediately. This argument is not valid in the context of the CTS issue." "The Commission would agree with Mr. Warren that we could be more precise, and refer to "actual taxes paid" as actual current taxes paid." Or, an "actual taxes paid" policy could be more precisely described as providing for "actual taxes paid and deferred taxes payable."

14 Case numbers for Commission cases prior to 1980 did not reflect the year in the case number and may not be available on the Commission Web Page. The Commission review of those cases was accomplished by reviewing copies of the Orders from those cases contained in the applicable volumes of the Annual Report Public Service Commission West Virginia. All Commission Orders reviewed by the Commission from that era contain a reference to the edition number (i.e. 65, 78, etc.) for the applicable Annual Report. Copies of those Annual Reports may not be readily available to interested parties; however, the Commission will provide access to those Annual Reports at the Commission upon request.

15 Docket No. EO12121072, December 17, 2014. The New Jersey Board of Public Utilities had historically imposed a pro rata share of all taxable losses of subsidiaries included in a consolidated federal income tax return filing based on the ratio of the positive taxable income of the New Jersey utility to the total positive taxable income of the consolidated group. Starting in 1991, the New Jersey Board of Public Utilities accumulated the (dollar) amount of the New Jersey pro rata share of tax losses (annual tax savings amount) as a rate base reduction. This Order significantly alters the application of the CTA for applicable New Jersey utilities by (i) limiting the rate base reduction to the accumulated annual tax savings amount to the latest five year historical period, and (ii) further limiting the accumulated annual tax savings amount in the latest five year historical period to a sharing mechanism, whereby, seventy-five percent of the accumulated annual tax savings is retained by the shareholder and 25 percent of the amount benefits the customers.

jurisdictions, the Commission will fully review and address the CTS issue and the alleged "taxes paid" argument in this case. The time for such a review is particularly appropriate given (i) the significant need for capital investment being faced by the electric utilities required to meet more stringent environmental standards, and (ii) the increasing need for capital improvements to replace aging utility infrastructure in the state.

c. Summary of Testimony and Record Evidence

The Companies proposed in their Petition and direct testimony in the 2014 Rate Case that the current federal income tax expense component of the cost of service be calculated using the 35 percent statutory federal income tax (FIT) rate applied to their adjusted standalone taxable income. Rule 42 Exh., Statement A, Schedule 5. The Companies did propose a reduction to their standalone taxable income for a pro rata share of the taxable loss of AEP, Inc. (AEP), the parent holding company. The Companies approach to the pro rata share of the AEP taxable loss is commonly referred to as the "parent company loss adjustment" (PCLA). The PCLA was reflected in the Companies' financial statements, consistent with the Tax Sharing Agreement between the Companies and AEP. Companies Exh. KAR-D at 9. In addition, the Companies provided the supplemental consolidated tax return data needed to calculate the effective FIT rate used in applying a CTS as required by Commission Tariff Rule 42.

Based on the Supplemental Rule 42 income tax information, the Companies provided a calculation of an effective FIT rate of 25.27 percent. Companies Exh. JBB-D, Exh. D2. The Companies' effective FIT rate calculation used the taxable income of all AEP subsidiaries; however, those taxable incomes were adjusted for (i) the impact of accelerated depreciation for all subsidiaries, (ii) the impact of the one-time catch-up for Unit of Property deductions recorded in 2009, and (iii) the impact of charitable contributions. Although the Companies provided the required calculation of the effective FIT rate used in the CTS, Mr. Bartsch and Mr. Highlander in their direct testimony expressed their disagreement with the required supplemental calculation and the CTS approach proposed by Staff, CAD and WVEUG in this case and used by the Commission in the 2010 Rate Case. Companies Exh. JBB-D at 15, and KAH-D at 11.

In this case, Staff again proposed the CTS be applied using an effective FIT rate. Staff recommended a FIT rate of 24.43 percent based on a four-year average of the effective FIT rates for the 2010-2013 historical period stating the most recent four-year historical data provided a better representation of the Companies tax position. Staff Exh. ELO-D at 20-21.

The use of a CTS approach as proposed by Staff, CAD and WVEUG is not an "incidental" expense adjustment. If followed, it represents a reduction to the revenue requirement for the Companies of $26 million. Companies Exh. JBB-D at 17. Staff included the losses of all members of the consolidated group in their calculation, but adjusted the taxable income of regulated operating utilities (only) for the impact of accelerated depreciation that is normalized for rate making purposes.

CAD proposed the CTS be applied using an effective FIT rate of 25.27 percent based on a five-year average for the 2008–2012 historical period. The CAD effective FIT rate calculation mirrored that provided (but rebuffed) by Companies witness Bartsch. CAD witness Smith indicated the supplemental effective FIT rate produced by Companies Witness Bartsch was reasonable, prevented ratepayers from paying taxes that are not actually paid and (he claimed) is consistent with past positions regarding CTS adopted by the Commission in the 2010 Rate Case. CAD Exh. RCS-D at 56-65. On cross examination about his appearances before other state regulatory commissions, Mr. Smith stated that he generally recommended a calculation of FIT expense in line with the prior decisions of that particular Commission, either a standalone calculation or the applicable CTA method. He also conceded that some state jurisdictions apply a PCLA only application through either an adjustment to the tax calculation (Kentucky and Connecticut) or through an adjustment to the capital structure (Indiana). Tr. 1/22 at 110-127.

WVEUG urged continuation of the historical Commission CTS approach of applying an effective FIT rate to determine current FIT expense and applying the 35 percent statutory FIT rate to determine current deferred FIT expense. WVEUG Exh. LK-D at 6. As an alternative to the CTS approach, the WVEUG proposed the Commission adopt a CTA methodology described as the "Interest Credit Method" whereby FIT payments made by APCo/WPCo to the parent holding company, to the extent utilized by AEP to provide refunds to subsidiaries with taxable losses, be treated as loans to the parent company for purposes of calculating current FIT expense. Id. at 14.

The Companies opposed the Staff, CAD and WVEUG recommendations. Mr. Patton testified that the Commission use of CTS provides an automatic erosion of the Companies' ability (opportunity) to achieve its authorized RoE. He also testified that the Companies dismal earnings performance is impacting the Companies' ability to attract discretionary capital within the AEP system. Companies Exh. CRP-D at 9-11 and CRP-R at 2-4.

Both Mr. Bartsch and Mr. Highlander addressed the various issues the Companies have with a CTS approach that utilizes loss companies, other than the parent company, for purposes of calculating the CTS. Consistent with that position, the Companies' income tax calculations provided in the Rule 42 Exhibit reflected a reduction to 2013 test-year West Virginia jurisdictional taxable income of $1.074 million for the PCLA, and then applied the statutory FIT rate of 35 percent to the resulting taxable income. Rule 42 Exh., Schedule 5 at 6. As mentioned earlier, Mr. Bartsch testified that the difference between the Companies PCLA only approach and the Staff and CAD CTS approach was a lower revenue requirement of approximately $26 million. Companies Exh. JBB-D, Exh. JBB-D1 at 1.

In support of the Companies PCLA only position, Mr. Highlander recited a number of Generally Accepted Accounting Principles (GAAP), Securities and Exchange

Commission (SEC), Financial Accounting Standards Board (FASB) and Federal Energy Regulatory Commission (FERC) pronouncements and guidelines. He argued that the use of a CTS approach based on the combined taxable losses of all other AEP subsidiaries "inappropriately redistributes" to the Companies customers the income and expenses that resulted in a tax loss for an unrelated subsidiary. Companies Exh. KAH-D at 11-17. He also testified that, in his opinion, it is highly unlikely that the SEC would accept financial statements for publicly traded companies that are based on the Commission CTS methodology. Companies Exh. KAH-D at 18. Mr. Highlander cited FERC Opinion 173, as support for his "inappropriate redistribution" argument:

> Our standalone policy in effect looks beneath the single consolidated tax liability and analyzes each of the deductions used to reduce the group's tax liability to determine the deductions for which each service is responsible. It then allocates to the jurisdictional services those deductions for which each service is responsible. It then allocates to the jurisdictional service those deductions which were generated by expenses incurred in providing that service. In making this allocation it is irrelevant on which member's return the deductions would be reported if the group filed separate returns. Instead, the test is whether the expenses that generate the deduction are used to determine the jurisdictional service's rates. Put more simply the test is whether the expenses are included in the relevant cost of service. If they are, the associated deductions and their tax reducing benefits will be taken into account in calculating that cost of service. If the expenses are not, the deductions will not be taken into account. In this way the tax allowance will reflect the profit the ratepayers contribute to the group's consolidated taxable income.

Companies Exh. KAH-D at 19.

In rebuttal testimony, Mr. Highlander addressed the Staff, CAD and WVEUG proposals to continue a CTS approach that uses all subsidiary losses. Mr. Highlander disagreed with the concept of "actual taxes paid" espoused by Staff and CAD as support for their CTS recommendations. Mr. Highlander testified that many of the tax losses of other AEP subsidiaries are driven by book/tax timing differences for such items as (i) accelerated depreciation, (ii) bonus depreciation, and (iii) Unit of Property expense deductions that result in ADITs related to IRS normalization accounting.[16] He testified that book/tax timing differences reverse over time and result in higher current FIT expense in future accounting periods. Mr. Highlander argued that, notwithstanding the language used, the historical Commission position on CTS and the Staff, CAD and WVEUG positions in this case have not reflected "actual taxes paid" because the impacts of tax deductions related to book/tax timing differences that are normalized for ratemaking purposes have been eliminated from the CTS calculation. Companies Exh. KAH-R at 3.

Mr. Highlander also took exception with Mr. Kollen's use of the term "historic" in describing the Commission methodology in the 2006 Mon Power Case that utilized all loss companies in the CTS calculation. Mr. Highlander testified that the Commission, prior to the 2010 Rate Case, had used a (CTA) approach in setting rates for the Companies that only included the PCLA. Companies Exh. KAR-R at 4-5. The Commission has historically used a CTS approach whether the CTS calculation included only the PCLA or the losses of all subsidiaries in the consolidated tax group, as will be discussed later in this Order. Mr. Highlander noted that the CTS approach is significantly different from the approach taken by the mainstream of regulatory jurisdictions with only West Virginia, Pennsylvania and New Jersey currently utilizing some form of CTA and that Texas and Oregon have recently passed legislation that prohibits the use of a CTA methodology in setting utility rates. Companies Exh. KAH-R at 9. Mr. Highlander argued that the alternative "Interest Credit Method" proposed by Mr. Kollen has been recently abolished by the Texas Legislature. Id. at 10, 11.

While this summary of the positions regarding the application of a CTS above is not a full discussion of the significant amount of testimony and exhibits provided by the parties, it does provide a good summary of major points of contention, a clear indication of the magnitude of the CTS issue and the wide disparity among the positions of the parties.

d. Review of Historical Commission Decisions

As indicated, the Commission has, for many years, used a CTS approach in setting rates and has for some time been concerned about the level and impact of the CTS. The CTS calculations used by the Commission have evolved and have been adjusted for

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16 Under normalization accounting, timing differences related to deductions that are written off in a more accelerated timeframe for tax purposes than for book purposes result in a current deferred income tax expense being recorded on the financial statements in the year the deduction is recorded for tax purposes. There is an offsetting entry recorded to accumulated deferred income taxes (ADIT). The normalization of the accelerated tax deduction results in a cash benefit to the Company that is provided by inclusion of the current deferred income tax expense in rates. Because the cash benefit comes from the rates supplied by customers, IRS normalization accounting rules permit rate base on which future rates are established be reduced by the ADIT balance. The ADIT balance will reverse to zero over the book life of the asset as the book write-off will exceed the tax write-off after the shorter tax life expires.

various purposes from case to case to address (i) unique consolidated tax positions posed in certain cases, (ii) changing IRS regulations, and (iii) the size and the impact of the CTS adjustment. These adjustments to the CTS methodology introduced a level of uncertainty and volatility in the ratemaking process and to corporate and utility planning. For the large West Virginia utilities that are part of a utility holding company group, CTS was frequently one of the largest issues in the determination of the revenue requirement.

To address fully the wide disparity of the positions of the parties in this case about the appropriate CTS methodology and to address our concerns about the approach to CTS, the Commission reviewed the evolution of rate cases in order to analyze the CTS issue over the last forty-five years or so. This review was necessary, particularly in light of assertions by the Companies that the Commission has followed different approaches to the CTS calculation in past rate cases with widely different impacts on the utilities. Unfortunately, while there have been numerous rate filings before the Commission over that time frame, many of those cases were settled based on a Joint Stipulation.

What is clear from the Commission review is that the Commission limited the CTS calculation to the PCLA only approach from 1969 until 1993, with one exception.[17] In several orders during this period, the Commission clearly addressed the CTS methodology. In West Virginia Water Co., Case No. 6470,[18] the Commission excluded losses of AWW operating subsidiaries from the CTS calculation and used a four-year average of the PCLA to determine the effective FIT rate.

In West Virginia Water Co., Case No. 8637,[19] the Commission addressed four methods of determining the CTS, including the use of the taxable losses of all subsidiaries. The Commission elected to base its decision on "a middle ground, computing consolidated tax liability by ignoring the losses of the tax loss operating companies, but including the tax loss the parent contributes to the consolidated return."

In Appalachian Power Co., Case No. 80-273-E-42T,[20] the Commission based the CTS on the PCLA only, addressed an issue related to investment tax credits (ITC), indicating that the tax losses should be determined prior to the ITC deduction, and excluded the 1975 PCLA, indicating that the loss in 1975 was abnormal. In Monongahela Power Co., Case No. 84-768-E-42T,[21] the Commission calculated CTS based on PCLA only, and specifically addressed elimination of the losses of Allegheny Generating Co. The Commission stated a preference for a three-year average of historical PCLA losses over the five-year average proposed by other parties.

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[17] Cabot Corporation, Case No. 6609, 58 ARPSCWV 132, October 23, 1970 Order. The Commission authorized rates with no income tax expense, stating the consolidated tax return indicated no tax liability to the IRS due to the presence of "foreign tax credits" related to drilling activity.

[18] West Virginia Water Co., Case No. 6470, 56 ARPSCWV 244-245, March 5, 1969 Order.

[19] West Virginia Water Co., Case No. 8637, 65 ARPSCWV 307-308, November 23, 1977 Order.

[20] Appalachian Power Co., Case No. 80-273-E-42T, May 8, 1981 Order.

[21] Monongahela Power Co., Case No. 84-768-E-42T, October 2, 1985 Order.

The Commission final order in the VEPCO Case has been cited by the parties in rate cases since 1978 as support for the adherence to an "actual taxes paid" doctrine regarding the application of CTS. The VEPCO Case was appealed to the West Virginia Supreme Court by VEPCO and the Commission Order was upheld.[22] A review of the Commission Order in the VEPCO Case reveals that each of the three areas of dispute regarding income taxes related to the standalone taxable income of VEPCO. The Commission order did not mention the CTS issue nor did it tie the income tax issues raised in the VEPCO Case to the application of the CTS. The Commission VEPCO Case order also stated that the Commission might have in the past and might in the future depart from disallowing "normalization" and may, in certain instances, decide various issues differently on a case-by-case basis.

The Commission review of the historical CTS issue, as described in this 2014 Rate Case Order, indicates that the Commission consistently applied only the PCLA in determining the CTS before and after issuance of the VEPCO Case order. In addition, after the Economic Recovery Tax Act of 1981, IRS regulations were modified to require post-1981 accelerated tax depreciation (ACRS) and ITC credits be afforded normalization accounting for rate recovery in order to maintain the ability of the utility to continue the tax benefit of those deductions.

The Commission adopted the normalization of ITC and accelerated depreciation as prescribed by IRS regulations starting in 1981. The adoption of normalization accounting for post 1981 ITC and accelerated tax depreciation resulted in the Commission no longer being able to flow through those accelerated tax deductions in the year incurred and no longer being able to base the standalone current FIT expense strictly on the "actual taxes paid." Neither the use of the "PCLA only" in applying the CTS nor normalization accounting support the premise that current FIT expense recognized in rates should be based strictly on the amount of FIT "actually paid to the Government."

In 1994 the Commission issued orders in two gas cases,[23] giving notice in both the 1993 Mountaineer Gas case and the 1993 Hope Gas case of its intention to utilize the taxable losses of all subsidiaries included in the consolidated income tax filing group to establish the CTS in future rate cases. In point of fact, however, in the 1993 Mountaineer Gas case the current FIT expense was calculated on a standalone basis, and in the

[22] Virginia Electric and Power Co. v. The Public Service Commission of W. Va., Case No. 14050, April 4, 1978 Order. The Court upheld the Commission Order regarding income tax expense that encompassed three areas of the federal income tax calculation (i) interest deductions related to debt issued to finance CWIP, (ii) whether the statutory tax deduction for accelerated IRS depreciation should be afforded normalization or flow-through treatment, and (iii) the method utilized to allocate various operating expenses and tax credits in determining the cost of service and taxable income. The Court upheld the VEPCO Commission Order regarding the income tax issue by reference to the Commission philosophy that the company cannot pass on to the rate payers the obligation of taxes that have not actually been paid to the Government.

[23] Hope Gas, Inc., Case No. 93-004-G-42T, October 29, 1994 Order, and Mountaineer Gas Co., Case No. 93-005-G-42T, October 29, 1994 Order.

1993 Hope Gas case the current FIT expense was based on a CTS approach that included only the PCLA.

The first rate case after the two 1994 gas rate case orders that gave an indication of the Commission intention of changing the CTS approach was West Virginia-American Water Co., Case No. 03-0353-W-42T.[24] Staff and CAD proposed using the taxable losses of all regulated and non-regulated subsidiaries of AWW in the CTS calculation. The Commission rejected the Staff and CAD positions and accepted the West Virginia-American Water Company (WVAWC) position to continue using only the PCLA in the CTS calculation.

The Commission, for the first time after the 1970 Cabot case, departed from the PCLA-only approach to CTS in the 2006 Mon Power Case.[25] In that case, however, the Commission was presented with an unusual set of facts. The Allegheny Energy consolidated tax group had experienced very large tax losses, primarily related to non-regulated subsidiary energy trading losses. The consolidated tax group had accumulated tax loss carry-forwards related to those non-regulated losses of such a magnitude that the entire Allegheny Energy consolidated tax group would have no positive current FIT liability (payment) to the IRS for a number of years. Staff and CAD argued that the Commission should not allow any (current) FIT expense because of the tax loss carry-forward position, claiming the Commission policy of "actual taxes paid." The Commission agreed with the Staff position that the 2006 Mon Power Case contained a fact pattern significantly different from that presented in the 2003 WVAWC rate case, and included no current FIT expense for rate recovery given the consolidated group tax loss position presented in the 2006 Mon Power Case.

The Commission drew a distinction between (current) FIT expense and (current) deferred FIT expense (related to accelerated depreciation subject to IRS normalization rules) and concluded that current deferred income taxes should be calculated at the statutory 35 percent FIT rate. The Commission also agreed with the Mon Power position that the calculation of the CTS, if applied using all taxable loss subsidiaries, should adjust those taxable losses for the portion of the tax loss attributable to accelerated depreciation in order to avoid any IRS normalization violations.

After the 2006 Mon Power Case, the term "actual taxes paid" became the mantra of Staff and various other interveners in rate cases to support a continuation of a CTS approach that included the adjusted taxable losses of all subsidiaries in the consolidated group. While the 2006 Mon Power Order mentioned the "actual taxes paid" in the context of the record in that case, the result of adjusting the actual taxes losses for the impact of accelerated tax depreciation does not constitute a strict adherence to an "actual taxes paid" to the IRS approach. Inclusion of all subsidiary loss companies simply

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[24] West Virginia-American Water Co., Case No. 03-0353-W-42T, January 2, 2004 Order.

[25] Monongahela Power Co., Case No. 06-0960-E-42T, May 22, 2007 Order at 28-33.

increased the tax savings over the level calculated using the PCLA only approach to CTS used by the Commission prior to the 2006 Mon Power Case.

In each case where CTS has been an issue after the 2006 Mon Power Case, the Companies have advanced various arguments and positions regarding new or changing conditions in tax law and accounting pronouncements that they argued should be adjusted in the CTS calculation. The Commission usually adjusted the CTS calculation on a case-by-case basis.

For instance, in West Virginia-American Water Co., Case No. 08-0900-W-42T,[26] WVAWC requested an effective FIT rate of 19.7 percent based on inclusion of adjustments to the consolidated group actual taxable income for (i) the impact of tax losses generated through parent company acquisition adjustments that were specifically excluded from rate recovery by conditions placed in the Order approving the acquisition of AWW stock by RWE,[27] (ii) the impact of tax losses of other regulated subsidiaries, and (iii) the impact on taxable income related to accelerated depreciation. The Commission specifically denied the adjustments related to the AWW acquisition adjustment and the losses of other regulated subsidiaries; however, the rates were established using the 19.7 percent FIT rate proposed by WVAWC. In support of the 19.7 percent FIT rate, the Commission at that time blessed the concept of "trending the historical period data" to attempt to forecast a prospective effective FIT rate for applying the CTS.

In Hope Gas, Inc., Case No. 08-1783-G-42T,[28] the Commission continued the use of trending of historical period data to determine an effective FIT rate on which to base the CTS. The trending of the historical period data produced a prospective effective FIT rate of approximately 30 percent compared to the effective FIT rate of 11.74 percent and 17.60 percent proposed by Staff and CAD, respectively, based on the average of the actual historical period data.

In West Virginia-American Water Co., Case No. 10-0920-W-42T,[29] WVAWC proposed a further adjustment to the actual taxable income of the consolidated AWW tax return group to reflect a requested change in income tax accounting submitted to the IRS regarding the accelerated write-off of Unit of Property/Capitalized Repairs expense. WVAWC proposed, and the Commission authorized, recognition of normalization accounting for Unit of Property/Capitalized Repairs accelerated tax deductions for both the 2001-2007 catch-up deduction, as permitted by the IRS, and accelerated annual deductions, subsequent to 2007 through the test-year. The Commission adjusted the actual consolidated taxable income used to establish the CTS for the Unit of

26 West Virginia-American Water Co., Case No. 08-0900-W-42T, March 25, 2009 Order.

27 West Virginia-American Water Co. and Thames Water Aqua Holding GMB, Case No. 01-1691-W-PC, October 23, 2002 Order.

28 Hope Gas, Inc., Case No. 08-1783-G-42T, November 20, 2009 Order.

29 West Virginia-American Water Co., Case No. 10-0920-W-42T, April 18, 2011 Order.

Property/Capitalized Repair deductions in a fashion identical to the modification made to the actual consolidated taxable income for accelerated depreciation.

An examination of the past decisions of the Commission regarding CTS provided only two cases in which the current FIT expense reflected "actual taxes paid" to the IRS. In both the 1970 Cabot case and the 2006 Mon Power Case, the new rates authorized no current FIT expense based on the specific records in those cases, records that demonstrated that in those cases the consolidated tax group paid no income taxes to the IRS. The review also indicated from 1969 to 2006 the Commission consistently based the CTS calculation on PCLA only, except for the 1970 Cabot case.

The income tax issues presented in the VEPCO Case did not relate to the CTS issue, but related only to the standalone taxable income of VEPCO on a West Virginia jurisdictional basis. The Commission gave notice to both Hope Gas and Mountaineer Gas in their 1993 rate cases that it would adjust its CTS approach to include all loss subsidiaries in their future cases.

The next litigated rate case before the Commission after giving that notice of changing the CTS approach in 1994, however, did not occur until 2003, the 2003 WVAWC case. In that case, the Commission stayed with the CTS approach, using only the PCLA. The 2006 Mon Power Case reflected the specific and different taxable loss position of the Allegheny Energy consolidated income tax group presented in the record for that case, but also reflected the Commission intention to modify actual taxable income for accelerated depreciation tax deductions due to potential normalization violations. After the 2006 Mon Power Case, the Commission included additional adjustments to the actual consolidated taxable income on which the CTS was based to include adjustments for (i) accelerated depreciation, (ii) trending of historical period tax data to determine a prospective effective FIT rate, and (iii) normalization of Unit of Property/Capitalized Repairs.

As discussed in the Introduction to this Order, the past Commission decisions have been rendered on a case-by-case basis. The Commission's historical treatment of CTS is not a basis for any claim for stare decisis or res judicata for "taxes paid." On the contrary, based on this review, the Commission has utilized a CTS approach, although in differing formats based on the record specific to each case, since at least 1969. Although the Commission through its orders, and Staff, CAD and other parties in some rate cases, have referred to the CTS approach as the "actual taxes paid" approach, this review indicated that the Commission has not adhered to an "actual taxes paid" to the IRS approach or practice, with rare exception and then only based on the specific record for the case. While the actual consolidated tax return data has always served as the starting point for the CTS calculation, those actual numbers have been adjusted in many ways in arriving at the CTS applied in determining fair and reasonable rates.

e. Commission Decision

The Commission has reviewed all of the evidence, testimony and arguments, considered cases cited by the Companies, reviewed various court decisions on this issue, and prior decisions of this Commission. Based on that review and the record presented in this case, the Commission will not abandon a consolidated tax adjustment approach to federal income taxes entirely, but will modify its approach to CTS from the effective tax method using some form of all subsidiary losses first used in the 2006 Mon Power Case. The Commission rejects the alternative "Interest Credit Method" proposed by the WVEUG because that method imputes the impact of losses of all subsidiaries and is not consistent with the modified CTS approach adopted by the Commission in this case. The Commission will limit the CTS to the PCLA adjustment only, and continue the Commission practice regarding CTS used for nearly forty years prior to 2006, through a modified approach as more fully described below.

The Commission will continue to utilize PCLA in determining current FIT expense because the taxable losses of the parent company are, at least arguably, different from the taxable losses of other subsidiaries in a utility holding company structure. The holding company parent taxable losses differ from subsidiary losses in that those taxable losses are expected to continue indefinitely. The parent company tax loss typically results from the exclusion of subsidiary company dividends, the primary source of income for the parent company, from taxable income. The subsidiary dividends are excluded from parent company taxable income because the income that generates those dividends is taxed at the subsidiary level. To avoid double taxation of the subsidiary income, the IRS Code permits the subsidiary dividends to be excluded from the taxable income of the parent company in a utility holding company structure. After excluding the subsidiary dividend income for income tax purposes, the parent company will generally generate a taxable loss when its expenses, including interest expense on parent company debt used to finance subsidiary investment, are deducted for income tax purposes.

Although the CTA is not a widely used regulatory approach in other state regulatory jurisdictions (most states simply use the statutory FIT rate applied to standalone taxable income), some regulatory jurisdictions do pass a portion of the parent company tax loss to regulated subsidiaries in the rate setting process through various other adjustments. Some jurisdictions adjust the standalone subsidiary capital structure equity ratio for the impact of the leverage present in the parent company capital structure, a regulatory practice commonly referred to as "double leverage." Other jurisdictions capture a portion of the parent company tax loss through the adjustments based on the consolidated capital structure and various other adjustments to the regulated subsidiary standalone financial data. Because the parent company loss continues indefinitely, and is largely driven by costs that are related to all subsidiaries, it is at least arguably reasonable to allocate a portion of the permanent tax savings of the parent company in the rate setting process. As described above, (i) the nature of the tax losses at non-parent company subsidiaries in a utility holding company structure, (ii) the volatility on the CTS calculation resulting when those tax losses are included, and (iii) the uncertainty placed on the utility because of that volatility has led the Commission to conclude that a change in the application of the CTS approach is both necessary and appropriate.

The Commission believes it is inappropriate to measure those non-parent company losses in the CTS adjustment and that such an approach is not reasonable and discourages investment in utility plant infrastructure to a point that it is no longer in the best interest of the customers or the state to continue that practice.

The Commission will base the CTS on only the PCLA and reduce the standalone taxable income of the Companies by their pro rata share of the parent company loss. The PCLA will be determined by multiplying the parent company taxable losses by the Companies' West Virginia jurisdictional ratio of positive taxable income (after adjustments for the impact of accelerated depreciation and Unit of Property/Capitalized Repairs deductions that are normalized for rate recovery) to total adjusted positive income of the consolidated group. This CTS methodology is consistent with the PCLA approach proposed by the Companies and consistent with the methodology prescribed by the Tax Sharing Agreement between the Companies and AEP.

The Companies filing reflects only their allocated share of the PCLA for the 2013 test-year; however, the Commission based the PCLA adjustment on the three-year average of the parent company losses included in the consolidated income tax information for the 2011-2013 historical period. The Companies average West Virginia jurisdictional adjusted pro rata share of the PCLA is $5.348 million based on the Companies pro rata share of AEP total adjusted positive taxable income for the 2011-2013 historical period. The Commission will apply the statutory FIT rate of 35 percent to the Companies resulting adjusted West Virginia jurisdictional taxable income. This calculation generates current FIT expense of $44.830 million. The Commission also determined a current deferred FIT expense of $55.173 million by applying the 35 percent FIT rate to both the accelerated depreciation deduction and the Unit of Property/Capitalized Repair deduction.

The Companies' adjusted West Virginia jurisdictional standalone taxable income was determined using (i) the utility operating income authorized in this case, (ii) interest deductions consistent with interest synchronization of the allowed rate base, (iii) the Staff statutory income tax deductions, and (iv) the $5.348 million PCLA deduction. The Staff statutory income tax deductions were used because they reflect the necessary adjustments to the book/tax accelerated depreciation timing differences related to the allocated portions of the Mitchell settlement interest and the new depreciation rates approved in Case No. 14-1151-E-D, the Companies depreciation case.

The Commission believes the modification to the CTS approach strikes the appropriate balance between the interests of the utility and its customers and is fully supported by the evidence and record presented in this case.

In addition, this approach to the CTS will remove much of the uncertainty and volatility regarding rate recovery of federal income taxes for the impacted regulated utilities resulting from the inclusion of non-parent company subsidiaries taxable losses in the determination of the CTS. The modification will (i) improve the Companies' opportunity to achieve a fair and reasonable return on their investment, (ii) encourage economic growth in the state, and (iii) improve the utility infrastructure investment climate of the state.

2. State Income Tax.

a. Normalization Accounting for Unit of Property Deduction

In 2009 the Companies adopted an accelerated write-off for income tax reporting to the IRS of certain utility property additions referred to as the Unit of Property/Capitalized Repairs deduction. The change in tax accounting resulted in Unit of Property/Capitalized Repairs plant additions being written-off as period expenses in the year incurred for tax purposes. Those utility plant additions are, however, reflected on the Companies books as utility plant assets and depreciated over the book life of the plant. The IRS permitted businesses adopting the accelerated Unit of Property/ Capitalized Repair deduction to reflect the retroactive impact of the tax accounting change back to 2001, on the 2009 federal income tax return. This difference in book/tax accounting creates a timing difference for Unit of Property/Capitalized Repairs similar to the timing differences related to accelerated depreciation.

In the 2010 Rate Case, the Companies proposed the Unit of Property/Capitalized Repairs timing difference be reflected in income tax expense using IRS normalization accounting. Staff recommended a hybrid approach that used normalization accounting for the 2001-2007 catch-up deduction and flow-through accounting for the ongoing deduction.

The Commission was not required to recognize normalization accounting for the accelerated Unit of Property/Capitalized Repairs deduction, as would be the case for accelerated depreciation. The Commission decision in the 2010 Rate Case reflected adoption of full normalization accounting for the Unit of Property/Capitalized Repair deductions as proposed by the Companies. The Commission did, however, indicate that it may or may not continue full normalization accounting in future rate cases.

In the present case, both the Companies and Staff appear to follow full normalization accounting for federal income tax purposes through the 2013 test-year, but flow-through accounting for state income tax purposes for all accelerated Unit of Property/Capitalized Repairs deductions except the 2001-2007 catch-up deduction.

The Commission will continue to recognize normalization accounting for all Unit of Property/Capitalized Repairs deductions for determining both federal and state income expense in this proceeding as described further below.

b. Current State Income Tax

The Companies proposed a state income tax (SIT) expense of $10.758 million. Companies Rule 42 Exh., Statement A. The Companies calculation of SIT expense reflected the per books SIT expense for the 2013 historical test-year, and adjusted test-year SIT expense for each of the going-level and pro forma adjustments included in the Rule 42 Exhibit. Companies Rule 42 Exh., Statement A, Schedule 5-State Income Taxes at 1-5. The Companies adjustments for SIT expense were addressed in the direct testimony of Mr. Bartsch. JBB-D at 9-11.

Staff recommended SIT expense of $0.155 million. Staff Exh. ELO-D, Exh. ELO-1, Schedule 1. Staff claimed that the vast majority of the Companies SIT expenses are paid in West Virginia and Virginia, and in each state the Companies calculation of SIT is predicated on a pro rata distribution of the total AEP taxable income. Staff Exh. ELO-D at 21. Staff did not include any of the incremental changes to revenues or expenses included in the Staff Rule 42 Exhibit in its determination of SIT expense because SIT expense for the Companies may or may not change from the increased revenue requirement proposed in this case due to SIT expense paid being based on the allocation of total AEP taxable income. Staff Exh. ELO-D at 21. CAD recommended a SIT expense of $3.624 million by applying an effective SIT rate of 6.15676 percent as part of the revenue conversion factor. CAD Exh. RCS-D, Exh. LA-1, Schedule A-1.

In rebuttal testimony, the Companies argued that it is not appropriate to disallow the Companies an incremental increase in SIT expense related to the going-level and pro forma adjustments included in their filing. They further argued that these adjustments increase state taxable income and should be recognized above and in addition to the historical test-year SIT expense. Companies Exh. JBB-R at 5. During cross examination, Mr. Bartsch asserted (i) the Virginia State Income Tax calculation is not based on the AEP consolidated taxable income as claimed by Staff, (ii) the absence of West Virginia SIT expense for 2010-2013 was related to the large IRS "Bonus Depreciation"[30] deductions, and (iii) the West Virginia deductions for certain qualifying pollution control property additions had started to turn around (become add backs to state taxable income). Tr. 1/21 at 53-54.

The Commission will not adopt the Staff position to limit SIT expense to only the level present in the 2013 historical test-year. The Staff recommendation is based on the premise that the Companies ratio of taxable income in West Virginia to total AEP taxable income will not change as a result of the additional revenue granted in this case. The Virginia state income tax is not based on the consolidated AEP taxable income as it

[30] Bonus Depreciation permits 50 percent of certain qualifying property additions to be deducted in the year acquired for federal income tax purposes. H.R. Bill 5771 extended the Bonus Depreciation through December 31, 2014. The Bonus Depreciation deduction expired on December 31, 2014, and there is no certainty it will be extended in 2015 or beyond.

relates to the Virginia state income tax allocated to the West Virginia jurisdiction as claimed by Staff. Further, a substantial portion of the base rate increase authorized in this case is directly related to the acquisition of the interests in the Amos Unit 3 and Mitchell generating units.

The Companies allocation factors for West Virginia state income tax were based on property, payroll and sales, all of which will likely be impacted by those acquisitions and changed the Companies' West Virginia SIT expense allocation factors from those present in the 2013 historical test-year. Bonus Depreciation expired on December 31, 2014, and there is no assurance that IRS provision will be renewed or extended by the U.S. Congress. Further, as the accelerated pollution control deductions expire, those deductions will turn around and increase state taxable income in the future. The Staff proposal to limit SIT expense to the 2013 historical test-year level also does not account for the normalization of Unit of Property/Capitalized Repair deductions as described above.

A SIT expense of $5.298 million is reasonable based on the record in this case. The current SIT expense was determined to be $8.537 million by applying the blended SIT rate of 6.2483 percent to the adjusted standalone West Virginia jurisdictional taxable income. The deferred SIT expense was determined to be a negative $3.238 million made up of current deferred SIT expense for the current Unit of Property/Capitalized repairs deduction at the statutory 6.5 percent SIT rate which offsets the negative $5.122 million of deferred SIT expense in the 2013 historical test-year.

C. Generation Expense

1. Mitchell Generation Expense

The Companies made an adjustment to the 2013 test year non-ENEC generation expense to reflect $32.068 million of additional expense needed to operate a fifty percent interest in the Mitchell Plant. Companies Exh. JDF-D at 14. Consistent with the Joint Stipulation in the Mitchell Case, Staff and CAD proposed to limit the recovery to 82.5 percent of that amount or $26.456 million. The Staff and CAD positions are reasonable, consistent with the terms of the Joint Stipulation and will be adopted by the Commission.

2. Two-thirds of Amos Unit 3 Non-Labor Expense

Because the acquisition of a two-thirds interest in the Amos 3 Unit occurred on December 31, 2013, the Companies made an adjustment to the 2013 test year non-ENEC generation expense of $7.698 million to annualize non-labor O&M expenses for the new unit. Companies Rule 42, Statement A, Schedule 2, (Statement G adjustments 16-PE and 31-AG). Staff reduced that amount by $2.454 million, stating that the Companies adjustment included fuel cost that will be recovered in ENEC rates and should not also be recovered in base rates. Staff Exhibit ELO-D at 7. No party disputed the Staff adjustment; therefore, the Commission will adopt the Staff position.

3. Non-ENEC Generation Expense – Other

In additional to the generation expense adjustments for Mitchell and Amos 3, the Companies proposed approximately $150.6 million for other non-ENEC generation expense at going level, an increase of $5.188 million over the test-year level. The adjustment was based on a three-year average (2011-2013) of generation expenses plus an inflation adjustment. Companies Exh. JDL-D at 12-14; Companies Exh. JDL-R at 6-7.

Staff witness Eads testified that the Companies' proposed generation expense should be reduced because the Companies will retire the Kanawha River Plant (Kanawha River), the Sporn Plant, the Glen Lyn Plant, and Unit 3 of the Clinch River Plant (Disposition Plants) by June 1, 2015, three days after new base rates go into effect from this case. Mr. Eads claimed the Companies made no adjustment to 2013 test year generation expenses to account for the retirements. Staff recommends that APCo's test year level of generation expenses be reduced by $14,386,730 on a total Companies basis, and $6,299,186 for the West Virginia jurisdiction, to reflect the planned retirements during 2015. Staff Exh. TRE-D at 7-10. Mr. Eads stated that after retirement, the plants will not require the levels of maintenance performed during the test year. Id. at 8-9. Staff argued in its Brief that it would not be logical to assume that the Companies would incur the same or an increased level of generation expense at the remaining generation plants after the equipment at the Disposition Plants is retired. Staff witness Eads estimated that an annual post-retirement expense of $750,000 for each of the three plants to be retired would provide a reasonable expense allowance for post retirement expenses. Id. at 10.

CAD witness Smith testified that the Companies forecasted expense levels for generation expense after retirement of the Disposition Plants should result in a reduction to the 2013 test year generation expenses. Mr. Smith stated that instead of using historical figures, the Commission should base generation expense levels on the average of budgeted amounts for 2014 and 2015. Mr. Smith recommended a $4 million downward adjustment consistent with the decision in Virginia of the VSCC. In addition, Mr. Smith argued that the inflation adjustment proposed by the Companies should not be accepted. CAD Exh. RCS-D at 90-93.

The Companies asserted that the Staff and CAD positions regarding the level of generation expense for the Disposition Plants after retirement are speculative, flawed and arbitrary. The Companies point to Mr. LaFleur's testimony that retirement of the Disposition Plants will not eliminate O&M expenses for those plants, and contrary to the Staff and CAD positions, there will be significant generation O&M expenses at the retired plants for the foreseeable future. Companies Exh. JDL-R at 8-9; Tr. 1/22 at 214-15. The Companies stated in their brief that the Staff and CAD recommendations do not consider the generation expenses of the whole APCo and WPCo generation fleet. Citing, Companies Exh. JDL-R at 9. The Companies also stated that Mr. Ead's testimony indicated that he lacked confidence in his estimate of generation O&M. Citing, Tr. 1/23 at 97, 102-03. We believe that the position of the Companies is that, instead of guessing, the Commission should evaluate generation O&M expense at the whole fleet level and that the Companies' requested three-year average expense with an inflation factor is reasonable.

The test-year in this case includes the non-ENEC generation expenses for the Disposition Plants and little, if any, of the additional generation expenses related to the acquisition of the Mitchell and Amos units. Because of the lack of historical information about the current generation fleet, each party put forth what can only be fairly referred to as their best estimate of the appropriate level of non-ENEC generation expense; unfortunately, the best estimates of the parties vary widely and provide the Commission with little comfort about the future costs. The parties have agreed to appropriate levels of ongoing expense for the acquired Mitchell and Amos units as addressed above. The Commission will not accept the Companies position that the remaining generation expense after the retirement of the Disposition Plants will be an increase over the 2013 test year because that position does not appear to be reasonable. The Staff witness on cross examination gave no assurance of their estimate and no calculation of that estimate, answering that the proposed level of generation expense for the Disposition Plants post retirement was at best a guess. CAD argued the amount should be based on how the matter was decided in Virginia by the VSCC without the benefit of the record developed in that case.

The Commission finds the proposals of each party to be lacking. The Commission will, therefore, use the unadjusted 2013 test year level of non-ENEC generation expense. Although the test year included the Disposition Plants that will be retired shortly, it is likely that there could be increased generation expense at the remaining plants once those plants are retired. Given the lack of a record to support any party's recommendation, the Commission determines the unadjusted 2013 test year level of non-ENEC generation expense is reasonable.

D. Incentive Compensation

1. Case Record – Incentive Compensation Plans

The Companies proposed four adjustments to incentive compensation including the TY Restrictive Stock Unit (RSU) incentive costs, savings plan expenses related to restrictive stock, the incentive compensation plan, and savings plan expenses related to incentive compensation.

Companies witness Carlin explained that employees of the AEP Service Company and the Companies are compensated by a salary that is a combination of base pay and variable pay. The variable portion of the compensation is classified as either annual incentive compensation or long-term incentive compensation. The annual incentive component of employee total compensation is tied to the achievement of operating efficiencies and operational goals and varies with the achievement of those operational goals. Companies Exh. ARC-D at 5, 12. Mr. Carlin stated that the Commission should allow recovery of incentive compensation expenses because the total compensation package of the Companies (the combined base pay and incentive pay) is at or below prevailing market compensation and results in direct benefits in the form of increased safety and cost savings for utility customers. Companies Exh. ARC-D at 6-7, 12, 21 attached Exh. 4, Exh. 5 and Exh. 6. Companies witness Ferguson urged the Commission to allow the Companies to recover the reasonable and prudent costs to provide market-competitive levels of employee compensation. Companies Exh. SHF-D at 12.

Mr. Carlin testified that during the test year, the long-term incentive compensation portion (LTIP) was available to 550 employees of the AEP Service Company and the Companies who engaged in long-term decision making for the Companies. Mr. Carlin testified that in the current year, the Companies and the AEP Service Company will compensate approximately 950 employees through the LTIP program. The LTIP includes both Performance Units and Restrictive Stock Units. Companies Exh. ARC-D at 6, 22; Tr. 1/21 at 162.

The Companies presented evidence that the total compensation package, including incentive compensation, is necessary to assure that the Companies and the AEP Service Company are able to hire and retain qualified employees. Companies Exh. SHF-D at 12; Companies Exh. ARC-R at 4; Tr. 1/21 at 193-94. Under cross-examination, however, Mr. Carlin stated that, although "pressure" exists on employee retention in some areas, no area has become a major level of concern at this time. Tr. 1/21 at 154.

CAD witness Akers recommended that the Commission authorize only one-half of the Companies' adjustment for incentive pay to direct employees in order to reflect a sharing of the costs between ratepayers and shareholders consistent with recent Commission rate case decisions. She noted that the Commission has stated that absent specific proof that incentive pay leads directly to a lower cost of service, it would not be appropriate to allow full recovery from ratepayers. CAD Exh. SJA-D at 7-8 <u>citing</u>, <u>West Virginia American Water Company</u>, Case No. 10-0920-W-42T, April 18, 2011 Commission Order at 39-40; 2010 Rate Case, March 30, 2011 Commission Order at 50.

In response to CAD witness Akers' testimony that the variable portion of compensation for direct employees of the Companies is not known and measurable, Mr. Carlin stated that the target level of incentive compensation is known and measurable because the Companies expect to achieve the target. In response to Ms. Akers testimony that the incentive compensation expense for APCo and WPCo employees should be shared among ratepayers and shareholders, Mr. Carlin testified that it would not be proper for the Companies to "share" the expense with stockholders when the variable compensation is a necessary expense for the Companies. Companies Exh. ARC-R at 3-4.

2. Service Company Incentive Compensation

With respect to incentive compensation for AEP Service Company (AEPSC) employees, Mr. Carlin testified that the Commission should allow full recovery because AEPSC provides important efficiencies and cost savings to the Companies by performing essential functions. Tr. 1/21 at 184-85. Mr. Carlin stated that AEPSC has reduced the cost of the services it performs for the Companies by fifteen percent since the 2009 test year in the 2010 Rate Case. Companies Exh. CRP-D at 8-9, Tr. 1/21 at 181. The Companies argued that the Commission decision not to allow AEPSC incentive compensation in the 2010 Rate Case should not determine the result in this case because the Companies did not present sufficient and thorough evidence in the 2010 Rate Case to enable the Commission to understand its total compensation package. Tr. 1/21 at 188. To the extent that the Commission based its 2010 Rate Case disallowance of incentive compensation for AEPSC employees on economic circumstances, the Companies argued in briefing that economic circumstances have markedly changed since that time.

Mr. Carlin testified that Restricted Stock Units (RSUs) made up thirty percent of the long-term incentive compensation program for 550 employees during the test year and for 950 employees in the current year. Tr. 1/21 at 184. In response to Staff witness Oxley's recommendation to eliminate the costs of the RSUs portion of incentive compensation on grounds that the RSUs were only available to top executives, Mr. Carlin testified that currently many employees who are not top executives participate in this program. Companies Exh. ARC-R at 7; Tr. 1/21 at 202-03. Mr. Carlin also said that RSUs make up a crucial part of the Companies' long-term incentive compensation program.

CAD witness Akers testified, however, that the Commission should disallow all the jurisdictional incentive compensation expense of $8,248,454 for AEPSC personnel because the Commission denied this expense line item in two prior rate cases. Citing 2010 Rate Case, March 30, 2011 Commission Order at 53, 54; West Virginia American Water Company, Case No. 10-0920-W-42T, April 18, 2011 Commission Order at 43. CAD Exh. SJA-D at 8-10.

CAD argued in briefing that the Companies did not present evidence in this case that AEPSC or APCo have not been able to attract or retain competent employees, or that they will not be able to continue to attract or retain competent employees without recovering incentive pay in rates. The Companies, instead, relied on studies showing that compensation is at or below market. CAD argued that in the absence of a showing that it is difficult to retain or attract employees, the adjustment is not appropriate. With no evidence in the record, CAD argued that the Companies' proposed adjustment must therefore be rejected.

In the CAD reply brief, CAD criticized the Companies for continuing to pay incentive compensation with knowledge that the Commission denied recovery of this expense in two prior recent rate cases. CAD also objected to the Companies position stated in its brief that economic conditions are now markedly different from what they were in 2010. CAD stated that the Companies presented no evidence to support this statement with respect to economic conditions in West Virginia.

Staff witness Oxley recommended that the Commission disallow recovery of the RSU portion of long-term incentive compensation and associated savings plan costs. Mr. Oxley stated that long-term incentive plan programs are typically available to top executives and the programs allow those executives to receive substantial additional compensation over and above their normal salary levels. Staff Exh. ELO-D at 8-9. During the test year, ninety-two percent of the APCo and WPCo RSU costs were related to AEPSC employees. Sixty-three percent of the total incentive compensation costs of the Companies during the test year related to AEPSC employees. Id. Mr. Oxley referenced the Commission decisions in two recent rate cases to remove executive supplemental compensation on grounds that it would be out of line with the economic conditions of West Virginia at that time. Mr. Oxley stated that the West Virginia economy remains challenged and has not improved since 2010. Id. Mr. Oxley did not recommend a downward adjustment, however, to incentive compensation expenses outside of the RSU program. Id.

3. Commission Decision on Incentive Compensation

In the 2010 Rate Case, the Commission took the unusual step of disallowing significant portions of the test year levels of incentive compensation for AEPSC employees and direct employees. The Commission cited specifically concern about the public perception of the Companies executive compensation levels, and the continuation of incentive compensation plans when the economic climate of the 2008 Great Recession was placing a significant financial hardship on West Virginia customers. 2010 Rate Case Order at 48.

Incentive compensation plans that tie some portion of the employees compensation to performance, and therefore that have some portion of the compensation at risk, is the prevalent compensation methodology currently used by most larger businesses and these arrangements have become the "norm" for most major utility companies. The use of incentive compensation has been a significant issue in a number of rate cases before the Commission in recent years. The Commission is aware that its decisions about incentive compensation have varied from case to case based on the facts of those cases. The decision about incentive compensation in the 2010 Rate Case was in large part driven by the extraordinarily tough economic times present at the time that case was decided. This is another of those issues outlined in the Introduction section of this Order that has been reviewed in developing this case and this Order.

The Companies' testimony in this case has demonstrated that the annual incentive compensation plan is an integral part of the overall compensation plan of the Companies, and that the total compensation (the combination of base pay and incentive pay) that eligible employees receive is intended to place that total compensation at or near the market rate for each particular job or salary band. The Commission was not presented with an in-depth analysis of the current economic climate compared to the economic climate present at the time of the 2010 Rate Case. Obviously, not everything is "rosy," but the Commission believes that much of the "Great Recession" is behind us and the economic climate is better than it was in 2009-2010. We did not intend our extraordinary treatment in 2010 to be the "norm."

The Companies have argued that the annual incentive compensation performance goals for each employee or group of employees are set at a level to drive improvement into metrics that measure safety, efficiency of operations and financial performance. Improvement in those metrics can and likely does lead to savings that eventually benefit the customer when those improvements are captured in a base rate case. The Commission understands that it may be difficult to measure the precise financial benefit of the incentive plan, but there is no valid argument that the savings that do result from the incentive plan cannot be retained by the Companies indefinitely, because those savings are included in the test-year for each base rate case and returned to benefit the customers

The Commission also understands that the AEPSC provides a significant amount of the workforce for the Companies, particularly in areas of the business that can benefit from the "economies of scale" available through sharing professional employees with other subsidiaries versus hiring that professional expertise at each subsidiary. No party to this case has argued that the services provided by AEPSC are imprudent or not cost effective. There is evidence in this case of savings for the AEPSC costs from the level included in the 2010 Rate Case. The Companies provided information that savings of approximately fifteen percent have been achieved in the total AEPSC charges requested in this case versus the level included in the 2010 Rate Case. As indicated by Mr. Patton the voluntary severance package and several other efficiency measure programs implemented across the AEP system have been successful in gaining higher efficiencies and lower AEPSC costs. Tr. 1/20 at 159-164.

Based on the record in this case, the Commission will allow the annual incentive plan costs proposed by the Companies and Staff for both the Companies' employees and employees of AEPSC. The Commission reminds the Companies that in future rate cases they should provide some analysis that demonstrates the total compensation to its employees (both direct and AEPSC employees) is in line with the market salary for each type of job classification. The analysis should address how the market value for each job classification is determined and provide examples that show how the actual salaries for various job classifications compare to the market-determined salaries.

The goals for the LTIP plan are largely tied to the overall financial performance of AEP stock. A financially strong utility is also important to customers. In the case of the LTIP goals, however, while those goals may result in favorable cost of capital and favorable other impacts for customers, they also directly benefit the shareholders. Because achievement of the LTIP plan goals benefits both customers and shareholders, the Commission will authorize the Companies to recover one-half of the LTIP (Restrictive Stock Plan) for the historical test-year.

E. Uncollectible Expense

The Companies proposed an adjustment of $3.925 million to reflect a revised three-year average of uncollectible expense for inclusion in rates. Companies Exh. JJS-R at 1-2. Companies witness Scalzo included in the three-year average a $4.6 million charge-off related to the bankruptcy of a major coal company and stated that this charge-off could be characterized as extraordinary. Id. at 2. Mr. Scalzo testified that the Companies do not oppose exclusion of the $4.6 million charge-off from the three-year average if the Commission allows an opportunity to recover the full amount of this charge-off through other means. Id.

Staff witness Shaffer in his pre-filed testimony removed the $4.6 million write-off from the three-year average. Staff Exh. CRS-D at 2-3. At hearing, Mr. Shaffer supported recovery of the $4.6 million charge-off over time, with the condition that the Companies seek to recover this sum in the bankruptcy proceeding of the major coal company and adjust the amortization amount for any such recovery in a future rate case. Tr. 1/23 at 39.

In the Companies brief, the Companies stated that they had already sought and received recovery in the amount of approximately $650,000 in the bankruptcy proceeding. The Companies, therefore, recommended that the Commission set base rates for the Companies that include uncollectible expense based on a three-year average, with the $4.6 million major coal company charge-off excluded, adjust the $4.6 million by the amount received from the bankruptcy case and amortize that amount over five years. Staff agreed with the Companies' proposal. Staff Reply Brief at 5-6.

The Commission has determined in the past that for ratemaking purposes, the use of a three-year average of uncollectible expense is appropriate when there are fluctuations that occur between the annual expense for each year included in the recent historical period and the test-year level of expense when represented as a ratio or percentage rate, relative to revenue levels. 2010 Rate Case, Commission Order March 30, 2011, at 43. The Commission agrees with the Companies, however, that the major coal company uncollectible expense is extraordinary and warrants special treatment. The agreement of the Companies and Staff regarding the large uncollectible amount is reasonable. The Commission accepts the Staff uncollectible expense adjustment based on the three-year historical period, adjusted by the agreed to write-off of the net large coal company charge-off over a five-year period.

F. Aviation Expense

CAD witness Smith recommended that the Commission disallow an adjustment allocation to APCo and WPCo for the corporate aviation expenses of AEPSC. CAD Exh. RCS-D at 85. During the test year, AEPSC charged APCo $1.385 million and WPCo

$23,218 for aviation costs. Mr. Smith testified that the aviation department is used by AEP Executives and often spouses. Accordingly, Mr. Smith would reduce the APCo aviation expense by $605,607 and the WPCo expense by $21,467. He stated that shareholders, and not ratepayers, should bear the burden of these costs. Id.

Companies witness Scalzo defended the aviation costs as reasonable and cost-efficient in his rebuttal testimony. Companies Exh. JJS-R at 14-17. Mr. Scalzo also testified regarding the allocation of the fixed and variable costs of corporate aviation. Mr. Scalzo testified that executives travel on leased aircraft for hearings, meetings and other business activities. Using corporate aircraft results in less time spent traveling and more time devoted to utility business. These results benefit the utility ratepayers. When multiple AEP personnel are traveling together, the cost-savings increase. In response to the testimony of CAD witness Smith, Mr. Scalzo testified that Mr. Smith ignored the fact that business trips are necessary and that in the absence of corporate aircraft, the personnel would have incurred commercial travel expenses. He also stated that use of the corporate aircraft often avoids the costs of an overnight stay. Id.

The record indicates that the West Virginia jurisdictional share of the corporate aviation expense charged to the Companies from AEPSC is approximately $0.627 million. CAD argued that the entire amount should not be authorized for rate recovery. Some level of commercial airline travel would be required if the corporate private aviation expense was discontinued. Unfortunately, the record in this case does not provide sufficient detail to determine what level that offsetting commercial aviation cost would be. The Commission will allow fifty percent of the requested total costs for corporate aviation. This allowance is reasonable given the location of West Virginia in the center of the AEP territory and less air travel would likely be needed for APCo/WPCo issues given its proximity to Columbus, Ohio, compared to other AEP subsidiaries, but still provides a reasonable level of recovery for required travel expenses.

G. PJM Administrative Fees

The Companies initially proposed to increase PJM Administrative fees over the test year amount by $9,279,421 on a total Companies basis, and $4,477,451 for the West Virginia jurisdiction, to reflect the impact of the expiration of the AEP East Pool Agreement. This change results in PJM charging fees to the Companies on a stand-alone basis. Companies Exh. AEV- D at 5. Staff witness Oxley testified that the proposed going-level increase was incorrect because it was based on 2015 forecasts. Mr. Oxley's review of actual PJM Administration fees for January through October 2014 produced an annualized increase over the test-year level of $2,109,771 ($1,017,994 for the West Virginia jurisdiction) or $7,169,650 less than the Companies request. Staff Exh. ELO-D at 9-10, attached Exh. ELO-2.

In rebuttal testimony, Companies witness Vaughan stated that Mr. Oxley omitted WPCo PJM administrative fees of $974,714 and that Mr. Oxley's PJM Administrative fee allowance in cost of service should be increased by $904,210 on a West Virginia jurisdictional basis. Companies Exh. AEV-R at 2, attached Exh. AEV-R1. Staff agreed with the Companies that an additional $904,210 should be included for the WPCo PJM fees in its post-hearing initial brief. Staff Init. Br. at 50-51.

The Commission does not agree with the Companies requested increase to PJM fees based on a forecast for 2015. The Staff analysis using the latest actual information produced only an increase for APCo of $1.017 million for the West Virginia jurisdiction over the test year levels. The use of the latest actual data is a more reasonable method for estimating the increase for PJM expense over the test-year level. The Commission will authorize an adjustment of $1.922 million to the test-year PJM expense, consisting of $1.017 million for APCo and $0.904 million for WPCo.

H. Additional Linemen

The Companies proposed to add distribution operation and maintenance payroll expense and payroll-related expenses including workers compensation, employee benefits and payroll tax for twenty new linemen. The Companies hired ten of the new linemen prior to August 31, 2014, and plan to hire an additional ten linemen. Companies Exh. PAW-R at 2. Mr. Wright testified that the Companies need to hire linemen to maintain workforce continuity because several distribution linemen are nearing retirement age, twenty-seven percent of the Companies' linemen are over age fifty-five, and six of those are over age sixty. Mr. Wright testified that the Companies train new linemen for five years from apprentice to journeyman level. Companies Exh. PAW-D at 13-14.

Staff did not object to including recovery of costs associated with twenty new linemen in base rates. CAD, however, opposed including the expenses associated with future, yet-to-be hired linemen in base rates. CAD witness Akers noted that as of August 31, 2014, none of the Companies' linemen has retired since the end of the test year. CAD argued the costs associated with the ten hired linemen should be included, but the costs associated with the linemen to be hired in the future should not be included. CAD Exh. SOA-D at 4-5. In the CAD brief, CAD argued that there is no certainty that the Companies will actually hire ten more linemen. CAD requested that if the Commission approves a revenue requirement for these ten additional linemen, the Commission direct the Companies to provide metric reporting similar to the requirements of WVAWC Case No. 11-0740-W-GI, and some mechanism to recoup these funds in the event the hiring does not take place.

The Commission believes it is important for the Companies to have sufficient linemen to properly maintain its distribution and transmission lines. It is reasonable to allow the costs for all twenty of the new linemen to be recovered in rates to address the orderly replacement of the twenty-seven percent of the Companies' linemen that are nearing retirement and to ensure that the new linemen begin the five-year training as soon as possible. The Commission will, however, require the Companies to make a closed entry filing 180 days after the date of this Order stating the number of linemen hired and that have left employment after the date of this Order and the status of the number of linemen. We take these statements regarding the need for employees seriously. See West Virginia-American Water Company, Case No. 11-0740-W-GI. If the Companies have not hired the additional linemen by that date, the Companies shall explain their efforts to do so and provide the expected date each of those additional positions will be filled.

VI. DEPRECIATION AND AMORTIZATION EXPENSE

A. Depreciation Rates

1. Position of the Parties

The Companies filed for a change in depreciation rates in Case No. 14-1151-E-D (Depreciation Case). That filing is based on a depreciation study of electric plant in service as of December 31, 2013. The proposed depreciation rates are based on the Average Remaining Life Method of computing depreciation[31] that was approved by the Commission in Case No. 91-1037-E-D. Staff Exh. EFD-D at 2.

The new depreciation rates proposed by the Companies will increase total Companies annual depreciation expense by $59,602,136. Depreciation Study Report (Depr. Study) at 5. The Companies originally proposed two sets of depreciation rates, one to be in effect through May 2015 and a second to go into effect in June 2015. The proposed depreciation rates through May 2015 applied to all production plants, including the plants scheduled to be retired in 2015. The proposed depreciation rates for the Amos Power Plant, Clinch River, and the Mountaineer Power Plant (Mountaineer) were higher beginning in June 2015, but the Companies Depr. Study eliminates depreciation for the retired plants from June 2015 forward. Considering the elimination of depreciation on the retired plants and the higher proposed rates applied to Amos, Clinch River, and Mountaineer, the total annual depreciation expense proposed using the June 2015 rates did not change from the annual depreciation expense from the proposed May 2015 rates.[32] The Companies subsequently agreed with Staff that it was appropriate to have a single set of new depreciation rates going into effect in June 2015. Companies Exh. DGH-R at 12; Companies Init. Br. at 50. It did not, however, agree with the level of the depreciation rates proposed by Staff or the continued application of specific depreciation rates on the plants scheduled to be retired in 2015. Companies Exh. DGH-R at 13.

The proposed annual depreciation expense increases by functional plant account categories of the Companies are:

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[31] The Average Remaining Life Method for depreciation recovers the original cost of the plant, adjusted for net salvage, less accumulated depreciation, over the average remaining life of the plant.

[32] The total annual depreciation for steam production plant is $184,509,803 using either the proposed May 2015 depreciation rates or the June 2015 depreciation rates.

APCo			
Functional Plant Category	Annual Depreciation at Present Depreciation Rates	Annual Depreciation at Proposed Depreciation Rates	Increase in Annual Depreciation
Steam Production Plant	$ 150,657,299	$ 184,509,803	$ 33,852,504
Hydro Production Plant	3,408,371	6,434,141	3,025,770
Other Production Plant (Gas)	13,973,115	13,252,009	(721,106)
Total Production Plant	168,038,785	204,195,953	36,157,168
Transmission Plant	33,815,872	33,959,455	143,583
Total Distribution Plant	97,834,189	120,529,656	22,695,467
Total General Plant	3,365,029	3,970,947	605,918
Total Depreciable Plant	$ 303,053,875	$ 362,656,011	$ 59,602,136

Depr. Study at 34 to 38.[33]

The Depr. Study filed in this proceeding included proposed new rates for WPCo, including the newly-acquired Mitchell steam production plant. In total, the new rates for WPCo result in a net decrease in annual depreciation expense of $411,802.

Wheeling			
Functional Plant Category	Annual Depreciation at Present Depreciation Rates	Annual Depreciation at Proposed Depreciation Rates	Increase in Annual Depreciation
Total Production Plant	$ 25,773,581	$ 25,773,581	$ 0
Transmission Plant	2,916,396	1,990,828	(925,568)
Total Distribution Plant	4,872,437	5,483,877	611,440
Total General Plant	166,748	69,074	(97,674)
Total Depreciable Plant	$ 33,729,162	$ 33,317,360	($ 411,802)

Depr. Study at 43-44.

The Depr. Study filed by the Companies included a review of experienced functional interim retirements, related salvage and removal history for the period 1996 to 2013. Interim net salvage calculations are based on annual life to date salvage, removal and net salvage percentages. The Companies stated in their filing that significant net salvage amounts for generating plants occurs at the end of their life.[34] To assist in establishing net salvage applicable to steam generation plants, the Companies hired Brandenburg Industrial Service Company (Brandenburg) to estimate APCo steam plant demolition costs. The Brandenburg study was based on 2011 costs of demolition, and

33 The Companies used a category of "Steam Production Plant" for all of its coal-fired power plants. While there is some steam production at its gas-fired combined cycle Dresden plant, it did not include any portion of that plant in the "Steam Production Plant" category. Both of the gas-fired plants owned by APCo are included in the "Other Production Plant" category.

34 Net salvage is the cost of removal of facilities, minus any salvage value received for the removed facilities. A net salvage ratio of less than unity means that the expected salvage value will exceed the cost of removal. A net salvage ratio of unity means that the expected salvage value will equal the cost of removal. A net salvage ration of more than unity means that the expected salvage value will be less than the cost of removal. Depr. Study at 21.

those costs were escalated to 2013 cost levels for inclusion in the Depr. Study. The Brandenburg study did not include asbestos removal or cost associated with landfills and ash ponds because removal of these facilities are accounted for as an Asset Retirement Obligation (ARO) and the accretion and depreciation associated with AROs are included separately in the revenue requirements filed in the 2014 Rate Case. A separate demolition estimate for Mitchell, now partially owned by Wheeling, was prepared by the firm of Sargent and Lundy, LLC. (S&L).

Staff presented depreciation recommendations by Staff members Eric deGruyter and David Pauley. Staff recommendations produced identical results to the Companies study for all accounts, except the steam production plant accounts. For the APCo steam production plant, Staff recommended an annual depreciation expense of $157,266,245 as compared to the Companies proposal of $184,509,803, a difference of $27,243,558. For Wheeling steam production plant, Staff recommended an annual depreciation expense of $25,044,212 as compared to the Companies proposal of $25,773,581, a difference of $729,369.

The differences between the Staff and Companies proposals were in the level of net salvage built into each recommendation and the remaining life used for the Clinch River plant. For Clinch River, Staff calculated depreciation rates based on a 2040 retirement date.

Mr. deGruyter testified that he believed there is a great likelihood that the steam generating plants would not actually be dismantled and removed. In contrast to opposing the negative net salvage included in the Companies study for demolition of the stations, Mr. deGruyter indicated that Staff has not typically objected to including negative net salvage in depreciation rates for mass property accounts where items are routinely removed and replaced. This portion of the negative net salvage is referred to as interim net salvage, as opposed to the final demolition of a plant, which is referred to as terminal net salvage. Staff Exh. EFD-D at 4-5.

The net terminal salvage issue is a relatively minor issue in this case. Staff recommended an increase in annual depreciation expense because of the change in depreciation rates of $32,358,576. APCo requested an increase in annual depreciation of $59,602,136. The difference between the two recommendations is $27,243,558 per year. Of this amount, only $2,332,984 is related to the Staff exclusion of terminal net salvage from its calculations. The remainder of the difference, $25,639,943, results from the different lives used for depreciation of the Clinch River plant. APCo proposed depreciation rates for Clinch River over the next 6.28 years. This shortened period of time is a weighted average life after considering a ten-year life for the new gas-fired units 1 and 2 and shorter lives for the coal-related portions of units 1 and 2 and all of unit 3. Staff proposed rates for all Clinch River investment over the next 26.51 years. This difference in the period over which to depreciate Clinch River, and a small difference for terminal net salvage at Clinch River, resulted in Staff recommending annual depreciation for Clinch River of $7.9 million, compared to the APCo proposed annual depreciation of $33.6 million.

CAD opposed the Companies depreciation request and presented Mr. Michael Majoros as CAD's depreciation witness. Mr. Majoros testified about even more significant differences with the Companies' Depr. Study than Staff. Mr. Majoros recommended lower rates and lower annual depreciation expense for all of the functional plant categories, as summarized below. CAD Exh. MJM-D at 16-18.

APCo Plant			
Functional Plant Category	APCo Annual Depreciation at APCo Proposed Rates	CAD Annual Depreciation at CAD Proposed Rates	Difference Between CAD and APCo
Steam Production Plant	$ 184,509,803	$ 155,305,708	$ (29,204,095)
Hydro Production Plant	6,434,141	4,859,660	(1,574,481)
Other Production Plant (Gas)	13,252,009	13,239,779	(12,230)
Total Production Plant	204,195,953	173,405,147	(30,790,806)
Transmission Plant	33,959,455	32,051,110	(1,908,345)
Total Distribution Plant	120,529,656	89,406,656	(31,123,000)
Total General Plant	3,970,947	3,875,566	(95,381)
Total APCo Depreciable Plant	$ 362,656,011	$ 298,738,479	$ (63,917,532)
Wheeling Plant			
Total Production Plant	$ 25,773,581	$ 25,044,212	$ (729,369)
Transmission Plant	1,990,828	1,839,767	(151,061)
Total Distribution Plant	5,483,877	4,103,695	(1,380,182)
Total General Plant	69,074	2,390	(66,684)
Total Wheeling Depreciable Plant	$ 33,317,360	$ 30,990,064	$ (2,327,296)

Mr. Majoros did not include any estimated cost of removal or salvage (negative net salvage) for either interim retirements or terminal retirements in any plant accounts. Mr. Majoros testified that a majority of the depreciation rates proposed by the Companies lead to excessive depreciation. He observed that the Companies used proposed negative net salvage factors and indicated that he disagreed with every depreciation rate that included a terminal or negative salvage value. CAD Exh. MJM-D at 11. Mr. Majoros testified that it is not necessary to accrue for cost of removal because those costs may be capitalized if incurred in connection with a replacement of plant in the future. CAD Exh. MJM-D at 15. Mr. Majoros, like Staff, calculated depreciation on Clinch River based on a 2040 retirement date.

Although he did not include negative net salvage factors in his recommendation for depreciation rates going forward, Mr. Majoros testified that there was a significant amount of accrued asset retirement costs on the books of the APCo and WPCo. He quantified the amounts as $615 million for APCo and $460,000 for Wheeling. Mr. Majoros testified that the Commission should officially recognize the accrued Cost of Removal Regulatory Liabilities embedded in the Companies' accumulated depreciation accounts to protect the interests of ratepayers if the Companies attempt to transfer the amounts to income or other companies. CAD Exh. MJM-D at 15. Mr. Majoros did not recommend that any portion of the regulatory liability accrued for cost of removal be amortized as credits to cost of service in this case. Id. at 18.

The Companies filed rebuttal testimony to the depreciation testimony of both Staff and CAD. Mr. Jeffery LaFleur disputed the Clinch River retirement date used by Staff and CAD. He testified that Mr. deGruyter is mistaken to assume that fifty-year old coal units converted to natural gas as a fuel source will be mechanically or operationally equivalent to the Ceredo and Dresden gas-fired plants. He testified that the operational lives of plants with such different pedigrees cannot be equated. Companies Exh. JDL-R at 2.

Mr. LaFleur also disagreed with the positions of Staff and CAD on cost of removal and net salvage. He testified that it was highly unlikely that any of the steam production plants that are scheduled for early retirement would eventually be transferred "as-is." The plants are being retired because they cannot meet emissions limits, and he believes that the most likely outcome for the plants is demolition. He conceded that the locations of the plants may be desirable for other uses, but he further testified that there would be decommissioning costs prior to any transfer. Companies Exh. JDL-R at 5.

David Hummel, testifying for the Companies, took issue with Staff and CAD on the terminal net salvage issue. He testified that a plant will experience many interim asset retirements during its lifetime, but at some point in time there will be a final retirement, or terminal retirement, at which time there will be a terminal net salvage. He testified that the final retirement will involve decommissioning and demolition, and depreciation rates should be increased in recognition of terminal negative net salvage when the cost of the decommissioning and demolition is expected to be greater than the salvage value of the plant components. Companies Exh. DGH-R at 5.

Mr. Hummel pointed to the historical record of generation plant retirements by APCo. He testified that since 1955, APCo has retired five steam generating plants, Kingsport, Roanoke, Kenova, Logan and Cabin Creek. According to Mr. Hummel, all of these plants have been demolished. Companies Exh. DGH-R at 8. He testified that a recent demolition of a 450 MW plant owned by AEP affiliate, Indiana and Michigan Power Company, had a net cost, after salvage value, of $10,766,584. He indicated that the net cost of removal relative to the gross cost of the plant was seven percent. He stated that that value compared favorably to the four percent estimated net cost of removal, relative to gross plant cost, that was used for the net salvage factor for the APCo steam plants in the Depreciation Study. Id. at 9.

Mr. Hummel disagreed with the recommendations of CAD witness Majoros for many of the same reasons he disagreed with Staff recommendations. He disagreed with the suggestion that future removal costs could be capitalized as part of future construction at an existing plant site. He stated that with or without replacement the Uniform System of Accounts requires that removal costs be charged to the accumulated depreciation accounts, rather than plant in service. Id. at 18.

2. Commission Decision

The Commission is faced with a wide range of depreciation rates in this proceeding. For the most part, the issues are fairly narrow, focusing on the amount of projected cost of removal, less salvage (net salvage),[35] to be included in the development of depreciation rates, and the depreciation period to be used for Clinch River.

The Commission has historically included some amount for projected cost of removal and projected salvage value in the development of depreciation rates. We do so when the projected cost of removal and salvage is reasonable and supported by substantial evidence. Both Staff and the Companies have included the projected cost of removal and salvage, generally resulting in negative net salvage, in the development of their depreciation rate recommendations. Staff has included negative net salvage of $187,753,799 in APCo steam production plant, alone. Staff Exh. DLP-D, Exh. 2 at 3. By comparison, APCo requested negative net salvage for steam production plant of $231,095,876. Depr. Study at 29. For other APCo plant categories, Staff has included negative net salvage of $524,094,917. Staff Exh. DLP-D, Exh. 2 at 8. .APCo likewise requested negative net salvage of $524,094,018 on plant other than steam production plant. Depr. Study at 32.

Staff included negative net salvage of $23,027,849 for all depreciable plant of WPCo in its depreciation recommendations. Staff Exh. DLP-D, Exh. 3. In comparison, WPCo requested the inclusion of $40,742,149 in total negative net salvage in the Depr. Study. Depr. Study at 42.

In stark contrast to the negative net salvage in the Depr. Study, or the lower but still significant negative net salvage recommended by Staff, both totaling over $700 million in negative net salvage to be recovered by APCo in depreciation rates over approximately the next 25 to 35 years, CAD recommended no negative net salvage in depreciation rates. CAD witness Majoros opposed the use of any negative net salvage. CAD Exh. MJM-D at 11. We do not find the CAD recommendation to be reasonable. The Commission does not agree with the CAD position that there should be no negative net salvage built into depreciation rates in this proceeding.

We note that the CAD witness acknowledged that there was already a significant amount of negative net salvage built into the Depreciation Reserves of the Companies.

[35] Net salvage can be a credit number or a cash inflow for the utility, if the salvage value of plant exceeds the cost of removal. If, however, the cost of removal exceeds the salvage value of plant, the net salvage is negative, which represents a net cash outlay for the utility. For most of the plant accounts at issue in this proceeding the net salvage is a negative number, indicating the cost of removal exceeds the cash salvage value. Some parties have referred to the net salvage issue as being related to "net cost of removal," or "net salvage," which can be either positive or negative.

He did not, however, make an argument or present any evidence that the amounts already included in the reserves were sufficient to cover all projected future negative net salvage, terminal or interim. Mr. Majoros asked only that the Commission "officially recognize" the existence of these significant amounts in the reserve to protect the interest of ratepayers from any attempts to transfer the amounts to income or other companies. CAD Exh. MJM-D at 15.

The Commission acknowledges the observations of Mr. Majoros, but we do not believe it is necessary for the Commission to make any pronouncements regarding amounts recorded in Account 108, Accumulated Provision for Depreciation of Electric Utility Plant. The instructions for Account 108 contained in the Uniform System of Accounts are clear. Credits (additions) to the account are allowed mainly to account for amounts debited to depreciation expense and extraordinary property losses (when authorized by the Commission). Debits (reductions) to the account are allowed mainly for plant retirements. The utility is already restricted by the Uniform System of Accounts for any other use of the accumulated depreciation without specific authorization by the Commission.

With regard to the portion of the future negative net salvage that the Companies consider being associated with AROs and that is recorded in a separate regulatory liability account, the Commission will require that charges (reductions) to the regulatory liability account follow the same rules applicable to depreciation accounting. The credit balances in the ARO-related regulatory liability account must be used for actual negative net salvage (net cost of removal) of the assets for which the regulatory liabilities have been accrued. If there are excess credit balances in the regulatory liability accounts, they may not be disposed of without specific authorization by the Commission.

The Staff-recommended depreciation rates are reasonable and should be adopted in this case. Staff allowed for significant amounts of negative net salvage in its recommended depreciation rates. There are already negative net salvage amounts built into the depreciation reserve accounts. The Commission current West Virginia depreciation rates reflect both interim and terminal net salvage. APCo Init. Br. at 51. While the negative net salvage included in the depreciation rates recommended by Staff are less than those requested by the Companies, the Commission is not convinced that the final negative net salvage costs (which are somewhat speculative as presented by either Staff or the Companies), will not be covered by the amounts already built into the depreciation reserve accounts and the amounts that will be added to the depreciation reserve accounts in the future using the Staff-recommended rates.

Staff and the Companies do not agree with the mechanisms to be used for continuing write off of plants that are retired but which have significant remaining undepreciated balances. Staff proposed to continue to write-off those plants with discrete accounting entries specific to the individual plants and plant accounts through 2040. The Companies proposed to fold the undepreciated value of retired plants into the depreciation rates used for remaining plants. The Companies used their estimate of the remaining life of Mountaineer and Amos[36] to write-off undepreciated balances for Kanawha River, Glen Lyn, and Sporn. The Companies used their estimate of the remaining life of the converted units of Clinch River[37] to write-off the undepreciated coal-related investments in those units and all of the undepreciated value of Clinch River unit 3. Staff used the 2040 projected retirement dates for Amos and Mountaineer to calculate all of its proposed depreciation rates.

The Staff remaining life treatment of the undepreciated balances in the plants to be retired in 2015, including the coal-related undepreciated balances for Clinch River units 1 and 2 and all of Clinch River unit 3, is consistent with the Companies treatment of undepreciated balances for Kanawha River, Glen Lyn and Sporn. We see no reason to shorten the recovery of the undepreciated value of any of the Clinch River investment over the compressed time frame proposed by the Companies simply because those retired properties are situated at the plant site of the natural gas units to be installed at Clinch River.

With regard to the life expectancy of the natural gas units to be installed at Clinch River, it is reasonable to use the Staff-proposed remaining life. Unlike the extraordinary retirements being forced on Kanawha River, Glen Lyn and Sporn by EPA emission limits, the natural gas units to be installed at Clinch River are intended to run for an extended period of time. Although generation plants start with an engineering expected life, there are almost always extensions of lives brought about with preventive maintenance and replacement of component parts of the plants. It is likely that the gas-fired units at Clinch River will have preventive maintenance and replacements over the engineering life of the original units projected by APCo. That should result in extended life beyond the APCo projected 2025. Whether that extension will be as long as fifteen years, to 2040, is dependent on many factors and cannot be determined with certainty at this time. Remaining life depreciation accounting is an ongoing and flexible process that allows for updating of depreciation rates as circumstances, including remaining lives, change. As 2025 approaches, there may be better data available to determine whether the life of the gas-fired units will end, or be extended by five, ten, fifteen or even more years. Remaining life depreciation can be adjusted in the future to take that new data into consideration. The Commission will adopt the Staff-proposed depreciation rates on a plant-by-plant and account-by-account basis in this case.

Finally, the Companies have criticized the Staff approach of continuing to write-off the undepreciated value of plants or portions of plants to be retired even after their retirement dates. We acknowledge this will require some modification to depreciation accounting after retirements, but we prefer the Staff approach to the Companies proposal to increase the depreciation rates at remaining plants to effectively over-depreciate the remaining plants to make up for the under-depreciation of the retired

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36 Mountaineer and Amos are currently projected to retire in 2040. All parties have used the 2040 retirement expectation to develop remaining life depreciation rates for Mountaineer and Amos.

37 The Companies expect to retire the converted gas units 1 and 2 at Clinch River in 2025.

plants. When Kanawha River, Sporn, Glen Lyn, Clinch River 3, and coal-related investments in Clinch River 1 and 2 are actually retired, we believe there will be an excessive charge (debit) to the Reserve for Depreciation Accounts that must be accounted-for as prescribed by the Uniform System of Accounts to return the reserve to the level related to the existing depreciable plants. This accounting is to restore the reserve by the amount of undepreciated value of the retired plant accounts (credit Reserve for Depreciation) and charge the undepreciated value to Extraordinary Property Losses (Account 182). The Companies should keep sufficient records to create subaccounts to Account 182 to identify the extraordinary losses due to retirement of the undepreciated plant values. The Commission will allow these balances (net of amortization) to be included in rate base and will allow continued amortization of the undepreciated balances at the annual depreciation accrual rates recommended by Staff.

B. West Virginia ENEC Amortization Expense

The Companies proposed a going level adjustment of $6.736 million to recover ENEC carrying costs in base rates. Company witness Brubaker argued that it is proper to include the amortization of ENEC carrying cost in base rates because there are also ENEC revenues in the Companies' cost of service that offset the amortization expense. Company Exh. JLB-R at 17-18. Mr. Brubaker stated that the amortization expense related to ENEC matches and offsets ENEC revenues and that the Staff proposal to eliminate the expense is incorrect. Id.

Staff witness Oxley argued that the Commission should not include the adjustment for amortization of ENEC carrying costs. Exh. ELO-D at 14-15. Mr. Oxley stated that the Companies did not include ENEC carrying cost in prior base rate cases and claimed that the Companies' explanation of the adjustment, labeled as WV ENEC, was entirely related to amortization of ENEC carrying costs, including the equity portion of those carrying charges, and over/under recovery of APCo's Consumer Rate Relief securitization revenues. Because the entire $6.736 million related to ENEC carrying cost recovery, Mr. Oxley argued they should not be included in base rates. Id. at 15.

Staff argued in its brief that it is normal and appropriate to synchronize ENEC revenues and costs in electric utility base rate cases so that no net costs or revenues related to ENEC rates impact the base rate determination. Staff claimed, however, that the inclusion of the $6.736 million amortization of ENEC carrying costs proposed by the Companies is not necessary to accomplish that synchronization. Staff argued that the Companies did not support their position on going level synchronization of ENEC costs to ENEC revenues in any exhibits, work papers, or testimony. Staff asserted that the Companies instead attempted to transfer the burden of proof to other parties. Staff urged the Commission to reject the Companies proposal to include the ENEC amortization expense in the determination of base rates. Staff initial brief at 32-34.

The Commission will adopt the Staff position. The Companies claimed to have synchronized the ENEC revenues and expenses in Company Rule 42, Statement G adjustments 14-PE and 29-CI. The Companies did not make an adequate showing in the record that the additional adjustment of $6.736 million for amortization of ENEC carrying cost is required to offset ENEC revenues for the 2013 test year.

VII. RATEMAKING MECHANISMS

A. Vegetation Management Program

The Companies proposed to recover an additional $44.6 million through a new surcharge for the Vegetation Management Program (VMP). The Commission approved the VMP by Commission Order issued March 18, 2014, in Case No. 13-0557-E-P (VMP Case). The Commission deferred the implementation of a cost recovery mechanism for VMP O&M expenses until the conclusion of the current base rate case. In this case, the Companies proposed that all VMP expenses be recovered through a surcharge and none through base rates. Companies Exh. CWG-D at 3.

Mr. Gary and Companies witnesses Wright and Ferguson testified that a VMP surcharge is the fairest and most accurate means of recovering VMP costs. The Companies witnesses stated that, because of the surcharge true-up mechanism, ratepayers will pay the actual costs incurred, no more, no less. Further, interested stakeholders will have the opportunity to review VMP costs. Companies Exh. CWG-D at 3-6; Companies Exh. PAW-D at 12; Companies Exh. SHF-D at 10. Mr. Gary agreed to a correction in the allocation of transmission-related VMP costs as identified by SWVA witness Daniel. Companies Exh. CWG-R1; SWVA Exh. JWD-D at 15-16; Companies Exh. CWG-R at 2. Mr. Gary had no objection to WVEUG witness Baron's alternative method of allocating distribution-related VMP costs among customer classes. WVEUG Exh. SJB-D at 16-19; Companies Exh. CWG-R at 2 and attached Exh. CWG-R1.

In response to the CAD and WVEUG testimony that VMP costs should be recovered through base rates and not through a surcharge, Companies witnesses Gary and Ferguson testified that base rate treatment would deprive the Companies and their customers of the flexibility to match costs and recovery during the implementation years of the VMP and of the protection that only VMP costs actually incurred are recovered. CAD Exh. RCS-D at 99-100; WVEUG Exh. SJB-D at 16. Companies Exh. CWG-R at 1-2; Companies Exh. SHF-D at 10.

CAD opposed the proposal of the Companies to recover VMP through a rate surcharge instead of as an O&M expense included in base rates. CAD Exh. RCS-D at 83-84. Mr. Smith reasserted the concerns of CAD that were expressed in the VMP Case, arguing (i) a surcharge is an extraordinary ratemaking mechanism, (ii) the need to perform vegetation management is not extraordinary, and (iii) the Companies have not shown documentary evidence to support the projected level of expense. The best protection for ratepayers is to maintain VMP costs in base rates. Id.

In the alternative, CAD argued that if the Commission does not agree with the CAD position that VMP costs should be recoverable in base rates, the Commission should adjust the proposed surcharge to reflect Commission determinations on proper return in the current rate case, application of the effective federal income tax rate determined by the Commission in the current rate case, and new depreciation rates approved by the Commission in Case No. 14-1151-E-D.

WVEUG also opposed the imposition of a VMP surcharge for the reasons stated by WVEUG witness Baron. Mr. Baron argued that the Companies failed in this case, as they did in the VMP Case, to demonstrate that the surcharge is necessary to deliver safe, reliable service. Mr. Baron testified that base rate proceedings are the preferred ratemaking approach to vegetation management because the Commission has the opportunity to review all costs and expenses, some of which decrease over time. WVEUG Exh. SJB-D at 16. WVEUG argued in its brief that the Companies did not cite any regulatory requirement mandating the surcharge and failed to show that a surcharge is of such necessity to forgo cost recovery through traditional means. WVEUG argued that the Companies have an opportunity to recover the full costs of their VMP in a traditional Rule 42 base rate proceeding. WVEUG questioned why the Commission should relieve the Companies from bearing the cost-related risks incident to the VMP, such as regulatory lag, and instead require ratepayers to bear those risks. WVEUG argued that the Companies did not justify a departure from traditional ratemaking.

Mr. Baron testified that to the extent the Commission approves implementation of the VMP surcharge in this case, it should require the Companies to allocate the distribution-related vegetation management expenses among applicable rate classes using the same allocation methodology employed by the Companies for their base rate calculations. Specifically, the Companies should allocate these distribution expenses in accordance with the approach used for Federal Energy Regulatory Commission (FERC) Account No. 593 for "overhead maintenance expenses." WVEUG Exh. SJB-D at 17-18. The Companies did not object to this allocation. Companies Exh. CWG-R at 2 and attached Exh. CWG-R1.

Staff witness Melton testified that Staff does not oppose the proposed VMP surcharge because the surcharge will be subject to true-up on an annual basis. Staff Exh. EEM-D at 6. Staff witness Melton testified that he recommends that the Commission require the Companies to file certain information with its yearly true-up filing, including:

(a) All contractual performance measures contractually required by the Companies.
(b) Miles of single phase lines to be cleared in the forecast period.
(c) Miles of three phase lines to be cleared in the forecast period.
(d) Miles of single phase lines cleared in the previous period.
(e) Miles of three phase lines cleared in the previous period.

(f) Miles of single phase lines where the ROW was widened.
(g) Miles of three phase lines where the ROW was widened.

Id.

Mr. Melton requested that the Commission direct the Companies to make the yearly filings as formal case filings or part of the ENEC by a date certain every year in order to ensure there is no confusion as to when and how the yearly formal review/ true-up filing will occur.

The Commission understands that, following a series of cases, including cases specifically focusing on vegetation management, we are initiating a significant change. The Commission will authorize the Companies to recover the vegetation management costs associated with the cycle-based VMP authorized by the Commission in the VMP Case through a surcharge mechanism. The Commission stated in the VMP Case that it would in the next base rate case consider a rate recovery mechanism not tied to traditional base rate standards. Commission Order March 18, 2014 at 14-15. The Commission determines that it is reasonable to approve a surcharge for the VMP because VMP surcharge annual review will assure that only the actual cost of the VMP will be recovered in rates, and the annual VMP review will assure that the VMP will be implemented as intended.

In the past, base rates included provisions for ongoing costs related to vegetation management, however, that type of rate recovery did not assure sufficient revenue to carry-out a cycle-based end-to-end VMP or a means for the Commission to assess the extent and effectiveness of such vegetation management efforts. The Commission understood that a cycle-based end-to-end VMP would result in increased rates when it authorized the VMP program, but determined that such an increase in cost was warranted in order to address the service related issues experienced from the lack of a focused VMP. The Commission believes that authorizing a VMP surcharge with annual reviews, that include annual rate true-ups, is the best way to assure the service related benefits related to the VMP are achieved and appropriate rate recovery is afforded that substantial increase in VMP effort and cost.

The VMP has been in effect since March 18, 2014, and is currently in the initial six-year transition period. The evidence presented in the VMP Case was that after the six-year transition period, the VMP will maintain vegetation along all distribution and transmission lines on a four-year cycle. After the VMP is well-established and the costs well defined, the Commission may find it appropriate to remove the VMP surcharge and roll the VMP costs into base rates in a future base rate case.

The initial VMP surcharge will be set to produce $44.472 million annually, allocated to the various customer tariff classifications as indicated in Mr. Gary's rebuttal testimony, including the modifications to the tariff allocation suggested by both Mr. Baron and Mr. Daniel. Companies Exh. CWG-R at 2-3. In order to avoid multiple rate changes regarding ENEC and VMP filings, the Companies will file their annual ENEC and the VMP review cases at the beginning of March of each year, and the revised ENEC rates and VMP surcharge revisions will take effect at the same time. The Commission will require, therefore, that the Companies file a formal petition for annual review and true-up of the VMP surcharge on or before the first business day of March 2016, and for each year thereafter, until further order of the Commission. As argued by the intervenors, the VMP surcharge review filing true-ups will be determined using the (i) RoE, (ii) federal and state income tax rates, (iii) tariff allocations and (iv) new depreciation rates approved in this Order.

B. PJM OATT Revenues.

The Companies proposed a shift of PJM Open Access Transmission Tariff (OATT) revenues from ENEC proceedings to base rate proceedings. Companies Exh. JJS-D at 6-11; Companies Exh. CRP-R at **3;** Companies Exh. SHF-D at 11-12; Tr. 1/20 at 50-55. Staff witness Eads and WVEUG witness Baron both opposed the shift. Staff Exh. TRE-D at 21-24; WVEUG Exh. SJB-D at 21-24; Tr. 1/22 at 146-149. The Companies stated in their initial brief that they decided to withdraw the proposed shift of PJM OATT revenues in this case. The Companies stated that although they continue to think that a shift of PJM OATT revenues to base rates is a sound concept, they have come to the conclusion that they can improve upon their proposal in a fashion that will permit PJM OATT revenues to continue to be handled in ENEC proceedings. Accordingly, the Companies presented their new proposal in their ENEC filing on March 2, 2015, in Case No. 15-0303-E-P. The issue will not, therefore, be considered in this case.

C. Major Storm Expense Tracker

Companies witness Scalzo testified that the Companies proposed implementation of a new tracker for major storm restoration expenses would allow the Commission and the Companies to true-up the storm expenses embedded in rates with those actually incurred. Companies Exh. JJS-D at 4-6. Mr. Scalzo stated in his rebuttal testimony, in response to WVEUG witness Kollen, that a major storm is one with severe weather where assistance is secured from outside of the affected district and restoration efforts last longer than twenty-four hours. The major costs are typically labor, contractor costs, fleet cost, materials and supplies. Under the proposed approach, capital costs associated with major storms would continue to be recovered in base rates. Companies Exh. JJS-R at 5. In response to Staff witness Melton, Mr. Scalzo stated that the storm tracker would assign the overall benefits of the VMP, which is expected to result in lower storm restoration costs in the future, to the customers who are paying for the VMP. The three-year average of major storm restoration costs, or $6.7 million, will be included in the 2012 Storm deferral. Then, if future major storm costs are less than $6.7 million annually, the difference would be used to reduce the 2012 storm deferral balance.

In their initial brief the Companies ask the Commission to consider authorizing the storm tracker on a trial basis. The Companies believe that over time, the tracker will "tilt in the ratepayer's favor" because the Companies expect that implementing the new VMP will lead to lower overall average storm restoration costs. Companies Init. Br. at 57; Companies Exh. JJS-R at 6.

WVEUG witness Kollen opposed the major storm restoration expense tracker because the proposal was not sufficiently defined. WVEUG Exh. LK-D at 35-37. The Companies did not specify whether the proposed deferred accounting approach would include depreciation or a return on construction or plant in service costs. In addition, the Companies did not state how insurance proceeds would be reflected, did not define or describe whether the deferred return would be calculated on the deferred costs net of ADITs, or describe how the deferred financing costs would be integrated with the deferred costs included in rate base. Id. at 36-37.

Staff witness Melton also opposed the major storm tracker. Staff Exh. EEM-D at 2-4. Mr. Melton stated that the Commission does not routinely use cost tracking and deferred accounting for specific elements of utility costs in ratemaking. The Commission's common practice is to establish rates based on a utility's historic cost, adjusted for known and measurable changes, to give the utility a reasonable opportunity to recover its cost of service and to earn a reasonable return on investor supplied capital.

The Commission has authorized expense tracking mechanisms in ratemaking that deviate from traditional ratemaking practice only on a case-by-case basis when costs are shown to be highly volatile, unusual, or of sufficient magnitude that if left constrained to the traditional rate setting process, could adversely impact the well-being of the utility or the customers. Staff Exh. EEM-D at 4. When major storms have occurred in the past, the Commission has allowed an electric utility to defer and recover the recovery costs. Staff Exh. EEM-D at 3, citing 2010 Rate Case (approving recovery by the Companies of $18.2 million in costs for the 2009/2010 major winter storm). The approach proposed in this case is different, however, because it would allow the Companies to automatically defer the cost of all storms that they classify as major, regardless of whether the storm is extraordinary or not. Staff Exh. EEM-D at 4.

As proposed by the Companies, any variance above or below an average amount that is embedded in base rates would be tracked and deferred. Mr. Melton provided historical figures to show that over and under-recovery of storm costs, while varying from year-to-year, are not unusual or of sufficient magnitude to cause a utility financial harm. Staff Exh. EEM-D at 4-5. Mr. Melton testified that the traditional ratemaking treatment of storm expense results in a better balance of the risks between utility shareholders and ratepayers and that if the utility is assured in advance of one hundred percent recovery of all its major storm expense the balance is upset. Id. at 5; Tr. 1/23 at 88-89; Staff Exh. EEM-D at 5. The risks would be out of balance because, on the one hand, the shareholder would be shielded from a normal aspect of the business profile while the ratepayer, on the other hand, would pay all of the recovery costs and experience the service interruption. Staff Exh. EEM-D at 5.

On cross-examination, Mr. Melton agreed that, under traditional ratemaking, the ratepayer would pay more than actual storm costs in some years and less than actual costs in other years. Tr. 1/23 at 88. Under the Companies' proposal, the Companies would not under-recover, and ratepayers would not pay for more than actual expenses. Id. at 88-89.

The Commission will not authorize a Major Storm Tracking ratemaking mechanism. As described earlier, the Commission has built into base rates a reasonable, normalized level of ongoing storm expense and a significant amount of rate recovery for the VMP. Given the presence of these two rate recovery mechanisms the Commission is not persuaded that an additional deferral mechanism for major storm damage expenses is warranted or appropriate at this time. If the Companies experience extraordinary storm expenses above the normalized level built into the rates authorized in this case, they can make the appropriate decisions regarding whether they should defer those expenses and seek recovery for those costs in a future base rate case where the necessity and prudence of its expenditures can be examined by all interested parties.

D. Security Rider

The Companies proposed approval of a security rider in the tariff to create a regulatory mechanism to track the Companies' investment and costs to defend against possible attacks on physical infrastructure and on computer and information systems. Companies witness Patton stated that security-related expenses may be required on short notice or even on an emergency basis to respond to attacks. Companies Exh. CRP-D at 11-14. Mr. Patton testified that the Companies must be prepared to respond to actual attacks against their generation, transmission, distribution, and other physical facilities, attacks on their systems in cyberspace, and to implement protective security measures. Id. at 14. Mr. Patton stated that in the future the North American Electric Reliability Corporation (NERC) and other authorities will mandate implementation of security measures. The security rider to track and defer capital and O&M costs will allow the Companies flexibility to respond. The Companies would request recovery of deferred costs in subsequent base rate proceedings. The Companies asked that capital investments in security be subject to carrying charges at the Companies' weighted average cost of capital and to any applicable depreciation expense. Id. at 14.

In response to the Staff and WVEUG objections to the Security Rider, Mr. Patton stated that the nature of terrorist activities and cyber-security threats is such that they cannot be known or measurable. Terrorists and wrong-doers constantly seek out new ways of causing harm. Companies Exh. CRP-R at 5-6 (responding to Staff Exh. TRE-D at 19-20; WVEUG Exh. LK-D at 38-41). A flexible mechanism for addressing these activities is required. Mr. Patton stated that implementing new security measures will require significant sums of money, the amount will fluctuate, and the amounts will exceed amounts spent in the past on traditional security measures. Id. at 6. Mr. Patton asked the Commission not to adopt a wait and see policy on emerging threats. Id.

In their brief, the Companies' argued that the Security Rider would not predetermine a Commission treatment of security investments and expenditures. It would, however, enable the Companies to make security investments and expenditures in a timely fashion.

WVEUG witness Kollen stated that the Companies did not support the request for approval of a Security Rider with projected costs, a statement of the security costs already in base rates, a methodology to determine incremental costs, or a date that an associated rate change would go into effect. WVEUG Exh. LK-D at 38-40. Mr. Kollen objected that the Companies did not consider that existing rate base investments in security will continue to depreciate. Mr. Kollen argued that the Companies should not be allowed to recover increment costs through a surcharge or defer costs for future base rate recovery while retaining the savings from the ongoing reductions in its revenue requirement. Id. at 39-40.

Staff witness Eads also opposed the Security Rider. Mr. Eads stated that although there may be increased requirements related to security, the requirements are speculative at this time and the associated costs are not known. Mr. Eads stated that the request to defer costs is premature, but that the Companies may raise the issue at a later date when they can demonstrate costs. Staff Exh. TRE-D at 20. In the Staff brief, Staff argued that the Commission should reject the Companies Security Rider proposal because it lacks sufficient detail to support it. Staff argued that even if the Companies reasonably believe they will incur increased investment and costs to implement security measures, the normal regulatory process should not be bypassed. Citing Hope Gas, Inc., dba Dominion Hope, Case No. 08-1783-6-42T, Commission Order November 20, 2009 at 5. Staff argued that if the Companies receive notice of upcoming regulations related to security, they are free to once again propose a security rider and would likely be better able to describe the magnitude of the costs associated with compliance. Staff Init. Br. at 59-60.

The Commission is aware of the increased security dangers presented in the modern world, particularly to the electric utility system. We know that extraordinary steps will become necessary (and may become common), but the Commission concludes that in the absence of concrete plans to implement specific security measures, projected costs, or new regulatory requirements, the proposal of the Companies to implement a Security Rider is premature.

E. Economic Development Rider

The Companies proposed the addition of an Economic Development Rider with this case filing. CRP-D at 12. Staff and WVEUG took issue with the lack of specificity in the Companies' proposal. In Mr. Patton's rebuttal testimony, he withdrew the Companies' request for the Economic Development Rider in this case. Companies Exh. CRP-R at 7.

F. Construction Surcharge – A History

The APCo Construction Surcharge originated by Commission Order issued July 26, 2006, in a base rate case proceeding, Case No. 05-1278-E-PC-PW-42T (2005 Rate Case). In that proceeding, the Commission reinstituted the annual ENEC mechanism for the Companies. In addition, the Commission authorized several special cost recovery mechanisms to address costs related to certain, specified, extraordinary construction projects that required annual evaluation and recalculation. The Commission implemented annual evaluation of the special cost recovery mechanism coincidental with, and as part of, the annual ENEC proceedings. At that time, the construction projects accorded special cost recovery treatment included the Wyoming-Jacksons Ferry (Wyoming) 765 kV transmission line and the retrofit of flue-gas desulfurization units ("scrubbers") on the Mountaineer generating plant and Units 1, 2 and 3 of the John Amos generating plant. 2005 Rate Case, July 26, 2006 Commission Order, Joint Stipulation attached as Appendix A at 10-12.

The Commission allowed rate recovery of costs for these construction projects through an immediate return on the documented CWIP during construction and continuing recovery after construction, until the costs could be rolled into base rates. To differentiate the changing nature (during construction and post-construction) of the special rate mechanism, the resulting surcharge was sometimes referred to as a Construction Surcharge, an Electric Plant in Service (EPIS) surcharge, or a Construction/765kV Surcharge.

Pursuant to Commission Order in the 2005 Rate Case, APCo filed a single new APCo tariff sheet designated Original Sheet No. 27. The initial rate increments for the Construction Surcharge included an energy rate of .162¢ per kWh for the residential class and demand rates from 45.3¢ to 67.9¢ per kW for the industrial class.

In the 2007 ENEC case, Case No. 07-0248-E-GI, the first ENEC proceeding after reinstatement of the ENEC, the Commission approved an updated Construction Surcharge based on a stipulation and settlement by the parties. The tariff filed by APCo, First Revision of Original Sheet No. 27, reflected the updated surcharge that included an energy rate of .358¢ per kWh for the residential class and demand rates from 96.5¢ to $1.301 per kW for the industrial class. June 22, 2007 Commission Order.

In the 2008 ENEC case, Case No. 08-0278-E-GI, the Commission updated the Construction Surcharge, again pursuant to a stipulation and settlement, to include an energy rate of .454¢ per kWh for the residential class and demand rates from $1.141 to $1.581 per kW for the industrial class. June 26, 2008 Commission Order.

In the 2009 ENEC proceeding, Case No. 09-0177-E-GI, the Commission explained the recalculation of the Construction Surcharge to include additional base-rate cost components that would continue after the designated special construction projects were placed in service. The Order stated that the Construction Surcharge would continue until the next base rate case. The Order recognized that the additional $18.1 million in surcharge revenue authorized in that case covered both costs during construction and post-construction. September 30, 2009 Commission Order at 49. APCo filed its tariff in that case continuing the rate schedule designation as "Construction/765 kV Surcharge." The rates in that schedule included an energy rate of .587¢ per kWh for the residential class and a demand rates from $1.474 to $1.847 per kW for the industrial class.

In the 2010 Rate Case, the Commission addressed the ratemaking treatment of the ongoing costs of completed projects that had previously been included in the Construction Surcharge. The test year in that case reflected the full costs of the Wyoming 765kV line and the Mountaineer scrubber because those projects were completed and placed in service prior to the beginning of the test year. The Commission moved a large portion of the costs that had been previously included in the Construction Surcharge into base rates. The Commission also determined that terminal rate base treatment was appropriate for the scrubbers on Amos Units 2 and 3 that had not been placed in service prior to the beginning of the test year but were, by the time of the Commission Order, completed and in service. The Commission continued the Construction Surcharge for the scrubber at Amos Unit 1 that was incomplete at the time of the final Order. March 30, 2011 Order at 73-74.

The movement of most of the costs that were previously recovered through the Construction Surcharge schedule into base rates greatly reduced the remaining costs to be recovered in the Construction Surcharge. Tariff sheet 27 filed pursuant to the Commission Order included an energy rate of .080¢ per kWh for the residential class and a demand rates from 20.3¢ to 24.4¢ per kW for the industrial class.

The Commission again addressed the Construction Surcharge and the timing for moving costs into base rates in its June 30, 2011 Order issued in combined Case Nos. 11-0274-E-GI (Companies 2011 ENEC case), and 11-0265-E-PC (Petition by APCo for acquisition of the Dresden generation plant). The Commission determined that it would include the Dresden costs in the Construction Surcharge. The Commission described the genesis and intent with regard to the surcharge mechanism, and indicated that the costs recovered through the Construction Surcharge were costs typically recovered in base rates and that eventually the surcharge would be eliminated from ENEC filings and recovered in base rates.

> Around 2005, APCo faced extraordinary costs to install pollution-control equipment to meet federal environmental standards and construct the Wyoming-Jackson Ferry 765 kV transmission line. In the annual ENEC proceeding the Commission allowed APCo/WPCo to recover a construction surcharge in lieu of accumulating a growing AFUDC for these extraordinary costs. Ratemaking treatment of using a surcharge for projects during construction is unusual, but in the 2005 Base Rate Case the Commission allowed the special surcharge because of the high level of construction expenditures APCo was experiencing and the reduced rate base

> that results from allowing current recovery of construction expenditure carrying costs rather than capitalizing AFUDC. In the 2005 Base Rate Case, the Commission required APCo/WPCo to file a new base rate case no later than June 30, 2010, so that the Commission could revisit base rates after the retrofit of scrubbers and construction of the transmission line were expected to be completed.
>
> By and large, these high-cost projects are now complete. In the 2010 Base Rate Case, we ordered that the Construction Surcharge related to the capital investments for the Wyoming-Jackson Ferry line and the flue gas desulfurization systems, or scrubbers, at the Mountaineer plant and Units 2 and 3 at the John Amos plant be eliminated from the annual ENEC proceedings. Rate recovery for the ongoing costs related to those items was moved to APCo/WPCo base rate proceedings. 2010 Base Rate Order at 20, 80 (citing Joint Stipulation ¶ 20). Because the Amos Unit 1 scrubber did not go into service until 2011, related costs for this scrubber were not moved into base rates in the 2010 Base Rate Case.

Case Nos. 11-0265-E-PC and 11-0274-E-GI, June 30, 2011 Commission Order at 2-3.

In ENEC proceedings processed after the 2010 Rate Case and prior to the 2014 Rate Case, the Commission continued to recalculate the Construction Surcharge to cover the construction cost, and then the post-construction costs related to the Dresden plant and the scrubber at Amos Unit 1.

In the 2013 ENEC proceeding, Case No. 13-0467-E-GI, the Commission adopted certain terms and conditions of a stipulation and settlement between the parties. One of the provisions in the stipulation stated:

> The Companies commit to file a base rate case no later than June 30, 2014, in which they will propose that the existing Construction Surcharge costs will be rolled into base rates. Upon approval of this proposal, the current Construction Surcharge would no longer be in effect.

APCo 2013 ENEC Case No. 13-0467-E-GI, August 30, 2013 Commission Order, Joint Stipulation attached as Attachment A at 7.

In this proceeding and in the pending 2015 ENEC proceeding, Case No. 15-0301-E-P, APCo is proposing that the Commission roll the costs previously included in the calculation of the Construction Surcharge into base rates and eliminate the Construction Surcharge from its tariff. Companies Exh. 1, Statement B. None of the parties objects to this proposal and the proposal is consistent with the intention of the Commission since the initiation of the Construction Surcharge. The proposal is also consistent with the Commission approved stipulation in Case No. 13-0467-E-GI. The

Commission will move the costs associated with the Dresden Plant and the Amos Unit 1 scrubber into base rates and eliminate APCo Tariff Sheet No. 27.

VIII. RATE DESIGN

A. Class Cost of Service Study

The Companies filing included a Class Cost of Service Study (COSS) that details how costs are classified and allocated among the various classes of West Virginia customers. Companies Exh. DRB-D at 3-4, Companies Rule 42 Exh., Volume VI. The COSS examined the level of revenue that should be recovered from each customer classification and compared those results to revenues at present rates. Id. at 14. The COSS information was provided to Companies witness Vaughan to assist in his determination of the allocation of the requested rate increase by customer classification. Id. at 15. No party raised significant issues with the COSS study but several parties did contest certain elements of the tariff design, particularly the level of subsidies that exist among the customer classifications at present rates.

The Companies have requested the Commission approve the Companies proposed COSS. The Commission understands that a COSS is developed from dozens of allocations and formulas that are largely based on parameters developed through case history and various manuals available on the subject. The Commission is also aware that a COSS is, to some extent, based on the judgment of the preparer and is subject to different methodologies and interpretations.

A COSS provides a point-in-time analysis of how the cost of service should be allocated to the various customer classifications, but those allocations can and do change from rate case to rate case because of changes in the makeup of customers in the different classifications, changes in operation, changes in generation fleet and a host of other factors. Because of the changing nature of the cost of service for each customer classification, the Commission does not normally approve a specific COSS or even a specific methodology. The cost allocations can and do vary from case to case, and the Commission has historically employed the concept of gradualism to move toward the results of the COSS to avoid over-correction in the current case. The Commission normally determines the cost of service allocations based on the record of each case, using its own informed judgment to determine a fair cost allocation in each case that does not overly burden any particular customer classification. The Commission will not deviate from its historical approach to COSS and will not approve the specific COSS offered by the Companies. The Commission, however, has relied on the Companies COSS study proposed in this case as a guideline in determining the specific cost allocation issues addressed below.

B. Inter-Class Subsidy

The Companies COSS demonstrated that the present rate structure of the Companies produces a RoR less than the current RoR of 5.05 percent for the Residential, Sanctuary Worship Service, School Service, and Small General Service classes of customers. Under-producing the current RoR is an indication that these customer classes are being subsidized by the other customer classifications. Companies Exh. AEV-D at 8-10; Tr. 1/22 at 340; WVEUG Exh. SJB-D at 9. The Companies proposed to move towards equalized RoR for the customer classes by reducing the subsidies by twenty-five percent. Companies Exh. AEV-D at 10; SHF-D at 8. Mr. Ferguson testified that a twenty-five percent subsidy reduction would be an appropriate step towards parity and would not be unduly disruptive to the subsidized classes. Companies Exh. SHF-D at 8; Tr. 1/22 at 343; see also Tr. 1/21 at 256. On cross examination, Mr. Vaughan confirmed that a twenty-five percent subsidy reduction would result in continuing inter-class subsidies of about $45 million. Tr. 1/21 at 255.

WVEUG and SWVA both proposed a fifty percent reduction in inter-class subsidies. WVEUG Exh. SJB-D at 8-12; SWVA Exh. JWD-D at 11. WVEUG witness Baron estimated in his testimony that the amount of the current subsidies exceeds $60 million annually. WVEUG Exh. SJB-D at 8, Table 1. Mr. Baron claimed the largest customers of the Companies, served on Rate Schedules IP, LCP, and Special Contracts pay approximately $40 million of the $60 million of subsidies. Id.; Tr. 1/22 at 341. Mr. Baron argued that a twenty-five percent reduction will not be meaningful because rates will still result in $45 million of subsidies annually, with the largest customers paying $30 million of that amount. WVEUG Exh. SJB-D at 9-10. Mr. Baron claimed the subsidies at the time of the 2010 Rate Case were roughly $15.5 million for the LCP and IP classes and $1.5 million for Special Contract customers. WVEUG Exh. SJB-D at 9; Tr. 1/22 at 155-57, 342. WVEUG argued that even if the Commission adopts the higher fifty percent reduction in subsidies, the result will be to maintain the status-quo, and not to move toward parity. Tr. 1/22 at 156; WVEUG Init. Br. at 8. WVEUG urged the Commission to adopt a rate design that moves meaningfully toward cost-based rates for all customer classes, and to establish a process to eliminate the subsidies in the future. WVEUG Init. Br. at 10-11.

WVEUG argued in its Reply Brief that the Companies failed to present evidence that their proposed twenty-five percent reduction in subsidies is more reasonable than a fifty percent reduction. WVEUG argued that a larger reduction is further supported by the impact of the ENEC process that does not take gradualism into consideration. The Companies' recent ENEC filing requests a $61.5 million increase, the heaviest burden of which will be borne by the largest customers because of the energy-based nature of ENEC rates. WVEUG argued that the Commission should adopt a rate design that meaningfully addresses the decades-long inter-class subsidy issue. WVEUG Reply Brief at 5-7.

SWVA witness Daniels stated that a twenty-five percent reduction would make it likely that large customers would continue to pay substantial subsidies to other customer classes for many years. Even if a twenty-five percent reduction occurred in each of the Companies next three base rate cases, subsidies could continue for the next fifteen years at an approximate total cost of $452 million to the subsidizing customer classes. SWVA Exh. JWD-D at 11; Tr. 1/21 at 255; Tr. 1/22 at 11-12.

Walmart witness Chriss testified that Walmart did not object to the Companies proposal to reduce existing subsidies by twenty-five percent. Mr. Chriss recommended, however, that if the Commission determined a lower revenue requirement in this case, the Commission should first allocate revenues so that twenty-five percent of current subsidies are eliminated and then determine the extent to which rates can be moved closer to the cost of service for each rate class beyond the twenty-five percent reduction. Walmart Exh. SWC-D at 15.

CAD argued in its Initial Brief that the Commission should adopt the Companies' proposal to reduce existing subsidies by twenty-five percent. CAD stated that the fifty percent reduction sought by WVEUG and SWVA would result in a twenty percent rate increase to residential customers and violate the ratemaking principle of gradualism. CAD Init. Br. at 83-84.

The Commission has reviewed the record in this proceeding about the existence of inter-class subsidies and the recommendations of the parties about how best to address movement to eliminate those subsidies. Rate subsidization sends inappropriate cost signals, and can unfairly burden a customer class. The Commission plans over time to eliminate those subsidies and will authorize tariffs that remove approximately one-third of the inter-class subsidies in this case. The one-third allocation results in a slight rate decrease for the OL and SL tariffs. The Commission will not lower rates to those two customer classes, but will reallocate that reduction to the residential class.

The Commission believes the reduction of the current inter-class subsidy by one-third is a reasonable approach to cost allocation issues in this case. This approach (i) will make significant progress towards eliminating the subsidy, (ii) improve the level of subsidies present in the 2010 Rate Case for large customers, and (iii) maintain the Commission practice of gradualism when moving to full cost based rates. This approach will not overburden any one customer classification with the rates authorized in this case. The Commission cost allocation by customer class (tariff) is attached as Appendix C to this Order.

C. Fuel Inventory Classification

SWVA witness Daniel recommended that the Commission consider the fuel inventory expenses of the Companies to be demand costs as opposed to energy costs. SWVA Exh. JWD-D at 6-8. The Companies did not agree and stated in their brief that the Commission should regard fuel inventory expenses as an energy cost. Companies

Init. Br. at 62. The Companies reasoned that although they have a target inventory that the plants are trying to maintain, the coal levels will vary: "The more a plant runs, the more coal the plant will burn." Id., Tr. 1/23 at 127. Because demand costs are fixed costs and energy costs vary based on the energy that is produced, it would be improper to classify fuel inventory costs as a demand cost. The Commission agrees that the fuel inventory costs are properly classified as an energy cost.

D. Basic Service Charges and Declining Block Tariff

Companies witness Vaughan testified in support of the request of the Companies to increase the basic service charge for the Residential, Small General Service and Sanctuary Worship Service customer classes. Specifically, the Companies proposed to increase the basic service charge in each of these customer classes by $5. Under the proposal, the residential service charge would increase from $5 to $10 per month, the SGS service charge would increase from $8.45 to $13.45 per month, and the SWS service charge would increase from $8.15 to $13.15 per month. Companies Exh. AEV-D at 14, 19-20. The Companies also proposed to remove the block differential by removing the higher charge for the first 500 kWh of usage per billing cycle. Mr. Vaughan stated the increase would better apportion the fixed costs of providing service among these customers. Id. at 14. To support the Companies proposal, Mr. Vaughan testified that the actual monthly fixed costs of standing ready to serve a residential customer, excluding generation, transmission, and costs that vary by kWh demand, is $32 per month. Id. at 16, attached Exh. AEV-D4. Under an alternative calculation method known as the marginal customer connection method, Mr. Vaughan calculated that the monthly fixed cost per customer was actually about $42 per month. Id. at 18. Mr. Vaughan stated that although cost causation principles support a higher charge, the policy of gradualism supports the $5 proposed service charge increases in this case. Id. at 16-17.

There is a tendency to equate high usage with high income levels. That is not necessarily true. Mr. Vaughan stated that some increase in the basic service charge and elimination of the block differential for residential customers will benefit high-usage residential customers with older, less energy efficient appliances, less efficient housing stock, and households with larger family sizes. Those customers will see a decrease in their bills while the average residential customer would have no bill increase. Companies Exh. AEV-D at 15-16, 19, Tr. 1/21 at 237, 239. Mr. Vaughan testified that the current basic service charge of the Companies is very low when compared to other jurisdictions. Tr. 1/21 at 274-75.

Mr. Vaughan testified that under current rates, many costs attributable to connection and maintenance of service on the distribution system are recovered through the volumetric rate instead of through the basic customer charge. Companies Exh. AEV-R at 7. He noted that recovery of fixed costs through a volumetric rate does not conform to cost causation principles. Id. Using a hypothetical example of three types of residential customers, Mr. Vaughan testified that Staff witness Eads' service charge proposal would slightly decrease (by two percent) existing intra-class subsidies, while the

Companies' proposal would reduce the subsidies more substantially (by ten percent). Mr. Vaughan stated that because base rate cases occur infrequently, the Staff approach is impractical and it is reasonable to take a measured but larger step in this case toward eliminating intra-class subsidies. Id. at 10.

CAD did not present testimony on this issue but objected to the proposed one-hundred percent increase in the basic service charge for residential customers from \$5 per month to \$10. CAD argued that the increase is regressive and will have a negative impact on those customers who struggle to pay utility bills. CAD Init. Br. at 83.

Staff witness Eads testified that Staff supports an increase in the customer charge, but that the Commission should base the amount of the customer charge primarily on the fixed costs associated with customer metering and billing. Mr. Eads said that the basic charge should also cover portions of property insurance, injuries and damages, employee pensions and benefits, and payroll related taxes. Staff Exh. TRE-D at 24, Tr. 1/23 at 93, Staff Exh. KJ-D at 2. Mr. Eads and Staff witness Jennings recommended a residential customer charge of \$6.25. They testified that the SGS customer charge should remain unchanged at \$8.15 and the SWS customer charge should be increased slightly to \$8.82. Id., attached Exh. KJ-1, Staff Exh., TRE-D at 26, 29. Mr. Eads did not agree with the Companies' proposal to eliminate the declining block tariff for residential customers. Mr. Eads argued that fixed charges should be recovered based on system demand, not energy usage, but residential meters only measure energy usage, not demand. Mr. Eads supports continuation of the under 500 kWh tariff block because doing so would result in a larger share of the fixed costs being be recovered in the under 500 kWh block and, therefore, the declining block structure is the best way to mimic the results of a demand charge for the residential class. Staff Exh. TRE-D at 24-29.

The Commission will not abandon its practice of determining the basic service charge based on costs related to meters, services and billing. The Commission believes the approach proposed by Staff for determining the basic service charge is reasonable. The Commission will, however, modify the Staff calculation to include the rate base, cost of capital and income tax expenses used in the cost of service determined by the Commission for this proceeding as shown on the attached Appendix A. In addition, based on the Commission review of the Staff calculation, it does not appear Staff included customer-related expenses of \$8.807 million for the categories of Customer Information Expense and Customer Service as shown on pages 9 and 10 of the Companies COSS. Companies Exhibit 1, Vol. VI. The Commission has also modified the Staff calculation to include the additional \$8.807 million of customer-related expenses missing from the Staff calculation.

The Commission modifications resulted in basic service charges of \$8.10 for the RS tariff, \$9.51 for the SGS tariff and \$10.92 for the SWS tariff. In order to maintain the general rounding applied to the basic service charges included in the current rate schedules, the Commission will authorize basic service charges of (i) \$8.00 for the

RS tariff, (ii) $9.50 for the SGS tariff and (iii) $10.90 for the SWS tariff. In addition, the Commission will adopt the Staff position to not combine the under/over 500 kWh blocks for the RS, SGS, and SWS tariffs as proposed by the Companies. The Commission agrees with Staff that maintaining the under 500 kWh tariff block is a better method of recovering the fixed cost normally recovered in a demand charge that is not currently part of these three tariff classifications.

E. General Service (GS) and Large General Service (LGS) Time of Day Rate Structure

Companies witness Vaughan testified that presently, the Companies bill General Service Time of Day Tariff (GS TOD) rates to customers with maximum demands of less than 500 kW. The Companies proposed to revise the availability of the GS TOD tariff to general service customers that the Companies serve at the secondary or primary delivery voltage levels and with maximum demands less than 150 kW. Customers with maximum demands greater than 150 kW taking service under schedule GS TOD as of July 30, 2014, however, could continue taking service under GS TOD. Companies Exh. AEV-D at 20.

Mr. Vaughan stated that the Companies are proposing new rates under a Large General Service Time of Day (LGS TOD) tariff, for general service customers with normal maximum demands of greater than 150 kW but less than 1,000 kW. Current GS TOD customers with demands of 150 kW or greater are not required to move to the LGS TOD tariff and may remain on the GS TOD tariff at this time. Mr. Vaughan testified that the GS TOD and the LGS TOD are similar because they both include a basic service charge, an on-peak energy charge and an off-peak energy charge. The new LGS TOD, however, also includes a demand charge. Companies Exh. AEV-D at 20-21.

Mr. Vaughan testified that the purpose of the proposed changes is to better align the TOD offering with standard tariffs and to include some fixed cost recovery through a demand charge instead of including all fixed costs in the energy charges. The LGS TOD tariff, therefore, will allow recovery of all primary and secondary distribution costs and a small portion of non-ENEC demand costs through the demand charge rather than entirely through the on-peak and off-peak energy charges as the GS TOD tariff does. Mr. Vaughan testified that the changes will have no impact on the average LGS TOD customer because they are not required to move to the new tariff structure at this time. Companies Exh. AEV-D at 21-22.

The Commission will approve these proposals based on the testimony and because no party objected to the proposed modification of the GS TOD tariff or the addition of an LGS TOD tariff and there will be no impact on current customers of the Companies.

F. LPS Tariff

Companies witness Vaughan testified that the Companies are proposing to eliminate the Large Capacity Power (LCP) and Industrial Power (IP) tariffs and replace them with a single new tariff, Large Power Service (LPS). Mr. Vaughan stated that the change will simplify the tariffs without eliminating customer choices. He explained that only approximately thirty customers were on the IP tariff during the test year because the load factor cross over point between LCP and IP had become skewed. Companies Exh. AEV-D at 22.

The proposed LPS tariff would include a monthly peak demand charge, an off-peak excess demand charge, an excess kVAr reactive demand charge, a basic service charge and a two-tiered energy charge. The first tier of the energy charge will apply to the first 500 kWh per kW of billing demand. The second tier energy charge will apply to all kWh over 500 kWh per kW of billing demand. Mr. Vaughan testified that the advantage of the LPS rate structure will be that it can accommodate the former LCP and IP customers with little or no rate impact because of the rate design change. The tiered energy charge makes this structure appealing to both high and low load factor customers, because all fixed costs will be recovered through the peak demand charge and the first-tier energy charge. High load factor customers in the first block of energy, therefore, will have essentially a one hundred percent full cost demand charge. Low load factor customers, conversely, will have an effective demand charge that will be a lower percentage of full cost because they will not use the entire first block of energy in the rate design. Companies Exh. AEV-D at 22-23.

Mr. Vaughan stated that this change in rate design will also be advantageous to customers near the crossover point between the former LCP and IP tariffs. He gave as an example a customer who now has to choose between LCP or IP although the customer might be better off under LCP some months, and under IP other months. With a single LPS tariff, that customer does not have to choose. Mr. Vaughan stated that use of a single LPS tariff will not have a rate impact on the average IP/LCP customer. Companies Exh. AEV-D at 23; Tr. 1/21 at 260-61.

WVEUG witness Baron testified that he did not object to combining the LCP and IP tariffs into a single tariff, but that he did not agree with Mr. Vaughan's rate design. Mr. Baron stated that, as proposed, about sixty percent of the fixed demand costs attributable to Rate Schedules LCP and IP will be recovered in the kW demand charge, with the remaining forty percent recovered in the first hours-use energy block. Under that approach, only sixty percent of fixed demand-related costs would actually be recovered in the kW demand charge, and a significant amount of demand costs would be recovered via a kWh energy charge. Mr. Baron regards these results as inconsistent with cost causation. He also believes that the rate design could result in a misallocation of cost responsibility to customers on the new schedule and customers with special contracts tied to the rate. Mr. Baron stated that it is appropriate to recover one hundred percent of the LCP/IP demand-related costs in the kW demand charge and have a single energy charge to recover base rate energy-related costs. WVEUG Exh. SJB-D at 13-14. Mr. Baron sponsored his Exhibit SJB-3 setting forth an alternative LPS rate design and schedule.

Walmart witness Chriss testified that the Companies' proposal of a single LPS tariff would not reflect the underlying cost of service and would shift cost responsibility within the rate class because it would charge customers for demand-related costs using energy charges. Mr. Chriss stated that the Companies' workpapers indicated that approximately ninety-nine percent of non-ENEC base revenues for proposed LPS Secondary are demand-related and that approximately ninety-seven percent of non-ENEC base revenues for proposed LPS Primary are demand-related, citing his attached exhibits SWC-6 and SWC-7; see also Tr. 1/21 at 259-60. Mr. Chriss stated that the proposed LPS rate design for LPS Secondary would result in thirty-seven percent of revenues being collected on the energy charges and sixty-two percent of revenues being collected on the demand charges.

For proposed LPS primary, the rate design would collect approximately forty percent of revenues on the energy charges and fifty-eight percent on the demand charges. Mr. Chriss testified that the collection of costs should reflect how those costs are incurred, and collecting demand-related costs through an energy charge would be inconsistent with cost causation principles. Mr. Chriss provided an example of how a tariff designed to recover demand related costs on a kWh energy basis instead of on a per kW demand charge inappropriately shifts fixed cost responsibility from lower load factor customers to higher load factor customers. Walmart Exh. SWC-D at 18-21.

Mr. Chriss testified that the proposal of the Companies for a new time of day tariff would mitigate the misallocation of costs but only to a limited extent. He stated that as load factor increases, the cost per kW charged to customers for demand-related costs increases. As load factors increase from zero to 59.4 percent, customers receive a subsidy because the cost per kW charged to customers for demand-related costs is below the full cost demand rate. As load factor increases beyond 59.6 percent, however, the customer overpays for demand by an increasing amount. Mr. Chriss stated that an increase in load factor should not result in an increase in the demand-related cost per kW charged to a customer. Walmart Exh. SWC-D at 22-23.

In rebuttal testimony, Mr. Vaughan stated that the Companies' proposal strikes a balance between higher and lower load factor industrial customers. The WVEUG position, conversely, would benefit the higher load factor customers at the expense of the lower load factor customers. Mr. Vaughan explained that Mr. Baron proposed to increase the demand charge to one hundred percent of demand costs as compared to the current LCP tariff that uses a kW demand charge that is eighty percent of full cost and the current IP tariff that contains a kW demand charge that is ninety percent of full cost. Mr. Vaughan stated that the average load factors for LCP and IP are approximately sixty and eighty percent respectively. Under Mr. Baron's proposal, therefore, low load factor LPS customers would experience a rate increase as high as thirty-one percent.

Mr. Vaughan stated that the Commission should not adopt an LPS rate design that would increase the percent of full cost that is included in the kW demand charge to more than eighty percent. Companies Exh. AEV-R at 11; Tr. 1/21 at 261.

In rebuttal to Walmart witness Chriss' recommendation to maintain the current LCP and IP tariffs, Mr. Vaughan disagreed that demand-related costs to serve a customer do not change with the load factor and that an increase in load factor should not result in an increase in the demand-related cost per kW charge to that customer. Mr. Vaughan testified that actual demand costs related to serving a customer are directly related to how coincident that customer's peak demand is with the Companies' peak demand. Higher load factor customers tend to be more coincident with the Companies' peak because their average usage is a larger percentage of their peak usage. Tr. 1/21 at 271-72. The higher the load factor, therefore, the more likely it is that the customer will consume its peak usage at the time of the Companies' peak demand. Companies Exh. AEV-R at 11-12.

Mr. Vaughan testified that neither Mr. Baron's nor Mr. Chriss' proposals balance the interests of both higher and lower load factor LPS customers. In the Companies' brief, the Companies argued that the proposed LCP rate design will benefit high load factor customers because the class will be diverse and lower load factor customers generally have peaks that are less coincident with the Companies' peaks. This will cause less cost to be allocated to the class. Companies Brief at 65-66.

The record is lacking in sufficient data for full evaluation of the impact the Companies' proposal will have on all customers in the LCP and IP classes. The bill analysis attached to Mr. Vaughan's testimony shows the impact on the average customer, but not the impact on the full range of customers with varying load factors within the class. Companies Exh. AEV-D3. The Companies should provide a full bill frequency analysis in the next rate case if they wish to pursue consolidation of the LCP and IP classes. Until then, the Commission will require the Companies to maintain the LCP and IP rate schedules.

IX. TARIFF TERMS AND CONDITIONS

A. Waivers of Provisions of the Electric Rules

1. Electric Rules Personal Contact Requirement

The Companies made two alternative requests to the requirement to make personal contact with a customer prior to disconnection that is set forth in the Commission Rules for the Government of Electric Utilities, 150 C.S.R. 3 (Electric Rules). The first request is to eliminate the personal contact requirement. If the Commission declines to eliminate the personal contact requirement, the Companies asked the Commission to eliminate the requirement to seek a waiver when attempts at personal contact have failed.

Electric Rules 4.8.a.1 and 4.8.a.1.A provide that before service may be terminated for non-payment of a delinquent bill, the utility must provide both a written notice to the customer and achieve personal contact at least twenty-four hours in advance of the termination. Attaining personal contact requires the Companies to determine under Electric Rule 4.8.a.1.E, if anyone in the home is sixty-five years old or older, or is physically, mentally or emotionally incapacitated. The utility may achieve personal contact by a telephone contact or in-person contact with a responsible person. Electric Rule 4.8.a.1.M requires that if an electric utility is unable to contact a customer by telephone, an employee or agent of the utility must make an on-site visit to the service location to accomplish the 24-hour advance personal contact or to leave a notice. If no one answers the door, the utility leaves a notice at the premise and files a petition for waiver of the personal contact requirement.

A utility may petition the Commission to waive the personal contact requirement only after the utility has made at least three attempts at personal contact, including an on-site visit. At least one of the attempts must be made after normal working hours of 8:00 a.m. to 6:00 p.m. The utility may make a telephone call as an after-hours attempt at personal contact. Companies witness Greenhowe testified that the Companies proposal is to provide a message on electric bills directing customers to inform the Companies that they are sixty-five years old or older, or are physically, mentally or emotionally incapacitated so the Companies would not be required to ask customers these questions when termination issues arise. Furthermore, the Companies request that personal contact consist only of a written notice at least ten days prior to termination and an attempt to make personal contact by telephone contact twenty-four hours in advance of termination. Companies Exh. RAG-D at 9.

Companies witnesses Patton and Querry testified in support of a permanent waiver of the personal contact requirement. They stated that on-site visits can present dangers to the safety of utility employees. Companies Exh. CRP-D at 15; Tr. 1/23 at 134-36. Mr. Querry spoke of specific threats that he has experienced involving weapons and animals. Companies Exh. BGQ-R at 2; Tr. 1/31 at 134-35. Mr. Patton and Mr. Querry stated that aggressive behavior by customers and associated safety risks are increasing over time. Companies Exh. BGQ-R at 3-4; Tr. 1/31 at 23, 137-38. Mr. Querry stated when the utility makes a home visit, customers are often either not at home or choose not to respond to a knock on the door. Tr. 1/31 at 131-32; Companies Exh. BGQ-R at 2. A home visit also informs the customer of the date that the utility will return to physically terminate service and therefore offers the opportunity for aggressive customers to interfere with employees doing their jobs. Tr. 1/23 at 131, 135-36.

In rebuttal testimony, Companies witness Greenhowe stated that the Companies document aggressive customers in two categories. Those who have physically threatened utility employees are "C1 Customers." The Companies require employees to obtain a police escort to perform any type of work on C1 Customers' property. Customers with a history of being verbally abusive or who threaten to destroy utility equipment or are otherwise difficult to deal with are categorized as "CU Customers." Companies Exh.

RAG-R at 7. She testified that of the West Virginia customers in the Charleston, Huntington, Wheeling and Christiansburg service districts 139 are labeled as C1 Customers, and 123 are labeled as CU Customers for a total of 262 customers. Companies Exh. RAG-R at 7-8; Tr. 1/22 at 302 correcting pre-filed testimony.

The Companies argued in their brief that on-site visits to provide notice of termination are unnecessary, letters and phone calls are as effective, and that the home visit requirement is an extraordinary and undue hardship. The Companies also stated that many other states do not require personal contact and that water utilities in West Virginia are not required to make personal contact. Companies Init. Br. at 68.

In the Staff brief, Staff opposed the changes proposed by the Companies to the personal contact requirements. Staff discussed the background of how the Commission's personal contact requirements evolved. The Commission's personal contact requirements were initially put in place in recognition of, among other things, a decision of the Supreme Court of Appeals of the United States that utility service is a necessity in modern life. Citing, Memphis Light, Gas & Water Div. v. Craft, 436 U.S. 1, 17, 98 S. Ct. 1554, 1565, 50 L.Ed.2d 30,44 (US. 1978). Following the Supreme Court decision in Memphis Light, the Commission addressed due process in utility termination procedures in several proceedings. Case No. 9579, Coalition on Legislation for the Elderly and Council of Senior West Virginians; General Order 185.1, In the matter of revisions of the Rules and Regulations for Gas Utilities; and General Order No. 184.2 (electric); General Order No. 185.2 (gas), 187.2 (telephone), 188.1 (water), (collectively, 1980 Termination of Service Rulemaking) Commission Order issued January 8, 1980; Order on rehearing issued November 7, 1980. The personal contact requirements were the subject of rehearing in the rulemaking cases. The Commission concluded on rehearing that attempts to make personal contact did not satisfy the personal contact requirement, and the Commission noted that a utility may apply for a waiver of the rule when personal contact would result in undue hardship. 1980 Termination of Service Rulemaking, Commission Order on rehearing, November 7, 1980 at 7.

Staff acknowledged the importance of utility employee safety, but made several arguments in support of its position that the Commission should not discard its longstanding personal contact requirement. Staff stated that only 262 of the total 750,731 customers who received disconnection notices, and the 12,770 customers who were actually terminated, were classified by the Companies as C1 and CU customers. In addition, utility employees make premises visits for reasons other than notice, including the actual disconnection, subsequent reconnection, and investigation of unauthorized usage. Staff argued, therefore, that removal of the personal contact notice requirement cannot eliminate all safety issues relating to a premise visit. Staff Init. Br. at 66-67.

Staff also argued that premises visits are valuable because they lead to customer understanding that a utility bill may no longer be ignored. The visit can also inform a utility of customers who are caring for sick household members. Some customers respond to personal contact visits by paying outstanding bills. Staff Init. Br. at 67-68.

Staff summarized the notice of termination requirements in Pennsylvania, Maryland, Ohio, Virginia and Kentucky. Staff stated that in states without a personal contact requirement, other customer protections, such as delayed termination for low income customers in cold weather and conditional reconnections, are included in the rules. In this case, however, the Companies did not propose including new customer protections. Staff Init. Br. at 68-70.

Staff argued in its brief that the Companies should continue to provide notice of termination by personal contact and observe all employee safety guidelines including seeking a waiver if a customer has made threats to an employee. Staff urged the Commission not to rush a decision to amend the longstanding personal contact requirement without exploring alternatives and reviewing the potential harm to customers. Staff stated that the Companies did not provide public notice of the request to eliminate personal contact notice to customers from its termination procedures. Staff believes that the Commission should examine the issue in a general investigation. Staff Init. Br. at 71.

The Commission appreciates the changing times. We are attempting to balance the interests of the customers with the safety of the Companies employees. On March 27, 2015, the Commission initiated a general investigation proceeding to consider recommended modifications to the termination rules applicable to both electric and gas utilities. Case No. 15-0469-E-G-GI, General Investigation into the utility discontinuance of service customer termination provisions of the Electric and Gas Rules. The personal contact requirements as well as waivers, Friday disconnections, the timing of overdue and delinquent bills, and termination of service to customers who may be aged or incapacitated, will be reviewed in that proceeding. Initial comments in the general investigation are due May 29, 2015 and reply comments are due June 29, 2015.

The majority of the Companies' requests regarding termination rules are appropriate for consideration in Case No. 15-0469-E-G-GI. The evidence presented by the Companies regarding threats to utility employees from certain customers, however, was compelling and merits a response in this case.

In view of the escalating concerns expressed by the Companies and their employees about customer aggression, the Commission is convinced that employees should not be required to make premises visits to customers that the Companies have documented to have 1) been verbally or physically aggressive/abusive to employees or utility facilities, 2) threatened to set loose vicious animals, or 3) brandished or made reference to weapons. The Companies have labeled these customers as C1 or CU customers.

Although Case No. 15-0469-E-G-GI is the appropriate case in which to consider permanent amendments to the Electric Rules applicable to terminations, it is reasonable in this case to grant the Companies a blanket waiver of personal contact with respect to C1 and CU customers on an interim basis until the conclusion of Case No. 15-0469-E-G-GI, or a subsequent rulemaking.

2. Tariff Terms and Conditions of Service

The Companies proposed to amend a number of the terms and conditions of service in their tariffs. In the Companies brief, however, they indicated that they do not oppose deferring the various proposals to a subsequent proceeding, so long as that proceeding is instituted in the near term. The proposed tariff changes related to: retaining security deposits; discontinuing the offer to waive the deposit requirement when a new customer enters into the Checkless Payment Plan; implementing charges to provide two or more estimates of the cost to relocate facilities; increasing costs for installation of underground service; changing responsibility for securing right-of-way easements and permits for residential extensions; changing responsibility for right-of-way clearing costs associated with residential extensions; implementing a customer investigation charge; amending the returned check charge; increasing the reconnection charge; adding provisions regarding customers' use of energy; providing for an average monthly billing plan; eliminating the special reconnect option; and adding provisions for credit card bill payments. The Commission believes that to ensure adequate public notice, the Companies should pursue the requested amendments by filing a petition to amend their tariffs. The future filing will be docketed as a "T" case.

X. REVENUE RECOVERY PROPOSAL

Based on a full review of the record, the Commission has determined that the proper level of additional annual revenue for the Companies is $123.5 million. That total increase consists of an increase in base rates of $78.986 million, or 5.76 percent over current rates. In addition, the Commission authorizes the Companies to implement a VMP Surcharge that initially produces an additional $44.472 million, or 3.24 percent, annually. At that level of revenue, however, the impact on residential customers will be large, will be immediate and will test the ability of many customers to afford to pay that rate without some sort of mechanism to phase-in the increase or at least to ameliorate that increase. As shown on Appendix C, the residential share of the $78.986 million base rate increase is $64.013 million. The VMP surcharge will add approximately $29.917 million to that increase, for a total residential increase of $93.930 million. Without a phase-in mechanism, the rate increase as currently proposed for residential customers will be in the range of 16.1 percent, or approximately $19.50 per month for the average residential customer.

APCo/WPCo made a strong case for that significant rate relief. The Commission is concerned, however, about the impact of those rates on customers. The Commission has in the past examined the impact of significant rate increases on customers. In some cases, the Commission has approved Joint Stipulations as fair and reasonable that provide for the implementation of step rates over time. Although those step rates were adopted based on a Joint Stipulation, we were still required to find that these step increases were a reasonable manner to recover the utility's cost of service.

In this case, we do not believe that the APCo/WPCo rates are unfair, unreasonable or not based primarily on costs. As we indicated earlier, the Companies rates are among some of the lowest in the country. Nevertheless, a rate increase of 16.1 percent is a sudden, large and heavy burden for many of the State's residential ratepayers. In order to address this situation, we have adopted an approach to rate relief in this case that is intended, to some degree, to help the ratepayers and to mitigate the rate or sticker shock arising from the relatively large increase while at the same time assuring APCo/WPCo that neither it nor its shareholders will be burdened by absorbing the shortfall between what we believe is a fair level of revenues in this case and some lower level of revenue granted.

Because of that concern about the level of rates for residential customers but bearing in mind the need for rate relief demonstrated by the Companies, the Commission has determined that, in the interest of gradualism in rate changes, there should be a phase-in of the residential base rate increase. The Commission will authorize an immediate base rate increase for the residential customers of $39.013 million which is $25 million less than the amount shown on Appendix C. Adding the effect of the VMP surcharge to this phase-in of the base rate increase, the immediate annual increase for residential customers will be $68.930 million instead of $93.930 million. This represents an average residential increase of 11.8 percent, or approximately $14.30 per month. The $25 million deferred amount may be accrued by APCo/WPCo into a deferred regulatory asset account. APCo/WPCo may also accrue a carrying charge on the monthly regulatory asset balance at the overall rate of return authorized in this case. The $25 million will be added to residential rates on July 1, 2016, which is coincidental with the next scheduled ENEC and VMP rate true-ups. Also, at that time, the Commission will authorize an amortization and recovery of the accrued regulatory asset balance.

XI. CONCLUSION

The rates authorized in this Order will become effective May 26, 2015. No later than ten days from the date of this Order, the Companies must prepare and file with the Commission revised tariff schedules that reflect (i) the increase to base rates by tariff classification as shown on Appendix C (less $25 million for the residential class) and consistent with the Commission decisions contained in section VIII. Rate Design of this Order and (ii) the VMP Surcharge in accordance with the Commission decision discussed in section VII.A. Ratemaking Mechanisms of this Order.

FINDINGS OF FACT

1. In the 2014 rate case filing APCo/WPCo originally proposed a rate increase of approximately $226.1 million and proposed to change depreciation rates.

CAPITAL STRUCTURE AND COST OF CAPITAL

Capital Structure

2. APCo retired a $500 million Term Loan Agreement on May 9, 2014, that was assumed from Ohio Power Co., as part of the acquisition of Amos 3 on December 31, 2013. Companies Exh. RVH-D at 5-9.

3. APCo redeemed its Series I Senior Note on May 22, 2014. Id.

4. APCo issued a $300 million Series U Senior Note on May 9, 2014. Id.

5. Short-term debt of the Companies was impacted by the non-typical levels of short-term debt balances in August, September and October 2013 related to the timing of the ENEC Securitization. Id.

6. The common stock balance of the Companies reflects removal of $1,901,500 of common equity from the December 31, 2013 actual balance related to Appalachian Consumer Relief Funding, LLC. Id.

7. Staff included the average balance of accounts receivable sold by APCo's Virginia operations as short-term debt. Staff Exh. JA-D at 3-4.

Cost of Short-Term Debt

8. The Companies' short-term debt interest rate of 0.346 percent was based on the average short-term debt rate for the 2013 test-year. Companies Exh. RVH-D at 8.

Cost of Long-Term Debt

9. The Companies calculated an average cost rate for long-term debt of 5.408 percent based on the adjustments to the capital structure to reflect the refinancing and retirement of long-term debt completed during the first half of 2014. Companies Exh. RVD-D at 7.

10. Staff calculated an average cost rate for long-term debt of 5.118 percent based on a capital structure that included debt subsequently retired and refinanced in May 2014. Staff Exh. JA-D at 4.

Return on Equity and Resulting Rate of Return

11. Dr. Avera provided analysis of APCo and WPCo, AEP, the electric sector and projected capital market information in his DCF, CAPM, risk premium, comparable risk and expected earning models and calculated the range of RoE to be 9.5 percent to 11.5 percent with a point estimate of 10.5 percent. Companies Exh. WEA-D at 23-60.

12. SWVA witness Dr. Woolridge recommended a RoE of 8.7 percent, relying primarily on his DCF results determined from a sample group of twenty-eight companies that he believed were comparable publicly-held electric utility companies. SWVA Exh. JRW-D at 7-14.

13. Dr. Woolridge examined a variety of growth rate indicators for projected and historical EPS, DPS and BVPS in developing his DCF recommendation. Id. at 30-39.

14. Dr. Woolridge did not apply a screening of his growth rates to eliminate outliers and negative growth rates. Id.

15. Dr. Woolridge did not apply the CAPM to the individual electric utilities included in his comparable sample group, but he used his estimates of market premium, beta and bond yields on a composite basis. Id. at 39-45, Exh. JRW-11.

16. Staff performed a cost of equity analysis on a sample group of twenty-two electric utilities it considered comparable that resulted in a recommended RoE of 9.24 percent based on the average of his DCF (8.63 percent) and CAPM (9.86 percent) results performed. Staff Exh. JA-D at 13.

17. Staff used various measures of historic and projected DPS and EPS growth rates to develop growth rates for the DCF calculation. Id. at 7-8.

18. Staff performed a screen of the growth rates to eliminate growth rates that produced a RoE that was 300 basis points above or below the average RoE. Id. at 8.

RATE BASE

Amos 3 Generating Unit Utility Plant

19. The rate base adjustment for the acquisition of two-thirds of the Amos 3 generation unit is $411.3 million of utility plant. Companies Rule 42 Exh., Statement B, Schedule 1.

Mitchell Settlement Interest Adjustments

20. The full utility plant value of a fifty percent interest in the Mitchell Plant is $972.890 million. Companies Rule 42 Exh., Statement B, Schedule 1, Statement G Adjustment 90-EPIS. Companies Exh. JDL-D at 8.

21. The Mitchell Plant acquisition was finalized after the Companies filed this rate case. Mitchell Case, Commission Order December 30, 2014.

22. The Commission approved the transfer of an interest in the Mitchell Plant according to the terms of a Joint Stipulation that provided that 82.5 percent of the various components making up the Mitchell Settlement Interest, as defined in the Joint Stipulation, would be recognized for rate recovery for up to the first five years from the date of acquisition. Id.

23. Staff recommended reclassifying $20 million of the Mitchell Plant value related to the cost of the Conner's Run impoundment from utility plant to a regulatory asset and to amortize that asset over twenty-six years. Staff Exh. ELO-D at 18-19.

Environmental CWIP - Mitchell

24. The $33.427 million of environmental CWIP proposed for rate recovery in the Mitchell Case was included in the Companies requested rate base. Staff Exh. ELO-D at 8.

25. The Joint Stipulation in the Mitchell Case limited the Mitchell rate base elements to 82.5 percent of each rate base element in determining the Mitchell Surcharge approved in that case. Companies Exh. SHF-R at 2-3.

26. The environmental CWIP in the Mitchell Case was part of the $577.973 million of rate base included in the surcharge calculation that produced a rate increase of $118.081 million as proposed in the original Mitchell Case. March 27, 2014 Petition, Exh. D; Companies Exh. SHF-D, Exh. SHF-D3.

Other CWIP

27. Neither the average test-year environmental CWIP nor the Amos 3 environmental CWIP is included in an existing surcharge, and if the CWIP is not included in rate base, the Companies should be permitted to record AFUDC on that CWIP. Companies Exh. SHF-R at 3.

Pension Asset

28. The Companies funded the pension obligation above the level of FAS 87 pension expense by $189.312 million as of December 31, 2013 ($92.102 million for the West Virginia jurisdiction), and recorded that amount as a prepaid pension asset in accordance with FAS 87 guidelines. Id. 3; Companies Exh. HEM-D1.

29. The additional pension fund contributions after 2005 were made to address a funding shortfall between the total pension obligation and the funding level of the qualified pension plan. Companies Exh. HEM-D at 6-8.

30. The additional pension fund contribution raised the pension obligation funding ratio to 95 percent as of December 31, 2013. Id.

31. The earnings and return on the additional contributions to the pension fund lowered 2014 pension expense by $15.7 million from the level of current pension expense absent the additional contributions. Id at 8.

32. The additional contributions to the pension fund resulted in a book/tax timing difference for pension expense that generated an ADIT provision of $29.511 million that the Companies included as an offset to the prepaid pension asset in the determination of rate base. Companies Exh. JBB-D at 11.

Cash Working Capital

AEPSC Service Company Invoice Lead Days

33. The AEPSC Agreement requires payment of the AEPSC invoice within thirty days of the invoice date. Staff Exh. DLK-D at 1.

34. The AEPSC invoice is normally issued the first working day after the month for which the AEPSC charges apply, and the Companies pay the invoice within two to four days of the invoice date. Id.

Intercompany Billing Lead Days

35. The Companies intercompany billing results in both revenues for services provided to other AEP subsidiaries and expenses for services received from other subsidiaries of the Companies. Companies Exh. JJJ-R at 10.

36. AEP subsidiaries pay an intercompany invoice on the day after receiving the invoice. Id.

37. In the test year, the net impact of the intercompany billings produced a net expense to the Companies. Id.

West Virginia Property Tax Lead Days

38. The property tax lead days result from property taxes the Companies pay to the States of West Virginia, Virginia, Tennessee and Ohio. Companies Exh. 1, Statement A, Schedule 4.

39. The Service period proposed by the Companies is consistent with one alternative method of determining the lead days for West Virginia property taxes described in Black Diamond Power Company, Case No. 12-0064-E-42T, August 10, 2012 Order. Id.

40. Using a service period that is the year following the year on which the property tax return is based produced 609 average lead days for West Virginia property tax payments. Companies Exh. 1, Vol. 3.

Depreciation and Return on Equity

41. Recording depreciation expense does not require the expenditure of cash at the time the expense is recorded but does reduce the net investment in that property (rate base) on which future returns on investment are determined. Companies Exh. JJJ-D at 17-18.

42. Approximately 22 percent of every dollar of the Companies total revenue is associated with the recovery of depreciation and return on equity. Id.

43. Other jurisdictions have included the revenue lag for depreciation expenses in the CWC calculation. Commonwealth of Virginia, State Corporation Commission, Case No. PUE-2008-00001, December 16, 2008, Order at 26, Schedule 17; Kentucky Public Service Commission, Kentucky-American Water Co., Case No. 2004-00103, February 28, 2005 Order at 17: Tennessee Regulatory Authority, Tennessee-American Water Company, Docket No. 08-0039, January 13, 2009 Order at 39-41 (footnote 146 referencing Petition Exhibit No. 1, Schedule 2); New Jersey Board of Public Utilities, Jersey Central Power & Light Company, BPU Docket No. ER12111052, January 9, 2014 Initial Decision (ALJ Order) at 9-11, upheld by March 18, 2015 Order on Reconsideration.

44. The Commission has generally authorized the utilities to record AFUDC during construction of new utility plant additions.

Prepaid Rent and Other Prepayments

45. Prepaid expenses are excluded from the lead/lag study to avoid double counting. Companies Exh. JJJ-R at 13.

Material and Supplies

2013 Average Test Year Coal Inventory

46. Using a forty-day average burn rate of 33,491 tons per day produced a normalized coal inventory of 1,339,621 tons. Staff Exh. TRE-R at 2-3.

47. The burn rate of 33,491 tons per day is based on a seventy percent capacity factor. Id. at 4.

48. The Companies average price per ton for coal burned during the eighteen months from December 2013 through May 2014 was $71.26. Tr. 1/23 at 107-108. CAD Exh. RCS-D at 45-46; Staff Exh. TRE-R at 5.

49. The Companies test-year coal inventory balances included coal inventory for the Kanawha River, Sporn and Glen Lyn plants that will be retired in June 2015. Id. at 4.

Amos – Other Material and Supplies

50. The Companies adjustment of $5.177 million to the average 2013 test-year other material and supplies for the Amos Unit 3 was not disputed or opposed by any party. Companies Rule 42 Exh., Statement B, Schedule 5.

Putnam Coal Terminal

51. A portion of the Putnam Coal Terminal located at the site of APCo's Amos Plant was formerly used to deliver coal to the Mountaineer Plant. Companies Exh. JLB-R at 8.

52. Although most of the Putnam Coal Terminal has been taken out of service, a portion of the facility ($8.55 million of $35.6 million of Gross Plant on the books) continues to be used. Companies Exh. JDL-R at 11-12, attached Exhibit JDL-R2; Tr. 1/22 at 219; JLB-R at 8-12; Tr., 1/23, at 31-33; Tr., 1/22, at 68-70.

53. The Putnam Coal Terminal assets should have been assigned to two categories: (1) conveyor and barge loader assets that the Companies have not used in recent years and (2) other assets, including an office building, land, rail assets, and runoff ponds, that APCo continues to use in operating the Amos Plant. Companies Exh. JLB-R at 10.

Asset Retirement Obligation – Accretion Expense

54. The Companies record expenses related to AROs on their financial statements as prescribed by accounting guidelines ASC-410-20 and ASC-410-25 (formerly known as SFAS 143 and FIN 47). Companies Exh. JLB-D at 20.

55. Staff reduced rate base by the accumulated ARO accretion expense recovered in base rates, not just the amount included in the test-year expenses. Staff Exh. ELO-D at 19.

56. Rate base should be reduced by the accumulated accretion expense recovered in base rates, but this should be limited to the average test-year amount, not the year-end balance. Companies Exh. JLB-R at 18-19.

Accumulated Depreciation

Amos Accumulated Depreciation Reserve Adjustment

57. The Commission and the VSCC have implemented different depreciation rates for APCo in their respective jurisdictions over the years and have recognized different plant balances, including different levels of accumulated depreciation. Companies Exh. SHF-R at 1-2.

58. The VSCC adjusted the accumulated depreciation reserve for the acquisition of Amos 3 in Case No. PUE-2014-00026. CAD Exh. RCS-D at 36.

Adjustment to Reflect Composite Depreciation Rates

59. APCo records depreciation expense on its financial statements using composite depreciation rates that differ from jurisdictional depreciation rates authorized in either Virginia or West Virginia. CAD Exh. RCS-D at 11-12.

60. APCo restated per books West Virginia jurisdictional depreciation expense using the depreciation rates authorized by the Commission. Id.

REGULATORY ASSETS

Deferred 2012 Storm Recovery Expenses and Carrying Charges

61. The Companies' restoration costs as a result of the Derecho and Hurricane Sandy in 2012 were approximately $84 million, $68.6 million of which were non-capital restoration costs. Companies Exh. JJS-D at 3-4.

62. The Companies have absorbed the carrying cost of those deferred expense for several years. Companies Exh. JJS-R at 3.

63. Because of the magnitude and severity of the two 2012 storms, the Staff recommended recovery of those costs by the Companies. Staff Exh. DLP-D at 4.

IGCC Study

64. The Companies incurred approximately $8.9 million in costs associated with an IGCC Study in connection with its certificate filing with this Commission. IGCC Order; Companies Exh. JDL-D at 16; Tr. 1/22 at 197.

65. The IGCC study informed the Companies and other parties of potential generation technology, the type of coal necessary for IGCC technology, and the capital costs and risks that vendors may be willing to assume in developing a project. Tr. 1/22 at 200-01, 223-25.

66. The IGCC project is no longer under consideration or development after a decision from the VSCC that the plant was not prudent or reasonable. WVEUG Exh. LK-D at 17-18.

67. The Commission Order rescinding certification for the IGCC plant caused APCo to place the IGCC project on hold, but the Commission Order did not indicate agreement with the VSCC holding that the IGCC project was imprudent or unreasonable. Tr. 1/22 at 174.

68. Front-end study costs for a major construction project are normally capitalized as part of the project and recovered over the life of the asset. Staff Exh. ELO-D at 10-11.

Carbon Capture and Sequestration Project

69. Carbon capture is no longer occurring at the Mountaineer Plant and current CCS operational costs pay for monitoring and maintenance of wells in which carbon is sequestered. Companies Exh. JDL-R at 5-6; Tr. 1/22 at 204, 220-222.

70. The Commission allowed CCS annual operation expense of $1,933,140 in the 2010 Rate Case. Staff Exh. ELO-D at 12-13.

71. The Companies expected to operate the CCS project for at least five years but ceased operation on May 28, 2011, forty-one months earlier than represented to the Commission in the last rate case. Id.

72. The Companies incurred $1,062,615 in costs to conduct a FEED study for the CCS facility that the Companies intended to operate for an extended period at the Mountaineer Plant. Id.

OPERATING INCOME AND OPERATION AND MAINTENANCE EXPENSES

Operating Income

EE/DR Lost Revenues

73. The Companies offer customers four current EE/DR programs: 1) SMART Lighting; 2) Residential HomeSMART Energy Audit; 3) Commercial and Industrial Prescriptive Program; and 4) Residential Low Income Weatherization Program. The Companies initiated the first three programs in 2011 and the fourth in April 2012. Companies Exh. JDF-D attached Exh. 1.

74. Independent third party EM&V Reports indicated that during the test year, customer usage declined by 50,000,000 kWh because of EE/DR programs. Id.

75. In Case No. 13-0462-E-P, the Commission held that it would be reasonable for the Companies to request recovery of lost revenues associated with EE/DR programs through reasonable and verifiable post-test year going-level adjustments in this base rate case. Appalachian Power Company and Wheeling Power Company, Case No. 13-0462-E-P, December 20, 2013 Order at 17.

76. Although customer usage appeared to decline because of savings from implementation of the EE/DR programs, the Companies did not have an overall reduction in total electric sales attributable to EE/DR programs in the state. CAD Exh. RCS-D at 75.

77. EE/DR programs reduce the billing units through which the Companies can recover the fixed costs of service. Staff Exh. TRE-D at 13-14.

78. A three-year average of the annual lost revenues is $3,932,428. Id. at 15-17.

79. The quantification of lost revenues is premised on estimates of EE/DR program savings. WVEUG Exh. SJB-D at 25-26.

Rate Treatment of Felman Production, LLC Revenues

80. Felman is a large, energy-intensive industrial customer of APCo with a special contract rate approved by the Commission pursuant to W.Va. Code §24-2-1j. Case No. 13-1325-E-PC, April 3, 2014 Commission Order.

81. During the test-year, the sales to Felman were 526,812 kWh and generated $3.979 million of revenue for the Companies. Staff Exh. ELO-D at 4-5.

82. In Case No. 13-1325-E-PC, the Commission addressed the issue of ratemaking treatment of the anticipated Felman revenues in the next base rate case of the Companies. Id.

Federal Income Tax

Consolidated Tax Savings Adjustment

83. The federal income tax expense applicable to each subsidiary of the consolidated tax filing group is based on a tax sharing policy outlined in a tax sharing agreement. Companies Exh. KAH-D at 7, 9; WVEUG Cross Examination Exh. 1.

84. The majority of state regulatory commissions establish federal income tax expense on a standalone basis for utilities that are members of a consolidated tax filing group. Companies Exh. KAH-D at 9; Tr. 1/20 at 104.

85. A smaller number of state regulatory commissions have historically determined current federal income tax expense for rate recovery by using a CTA (referred to as a Consolidated Tax Savings – CTS – in West Virginia). Companies Exh. KAH-D at 11; Tr. 1/20 at 34; Tr. 1/22 at 109-127.

86. The CTA calculation captures a portion of the taxable losses that are netted against positive taxable income at the consolidated tax return level. Companies Exh. KAH-D at 14.

87. The number of state regulatory jurisdictions utilizing the CTA approach is dwindling. The Texas and Oregon legislatures recently eliminated the CTA approach, leaving only West Virginia, Pennsylvania and New Jersey as states that apply a CTA. Companies Exh. KAR-R at 9.

Summary of Testimony and Record Evidence

88. The Companies' approach to the pro rata share of the AEP taxable loss is commonly referred to as the PCLA. The PCLA was reflected in the Companies' financial statements, consistent with the Tax Sharing Agreement between the Companies and AEP. Companies Exh. KAR-D at 9.

89. The difference between the Companies PCLA only approach and the Staff and CAD CTS approach was a lower revenue requirement of approximately $26 million. Companies Exh. JBB-D, Exh. JBB-D1 at 1.

90. The impacts of tax deductions related to book/tax timing differences that are normalized for ratemaking purposes have been eliminated from the CTS calculation. Companies Exh. KAH-R at 3.

Review of Historical Commission Decisions

91. The Commission departed from the PCLA-only approach to CTS in the 2006 Mon Power Case, a proceeding that presented unusual facts because of a large tax loss carry-forward. Monongahela Power Co., Case No. 06-0960-E-42T, May 22, 2007 Order at 28-33.

92. The Commission from 1969 to 2006 in most cases generally based the CTS calculation on PCLA only. See cited cases supra, at 59-64.

93. While the actual consolidated tax return data has always served as the starting point for the CTS calculation, those CTS calculations have been adjusted in many ways in arriving at the CTS applied in determining fair and reasonable rates. Id.

State Income Tax

Normalization Accounting for Unit of Property Deduction

94. In 2009 the Companies adopted an accelerated write-off for income tax reporting to the IRS of certain utility property additions referred to as the Unit of Property/Capitalized Repairs deduction. 2010 Rate Case, March 30, 2011 Order at 57.

95. The change in tax accounting resulted in Unit of Property/Capitalized Repairs plant additions being written-off as period expenses in the year incurred for tax purposes. Those utility plant additions are, however, reflected on the Companies books as utility plant assets and depreciated over the book life of the plant. Id. at 57-58.

96. The Commission decision in the 2010 Rate Case reflected adoption of full normalization accounting for the Unit of Property/Capitalized Repairs deductions. Id. at 60.

Current State Income Tax

97. The vast majority of the Companies SIT expense is paid in West Virginia and Virginia, and each state bases the current SIT expense on a pro rata share of AEP taxable income. Staff Exh. ELO-D at 21.

98. The Companies allocation factors for West Virginia SIT were based on property, payroll and sales. Id.

99. IRS Bonus Depreciation provisions have not been extended by the U.S. Congress. Tr. 1/21 at 53-54.

100. As the accelerated pollution control deductions expire, those deductions will turn around and increase state taxable income in the future. Id.

Generation Expense

Mitchell Generation Expense

101. The Companies did not object to the proposal of Staff and CAD to limit recovery of non-ENEC generation expense for the Mitchell Plant to 82.5 percent of the requested amount. Company Exh. SHF-R at 2-3; Companies Init. Br. at 12.

Two-thirds of Amos Unit 3 Non-Labor Expense

102. Staff removed fuel cost that will be recovered in the ENEC rates from the Amos Unit 3 non-labor expense. Staff Exh. ELO-D at 7.

Non-ENEC Generation Expense – Other

103. The test-year in this case includes the non-ENEC generation expenses for the Disposition Plants. Companies Exh. JDL-D at 12-14.

104. Non-ENEC generation expenses proposed by all parties were based on estimates. Exh. JDL-D at 12-14; Companies Exh. JDL-R at 6-7; Id. at 8-9; Tr. 1/22 at 214-15; Staff Exh. TRE-D at 7-10; CAD Exh. RCS-D at 90-93.

Incentive Compensation

105. AEP Service Company employees and the Companies employees are compensated by a salary that is a combination of base pay and variable pay. Companies Exh. ARC-D at 5, 12.

106. The Companies total compensation package is at or below prevailing market compensation and places a portion of the compensation at risk depending on achieving operational goals. Id. at 6-7, 12, 21 and attached Exh. 4-6.

Uncollectible Expense

107. During the test-year the Companies recorded a $4.6 million charge-off for a major coal company. Staff Exh. CRS-D at 2-3.

108. The Companies recovered unpaid bills in the amount of approximately $650,000 in the bankruptcy proceeding of a major coal company. Companies Init. Br. at 46-47.

Aviation Expense

109. Some level of commercial airline travel would be required if the corporate private aviation expense was discontinued. Companies Exh. JJS-R at 14-17.

PJM Administrative Fees

110. Actual PJM Administration fees for January through October 2014 produced an annualized jurisdictional increase over the test-year level of $1,017,994 for APCo and $904,214 for WPCo. Staff Exh. ELO-D at 9-10, attached Exh. ELO-2; Companies Exh. AEV-R at 2, attached Exh. AEV-R1; Staff Init. Br. at 50-51.

Additional Linemen

111. The Companies hired ten new linemen prior to August 31, 2014, and plan to hire an additional ten linemen. Companies Exh. PAW-R at 2.

112. Several of the Companies' distribution linemen are nearing retirement age, twenty-seven percent of the Companies' linemen are over age fifty-five, and six of those are over age sixty. The Companies train new linemen for five years from apprentice to journeyman level. Id. at 13-14.

DEPRECIATION AND AMORTIZATION EXPENSE

Depreciation Rates

113. The Commission is faced with a wide range of depreciation rate issues in this proceeding that focus on the amount of projected cost of removal, less salvage (net salvage), to be included in the development of depreciation rates, and the depreciation period to be used for Clinch River. Depr. Study at 34-38, 43-44; Companies Exh. JDL-R at 2, 5; Companies Exh. DGH-R at 5, 9, 18; Staff Exh. EFD-D at 4-5; CAD Exh. MJM-D at 16-18.

114. Staff and the Companies included the projected cost of removal and salvage, generally resulting in negative net salvage, in the development of their depreciation rate recommendations. CAD did not include any negative net salvage. Staff Exh. DLP-D, Exh. 2 at 3; Id. at 8; Staff Exh. DLP-D, Exh. 3; Companies Depr. Study at 29, 32, 42; CAD Exh. MJM-D at 11, 16-18.

115. The depreciation reserve accounts of the Companies have built-in negative net salvage amounts. The current West Virginia depreciation rates reflect both interim and terminal net salvage. Company Exh. DGH-R at 6-7.

West Virginia ENEC Amortization Expense

116. The Companies included the $6.736 million amortization of ENEC carrying costs to synchronize the ENEC revenues and expenses for the 2013 test year. Companies Rule 42, Statement G adjustments 14-PE and 29-CI; Companies Exh. JLB-R at 17-18.

RATEMAKING MECHANISMS

Vegetation Management Program

117. The proposed VMP surcharge has an annual true-up to assure that ratepayers pay the actual costs incurred and interested stakeholders have the opportunity to review those VMP costs. Companies Exh. CWG-D at 3-6; Companies Exh. PAW-D at 12; Companies Exh. SHF-D at 10; CAD Exh. RCS-D at 99-100; WVEUG Exh. SJB-D

at 16. Companies Exh. CWG-R at 1-2; Companies Exh. SHF-D at 10; Staff Exh. EEM-D at 6.

118. The Commission stated in the VMP Case that it would, in the next base rate case, consider a rate recovery mechanism not tied to traditional base rate standards. Case No. 13-0557-E-P, Commission Order March 18, 2014 at 14-15.

PJM OATT Revenues

119. The Companies withdrew a proposal in this case to shift PJM OATT revenues from ENEC proceedings to base rate proceedings. Companies Init. Br. at 55-56; see also ENEC filing on March 2, 2015, Case No. 15-0303-E-P.

Major Storm Expense Tracker

120. The Companies proposed a storm expense tracker that would allow the Companies to automatically defer the cost of all storms that they classify as major. Staff Exh. EEM-D at 4.

121. When major storms have occurred in the past, the Commission has allowed the Companies to defer and recover the costs. Staff Exh. EEM-D at 3, citing 2010 Rate Case (approving recovery by the Companies of $18.2 million in costs for the 2009/2010 major winter storm).

Economic Development Rider

122. The Companies withdrew their proposal to add an Economic Development Rider to the tariff. Companies Exh. CRP-R at 7.

Construction Surcharge

123. The APCo Construction Surcharge originated by Commission Order issued July 26, 2006, in the 2005 Rate Case.

124. The Construction Surcharge has been updated and continued in formal cases since it was first implemented. Case No. 07-0248-E-GI, Commission Order June 22, 2007; Case No. 08-0278-E-GI, Commission Order June 26, 2008; Case No. 09-0177-E-GI, September 30, 2009 Commission Order; 2010 Rate Case, Commission Order March 30, 2011; Case Nos. 11-0274-E-GI (Companies 2011 ENEC case), and 11-0265-E-PC (Petition by APCo for acquisition of the Dresden generation plant), Commission Order June 30, 2011 Order; Case No. 13-0467-E-GI, Commission Order August 30, 2013.

125. In this proceeding and in the pending 2015 ENEC proceeding, Case No. 15-0301-E-P, APCo proposed that the Commission roll the costs previously included in

calculation of the Construction Surcharge into base rates and eliminate the Construction Surcharge from its tariff. Companies Exh. 1, Statement B. None of the parties objected to this proposal.

RATE DESIGN

Class Cost of Service Study

126. The Companies were the only party to file a COSS. Companies Exh. DRB-D at 3-4, Companies Rule 42 Exh., Volume VI.

127. No other party raised significant issues with the COSS, but several parties contested the tariff design issues related to the COSS, particularly the level of subsidies that exist among the customer classifications at present rates. WVEUG Exh. SJB-D at 8-12; SWVA Exh. JWD-D at 11; Tr. 1/22 at 155-157, 341-342.

Inter-Class Subsidy

128. The Companies COSS reflects that the present rate structure of the Companies produced a RoR from the Residential, Sanctuary Worship Service, School Service, and Small General Service classes of customers that is less than the current overall RoR of 5.05 percent. Companies Exh. AEV-D at 8-10; Tr. 1/22 at 340; WVEUG Exh. SJB-D at 8-10.

129. According to the COSS, the amount of the current subsidies exceeds $60 million annually. WVEUG Exh. SJB-D at 8, Table 1.

Basic Service Charges and Declining Block Tariff

130. The Companies increased the basic service charge for Residential, Small General Service and Sanctuary Worship customer classes by $5 per month, $5 to $10 for Residential, $8.45 to $13.45 for Small General Service, and $8.15 to $13.15 for Sanctuary Worship. Companies Exh. AEV-D at 14, 19-20.

131. Cost causation principles support a higher basic service charge than the proposed $5 per month increase. Id. at 16-17.

132. The Commission should not abandon its practice of determining the basic service charge based on costs related to meters, services and billing. Staff Exh. TRE-D at 24.

General Service (GS) and Large General Service (LGS) Time of Day Rate Structure

133. The Companies proposed several changes to the GS TOD tariff and LGS TOD tariff. Companies Exh. AEV-D at 20.

134. The GS TOD and the LGS TOD are similar because they include a basic service charge, an on-peak energy charge and an off-peak energy charge. The new LGS TOD, however, also includes a demand charge. Companies Exh. AEV-D at 20-21.

LPS Tariff

135. The Companies proposed to combine the current LCP and IP tariffs into one new tariff called the LPS Tariff. Parties took varying positions regarding the tariff design proposed by the Companies. Companies Exh. AEV-D at 22-23 Companies Exh. AEV-D3, AEV-R at 11; Tr. 1/21 at 260-61; WVEUG Exh. SJB-D at 13-14, attached Exh. SJB-3; Walmart Exh. SWC-D at 18-23, attached Exhibits SWC-6 and SWC-7; See also Tr. 1/21 at 259-60; Tr. 1/21 at 271-72.

136. The bill analysis attached to Mr. Vaughan's testimony shows the impact on the average customer under the proposed LPS tariff, but not the impact on the full range of customers with varying load factors within the tariff. Companies Exh. AEV-D3.

TARIFF TERMS AND CONDITIONS

Waivers of Provisions of the Electric Rules

Electric Rules Personal Contact Requirement

137. The personal contact requirement for disconnection of electric utility service is set forth in the Commission Electric Rules.

138. Electric Rules 4.8.a.1 and 4.8.a.1.A provide that before service may be terminated for nonpayment of a delinquent bill, the utility must provide both a written notice to the customer and achieve personal contact at least twenty-four hours in advance of the termination.

139. Attaining personal contact requires the Companies to determine under Electric Rule 4.8.a.1.E, if anyone in the home is sixty-five years old or older, or is physically, mentally or emotionally incapacitated. The utility may achieve personal contact by a telephone contact or in-person contact with a responsible person. Electric Rule 4.8.a.1.M.

140. A utility may petition the Commission to waive the personal contact requirement only after the utility has made at least three attempts at personal contact,

including an on-site visit. At least one of the attempts must be made after normal working hours of 8:00 a.m. to 6:00 p.m. The utility may make a telephone call as an after-hours attempt at personal contact.

141. The Companies document aggressive customers in two categories. Those who have physically threatened utility employees are "C1 Customers." Customers with a history of being verbally abusive or who threaten to destroy utility equipment or are otherwise difficult to deal with are categorized as "CU Customers." Companies Exh. RAG-R at 7.

142. The Companies require employees to obtain a police escort to perform any type of work on C1 Customers' property. Id.

Tariff Terms and Conditions of Service

143. The Companies stated they did not oppose deferring their proposals to amend a number of the terms and conditions of service in their tariffs to a future proceeding.

144. The proposed tariff changes relate to retention of security deposits; discontinuing the offer to waive the deposit requirement when a new customer enters into the Checkless Payment Plan; implementing charges to provide two or more estimates of the cost to relocate facilities; increased costs for installation of underground service; changes in responsibility for securing right-of-way easements and permits for residential extensions; changes in responsibility for right-of-way clearing costs associated with residential extensions; implementing a customer investigation charge, amending the returned check charge, increasing the reconnection charge, new provisions regarding customers' use of energy; an average monthly billing plan; eliminating the special reconnect option; and adding provisions for credit card bill payments. Companies Exh. RAG-D at 4-14.

CONCLUSIONS OF LAW

1. The Commission acts in a quasi-judicial capacity but exercises legislative powers in appraising and balancing the general interests of current and future utility service customers, the general interests of the State's economy and the interests of the utilities subject to its jurisdiction, deliberations and decisions. In doing so the Commission is charged under W.Va. Code §§24-1-1et seq., and by the decisions of the United States Supreme Court and the West Virginia Supreme Court of Appeals to ensure the fair and prompt regulation of public utilities in the interests of the consuming public; provide the availability of adequate, economical and reliable utility services throughout the state; ensure that rates and charges for utility services are just, reasonable, based primarily on the cost of providing that service, applied without unjust discrimination or preference, are not contrary to the evidence, or without evidence to support them, and are not arbitrary or result from misapplication of legal principles. United Fuel Gas Company

v. Pub. Serv. Comm'n, 143 W. Va. 33, 99 S.E.2d 1 (1957); Boggs v. Pub. Serv. Comm'n, 154 W. Va. 146, 174 S.E.2d 331 (1970); Monongahela Power Co. v. Pub. Serv. Comm'n of W. Va., 166 W. Va. 423, 276 S.E.2d 179 (1981); Chesapeake & Potomac Telephone Company v. Public Service Commission, 1982 W.Va. LEXIS 687, 300 S.E.2d 607 (1982); Broadmoor/Timberline Apartments v. Pub. Serv. Comm'n, 180 W.Va. 387, 376 S.E.2d 593 (1988); Sexton v. Pub. Serv. Comm'n, 188 W. Va. 305, 423 S.E.2d 914 (1992); and most recently, Allied Waste Serv. of North Amer., LLC v. Pub. Serv. Comm'n, No. 14-1131 (West Virginia Supreme Court of Appeals Memorandum Decision filed March 11, 2015).

2. The Commission may examine the individual facts and circumstances of each case before it in order to decide cases without being absolutely bound by the doctrine of stare decisis. Central West Virginia Refuse v. Public Serv. Comm'n, 438 S.E.2d 596, 600, 601, St. Joseph Stock Yards Co. v. United States, 298 U.S. 38 (1936), The Chesapeake and Potomac Telephone Company of West Virginia v. Public Service Commission of West Virginia, 300 S.E.2d 607, 613 (1982).

CAPITAL STRUCTURE AND COST OF CAPITAL

Capital Structure

3. A utility capital structure will normally reflect the amount of capital acquired through borrowing (debt), the issuance of stock (common and preferred), retained earnings and other paid in capital contributions from stockholders.

4. The measurement of the ratio of individual capital components to the total capital establishes the relationship among the various capital sources for use in determining a composite weighted cost of capital. West Virginia-American Water Company, Case No. 10-0920-W-42T, Order at 10 (April 18, 2011).

5. The Commission uses the cost rate for each type of capital (long-term debt, short-term debt, preferred equity, and common equity) multiplied by its percentage of the total capital structure, to derive a weighted cost of capital that serves as a proxy for the overall RoR the utility is authorized to earn.

6. The level of short-term debt proposed by the Companies is reasonable; however, the Commission expects a more thorough examination and explanation of costs and benefits of the receivable sale arrangement in the next base rate filing of the Companies.

7. Changes in long-term debt including refinancing and retirements of debt after the test year in the first half of 2014 are now known and should be included in the calculation of the appropriate capital structure.

8. The capital structure proposed by the Companies that adjusts the 2013 test-year balances for (i) known post test-year financing activity and (ii) the impacts of financing activities not related to on-going operations is reasonable and reflects the capital structure that will be in place during the time rates from this case will be in effect.

Cost of Short-Term Debt

9. The Commission will adopt the average short-term debt cost rate during the test year of 0.346 percent as recommended by the Companies, SWVA and CAD.

10. Staff did not establish the basis or source for its recommended cost rate of 0.310 percent.

Cost of Long-Term Debt

11. The Commission will adopt the Companies 5.408 percent recommendation for the cost of long-term debt because that cost takes known post-test year changes for the retirement and issuance of long-term debt into consideration.

Return on Equity and Resulting Rate of Return

12. Utility rates should allow a public utility the opportunity to earn a level of revenue sufficient to attract capital in the competitive capital market balanced with the interests of the consuming public in receiving fair and reasonable rates. Bluefield Water Works v. Public Service Commission, 320 U.S. 679 (1923); Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 64 S. Ct. 281 (1944); Permian Basin Area Rate Cases, 390 U.S. 747, 88 S. Ct. 1344 (1968); Monongahela Power Company v. Public Service Commission, 276 S.E.2d 179 (W.Va. 1981).

13. This Commission determines a RoE based on empirical studies of returns in the capital markets while balancing the interests of ratepayers in receiving fair and reasonable rates. Black Diamond Power Company, Case No. 12-0064-E-42T, Order at 5 (August 10, 2012); West Virginia-American Water Company, Case No. 10-0920-W-42T, Order at 15 (April 18, 2011).

14. A fair RoE determination lies within a zone of reasonableness that is framed by the evidence, including the testimony and exhibits of various witnesses. The final determination of RoE, however, rests with the Commission based on the Commission's judgment and the application of Commission established regulatory principles and policies. West Virginia-American Water Company, Case No. 10-0920-W-42T Order at 18.

15. There is no absolute correct answer with regard to RoE, even though the determination of a reasonable RoE involves calculations on a mass of data presented by expert witnesses.

16. The DCF method has long been one of the methods relied on by the Commission for determining a reasonable RoE, but the Commission also considers CAPM as a valuable tool in evaluating the range from which to determine a reasonable RoE.

17. The CAPM compares the risk adjusted RoE result to alternative utility investments, and provides the Commission with a basis to compare the reasonableness of the DCF results.

18. It is not reasonable in this case to use current short-term interest rates as the risk-free rate in the CAPM calculation because of the ongoing actions of the Federal Reserve to keep short-term interest rates at record lows in order to stimulate the economy.

19. The Staff *ex poste* approach to the CAPM analysis is reasonable because it incorporates historical market premiums and the average historical risk-free rate for U.S. Treasury bills.

20. The SWVA CAPM analysis that produced a CAPM cost of equity of 7.6 percent lacked specific market data support. SWVA Exh. JRW-D at 2, 7-14.

21. Based on a review of all of the evidence, testimony and arguments, cases cited by the Companies, and prior decisions of the Commission, the Commission determines a RoE of 9.75 percent is reasonable, falls within the range of reasonable RoEs presented by the parties, fairly balances the interests of the Companies and their customers, and meets the standards set forth by the United States Supreme Court and the Supreme Court of Appeals of West Virginia.

<u>Summary of Capital Structure and Cost of Capital</u>

22. An overall weighted cost of capital of 7.379 percent is reasonable for establishing rates in this proceeding and fairly balances the interests of the Company and its customers.

<u>RATE BASE</u>

<u>Amos 3 Generating Unit Utility Plant</u>

23. The Commission will adopt as reasonable the inclusion of $411.3 million in the Companies utility plant accounts for the acquisition of Amos 3. No party took issue with that proposal.

Mitchell Generating Unit

24. The Commission fixes $782.634 million for the Mitchell utility plant value, and an unamortized balance of $19.230 million for the Conner's Run regulatory asset, as reasonable amounts to be included in rate base for rate recovery in this proceeding. It is also reasonable to amortize the Conner's Run regulatory asset over twenty-six years as proposed by Staff.

Environmental CWIP - Mitchell

25. The inclusion of 82.5 percent of the $33.427 million of the Mitchell environmental CWIP as rate base in this proceeding is reasonable because the recent order in the Mitchell Case approved the Mitchell Plant transfer (including the environmental CWIP) and associated surcharge.

26. The inclusion of the Mitchell environmental CWIP in rate base in this case reflects the intent of the parties to the Joint Stipulation in the recent Mitchell Case and does not reflect a policy change by the Commission to include CWIP in future rate proceedings.

27. After issuance of this Order, the Companies should no longer record AFUDC on the Mitchell environmental CWIP of $33.427 million.

Other CWIP

28. The Commission will not authorize the $18.631 million of other environmental CWIP as rate base, but it is reasonable to authorize the Companies to record AFUDC on that environmental CWIP until the underlying projects are placed in service.

Pension Asset

29. It would not be reasonable to allow a pension expense to be lowered by $15.7 million from the earnings on the investment of the additional contributions to the pension plan as proposed by the Companies in their filing, but ignore the carrying cost of the prepaid pension asset that generated those savings.

30. The amount of pension expense recorded on the financial statements under FAS 87 guidance and the level of funding required by ERISA standards may differ.

31. The net pension asset of $62.6 million in this case will be included as rate base and the Companies should be permitted to generate a return on that asset at the overall weighted cost of capital because the pension asset is a long-term asset that is financed by all components of the Companies' capital structure.

Cash Working Capital

AEPSC Service Company Invoice Lead Days

32. The 19.9 lead days regarding payment of AEPSC invoices used in the Companies CWC calculation is reasonable and will be adopted by Commission.

33. The payment history of the Companies with respect to the AEPSC invoices does not violate the AEPSC Agreement.

34. It is not reasonable to adjust the lead days for the AEPSC charges as proposed by Staff without making a corresponding adjustment to increase the AEPSC charges to the Companies for the additional financing costs incurred by AEPSC.

Intercompany Billing Lead Days

35. Because a one-day payment lead for intercompany invoices is applied equally to billings from the Companies and its subsidiaries, it is reasonable to base the lead days for intercompany billing on the AEP practice of paying those invoices on the first working day after receipt of the invoice.

West Virginia Property Tax Lead Days

36. The appropriate service period for West Virginia property tax payments is the year in which the property tax report is filed and the year when the assessments of the property values are determined by the Board of Public Works.

37. It is reasonable to depart from the service period used by the Commission in the 2010 Rate Case because a service period based on the year in which the property tax return is filed and appealable assessments are issued by the Board of Public Works is consistent with one of the alternative methods of determining the lead days for West Virginia property taxes described in Black Diamond Power Company, Case No. 12-0064-E-42T, Commission Order August 10, 2012.

38. It is reasonable to base the service period on the assessment year as defined by W.Va. Code §11-3-1(f)(2) enacted in 2010. Attorney General of West Virginia. 59 W. Va. Op. Att'y Gen. 94, 1981, WL 157185 (March 23, 1981).

39. The Commission will adopt 390.28 as the lead days for property tax payments and believes that number of days accurately reflected the level of CWC attributable to property tax payments in this case.

Depreciation and Return on Equity

40. It is reasonable to include depreciation expense in the CWC calculation because depreciation expense is part of the cost of service that determines the Companies authorized level of revenue.

41. All elements of the cost of service used to determine the total revenue billed to utility customers is subject to the revenue lag, and the Companies experience the same 36.5 day revenue lag in receiving cash for depreciation expense from the time it is recorded as they do for any other cost of service element.

42. Some portion of the cash collected for the return on equity component of revenue will eventually be paid as dividends, however, because of the lack of record evidence about the Companies dividend retention policy or the lead days for dividend payments, no return on equity will be granted in the CWC calculation in this case.

43. In the next base rate case, the Companies should address whether the Commission should limit AFUDC for rate recovery to only the AFUDC applicable to the level of annual utility plant additions that exceed the annual depreciation and normalized current deferred income tax expense included in current base rates.

44. If the Commission determines that AFUDC has been overstated as a result of accruing AFUDC on construction funded by depreciation and deferred income tax cash flow, any adjustment should be limited to the time period from the effective date of rates in this case forward.

Summary of Cash Working Capital

45. The Commission will approve a CWC allowance of $2.982 million. The CWC balance was determined from the Commission decisions regarding AEPSC bill lead days, intercompany billings lead days, West Virginia property tax lead days, and inclusion or exclusion of depreciation expense and return on equity in the CWC calculation, applied to the cost of service elements included in Attachment A to this Order.

Prepaid Rent and Other Prepayments

46. It is reasonable to include $3.306 million of prepaid expenses in rate base in this case because the prepaid expenses were not included in the lead/lag study or the resulting CWC calculation.

Material and Supplies

Mitchell – Coal Inventory

47. It is reasonable to include 82.5 percent or $28.067 million of the Mitchell coal inventory as rate base in this case because that level of rate base is consistent with the terms of the Joint Stipulation in the Mitchell Case.

Mitchell – Other Materials and Supplies

48. It is reasonable to include 82.5 percent or $11.295 million of Mitchell - Other Material and Supplies as rate base in this case because that level of rate base is consistent with the Joint Stipulation in the Mitchell Case.

2013 Average Test-Year Coal Inventory

49. The Commission must balance the need for the reliability of coal supply in the event of supply disruption with the need to include a normalized level of coal inventory that will be recovered in rates at a reasonable cost to the ratepayers.

50. The test-year included coal inventory for the three coal-fired generation units to be retired in June 2015, but did not include the coal inventory related to the acquisition of the Amos Unit 3 generation plant. These events introduced a level of uncertainty regarding the appropriate, normalized level of coal inventory necessary to operate the remaining generation plants after June 2015.

51. It is reasonable to include a level of coal inventory for the non-Mitchell generation units based on the Staff-recommended forty-day average burn rate because that level of coal inventory is representative of the Companies generation fleet that will be operating after June 2015.

52. A price for the coal inventory of $71.26 per ton in this case reasonably reflects the cost of coal inventory to be experienced after the three coal-fired generation units are retired near to the time that new rates from this case will become effective.

Amos – Other Material and Supplies

53. The Staff adjustment of $5.177 million to the average 2013 test-year Other Material and Supplies for Amos Unit 3 is reasonable because it does not include fuel costs that are recovered in the ENEC surcharge.

Putnam Coal Terminal

54. The Commission will reduce rate base by $2.043 million on a jurisdictional basis for the portions of the Putnam Coal Terminal that have been retired and are no

longer in rate base. CAD Exh. RCS-D, attached Exhibit LA-1, B-5; Tr. 1/22 at 69-71; Tr. 1/23 at 32-33.

55. The Commission will approve the related revised depreciation expense of $77,846 for the Putnam Coal Terminal recommended by Mr. Brubaker.

Asset Retirement Obligation – Accretion Expense

56. The Staff position to reduce rate base by an additional $28.480 million for the average test-year balance of accumulated ARO accretion expense recovered in base rates is reasonable and will be approved in this case.

57. It is not reasonable to adopt the Staff position to lower depreciation expense by $3.105 million for depreciation of the ARO asset. The ARO asset should be depreciated over the expected life of the ARO asset to avoid intergenerational issues.

Accumulated Depreciation

Amos Accumulated Depreciation Reserve Adjustment

58. The regulatory treatment of Amos Unit 3 is not required to be the same in West Virginia and Virginia.

59. Based on the Commission decision to adopt the Staff depreciation rates, it is not necessary or reasonable to adjust for the Amos Unit 3 depreciation reserve deficiency recognized by the Virginia SCC as proposed by the CAD and WVEUG.

60. There is no requirement that the regulatory treatment of Amos 3 be the same in both the West Virginia and Virginia jurisdictions.

Adjustment to Reflect Composite Depreciation Rates

61. The West Virginia jurisdictional rate base should be determined using depreciation rates approved by the Commission.

Summary of Commission Decision on Accumulated Depreciation

62. The appropriate accumulated depreciation balance for establishing a fair and reasonable rate base is $2.097 billion.

Accumulated Deferred Income Taxes

63. The appropriate accumulated deferred income tax balance for establishing a fair and reasonable rate base is $828 million.

REGULATORY ASSETS

Deferred 2012 Storm Recovery Expenses and Carrying Charges

64. Because the Companies have carried the deferred 2012 storm expense for over two years, allowing recovery over a five-year period without rate base recognition achieves a reasonable sharing of the risk and cost between the customers and shareholders for the non-capital service restoration costs experienced during these extraordinary weather events.

65. Storm expenses are non-capital in nature and should not be treated as rate base that will generate a return on the deferred costs.

IGCC Study

66. Front-end costs of a major utility project are normally capitalized as part of the project and then recovered over the life of the asset. Blue Ridge Pumped Storage Project, Case No. 9091, Commission Order November 1, 1978, and Brumley Gap Pumped Storage Project, Case No. 83-697-E-42T, Commission Order September 28, 1984.

67. It is reasonable to allow amortized recovery over five years of the jurisdictional portion of the IGCC Study costs.

68. The record of the IGCC case, Case No. 06-0033-E-CN reflects that the study was reasonable, undertaken in good faith, and used to support the certificate application.

69. Amortization of the IGCC Study costs over five years is reasonable and consistent with Commission treatment of other abandoned utility projects.

Carbon Capture and Sequestration Project

70. The Companies have justified the continuing operational costs to monitor the wells at the CCS project, and the Commission will allow CSS operational expenses of $2,167,095 annually.

71. Reassigning the prior CCS O&M expense rate recovery revenues to offset the ongoing monitoring and maintenance costs would be retroactive ratemaking.

72. The FEED study costs for the CCS project were prudently incurred by the Companies and should be recovered in rates.

73. A seven-year amortization of the West Virginia jurisdictional share of the FEED study costs of $1,062,615 is reasonable and consistent with prior Commission decisions for amortization of deferred costs that were not afforded rate base treatment.

OPERATING INCOME AND OPERATION AND MAINTENANCE EXPENSES

Operating Income

EE/DR Lost Revenues

74. The Commission previously concluded that it would be reasonable for the Companies to request recovery of lost revenues associated with EE/DR programs through reasonable and verifiable post-test year going-level adjustments in this base rate case. Case No. 13-0462-E-P, December 20, 2013 Commission Order at 17.

75. The EM&V reports provide reasonable estimates of reduced kWh customer usage savings resulting from implementation of EE/DR programs.

76. The level of net lost revenues up to the date this Order is effective for EE/DR programs currently in place are known and reasonably measurable.

77. The Companies projections of EE/DR lost revenues in this case that reach three years past the historical test-year, and two years past the year on which new rates from this case are to be effective are not known and measurable.

78. The Commission will approve a downward revenue adjustment of $3,932,428 based on a three-year average of the test year lost revenues.

Large Customer Load Changes

79. The Commission will not approve a revenue adjustment based on forecasted sales growth related to large customers because the adjustment is limited to a small segment of the customer base and that sales growth may be accompanied by increased capital investment and operating expenses that have not been analyzed.

Rate Treatment of Felman Production, LLC Revenues

80. Test year revenues from Felman should not be used to determine the revenue requirement increase applicable to this case. All Felman revenues will be credited in the pending ENEC case of the Companies. Case No. 13-1325-E-PC, Felman Production, LLC, April 3, 2014 Commission Order at 25.

Annualized Test-Year Revenues

81. The Staff proposed annualized test year revenue at current rates of $35.622 million is reasonable and will be adopted.

Pole Attachment Rental Income

82. The Companies proposed adjustment to increase 2013 test year revenues by $4.441 million to reflect the removal of pole attachment revenue recorded in the 2013 historical test year that related to prior accounting period is reasonable and will be adopted.

West Virginia Transco Rental Payments

83. The Staff proposed adjustment to increase 2013 test year revenues by $350,000 to impute rental payments from West Virginia Transco that will be received during the period the rates from this case will be in effect is reasonable and will be adopted.

Income Tax Expense

Federal Income Tax

Consolidated Tax Savings Adjustment

84. The Commission will not abandon a consolidated tax adjustment approach to federal income taxes entirely, but will limit CTS to the PCLA adjustment only, and continue the Commission practice regarding CTS used for nearly forty years prior to 2006.

85. Because the parent company loss continues indefinitely, and is largely driven by costs that are related to all subsidiaries, it is at least arguably reasonable to allocate a portion of the parent company losses in the rate setting process. The Commission will, therefore, continue to utilize PCLA in determining current FIT expense.

86. Although CTA is not a widely used regulatory approach in other state regulatory jurisdictions, some regulatory jurisdictions do pass a portion of the parent company losses to regulated subsidiaries in the rate setting process through various types of adjustments other than CTA.

87. The CTS approach using PCLA is reasonable, necessary and appropriate because of, (i) the nature of the tax losses at non-parent company subsidiaries in a utility holding company structure, (ii) the volatility on the CTS calculation resulting when those

tax losses are included, and (iii) the uncertainty imposed on the utility because of that volatility.

88. Non-parent company losses should not be included in the CTS adjustment because that approach discourages investment in utility plant infrastructure, and it is not in the best interests of the customers or the state to continue that practice.

89. The Commission will base the CTS on only the PCLA and reduce the standalone taxable income of the Companies by APCo/WPCo's $5.348 million pro rata share of the parent company loss.

90. The Commission based the PCLA adjustment on the three-year average of the parent company losses included in the consolidated income tax information for the 2011-2013 historical period.

91. The Commission will apply the statutory FIT rate of 35 percent to the Companies adjusted West Virginia jurisdictional taxable income resulting in a current FIT expense of $47.129 million.

92. The Commission will apply the 35 percent FIT rate to both the accelerated depreciation deduction and the Unit of Property/Capitalized Repair deduction resulting in a current deferred FIT expense of $55.076 million.

93. The modification to the CTS approach adopted in this Order strikes the appropriate balance between the interests of the utility and its customers and is fully supported by the evidence and record presented in this case.

94. The modification to the CTS approach will remove much of the uncertainty and volatility regarding rate recovery of federal income taxes for the impacted regulated utilities resulting from the inclusion of non-parent company subsidiaries taxable losses in the determination of the CTS.

State Income Tax

Normalization Accounting for Unit of Property Deduction

95. It is reasonable to continue to recognize normalization accounting for all Unit of Property/Capitalized Repairs deductions for determining both federal and state income expense in this proceeding.

Current State Income Tax

96. The acquisitions of Mitchell and Amos 3, the lack of a congressional action to extend "Bonus Depreciation", and expiration of the pollution control deductions

significantly change the allocation factors used to determine West Virginia state income tax expense from the allocations that were present in the historical test-year.

97. Limiting the SIT expense recovery to the historical test-year does not account for the Unit of Property/Capitalized Repairs as addressed in this Order.

98. SIT expense of $5.736 million is reasonable based on the record in this case. The current SIT expense was determined to be $8.974 million by applying the blended SIT rate of 6.2483 percent to the adjusted standalone West Virginia jurisdictional taxable income. The deferred SIT expense was determined to be a negative $3.238 million made up of current deferred SIT expense for the current Unit of Property/Capitalized repairs deduction at the statutory 6.5 percent SIT rate which offsets the negative $5.122 million of deferred SIT expense recorded in the 2013 historical test-year.

Generation Expense

Mitchell Generation Expense

99. The Staff and CAD recommendations to limit recovery to 82.5 percent of the requested Mitchell Generation Expense, or $26.456 million, is consistent with the Joint Stipulation in the Mitchell Case, is reasonable, and will be adopted by the Commission.

Two-thirds of Amos Unit 3 Non-Labor Expense

100. The Staff adjustment to the 2013 test year non-ENEC generation expense related to Amos Unit 3, to annualize non-labor O&M expenses for the new unit, is reasonable and will be adopted by the Commission.

Non-ENEC Generation Expense – Other

101. The Companies position that the remaining generation expense after the retirement of the Disposition Plants will be an increase over the 2013 test year is not reasonable.

102. Given the lack of a record to support any party's recommendation, the Commission determines the unadjusted 2013 test year level of non-ENEC generation expense is reasonable.

Incentive Compensation

103. The decision about incentive compensation in the 2010 Rate Case was in large part driven by the extraordinarily tough economic times present at the time that case was decided. 2010 Rate Case Order at 48.

104. The current economic climate is better than it was in 2009-2010.

105. Annual incentive compensation performance goals for each employee or group of employees can drive improvement in safety, efficiency of operations and financial performance metrics that lead to savings that eventually benefit the customer when those improvements are captured in a base rate case.

106. AEPSC provides a significant amount of the workforce for the Companies, particularly in areas of the business that can benefit from the "economies of scale" available through sharing professional employees with other subsidiaries versus hiring that professional expertise at each subsidiary.

107. The record in this case shows that the Companies pay a lower amount for the services provided by AEPSC than the level included in the 2010 Rate Case.

108. Based on the record in this case, it is reasonable to allow the annual incentive plan costs for both the Companies' employees and employees of AEPSC to be recovered in rates.

109. In future rate cases the Companies should provide further analysis that demonstrates the total compensation to its employees (both direct and AEPSC employees) is in line with the market salary for each type of job classification.

110. The Commission will limit recovery of the Companies LTIP (Restrictive Stock Plan) costs to one-half of the historical test-year amount because the threshold for payment under the LTIP is based on corporate financial goals.

Uncollectible Expense

111. The use of a three-year average of uncollectible expense is appropriate and reasonable when there are fluctuations that occur between the annual expense for each year included in the recent historical period and the test-year level of expense when represented as a ratio or percentage rate, relative to revenue levels. 2010 Rate Case, Commission Order March 30, 2011, at 43.

112. The major coal company uncollectible expense presented in this case is extraordinary and warrants special treatment. The Commission accepts the Staff uncollectible expense adjustment based on the three-year historical period, adjusted by the agreed to write-off of the net large coal company charge-off over a five-year period.

Aviation Expense

113. The Commission will allow fifty percent of the allocated portion of corporate aviation. This allowance is reasonable given (i) the location of West Virginia

in the center of the AEP territory and (ii) that less air travel would likely be needed for APCO/WPCO given its proximity to Columbus, Ohio, compared to other AEP subsidiaries. This level provides a reasonable level of recovery for required travel expenses.

PJM Administrative Fees

114. The use of the latest actual data is a more reasonable method for estimating the increase for PJM expense over the test-year level. The Commission will authorize an adjustment of $1.922 million to the test-year PJM expense that includes the Staff adjustment for APCo and the additional $0.904 million for WPCo.

Additional Linemen

115. The Companies need sufficient linemen in order to properly maintain the Companies distribution and transmission lines.

116. It is reasonable to allow the costs for all twenty of the new linemen to be recovered in rates in order to address the loss of the twenty-seven percent of the Companies' linemen that are nearing retirement and to ensure that the new linemen begin the five-year training as soon as possible.

117. It is reasonable to require the Companies to make a closed entry filing 180 days after the date of this Order providing the number of linemen hired, the number lost after the date of this Order and the status of the number of linemen.

118. If the Companies have not hired the additional linemen within 180 days, the Companies must explain their efforts to do so and provide the expected date each of those additional positions will be filled.

DEPRECIATION AND AMORTIZATION EXPENSE

Depreciation Rates

119. The Commission has historically included some amount for projected cost of removal and projected salvage value in the development of depreciation rates when the projected cost of removal and salvage is reasonable and supported by substantial evidence.

120. The Commission finds no reasonable basis in the record of this case to support the recommendation that there be no negative salvage built into depreciation rates or that the levels of negative salvage included in the depreciation reserves are sufficient to cover all future negative net salvage, terminal or interim.

121. It is reasonable to require the Companies to follow the Uniform System of Accounts instructions for Account 108 – Accumulated Provision for Depreciation of Electric Plant regarding the regulatory liability associated with AROs.

122. The Staff-recommended depreciation rates are reasonable, and the Commission will adopt the Staff depreciation rates on a plant-by-plant and account-by-account basis in this case.

123. The negative net salvage costs included in the Staff recommended depreciation rates, along with the negative net salvage already included in the depreciation reserves, should be sufficient to cover the negative net salvage on future utility plant retirements.

124. It is not reasonable to shorten the recovery of the undepreciated value of any of the Clinch River investment to the compressed timeframe proposed by the Companies simply because those retired properties are situated at the plant site of the natural gas units to be installed at Clinch River.

125. The Staff-proposed remaining life for the natural gas units to be installed at Clinch River is reasonable because the units are intended to run for an extended period of time, unlike the extraordinary retirements being implemented at Kanawha River, Glen Lyn and Sporn because of EPA emission limits.

126. As 2025 approaches, better data should be available to determine whether the life of the gas-fired units will end, or be extended by five, ten, fifteen or even more years, and the remaining life depreciation method can self correct any reserve imbalance in a future depreciation study case.

127. The Staff approach of continuing to write-off the undepreciated value of plants or portions of plants to be retired will require some modification to depreciation accounting after retirement, but the Commission prefers the Staff approach to the Companies proposal to increase depreciation rates at the remaining plants which would effectively over depreciate the remaining plants.

128. This accounting modification is needed to restore the reserve by the amount of undepreciated value of the retired plant accounts (credit Reserve for Depreciation) and charge the undepreciated value to Extraordinary Property Losses (Account 182).

129. The Companies should keep sufficient records to create subaccounts to Account 182 to identify the extraordinary losses due to retirement of the undepreciated plant values.

130. The Commission will allow these Account 182 balances (net of amortization) to be included in rate base and will allow continued amortization of the undepreciated balances at the annual depreciation accrual rates recommended by Staff.

West Virginia ENEC Amortization Expense

131. The Commission will not include the adjustment for amortization of ENEC carrying costs because there was not an adequate showing in the record that the additional adjustment of $6.736 million for amortization of ENEC carrying cost is required to offset ENEC revenues for the 2013 test year.

RATEMAKING MECHANISMS

Vegetation Management Program

132. It is reasonable to approve a surcharge for the VMP because a VMP surcharge annual review will assure that only the actual cost of the VMP will be recovered in rates and the annual VMP will assure that the VMP is implemented as intended. The past practice of including provisions for vegetation management in base rates did not assure sufficient revenue to carry-out a cycle-based end-to-end VMP or a means for the Commission to assess the extent and effectiveness of such vegetation management efforts.

133. The Commission believes that authorizing a VMP surcharge with annual reviews that include annual rate true-ups is the most reasonable way to assure that service related benefits are achieved.

134. After the VMP is well-established and the costs well defined, it may be appropriate to remove the VMP surcharge and include the VMP costs in base rates in future base rate cases.

135. The initial VMP surcharge will be set to produce $44.472 million annually, allocated to the various customer tariff classifications as indicated in Mr. Gary's rebuttal testimony, including the modifications to the tariff allocation suggested by both Mr. Baron and Mr. Daniel.

136. To avoid multiple rate changes regarding ENEC and VMP filings, the Companies should file their annual ENEC and the VMP review cases at the beginning of March of each year, and the revised ENEC rates and VMP surcharge revisions should take effect at the same time.

137. It is reasonable to require the Companies to file the following information with each yearly true-up filing:

(a) All contractual performance measures contractually required by the Companies.
(b) Miles of single phase lines to be cleared in the forecast period.
(c) Miles of three phase lines to be cleared in the forecast period.

(d) Miles of single phase lines cleared in the previous period.
(e) Miles of three phase lines cleared in the previous period.
(f) Miles of single phase lines where the ROW was widened.
(g) Miles of three phase lines where the ROW was widened.

PJM OATT Revenues

138. The Companies presented a new proposal for treatment of PJM OATT Revenues in their ENEC filing on March 2, 2015, in Case No. 15-0303-E-P, and it is reasonable to withdraw the issue from consideration in this case.

Major Storm Expense Tracker

139. The Commission has built into base rates a reasonable, normalized level of on-going storm expense and a significant amount of rate recovery for the VMP. Given the presence of these two rate recovery mechanisms the Commission is not persuaded that an additional deferral mechanism for major storm expenses is reasonable or necessary at this time.

140. If the Companies experience extraordinary storm expenses above the normalized level built into the rates authorized in this case, they may make the appropriate decisions regarding whether they should defer those expenses and seek recovery for those costs in a future base rate case where the necessity and prudence of its expenditures can be examined by all interested parties.

Security Rider

141. The Commission is aware of the security dangers existing in the modern world, but in the absence of concrete plans to implement specific security measures, projected costs, or new regulatory requirements, the implementation of a Security Rider is premature.

Economic Development Rider

142. Because the Companies withdrew the proposal, the Commission will not consider the proposal of the Companies to add an Economic Development Rider to the tariffs.

Construction Surcharge

143. The proposal of the Companies to roll the costs previously included in the calculation of the Construction Surcharge into base rates and to eliminate the Construction Surcharge from its tariff is consistent with the intention of the Commission after the initiation of the Construction Surcharge.

144. The proposal is also consistent with the Commission approved stipulation in Case No. 13-0467-E-GI. The Commission will move the costs associated with the Dresden Plant and the Amos Unit 1 scrubber into base rates and eliminate APCo Tariff Sheet No. 27.

Class Cost of Service Study

145. Because of the changing nature of the cost of service for each customer classification, the Commission does not typically approve a specific COSS or even a specific methodology and will not do so here.

146. The cost allocations can and do vary from case to case, and the Commission has historically employed the concept of gradualism to move towards the results of the COSS to avoid over-correction in the current case.

147. The Commission normally determines the cost of service allocations based on the record using its own informed judgment to determine a fair cost allocation in each case that does not overly burden any particular customer classification.

148. The Commission will not deviate from its historical approach to COSS and will not approve the specific COSS offered by the Companies. The Commission, however, has relied on the Companies COSS study proposed in this case as a guideline in determining the specific cost allocation issues.

Inter-Class Subsidy

149. Rates paid by the Residential, Sanctuary Worship Service, School Service, and Small General Service classes are being subsidized by the other customer classifications.

150. Rate subsidization sends inappropriate cost signals, and can unfairly burden a customer class. Over time, inter-class subsidies should be eliminated.

151. It is reasonable in this case to approve tariffs that are designed to remove approximately one-third of the inter-class subsidies in this case as shown on Appendix C attached to this Order.

152. It is a reasonable cost allocation approach in this case to reduce the current inter-class subsidies at present rates by one-third. This approach (i) will make significant progress towards eliminating the subsidy, (ii) improve the level of subsidies present in the 2010 Rate Case for large customers, and (iii) maintain the Commission practice of gradualism when moving to full cost based rates.

Fuel Inventory Classification

153. It is reasonable to classify fuel inventory costs as an energy cost.

Basic Service Charges and Declining Block Tariff

154. The Commission will not abandon its practice of determining the basic service charge based on the costs related to meters, services and billing.

155. The Staff approach to determining basic service charges is reasonable, but the calculation should be modified to include additional customer-related costs not included in the Staff analysis.

156. When all fixed costs comprising customer meter and billing costs are included, the basic service charges should be modified to \$8.10 for the RS tariff, \$9.51 for the SGS tariff and \$10.92 for the SWS tariff.

157. In order to maintain the general rounding applied to the basic service charges included in the current rate schedules, the Commission will authorize basic service charges of (i) \$8.00 for the RS tariff, (ii) \$9.50 for the SGS tariff and (iii) \$10.90 for the SWS tariff.

158. The Commission will not combine the under/over 500 kWh blocks for the RS, SGS, and SWS tariffs as proposed by the Companies because maintaining the under 500 kWh tariff block is a better method of recovering the fixed cost normally recovered in a demand change that is not currently part of these three tariff classifications.

General Service (GS) and Large General Service (LGS) Time of Day Rate Structure

159. It is reasonable to approve the proposals to modify the GS TOD tariff and add the LGS TOD tariff because no party objected to the proposals and because there will be no impact on current customers of the Companies because they are not required to move to the new tariff structure at this time.

LPS Tariff

160. The Commission will not approve the Companies' proposal to eliminate the LCP and IP tariffs and replace them with a single new LPS tariff because the record lacks sufficient data for full evaluation of the impact the Companies' proposal will have on all current customers in the LCP and IP classes.

161. The Companies should provide a full bill frequency analysis in the next rate case if they wish to pursue consolidation of the LCP and IP classes.

TARIFF TERMS AND CONDITIONS

Electric Rules Personal Contact Requirement

162. The Commission should balance the interests of the customers with the safety of the Companies employees.

163. The majority of the Companies' requests regarding termination rules are appropriate for consideration in Case No. 15-0469-E-G-GI.

164. In view of the escalating concerns expressed by the Companies and their employees about customer aggression, employees of the Companies should not be required to make premises visits to customers that the Companies have documented to have 1) been verbally or physically aggressive/abusive to employees or utility facilities, 2) threatened to set loose vicious animals, or 3) brandished or made reference to weapons. The Companies have labeled these customers as C1 or CU customers.

165. Although Case No. 15-0469-E-G-GI is the appropriate case in which to consider permanent amendments to the Electric Rules applicable to terminations, it is reasonable in this case to grant the Companies a blanket waiver of personal contact with respect to C1 and CU customers on an interim basis until the conclusion of Case No. 15-0469-E-G-GI, or a subsequent rulemaking.

Tariff Terms and Conditions of Service

166. To ensure adequate public notice, the Companies should pursue the requested amendments relating to retention of security deposits; discontinuing the offer to waive the deposit requirement when a new customer enters into the Checkless Payment Plan; implementing charges to provide two or more estimates of the cost to relocate facilities; increased costs for installation of underground service; changes in responsibility for securing right-of-way easements and permits for residential extensions; changes in responsibility for right-of-way clearing costs associated with residential extensions; implementing a customer investigation charge; amending the returned check charge; increasing the reconnection charge; new provisions regarding customers' use of energy; an average monthly billing plan; eliminating the special reconnect option; and adding provisions for credit card bill payments, by filing a petition to amend their tariffs.

167. The future filing should be docketed as a "T" case.

ORDER

IT IS, THEREFORE, ORDERED that the Commission authorizes an overall increase in rates of $123.5 million as set out in the cost of service calculation, attached and incorporated herein as Appendix A, which Appendix A is hereby established as the cost of service and revenue requirement approved in these proceedings for APCo/WPCo for providing electric utility service to its customers in West Virginia.

IT IS FURTHER ORDERED that the overall increase to be in effect after the phase-in described herein consists of an increase in base rates of $78.986 million or 5.76 percent, annually as set out in the authorized base rate allocation attached hereto and incorporated herein as Appendix C.

IT IS FURTHER ORDERED that in addition to the base rate increase shown in Appendix C (less $25 million for the residential class phase-in discussed herein), the Commission authorizes the Companies to implement a VMP Surcharge that initially produces an additional $44.472 million, or 3.24 percent, annually.

IT IS FURTHER ORDERED that the Companies shall file a formal petition for annual review and true-up of the VMP surcharge on or before the first business day of March 2016, and for each year thereafter, until further order of the Commission.

IT IS FURTHER ORDERED that the VMP surcharge review filing true-ups will be determined using the (i) RoE, (ii) federal and state income tax rates, (iii) tariff allocations and (iv) new depreciation rates approved in this Order until such time as the Commission issues a future order changing those cost of service elements.

IT IS FURTHER ORDERED that no later than ten days from the date of this Order, the Companies must prepare and file with the Commission revised tariff schedules that reflect (i) the increase to base rates by tariff classification as shown on Appendix C (less $25 million for the residential class) and consistent with the Commission decisions contained in section VIII. Rate Design of this Order and (ii) the VMP Surcharge in accordance with the Commission decision discussed in section VII.A. Ratemaking Mechanisms of this Order.

IT IS FURTHER ORDERED that the costs associated with the Dresden Plant and the Amos Unit 1 scrubber that are currently recovered through the Construction Surcharge on APCo Tariff Sheet No. 27 are moved into the base rates approved in this case and Tariff Sheet No. 27 is eliminated.

IT IS FURTHER ORDERED that the Companies request to eliminate the personal contact requirement of Electric Rule 4.8.a.1 is denied and should be taken up as part of the review of Electric Rules in Case No. 15-0469-E-G-GI; provided, however, the Commission grants the Companies a blanket waiver of personal contact with respect to C1 and CU customers, on an interim basis, until the conclusion of Case No. 15-0469-E-G-GI.

IT IS FURTHER ORDERED that the Companies should pursue tariff changes related to: retaining security deposits; discontinuing the offer to waive the deposit requirement when a new customer enters into the Checkless Payment Plan; implementing charges to provide two or more estimates of the cost to relocate facilities; increasing costs for installation of underground service; changing responsibility for securing right-of-way easements and permits for residential extensions; changing responsibility for right-of-way clearing costs associated with residential extensions; implementing a customer investigation charge; amending the returned check charge; increasing the reconnection charge; adding provisions regarding customers' use of energy; providing for an average monthly billing plan; eliminating the special reconnect option; and adding provisions for credit card bill payments by filing a petition to amend their tariffs. If the Companies make such filing it shall be docketed as a "T" case.

IT IS FURTHER ORDERED that on or before 180 days after the date of this Order, the Companies shall make a closed entry filing in this case stating the number of linemen that have been hired and that have left employment after the date of this Order, and the status of the number of lineman. If the Companies have not hired the twenty additional linemen within 180 days, the Companies shall explain their efforts to do so and provide the expected date each of those additional positions will be filled.

IT IS FURTHER ORDERED that the Companies shall modify the depreciation accounting for the Disposition Plants after retirement. This modification will require the Companies to keep sufficient records to create subaccounts to Account 182 in order to identify the extraordinary losses due to retirement of the undepreciated plant values.

IT IS FURTHER ORDERED that on entry of this Order this case shall be removed from the Commission's docket of open cases.

IT IS FURTHER ORDERED that the Executive Secretary of the Commission serve a copy of this Order by electronic service on all parties of record who have filed an e-service agreement, and by United States First Class Mail on all parties of record who have not filed an e-service agreement, and on Commission Staff by hand delivery.

A True Copy, Teste,

Ingrid Ferrell

Ingrid Ferrell
Executive Secretary

JML/klm
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Appalachian Power Co./Wheeling Power Co.
Case Number 14-1152-E-42T

Commission Authorized Revenue Requirement

	Commission Decision
Rate Base	$ 3,700,116,899
RoR	7.379%
Return on Rate Base	$ 273,014,990
O&M Expenses	$ 1,110,014,116
Depreciation Expense	$ 186,041,194
Taxes Other	$ 74,879,317
FIT Expense	$ 100,003,681
SIT Expense	$ 5,298,431
Other	$ (2,778,219)
Revenue Requirement	$ 1,746,473,511
Going-Level Revenue	$ 1,668,620,886
Increase before Proforma Adj.	$ 77,852,625
Gross Receipts	$ 851,786
Uncollectible Expense	$ 281,593
Total Increase - Base Rates	$ 78,986,003
Add: Vegetation Surcharge	$ 44,471,708
Total Increase in Rates	$ 123,457,711

Appalachian Power Co./Wheeling Power Co.
Case Number 14-1152-E-42T

Commission Authorized Weighted Average Cost of Capital

Commission:	$	%	Cost Rate	Weighted Cost
ST Debt	107,955,743	1.520%	0.346%	0.005%
LT Debt	3,645,854,787	51.325%	5.408%	2.776%
Pref. Stk.	0	0.000%	0.000%	0.000%
Com. Equity	3,349,657,879	47.155%	9.750%	4.598%
Total Capital	7,103,468,409	100.000%		7.379%

Appalachian Power Company and Wheeling Power Company, Case No. 14-1152-E-42T
Commission Authorized Base Revenue Allocation

As Filed (Company Ex. AEV-D, attached Ex. AEV D1 & D2					Commission Decision						
Customer Classification (1)	Current Revenue (2)	Increase Needed to Produce Class Cost of Service (3)	Total Revenue (4)	% of Revenue per CCOS (5)	Authorized Base Rate Increase (6)	Authorized Total Revenue per COSS (7)	Increase Needed to Produce Class Cost of Service (8)	Subsidy per COSS at Present Rates (9)	Two-thirds of Current Subsidy (10)	Commission Authorized Increase by Cust. Class (11)	% Increase (12)
RS	581,533,464	151,935,571	733,469,035	47.22%		685,063,207	103,529,743	59,074,676	39,343,734	* 64,012,626	11.01%
SWS	8,746,044	1,911,627	10,657,671	0.69%		9,954,310	1,208,266	544,883	362,892	845,374	9.67%
SGS	25,922,641	4,091,322	30,013,963	1.93%		28,033,169	2,110,528	412,315	274,602	1,835,927	7.08%
GS	251,074,133	12,084,024	263,158,157	16.94%		245,790,841	(5,283,292)	(18,979,719)	(12,640,493)	7,357,201	2.93%
LCP	283,692,256	(2,677,783)	281,014,473	18.09%		262,468,716	(21,223,540)	(32,463,874)	(21,620,940)	397,400	0.14%
IP	74,061,866	5,246,940	79,308,806	5.11%		74,074,763	12,897	(2,750,288)	(1,831,692)	1,844,589	2.49%
Spec Con.	99,355,720	4,691,827	104,047,547	6.70%		97,180,853	(2,174,867)	(3,999,232)	(2,663,489)	488,621	0.49%
SS	33,463,932	4,926,467	38,390,399	2.47%		35,856,796	2,392,864	283,182	188,599	2,204,265	6.59%
OL	10,241,296	(258,575)	9,982,721	0.64%		9,323,904	(917,392)	(1,278,780)	(851,667)	0	0.00%
SL	3,689,664	(455,783)	3,233,881	0.21%		3,020,459	(669,205)	(843,166)	(561,549)	0	0.00%
Total	1,371,781,016	181,495,637	1,553,276,653	100.00%	78,986,003	1,450,767,019	78,986,003	(3)	(2)	78,986,003	5.76%

Note: The Commission will not reduce any current tariff classification, and has reallocated a decrease of $64,917 for the OL tariff and $107,138 for the SL tariff to the RS tariff.

* This dollar amount will be reduced by $25 million in the first year in order to phase in the total increase gradually.

**PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA**

Case No. 14-1152-E-42T

APPALACHIAN POWER COMPANY and
WHEELING POWER COMPANY, both dba
AMERICAN ELECTRIC POWER
Rule 42T tariff filing to increase electric
rates and charges.

and

Case No. 14-1151-E-D

APPALACHIAN POWER COMPANY and
WHEELING POWER COMPANY, both dba
AMERICAN ELECTRIC POWER
Petition to change depreciation rates.

PROCEDURAL BACKGROUND

On June 30, 2014, Appalachian Power Company (APCo) and Wheeling Power Company (WPCo) both public utilities and both operating as American Electric Power (APCo/WPCo or Companies) tendered for filing revised tariff sheets reflecting a system average rate increase of approximately seventeen percent annually, or a net increase in current rates of $226 million or approximately seventeen percent for furnishing electric utility service to approximately 476,598 customers in the Counties of Boone, Brooke, Cabell, Clay, Fayette, Greenbrier, Jackson, Kanawha, Lincoln, Logan, Marshall, Mason, McDowell, Mercer, Mingo, Monroe, Nicholas, Ohio, Putnam, Raleigh, Roane, Summers, Wayne, and Wyoming. The filing was docketed as Case No. 14-1152-E-42T (Base Rate Case).

Also on June 30, 2014, the Companies filed an application to request revised depreciation rates under Rule 20 of the Commission Rules of Practice and Procedure, 150 C.S.R. Series 1 (Rules). This filing was docketed as Case No. 14-1151-E-D (Depreciation Rate Case). The Companies stated that the revised depreciation rates require a $59.6 million increase in annual depreciation expense that is included in the overall $181.5 million increase in base rates requested by the Companies in the rate filing in the Depreciation Rate Case.

By Order issued July 28, 2014, the Commission suspended the proposed rate increases, established a procedural schedule, including but not limited to, an intervention deadline of September 8, 2014, and an evidentiary hearing date in these matters. The Commission granted the Companies' request for a limited waiver of Rule 23 of the Commission Rules for the Construction and Filing of Tariffs, 150 CSR 2 (Tariff Rules) to allow the Companies to provide individual customer notice as a bill insert no later than the next regular billing cycle. The Commission also required that the Companies comply with all remaining provisions of Rule 23 and timely file proof of compliance with the Commission.

Intervenors in the Base Rate and Depreciation Rate Cases include the Consumer Advocate Division (CAD), SWVA, Inc., the West Virginia Energy Users Group (WVEUG), and Wal-Mart Stores East, L.P. and Sam's East, Inc. (Walmart), The Kroger Co. (intervened in the Base Rate Case only) and The Honorable Marty Gearheart (Delegate Gearheart). Commission Orders issued July 28, 2014, September 18, 2014, and October 29, 2014.

By Orders issued August 27, 2014, September 12, 2014, and November 14, 2014, the Commission scheduled public comment hearings in Bradshaw, Charleston, Princeton, Huntington, Wheeling and Oak Hill and an evidentiary hearing in Charleston.

The Commission received numerous written public protests in these cases. Many of the early protests complained that the customers received the bill insert notice of the Base Rate filing immediately prior to, or several days after, a stated protest period expiration date of September 8, 2014.

On September 26, 2014, the Companies filed a Motion for Extension of the Intervention and Protest Period and Further Partial Waiver of Rule 23 (the Motion for Extension). In this Motion, the Companies stated that they failed to publish the required Class II legal notice of the rate filing in newspapers in the service territories. The Companies also admitted to having caused customer confusion by stating in the customer bill inserts that the protest period would expire on September 8, 2014. The Motion stated that the Companies did not intend to limit or constrain the ability of customers to file protests.

Staff and WVEUG both filed responses to the motion of the Companies.

On October 3, 2014, the Companies filed a Motion for a Procedural Order. The Companies suggested that they provide additional public notice, that the Commission approve certain revisions to the procedural schedule, and that the Commission toll the statutory suspension period applicable to this proceeding by thirty days.

By its October 7, 2014 Order, the Commission (i) granted the October 3, 2014 Motion of the Companies for a thirty-day tolling of the running of the statutory suspension period, and stated that the suspension period would expire at 12:01 a.m. on Tuesday, May 26, 2015. The Commission also extended the intervention period and certain filing and discovery dates and ordered the Companies to immediately publish a Public Notice of Change in Rates and Extended Deadlines as a Class II legal publication in newspapers of general circulation in all counties in which they provide service and approved the bill insert notice proposed by the Companies to be included in West Virginia customer bills.

By Order issued October 31, 2015, the Commission revised the procedural schedule in the Depreciation Rate Case to be consistent with the procedural schedule set in the Base Rate Case.

By Order issued November 14, 2014, the Commission ruled on pending petitions to intervene, scheduled the Oak Hill public comment period, and ordered the Companies to publish notice of the public comment and the evidentiary hearing.

By Order issued November 18, 2014, the Commission corrected several incorrect dates listed in the November 14, 2014, Commission Order.

The Commission conducted public comment hearings in these matters (at 1:00 p.m. and 6:00 p.m. each day) in (i) Bradshaw (McDowell County) on November 5, 2014; (ii) Princeton (Mercer County) on November 6, 2014; (iii) Huntington (Cabell County); (iv) Wheeling (Ohio County) on November 20, 2014; (v) Oak Hill (Fayette County) on December 17, 2014; and (vi) Charleston (Kanawha County) on January 12, 2015.

On January 2, 2015, the Commission granted a December 24, 2014 Motion of the Companies for a partial waiver of the timing requirements for publication of notice of the January 13, 2015 evidentiary hearing.

On January 9, 2015, Staff filed a Motion to Continue the Evidentiary Hearing that was scheduled to begin Tuesday, January 13, 2015, to allow additional time for settlement negotiations and to make sure all parties to the matter had the ability to present their cases. By filing on January 12, 2015, the Companies stated that they did oppose the continuance.

On January 12, 2015, the Commission ordered that it would take appearances and address preliminary matters on Tuesday, January 13, 2015, and begin taking evidence at 9:30 a.m. on Tuesday, January 20, 2015.

The Companies filed proof of publication of the public notices required by Tariff Rule 23 and by the Commission Orders issued on September 12, 2014, and November 14, 2014. Affidavits of publication filed December 22, 2014 and January 9, 2015.

The evidentiary hearing in this matter convened January 13, 2015, for the purpose of taking appearances and addressing preliminary matters. The evidentiary hearing reconvened January 20, 2015, and each consecutive day thereafter, through January 23, 2015.

Initial briefs were filed February 27, 2015, by SWVA and Kroger and March 6, 2015, by the Companies, Staff, CAD, Walmart and WVEUG. Reply briefs were filed March 17, 2015, by the Companies, Staff, CAD, Walmart, SWVA and WVEUG.

Attorney General's Brief Exhibit C

APPALACHIAN POWER COMPANY
WHEELING POWER COMPANY
DIRECT TESTIMONY
OF
JEFFREY B. BARTSCH

**DIRECT TESTIMONY OF
JEFFREY B. BARTSCH
ON BEHALF OF APPALACHIAN POWER COMPANY AND
WHEELING POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF
WEST VIRGINIA IN CASE NO. 14-1152-E-42T**

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 American Electric Power Service Corporation (AEPSC) as the Director of Tax Accounting and Regulatory Support. AEPSC is a wholly owned subsidiary of American Electric Power Company, Inc. (AEP), which provides centralized professional and other services to subsidiaries of AEP. AEP is the parent company of Appalachian Power Company and Wheeling Power Company. I will refer to these entities individually as APCo or WPCo or collectively as the "Companies".

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

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

Q. BRIEFLY DESCRIBE YOUR DUTIES AND RESPONSIBILITIES.

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

Q. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY PROCEEDING?

A. Yes. In addition to previous testimony before the Public Service Commission of West Virginia (Commission), I have filed testimony before the Public Utilities Commission of Ohio on behalf of Columbus Southern Power Company and Ohio Power Company (OPCo); with the Michigan Public Service Commission on behalf of Indiana Michigan Power Company; with the Public Service Commission of Kentucky on behalf of Kentucky 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 Virginia State Corporation Commission on behalf of Appalachian Power Company and the Indiana Utility Regulatory Commission on behalf of Indiana Michigan Power Company. Like APCo and

WPCo, all of these companies, except Electric Transmission Texas, LLC, are AEP operating companies.

Q. FOR WHOM ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of both APCo and WPCo.

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

A. The purpose of my testimony in this proceeding is to present and support the federal and state tax information on Statements A, A-1, B, G and G-1 included in the Companies' filing. I am also sponsoring certain of the Statements of the Rule 42 Data and certain accounting and going-level adjustments to the test year data to reflect the tax effects of other accounting and certain going-level revenues, expenses and rate base amounts included in this filing. I will also discuss the applicable service period for West Virginia Public Utility property (ad valorem) tax, which information was provided to Company witness Joyce for use in his lead-lag study, and the amount of ADFIT that has been included in rate base related to the prepaid pension asset discussed by Company witness McCoy. Finally, I will compute the potential impact that the Consolidated Tax Savings (CTS) adjustment that the Commission has adopted, for ratemaking purposes, in a number of base rate cases, including the Companies' last base rate proceeding, Case No. 10-0699-E-42T, would have on the Companies' revenue requirement. This subject is discussed in greater detail by Company witnesses Ferguson and Highlander.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring Company Exhibits JBB-D1, JBB-D2 and JBB-D3, which I will describe later in my testimony.

Q. WHICH STATEMENTS OR PORTIONS OF STATEMENTS OF THE RULE 42 DATA ARE YOU SPONSORING?

A. I am sponsoring Statement A - Schedule 4 and Schedule 5, Statement B – Schedule 13 and 14, and Statement G Adjustments 2-CFIT, 3-DFIT, 4-SIT, 7-ADFIT, tax depreciation adjustments related to 55-DE and 57-DE, 60-OT through 68-OT, 70-OT through 82-OT, 84-CFIT, 85-DFIT, 86-SIT, 106-ADFIT, 107-ADFIT, 111-OT, 112-CFIT and 113-SIT including supporting Schedules where applicable. Company witness Listebarger furnished either the West Virginia Jurisdictional amounts shown on these Statements or the allocation factors required to calculate such amounts. Company witness Listebarger is also responsible for the allocation methodology.

Q. WERE THE STATEMENTS OR PORTIONS OF THE STATEMENTS THAT YOU ARE SPONSORING PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes.

Q. WERE THESE STATEMENTS PREPARED IN ACCORDANCE WITH THE COMMISSION'S RULE 42 REQUIREMENTS?

A. Yes.

Q. PLEASE DESCRIBE STATEMENT A – SCHEDULE 4.

A. Statement A – Schedule 4 is a Summary of Taxes Other Than Income Taxes for the test year ended December 31, 2013. This schedule starts out with the Total Company per books amounts and then allocates a portion to West Virginia jurisdictional operations. To these amounts, accounting adjustments, going-level adjustments, and pro-forma adjustments have been applied to reflect the final West Virginia jurisdictional expense levels for taxes other than income taxes. I will describe these adjustments later in my testimony.

Q. PLEASE DESCRIBE STATEMENT A – SCHEDULE 5.

A. Statement A – Schedule 5 is a Summary of State and Federal Income Taxes Charged to Operations for the test year ended December 31, 2013. Included in the Schedule are details for Current and Deferred Federal Income Taxes, Deferred Investment Tax Credits, and State Income Taxes. All of these Schedules start out with the Total Company per books amounts and then allocate a portion to West Virginia jurisdictional operations. To these amounts, accounting adjustments, going-level adjustments, and pro-forma adjustments have been applied to reflect the final West Virginia jurisdictional expense levels for state and federal income taxes. I will describe these adjustments later in my testimony.

Q. PLEASE DESCRIBE STATEMENT B – SCHEDULES 13 & 14.

A. Statement B - Schedule 13 provides detail of Accumulated Deferred Income Taxes. Statement B – Schedule 14 provides detail of Deferred Investment Tax Credits. For both Schedules, a rolling 5 quarter average is used to determine the West Virginia jurisdictional amounts for the test year ended December 31, 2013. To these amounts, accounting adjustments, going-level adjustments, and pro-forma adjustments have been applied to reflect the final West Virginia jurisdictional amounts. I will describe these adjustments later in my testimony.

Q. PLEASE DESCRIBE THE GOING-LEVEL ADJUSTMENTS THAT IMPACT

TAXES OTHER THAN INCOME TAXES ON STATEMENT A– SCHEDULE 4.

A. Adjustment 60-OT provides the FICA tax expense associated with Adjustment 38-AG, (restricted stock unit incentive plan adjustment), and increases taxes other than income taxes expense by $4,964. Employees with wages exceeding the $113,700 FICA earnings limitation have been excluded from this calculation. Adjustment 61-OT provides for the Medicare tax expense associated with Adjustment 38-AG, (restricted stock unit incentive plan adjustment), and increases taxes other than income taxes expense by $1,161. Adjustment 62-OT provides for the FICA tax expense associated with Adjustment 40-AG, (annual incentive compensation plan adjustment related to the Companies' employees), and decreases taxes other than income taxes expense by $96,213. Employees with wages exceeding the $113,700 FICA earnings limitation have been excluded from this calculation. Adjustment 63-OT provides for the Medicare tax expense associated with Adjustment 40-AG, (annual incentive compensation plan adjustment related to the Companies' employees), and decreases taxes other than income taxes expense by $22,501. Adjustment 64-OT provides for the FICA tax expense associated with Adjustments 45-PL and 46-PL, and increases taxes other than income taxes expense by $22,108. Employees with wages exceeding the $113,700 FICA earnings limitation have been excluded from this calculation. Adjustment 65-OT provides for the Medicare tax expense associated with Adjustments 45-PL and 46-PL, and increases taxes other than income taxes expense by $5,328. Adjustment 66-OT provides for the FICA tax expense associated with Adjustments 38-AG, 40-AG, 45-PL and 46-PL (which recognized the adjustments related to incentive plans, salary and overtime adjustments), and decreases taxes other than income taxes expense by $10,692. This adjustment uses data applicable to those employees subject to the 2014 FICA wage base limitation of $117,000 and provides for the additional employer matching FICA expense at 6.20%. Adjustment 67-OT provides for the FICA tax expense associated with Adjustments 48-PL and 49-PL (going-level salary adjustments), and increases taxes other than income taxes expense by $59,343. Adjustment 68-OT provides for the Medicare tax expense associated with Adjustments 48-PL and 49-PL, and increases taxes other than income taxes expense by $14,270. Adjustment 70-OT increases taxes other than income taxes expense by $500,133 to allow for the expected increase in Virginia Real & Personal Property tax based on 2013 year-end Virginia owned property. Adjustment 71-OT increases taxes other than income taxes expense by $36,774 to allow for the expected increase in Virginia Real & Personal Property tax based on 2013 year-end Virginia leased property. Adjustment 72-OT decreases taxes other than income taxes expense by $679,456 to adjust the Virginia Minimum Tax to an expense level estimated for 2014. Adjustment 73-OT increases taxes other than income taxes expense by $1,975,771 to adjust the estimated 2013 West Virginia Real & Personal Property tax from a West Virginia retail jurisdictional amount of $18,494,510 to the 2014 assessment level of $20,470,281 to be recorded July 2014 through June 2015 for owned property. Adjustment 74-OT decreases taxes other than income taxes expense by $518 to allow for the expected decrease in West Virginia Real & Personal Property tax based on 2013 year-end West Virginia leased property. Adjustment 75-OT decreases taxes other than income taxes expense by $93,560 to reflect the expected reduction in the West Virginia Franchise tax expense in

2014. Adjustment 76-OT increases taxes other than income taxes expense by $544,645 to reflect the correct level of expense for the West Virginia Public Service Commission Fees for 2013. Adjustment 77-OT increases taxes other than income taxes expense by a net $2,882,046 to adjust West Virginia B&O Tax to an expense level estimated for 2014 as a result of an expected increase in the B&O Tax of $4,427,124 net of an expected increase in the Credit for Industrial Expansion or Revitalization for $1,545,078. Adjustment 78-OT increases taxes other than income taxes expense by $29,724 to allow for the expected increase in Tennessee Real & Personal Property tax based on 2013 year-end property owned in Tennessee. Adjustment 79-OT decreases taxes other than income taxes expense by $42,149 to reflect the expected reduction in the Tennessee Franchise tax expense in 2014. Adjustment 80-OT increases taxes other than income taxes expense by $140,474 to adjust the Ohio Commercial Activity Tax to an expense level estimated for 2014. Adjustment 81-OT increases taxes other than income taxes expense by $216,505 to allow for the expected increase in Ohio Real & Personal Property tax based on 2013 year-end property owned in Ohio. Adjustment 82-OT decreases taxes other than income taxes expense by $155,068 to eliminate Pennsylvania Gross Receipts tax expense that is non-recurring.

Q. PLEASE DESCRIBE THE PROFORMA ADJUSTMENTS THAT IMPACT TAXES OTHER THAN INCOME TAXES ON STATEMENT A– SCHEDULE 4.

A. Adjustment 111-OT increases the West Virginia Municipal B&O tax expense by $1,978,808 associated with the proposed revenue increase.

Q. PLEASE DESCRIBE THE ACCOUNTING ADJUSTMENTS THAT IMPACT

STATE AND FEDERAL INCOME TAXES ON STATEMENT A– SCHEDULE 5.

A. Accounting Adjustment 2-CFIT increases current Federal income tax expense by $16,981 to reflect the current Federal income tax effect at 35% of the taxable income related to the other accounting adjustments discussed by Company witness Brubaker. This adjustment is calculated on Statement A, Schedule 5, Page 6 of 17. Accounting Adjustment 3-DFIT increases deferred Federal income tax expense by $3,864,503 to reflect the appropriate Deferred FIT effect at 35% of the accounting Schedule M adjustment related to 1-DP (see Statement A, Schedule 5, Page 11 of 17). Accounting Adjustment 4-SIT increases state income taxes by $3,306 to reflect the state income tax effect of the accounting Schedule M adjustment related to 1-DP. Supporting information for adjustment 4-SIT is shown in Statement A, Schedule 5 – State Income Taxes.

Q. PLEASE DESCRIBE THE GOING-LEVEL ADJUSTMENTS THAT IMPACT STATE AND FEDERAL INCOME TAXES ON STATEMENT A– SCHEDULE 5.

A. Going-level Adjustment 84-CFIT increases current Federal income tax expense by $11,835,157 to reflect the current Federal income tax effect at 35% of the taxable income related to the other going-level adjustments supported by other Company witnesses which affect pre-tax income and the related Federal income tax Schedule M adjustments as detailed in Statement A, Schedule 5, Page 6 of 17. Going-level Adjustment 85-DFIT decreases deferred Federal income tax expense by $10,956,487 to reflect the appropriate Deferred FIT effect at 35% of the going-level Schedule M adjustments detailed in Statement A, Schedule 5, Page 11 of 17. Accounting Adjustment 86-SIT decreases state income taxes by $421,876 to reflect the state income tax effect of the going-level adjustments and the related Schedule M adjustments. In addition, Adjustment 86-SIT includes amortization of accumulated deferred state income taxes that were recorded on APCo's books as a result of the transfer to it of OPCo's two-thirds interest in Amos Unit 3, as well as those that would be recorded on WPCo's books, assuming that the Commission approves the proposed transfer of 50% of the Mitchell Plant from AEP Generation Resources, Inc. Supporting information for adjustment 86-SIT is shown in Statement A, Schedule 5 – State Income Taxes.

Q. PLEASE DESCRIBE THE PROFORMA ADJUSTMENTS THAT IMPACT STATE AND FEDERAL INCOME TAXES ON STATEMENT A– SCHEDULE 5.

A. Proforma Adjustment 112-CFIT increases current Federal income tax expense by $58,688,515 to reflect the current Federal income tax effect at 35% of the taxable income related to the proposed revenue increase. This adjustment is calculated on Statement A, Schedule 5, Page 6 of 17. Proforma Adjustment 113-SIT increases state income taxes by $11,179,757 to reflect the state income tax effect of the proposed revenue increase. Supporting information for adjustment 113-SIT is shown in Statement A, Schedule 5 – State Income Taxes.

Q. PLEASE DESCRIBE THE ACCOUNTING ADJUSTMENTS THAT IMPACT ACCUMULATED DEFERRED FEDERAL INCOME TAXES.

A. Accounting Adjustment 7-ADFIT decreases Accumulated DFIT by $1,932,252 to reflect the ADFIT effect of Accounting Adjustment 3-DFIT.

Q. PLEASE DESCRIBE THE GOING-LEVEL ADJUSTMENTS THAT IMPACT ACCUMULATED DEFERRED FEDERAL INCOME TAXES.

A. Going-level Adjustment 106-ADFIT decreases Accumulated DFIT by $11,803,160 to reflect the ADFIT effect of the Going-level Adjustments.

Q. PLEASE INDICATE THE AMOUNT OF ADFIT THAT HAS BEEN INCLUDED IN RATE BASE RELATED TO THE PREPAID PENSION ASSET AS DESCRIBED BY COMPANY WITNESS MCCOY.

A. The Company has included all ADFIT related to the prepaid pension asset as a reduction to rate base. Therefore, if the Commission were to exclude the prepaid pension asset from rate base, it would be both necessary and proper to make an adjustment to decrease ADFIT (increase rate base) by 35% of the amount of the exclusion since there is a direct link between the prepaid pension asset and the ADFIT that was created from it.

Q. WERE YOU INVOLVED IN ADVISING COMPANY WITNESS JOYCE AS TO THE APPLICABLE SERVICE PERIOD FOR WEST VIRGINIA PUBLIC UTILIITY PROPERTY (AD VALOREM) TAX?

A. Yes. The Companies formed their conclusions based upon legal authority and accounting principles. I was a part of that analytical process. While I am not a lawyer, I often have to consider the application of tax statutes, tax regulations and other legal authority to various tax issues. I will provide my understanding of the relevant authorities, but the ultimate resolution of any disputes as to the law will need to include legal argument at the briefing stage of this case.

Q. WHAT WAS COMPANY WITNESS JOYCE ADVISED IS THE APPLICABLE SERVICE PERIOD FOR WEST VIRGINIA PUBLIC UTILITY PROPERTY TAX?

A. Company Witness Joyce was advised that the applicable service period for West Virginia Public Utility Property Tax (Service Period) is the "tax year" as defined by W. Va. Code section 11-5-3, which is the calendar year following the year covered by the return.

Q. IS THIS THE SERVICE PERIOD THAT THE COMMISSION USED IN THE COMPANIES' LAST BASE RATE PROCEEDING, CASE NO. 10-0699-E-42T?

A. No. In that case the Commission accepted the Staff's view that the Service Period for the West Virginia Public Utility Property Tax is the year covered by the return. However, the Commission has since expressed its willingness to consider a reasonable alternative. In Black Diamond Power Company, Case No. 12-0064-E-42T, Order dated August 10, 2012 (Black Diamond Order), the Commission stated that it would consider alternatives for the property tax service period in future cases if a reasonable alternative is proposed.

Q. IS IT THE COMPANIES' VIEW THAT THE ALTERNATIVE CONSIDERED IN THE BLACK DIAMOND CASE IS A REASONABLE ALTERNATIVE?

A. Yes. It is not only a reasonable alternative, but a more reasonable alternative, consistent with the definition of "tax year" that was added to the personal property tax statute in 1997. Under that amendment, the personal property tax year for public service companies is defined in W.V. Code Section 11-5-3 as follows: "Tax year" means the calendar year following the July first assessment day or, in the case of a public service business assessed pursuant to article six of this chapter, the calendar year beginning on the January first assessment day."

Q. CAN YOU EXPLAIN THE TIMETABLE FOR THE REPORTING, ASSESSMENT AND PAYMENT OF THE WEST VIRGINIA PUBLIC UTILITY

PERSONAL PROPERTY TAX?

A. Certainly. The Companies are assessed pursuant to article six of chapter 11. Under section 11-6-1(a), the Companies file by May 1 of each year a return with the Board of Public Works (BPW). The return covers the year ending the previous December 31, in accordance with section 11-6-1(e), on the form prescribed by the BPW for its use in determining the true and actual value of the property.

Pursuant to section 11-6-9(e), the Tax Commissioner examines the returns filed by public service companies, and then, on or before September 15, presents his recommended tentative assessment to the BPW, and provides a notice of the tentative assessment to each public service company. Section 11-6-11 provides that within 15 days following the tentative assessment, or by October 1, the BPW assesses and fixes the true and actual value of the property of each public service company in each county. Thus, the year in which the BPW sets a tentative value subject to appeal by the taxpayer is the same calendar year in which the return is filed.

Once the BPW's assessment becomes final, the State Auditor apportions the value of each public service company's property among the various counties and taxing jurisdictions in which it operates. Within 30 days thereafter, the clerk of each county commission must certify to the State Auditor the amount to be levied upon each one hundred dollars' value of each class of property in the county. The State Auditor then assesses the amount of tax on each class of property for each county and each taxing jurisdiction.

As soon as possible after such tax assessment is completed, the State Auditor delivers to each public service company a statement of the taxes due. One half of the taxes levied must be paid to the State Treasurer by September 1 of that year (the year following the assessment year), and the remaining one-half must be made by the following March 1.

Q. WHAT IS THE SIGNIFICANCE OF THE ASSESSMENT DAY AND THE ASSESSMENT YEAR IN DETERMINING THE APPLICABLE SERVICE PERIOD FOR THE WEST VIRGINIA PUBLIC UTILITY PROPERTY TAX?

A. The January 1 assessment day is significant because it is on that day that the taxpayer becomes liable for the tax.

The year covered by the return is used only for purposes of measuring the value of the property in an [drawn-out?] administrative process. But it is not the ownership and use of property in the year covered by the return that gives rise to the liability for property tax. Rather, it is ownership of the property on the assessment day that causes the Companies to become liable for the tax. If, for example, the Companies owned and used property in the state in the year covered by the return, but transferred all of the property to another business on December 31 of that year, they would not become liable for the tax on the following January 1 assessment day.

Q. WHAT IS THE COMPANIES' CONCLUSION REGARDING THE APPLICABLE SERVICE PERIOD FOR WEST VIRGINIA PUBLIC UTILITY PROPERTY TAX?

A. It is the Companies' conclusion that the service period covered by the West Virginia Public Utility Property Tax is the "tax year" as defined by W. Va. Code section 11-5-3, which is the calendar year that begins on the "assessment day." The tax year and the assessment year coincide in the same calendar year, which is the calendar year following the year covered by the return. The service period should be the tax year and assessment year because it is the ownership and use of property in the state on January 1 of the assessment year that makes the company become liable for the tax. This conclusion was provided to Company witness Joyce for use in the Companies' lead-lag study.

Q. HAVE YOU CALCULATED THE CONSOLIDATED TAX SAVINGS ADJUSTMENT FOR THE COMPANIES USING THE METHODOLOGY ADOPTED BY THE COMMISSION IN THE COMPANIES' LAST RATE PROCEEDING?

A. Yes. Even though the Companies do not agree that such a CTS adjustment is appropriate, as discussed in detail in the testimonies of Company witnesses Ferguson and Highlander, the Companies asked me to provide an estimate of the potential impact that such CTS adjustment would have on their revenue requirement in this proceeding. This calculation is shown in Company Exhibit JBB-D1.

Q. PLEASE DESCRIBE THE INFORMATION THAT WAS USED IN ORDER TO DEVELOP THE EFFECTIVE FEDERAL INCOME TAX RATE USING THE COMMISSION'S CTS ADJUSTMENT METHODOLOGY.

A. I developed the effective federal income tax rate by taking into account the last five years of historical AEP Consolidated taxable incomes from the federal income tax returns and adjusted them to exclude the effects of accelerated depreciation and the one-time adjustment related to the adoption of the Unit of Property Repairs Deduction in 2009, consistent with the Commission's Order in the Companies' previous case. This tax information is available in the Statement A, Schedule 5, Supplemental Sheets and has been reproduced in Company Exhibit JBB-D2.

Q. DID YOU MAKE ANY ADJUSTMENTS FOR OTHER UNUSUAL TAX LOSSES DURING THIS FIVE-YEAR PERIOD?

A. No.

Q. HOW WAS THE ADJUSTED TAXABLE INCOME INFORMATION THEN USED TO CALCULATE THE FEDERAL EFFECTIVE INCOME TAX RATE FOR AEP?

A. As shown on Exhibit JBB-D2, I multiplied the adjusted total AEP consolidated taxable income by the federal statutory tax rate of 35% to arrive at the theoretical AEP consolidated federal income tax paid. This amount was then divided by the adjusted total consolidated taxable income for those companies that had positive taxable income in order to arrive at the effective income tax rate for the year. This calculation was completed for each of the tax years 2008 through 2012 and resulted in a five-year average effective federal income tax rate of 25.27%.

Q. HOW DID YOU USE THE EFFECTIVE FEDERAL INCOME TAX RATE OF 25.27% TO COMPUTE THE CONSOLIDATED TAX SAVINGS ADJUSTMENT?

A. I recalculated the current federal income taxes on Statement A, Schedule 5 using this rate. Deferred federal income taxes (where appropriate) were still calculated using the statutory federal income tax rate of 35% (see Company Exhibit JBB-D1). The difference between the total federal income tax expense in this calculation and the federal income tax expense included in the filing represents the CTS adjustment using the Commission's CTS methodology.

Q. DID YOU ALSO RECOMPUTE THE REVENUE CONVERSION FACTOR USING THE COMMISSION'S EFFECTIVE FEDERAL INCOME TAX RATE THAT YOU COMPUTED?

A. Yes. This is shown on Company Exhibit JBB-D3.

Q. WHAT IS THE IMPACT ON THE COMPANIES' REVENUE REQUIREMENT IF THE COMMISSION WERE TO CONTINUE TO EMPLOY ITS CTS ADJUSTMENT?

A. The adjustment would reduce the Companies' revenue requirement by approximately $26,000,000 (see Company Exhibit JBB-D1).

Q. HAS THE COMPANY INCLUDED A CTS APPROACH THAT ALLOWS THE COMPANIES THE OPPORTUNITY TO EARN THEIR ALLOWED RATE OF RETURN?

A. Yes. As discussed by Company witnesses Ferguson and Highlander, using the CTS Adjustment described above to set rates would deny the Companies an opportunity to earn their allowed rate of return. In order to allow the Companies an opportunity to earn their allowed rate of return, the Commission should adopt the Parent Company Loss Allocation Methodology, which is determined in accordance with the AEP Tax Allocation Agreement and is the approach recommended by Company witness Highlander. This CTS adjustment has already been included in this rate filing.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.