COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

AT RICHMOND, JULY 15, 2010

APPLICATION OF

APPALACHIAN POWER COMPANY | CASE NO. PUE-2009-00030

For a statutory review of the rates, terms and conditions for the provision of generation, distribution and transmission services pursuant to § 56-585.1 A of the Code of Virginia

FINAL ORDER

On July 15, 2009, pursuant to § 56-585.1 A of the Code of Virginia ("Code") and the State Corporation Commission's ("Commission") Rules Governing Utility Rate Applications and Annual Informational Filings (20 VAC 5-201-10 *et seq.*) ("Rate Case Rules"), Appalachian Power Company ("APCo" or "Company") filed an application with the Commission requesting a statutory review of the Company's rates, terms and conditions for the provision of generation, distribution and transmission services ("Application").[1] On July 23, 2009, the Company supplemented and completed its Application by filing a revised Schedule 36 and submitting all of the information required by Schedules 18 and 28 of the Rate Case Rules.[2]

On July 23, 2009, APCo filed a Motion for Leave to File Supplemental Direct Testimony and Schedules in order to calculate the Company's revenue requirement in this proceeding based

[1] On February 24, 2009, pursuant to § 56-585.1 of the Code, the Commission issued an Order Scheduling Rate Proceedings in Case No. PUE-2009-00002 that, among other things, directed APCo to file the instant rate case on July 1, 2009. *Commonwealth of Virginia, At the relation of the State Corporation Commission, Ex Parte: Establishing rate case filing schedule for Virginia's investor-owned electric utilities pursuant to § 56-585.1 A of the Code of Virginia*, Case No. PUE-2009-00002, Order Scheduling Rate Proceedings (Feb. 24, 2009). The Commission subsequently issued an Order on June 22, 2009 in Case No. PUE-2009-00030, which extended APCo's filing date to no later than July 15, 2009.

[2] *See* July 22, 2009 Memorandum of Incompleteness (finding that the Company's Application was incomplete as filed and requesting supplementation of Schedules 18, 28, and 36); July 24, 2009 Memorandum of Completeness (finding that APCo completed its Application on July 23, 2009).

on its actual end-of-test year capital structure and cost of capital as of December 31, 2008, instead of the November 30, 2010 projected capital structure proposed in the Company's Application.[3] On July 27, 2009, the Commission entered an Order Granting Motion, which directed the Company to file its supplemental testimony and schedules on or before August 14, 2009. In accordance with the Commission's July 27, 2009 Order, APCo filed its supplemental testimony and schedules on August 14, 2009.

The Application, as amended, requests an increase in base rates of approximately \$154 million.[4] The Application, as further supplemented, asserts that a rate increase of approximately \$167 million is warranted based on the Company's operations for the test year ended December 31, 2008, as adjusted.[5] The Company requests a return on rate base of 9.027% and a return on common equity of 13.35%.[6] APCo states that the proposed 13.35% return on common equity is based on a traditional cost of equity calculation of 12.50% plus a proposed 0.85% performance incentive for the Company's generating plant performance, customer service, and operating efficiency as authorized by § 56-585.1 A of the Code.[7] The Company represents that the proposed rate increase would raise the monthly bill of a typical residential customer

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[3] The Company's Motion For Leave to File Supplemental Direct Testimony and Schedules was filed in response to the Commission's Order on Commission Staff's Motion *in Limine* entered in Case No. PUE-2009-00019, which held that § 56-585.1 A 10 of the Code requires that an actual end-of-test period capital structure and cost of capital be used in statutory reviews under § 56-585.1 A of the Code. *Application of Virginia Electric and Power Company, For a 2009 statutory review of the rates, terms and conditions for the provision of generation, distribution and transmission services pursuant to § 56-585.1 A of the Code of Virginia*, Case No. PUE-2009-00019, Order on Commission Staff's Motion *In Limine* (July 14, 2009).

[4] Ex. 14 (Waldo supplemental direct) at 2.

[5] Ex. 27 (Allen additional direct) at 7.

[6] Ex. 26 (Allen supplemental direct) at 2-3; Application at 3.

[7] Application at 3.

using 1,000 kilowatt-hours of electricity from $91.49 per month to $107.14 per month, an increase of $15.65, or 17.1%.[8]

APCo asserts that an increase in base rates is necessary because its current earnings are inadequate to allow the Company to fully recover its costs and earn a fair rate of return on common equity.[9] The Company states that several factors have contributed to its need for rate relief, including: the loss of a large industrial customer in West Virginia in 2009, which causes additional costs to be allocated to the Company's Virginia jurisdictional operations; increases in APCo's capacity equalization charges from affiliated companies; and the rising costs incurred to comply with state and federal environmental requirements.[10]

The Company also proposes several changes to its existing tariffs in order to recover its proposed base rate increase. APCo states that the discrete charges embedded in its rate schedules have been revised to recover the Company's proposed rate increase and to move each customer class closer towards cost of service. In addition, the Company proposes to implement a new rate schedule and rider for its medium and large commercial and industrial customers. The new rate schedule, which the Company designates as Schedule GS (General Service), would combine the Company's current Schedules MGS (Medium General Service) and LGS (Large General Service) into a single rate schedule. The Company states that it developed Schedule GS in order to provide an additional option for the Commission to consider when deciding how best to address customer migration between the Company's medium and large general service rate schedules.[11]

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[8] Ex. 7 (Supplemental Schedules Volume II) at Supplemental Schedule 43, page 1.

[9] Application at 2-3.

[10] Ex. 13 (Waldo direct) at 7-9.

[11] Application at 4; Ex. 78 (Bethel direct) at 12-18.

The Company proposes to place Schedule GS into effect on the date of the Commission's final order in this proceeding.

In addition, APCo proposes to implement a new Economic Development Rider designed to encourage economic development in the Company's service territory. The Company asserts that the Economic Development Rider would offer demand charge reductions to qualifying new and existing large commercial and industrial customers who increase their load by one megawatt or more by investing in new plant and other facilities that help sustain the economy and create jobs.[12]

The Company also proposes certain changes to its terms and conditions of service and its credit and collections program. The proposed changes include, among other things: (i) suspending the Company's current credit and collections program that allows it to require additional deposit amounts if a residential customer exhibits an extended pattern of delinquency or if the deposit on hand is inadequate given the size of a customer's monthly bill; (ii) changing deposits to an amount that is equal to two times the average monthly usage of a customer rather than an amount equal to the customer's estimated bill for the two highest consecutive months of usage; (iii) allowing payments for deposits to be extended up to six months in cases of hardship; and (iv) allowing customers who participate in the Company's budget billing program to spread their settlement payments over the next twelve months of the budget year rather than paying the settlement over three months.[13]

APCo sought to place its proposed rates, terms and conditions of service, with the exception of Schedule GS, into effect on an interim basis beginning December 12, 2009, at

[12] Ex. 13 (Waldo direct) at 17.

[13] *Id.* at 11-12.

which time the Company's proposed transmission rider would also take effect. In this regard, APCo noted that it filed a companion application on July 15, 2009, proposing that certain transmission-related costs charged by PJM Interconnection LLC ("PJM"), be removed from the Company's base rates and recovered through a separate rate adjustment clause, as authorized by § 56-585.1 A 4 of the Code.[14] In order to avoid any duplication of transmission revenues or omission of transmission costs in the Company's rates, the Company proposed that both its requested base rate increase and its approved transmission rider be placed into effect simultaneously on December 12, 2009.

On August 26, 2009, the Commission issued an Order for Notice and Hearing that, among other things: (1) established a procedural schedule for this case; (2) directed APCo to provide public notice of this matter; and (3) as directed by statute, permitted (but did not require) APCo to place its proposed rates into effect on an interim basis, subject to refund, for service rendered on and after December 12, 2009.

The following parties filed notices of intent to participate in this proceeding: VML/VACO APCo Steering Committee ("VML/VACO"); Wal-Mart Stores East, LP & Sam's East, Inc. ("Wal-Mart"); Steel Dynamics, Inc. ("Steel Dynamics"); The Kroger Company ("Kroger"); Old Dominion Committee for Fair Utility Rates ("Committee"); Office of the Attorney General's Division of Consumer Counsel ("Consumer Counsel"); and Utility Management Services, Inc.

The Company placed its proposed rates into effect on an interim basis, subject to refund, for service rendered on and after December 12, 2009. On February 24, 2010, APCo filed a letter and tariffs with the Commission explaining that for bills rendered on and after that date it was:

[14] Application at 4. The Commission approved the Company's transmission rate adjustment clause, in Case No. PUE-2009-00031, on October 6, 2009.

(1) suspending further collection of its interim rates; and (2) collecting revenue at the level of base rates prior to December 12, 2009 (with the exception of transmission expenses approved as part of the Company's transmission rate adjustment clause in Case No. PUE-2009-00031). The Company explained that it was taking this action pursuant to emergency legislation enacted during the 2010 Session of the Virginia General Assembly.[15] This same legislation further directs the Commission to issue a final order in the instant case "not later than July 15, 2010, for rates to become effective for bills rendered on and after August 1, 2010."[16]

The Commission held public hearings and received testimony from public witnesses in Abingdon (November 18, 2009), Rocky Mount (November 19, 2009), and Richmond (March 16, 2010). The Commission convened the public evidentiary hearing on March 30 and 31, 2010 and April 1 and 2, 2010. In addition, the Commission admitted more than 140 exhibits into the record and received more than 37,000 written and electronic comments in this case.

On or before May 18, 2010, the following participants filed post-hearing briefs: APCo; VML/VACO; Wal-Mart; Steel Dynamics; Kroger; Committee; Consumer Counsel; and the Commission's Staff ("Staff").

NOW THE COMMISSION, upon consideration of this matter, is of the opinion and finds as follows.

Cost of Capital

Capital Structure

Section 56-585.1 A 10 of the Code requires the Commission to "utiliz[e] the actual end-of-test period capital structure" in this proceeding. We reject APCo's suggestion that using

[15] 2010 Va. Acts of Assembly Chaps. 1 and 2, and Second Enactment Clause.

[16] *Id.*

this statutorily-required capital structure may prevent the Company from having an opportunity to earn a reasonable return on its capital investment.[17] As explained by Staff: (1) APCo's "argument that *some* components of a weighted average cost of capital calculation have increased [after the test year] fails to take into account any decreases in *other* components of that calculation;" (2) "[f]or example, the current cost of short-term debt is lower – indeed, significantly lower – than the 3.906% end-of-test year cost rate, which is also required by law;" (3) "[m]oreover, the costs and relative ratios that determine a weighted average cost of capital are influenced by all issuances, including any future issuances that have not yet occurred;" and (4) "[g]iven these facts, the evidence simply does not show that compliance with the law will not allow [APCo] the opportunity to recover its cost of capital."[18] We find that Staff's proposed use of an actual per books capital structure complies with § 56-585.1 A 10 of the Code, is "consistent with Commission precedent," and is reasonable for purposes of this proceeding.[19]

Cost of Debt

Section 56-585.1 A 10 of the Code also requires the Commission to "utiliz[e] the actual end-of-test period . . . cost of capital" in this proceeding, which includes (i) long-term debt, and

[17] *See, e.g.,* Company's May 18, 2010 Post-hearing Brief at 11-13 (citing Tr. 502 (Avera); Tr. 542 (Gorman); Tr. 596 (Maddox); Tr. 783 (Avera); Ex. 60 (Maddox supplemental direct); Ex. 132 (Waldo rebuttal) at 4-5).

[18] Staff's May 18, 2010 Post-hearing Brief at 55 (emphasis in original) (citing Ex. 96 (Bloomberg Key Rates)).

[19] *Id.* at 54 (citing *Application of Appalachian Power Company, For an increase in electric rates*, Case No. PUE-2006-00065, 2007 S.C.C. Ann. Rept. 321, 326, Final Order (May 15, 2007)). *See also* Ex. 59 (Maddox direct) at 3-7. The test period for this case ended on December 31, 2008. *See, e.g.,* Application at 2. The Company's actual end-of-test period capital structure is as follows:

Short-term debt	3.140%
Long-term debt	54.892%
Preferred stock	0.307%
Common equity	41.525%
Investment tax credits	0.136%
Total Capitalization	*100%*

See Ex. 59 (Maddox direct) at Schedule 1.

(ii) short-term debt. Accordingly, we approve the actual end-of-test period cost of (i) long-term debt (6.065%), and (ii) short-term debt (3.906%).[20]

Cost of Equity

Section 56-585.1 A of the Code states that "the Commission shall determine fair rates of return on common equity [and] may use any methodology to determine such return it finds consistent with the public interest." We find that a market cost of equity within a range of 9.5% to 10.5% results in a fair and reasonable return on common equity. This return is reasonably supported by the testimony and resulting recommendations of Staff witness Maddox and Committee witness Gorman.[21] Moreover, we find that the methodologies employed by these witnesses are consistent with the public interest and satisfy the standards as stated by Mr. Maddox: "maintenance of financial integrity, the ability to attract capital on reasonable terms, and earnings commensurate with returns on investments of comparable risk."[22]

In addition, we find that the Company's proposed cost of equity of 12.5% does not represent the actual cost of equity in the marketplace and a reasonable return on common equity. In addition to other valid criticisms, Company witness Avera's "cost of equity testimony was never updated with any data beyond March 2009, which was the bottom of a severe drop in the market[, and in] the thirteen months that passed between March 2009 and the conclusion of the evidentiary hearing, the market increased approximately 50%."[23] Indeed, this deficiency in

[20] *See, e.g.,* Ex. 59 (Maddox direct) at 7; Ex. 2 (Application Volume IV) at Schedule 3, page 3 of 7 and Schedule 4, page 1 of 5; Staff's May 18, 2010 Post-hearing Brief at 53.

[21] *See, e.g.,* Ex. 59 (Maddox direct); Ex. 58 (Gorman direct); Staff's May 18, 2010 Post-hearing Brief at 38-49; Committee's May 18, 2010 Post-hearing Brief at 3-18.

[22] Ex. 59 (Maddox direct) at 9.

[23] Staff's May 18, 2010 Post-hearing Brief at 40 (citing Avera testimony; Ex. 51 (Yahoo! Finance S&P 500 Index Chart); Ex. 52 (Yahoo! Finance Dow Jones Industrial Average chart); *Bluefield Water Works & Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679, 693 (1922) (quotation omitted)).

Company witness Avera's recommendation is underscored by more recent testimony that he provided on behalf of other American Electric Power Company ("AEP") operating companies before the Kentucky and Michigan Public Service Commissions – where his use of updated information results in significantly *lower* cost of equity estimates.[24]

Finally, we find that "Staff witness Maddox's proxy group is reasonably constituted both in size and composition" and "has risk comparable to [APCo]."[25] Moreover, Staff notes that: (i) Company witness Avera previously presented a proxy group on behalf of AEP in a recent Federal Energy Regulatory Commission ("FERC") proceeding, wherein he included "three of the same companies that Dr. Avera now criticizes Mr. Maddox for including in his proxy group;" and (ii) although Dr. Avera criticizes Mr. Maddox for including utilities with a Value Line safety rating above AEP's, "Dr. Avera included in testimonies filed on behalf of other AEP operating subsidiaries only a few months before Mr. Maddox's testimony four of the same companies with Value Line safety ratings higher than those of AEP."[26]

Statutory Peer Group Floor

Section 56-585.1 A of the Code states as follows:

> [T]he Commission shall determine fair rates of return on common equity applicable to the generation and distribution services of the utility . . . but such return shall not be set lower than the average of

[24] *See, e.g., id.* at 42-49. *Compare* Ex. 49 (Avera direct) *with* Ex. 93 (Avera Michigan DCF Model), Ex. 94 (Avera Kentucky DCF Model), and Ex. 95 (Avera Michigan and Kentucky CAPM Model). Staff also notes that many of "Dr. Avera's updated estimates . . . are *several hundred basis points lower* than his estimates in this case," and that "Dr. Avera's more recent testimony [in other jurisdictions] uses a 7.7% forward-looking market risk premium, which is *200 basis points lower* than what he continues to support in Virginia." Staff's May 18, 2010 Post-hearing Brief at 43, 47 (emphasis in original).

[25] Staff's May 18, 2010 Post-hearing Brief at 38 (typeface and case modified). For example: (1) Staff's proxy group was reasonably "screened based on a number of criteria, including net plant, primary source of income, credit rating, financial strength, and safety rating to ensure the group has risk comparable to [APCo];" and (2) "Staff's peer group has a beta of .69, which is closer to AEP's beta of .70 than [APCo] witness Avera's proxy group with a beta of .73." *Id.* at 38-39 (footnotes omitted).

[26] *Id.* at 39 (footnotes omitted).

> the returns on common equity reported to the Securities and Exchange Commission for the three most recent annual periods for which such data are available by not less than a majority, selected by the Commission as specified in subdivision 2 b, of other investor-owned electric utilities in the peer group of the utility, nor shall the Commission set such return more than 300 basis points higher than such average. The peer group of the utility shall be determined in the manner prescribed in subdivision 2 b.

Next, in selecting the majority of the peer group utilities to calculate the statutory floor for rate of return on common equity, § 56-585.1 A 2 b of the Code directs as follows:

> In selecting such majority of peer group investor-owned electric utilities, the Commission shall first remove from such group the two utilities within such group that have the lowest reported returns of the group, as well as the two utilities within such group that have the highest reported returns of the group, and the Commission shall then select a majority of the utilities remaining in such peer group.

No party contested the composition of the peer group – which in this case is comprised of seven utilities after removing the companies with the two highest, and the two lowest, reported returns as required by the above statute.[27] The participants, however, differ on which utilities should comprise the "majority" to be selected by the Commission to determine the statutory floor.

In this regard, the statute clearly leaves this selection to the Commission's discretion. A statutory floor comprised of *any* four of the seven-member peer group satisfies the statute. Indeed, APCo acknowledged during the hearing that the statute gives the Commission this discretion.[28] We select a majority consisting of four peer group utilities that, on average, had a return on average equity of 10.53%.[29] Thus, we approve a fair rate of return on common equity for APCo of 10.53%, which results in an overall rate of return on rate base of approximately

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[27] *See, e.g., id.* at 49 n.172.

[28] *See* Tr. 1183-1185 (Waldo).

[29] *See, e.g.,* Ex. 60 (Maddox supplemental direct) at Schedule 15 – Updated. We find that, on the facts before us in this case, it is reasonable to utilize returns on average equity for this purpose.

7.85%. We find that the cost of equity and overall rate of return approved herein are fair and reasonable, permit the attraction of capital on reasonable terms, fairly compensate investors for the risks assumed, and enable the Company to maintain its financial integrity. This finding reduces the Company's requested rate increase by approximately $28.0 million.[30]

Rate of Return Adder

Section 56-585.1 A of the Code states as follows:

> The Commission may increase or decrease such combined rate of return by up to 100 basis points based on the generating plant performance, customer service, and operating efficiency of a utility, as compared to nationally recognized standards determined by the Commission to be appropriate for such purposes.

We reject APCo's request to increase its fair rate of return on equity by 0.85%. This statute does not require the Commission to approve *any* increase to APCo's fair rate of return as determined above. Based on the record in this case, we find that the Company's generating plant performance, customer service, and operating efficiency do not warrant any adder above APCo's fair rate of return at this time.[31] This finding reduces the Company's requested rate increase by approximately $13.0 million.[32]

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[30] In addition, any comparison by APCo to cost of equity, rate of return floor, rate of return adder, or any other issue in the Commission's prior rate case for Dominion Virginia Power ("Dominion") (Case No. PUE-2009-00019) is inapposite to the instant proceeding. *See, e.g.*, Ex. 132 (Waldo rebuttal) at 5-6. The facts and circumstances of the two cases are simply not comparable. For example, the settlement approved by the Commission in the Dominion rate case encompassed a number of items not present in the instant proceeding, including: (1) refunds or credits of fuel, base rate, and rate adjustment clause recoveries that totaled approximately $726 million; and (2) the Dominion stipulation also provided for no change in base rates until December 2013, at the earliest. *See, e.g.*, Staff's May 18, 2010 Post-hearing Brief at 37-38 (citing Tr. 1191-92 (Waldo); *Application of Virginia Electric and Power Company, For a 2009 statutory review of rates, terms and conditions for the provision of generation, distribution and transmission services pursuant to § 56-585.1 A of the Code of Virginia*, Case No. PUE-2009-00019 *et al.*, Order Approving Stipulation and Addendum (Mar. 11, 2010)).

[31] *See, e.g.*, Staff's May 18, 2010 Post-hearing Brief at 56-72; Consumer Counsel's May 18, 2010 Post-hearing Brief at 30-34; Committee's Post-hearing Brief at 18-23; VML/VACO's May 18, 2010 Post-hearing Brief at 12.

[32] *See* Company's May 18, 2010 Post-hearing Brief, Attach. 2.

Capacity Equalization Expense

The Company "is a member of the AEP-East Power Pool which is governed by an interconnection agreement [('Interconnection Agreement')]."[33] Staff and Consumer Counsel present extensive evidence and argument regarding the capacity equalization charges that APCo is required by the Interconnection Agreement to pay to certain other AEP operating affiliates. Under the Interconnection Agreement, "[a] generating capacity obligation is calculated for each AEP-East company, and those companies that do not own enough capacity to satisfy their calculated obligation must make payments to those with surplus capacity."[34] Further, "[s]ince 2007, [APCo] has been the most deficient company in the AEP-East pool by a substantial margin."[35] Staff also contends that "AEP has maintained [APCo] as a capacity-deficient company notwithstanding the fact that AEP's capacity equalization charges to [APCo] have tripled – from $138 million to $394 million – since 2006,"[36] and that "AEP has also maintained [APCo] as a capacity-deficient company as it has taken aggressive steps to move another AEP-East operating company from a deficiency comparable to that of [APCo] to a surplus position."[37]

In fact, Consumer Counsel argues that "APCo's capacity deficit position is the most troubling driver of the requested rate increase" – although the Interconnection Agreement "calls for each AEP-East company to have sufficient capacity resources to serve its native load . . .

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[33] Consumer Counsel's May 18, 2010 Post-hearing Brief at 2.

[34] Staff's May 18, 2010 Post-hearing Brief at 21.

[35] *Id.* (citing Ex. 100 (Carr direct) at 37).

[36] *Id.* (citing Ex. 33 (Company response to request OAG 6-126)).

[37] *Id.* (citing Ex. 34 (Company response to request OAG 9-181); Ex. 124 (Company response to request OAG 7-142); Ex. 140 (Company response to request OAG 9-175); Ex. 137-C; Ex. 138-C; Ex. 139-C).

APCo's deficit has increased as new generation capacity has been repeatedly assigned by AEP to other members of the pool."[38] Some of the limited capacity additions proposed for APCo have reflected some of AEP's highest cost generation, while lower cost generation has been assigned to an affiliated company, Columbus Southern Power Company ("Columbus Southern"). For example, Consumer Counsel asserts that AEP assigned new capacity to Columbus Southern when AEP could foresee that such action would increase Columbus Southern's earned return on investment and leave APCo to pay increasing capacity charges, which would put pressure on APCo's earned returns and upward pressure on rates.[39] While APCo now states that it has earned low returns over the past several years, this should be viewed in connection with the fact that Columbus Southern – another AEP-owned subsidiary – "is earning returns of up to 22%" according to evidence presented in this case.[40]

Indeed, it can be reasonably argued, as Consumer Counsel has done, that over the past several years AEP has repeatedly taken actions in assigning capacity that have harmed APCo and its customers while benefitting other AEP subsidiaries.[41] As noted above, the Company's capacity deficit position "has increased as new generation capacity has been repeatedly assigned by AEP to other members of the pool," and this "new capacity for other AEP-East companies consists of relatively low cost gas-fired generating units which were acquired by AEP . . . at costs below a new build."[42] Based on a variety of factors, including this capacity deficit, "APCo

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[38] Consumer Counsel's May 18, 2010 Post-hearing Brief at 4 (citing Ex. 100 (Carr direct), App. B, at 1, 3; Ex. 109 (Nelson chart)).

[39] *See, e.g., id.* at 4-16.

[40] *See, e.g., id.* at 5-16 (citations omitted).

[41] *See, e.g., id.* at 3-19 (citations omitted).

[42] *Id.* at 4-5.

is paying nearly $258 million . . . more annually to its sister companies for capacity equalization than it did in 2006."[43]

APCo acknowledges that it did not necessarily act in its own best interests regarding the assignment of capacity within the AEP-East Pool. That is, in this instance, APCo indicated that it supported what was deemed best for the AEP system – not what was necessarily best for APCo:

> [T]his is a zero sum construct, so I'm viewing that in terms of the total AEP system. I weigh in with the considerations of the specific impact on APCo, but my vote is a reflection of what I believe is best for the AEP System.[44]

Indeed, as summed up by Consumer Counsel, "[i]f the pooling arrangement is a zero sum construct as APCo insists, then it becomes even clearer that by assigning so much capacity to [Columbus Southern], AEP has intentionally benefitted other pool parties at APCo's expense."[45] The Commission, however, is limited in its jurisdiction regarding APCo's capacity equalization expense under the Interconnection Agreement, which is a wholesale power pooling agreement that has been approved by FERC, and cannot "reallocate" capacity responsibility among the AEP operating companies as dictated by the terms of the Interconnection Agreement.

A number of key factors affect APCo's overall capacity costs, and Staff and Consumer Counsel are correct that decisions by APCo and AEP regarding capacity additions, and which

[43] *Id.* at 3. While this discussion focuses on APCo's capacity equalization payments, we recognize that the Company's generation costs are not limited to such payments; that is, if APCo possessed more of its own generation, it obviously would be incurring the costs associated therewith. We further note, however, that when AEP did propose new capacity for APCo, its major project – a new coal-fired facility known as an Integrated Gasification Combined Cycle plant – (i) was originally projected to cost far more than other coal-fired options, and (ii) was further burdened with such significant and unquantifiable cost and technological uncertainties that the Commission found it must be rejected. *See, e.g., Application of Appalachian Power Company, For a rate adjustment clause pursuant to § 56-585.1 A 6 of the Code of Virginia*, Case No. PUE-2007-00068, 2008 S.C.C. Ann. Rept. 405, 406-408, Final Order (Apr. 14, 2008).

[44] Tr. 326 (Waldo).

[45] Consumer Counsel's May 18, 2010 Post-hearing Brief at 16. *See also* Tr. 626 (Norwood).

affiliated operating companies undertake those additions, can and do have significant impacts on APCo. We are concerned that the decision making over recent years regarding capacity changes has had a significant adverse effect on APCo and its ratepayers. Accordingly, we direct APCo and AEP to submit a written report to Staff (beyond what has been presented in this record), on or before January 4, 2011, on the reasons for their past actions regarding capacity, as well as the steps that can be taken to ameliorate the negative effects of high capacity charges on APCo and its customers.

In determining a reasonable level of capacity equalization expense to be included in APCo's going-forward rates for purposes of this proceeding, the participants have litigated two issues that must be considered for rate setting purposes in this case: (1) Member Load Ratio ("MLR"); and (2) Capacity Equalization Rate. We address both of these issues below. In sum, based on our findings below, we approve a Virginia jurisdictional capacity equalization expense of approximately $154.6 million.

Member Load Ratio

APCo's MLR is used to determine its generating capacity obligation to the AEP-East Power Pool.[46] The Company proposes to utilize a forecasted average MLR for the rate year of approximately 33.165%.[47] Staff asserts that the MLR "is not reasonably predictable," and that

[46] The Company's "MLR is the relationship between its peak demand and the total non-coincident peak demand of the AEP-East system, all measured over the preceding twelve months," and "[e]ach member's capacity obligation is determined on a monthly basis by multiplying the total AEP-East capacity by its MLR." Staff's May 18, 2010 Post-hearing Brief at 23 (citations omitted). In addition, "Pool members that do not own enough generating capacity to satisfy their obligations purchase capacity from the surplus members of the Pool," and the "amount of payments/receipts (capacity settlements) is based on the relative deficits/surpluses and the generation costs of the surplus members." Company's May 18, 2010 Post-hearing Brief at 29 (citing Ex. 100 (Carr direct) at 31).

[47] *See, e.g.*, Company's May 18, 2010 Post-hearing Brief at 33 (citations omitted); Staff's May 18, 2010 Post-hearing Brief at 24; Consumer Counsel's May 18, 2010 Post-hearing Brief at 20 n.80.

"rates should instead be based on the five-year average [MLR] of 31.98%."[48] Consumer Counsel similarly proposes a five-year average MLR.[49] Both Staff and Consumer Counsel note that the Commission has previously used a five-year average MLR to calculate a reasonable rate year level of capacity equalization expense for APCo.[50]

We continue to find that it is reasonable to establish APCo's MLR based on a five-year average. While we do not preclude consideration of other approaches in the future, as we previously found in a prior APCo rate case, "[u]se of a five-year average MLR at this time should moderate the volatility of the MLR in general and avoids setting rates solely on the basis of an extremely high or low MLR."[51] Such use of a five-year average reasonably addresses the unpredictable nature of the MLRs throughout the AEP-East system.[52] Over the past ten years, APCo has seen MLRs ranging from approximately 28% to over 35%.[53] Staff also notes that "[d]uring the last ten years, the Company's MLR has experienced several rapid increases and decreases alike."[54] Moreover, it is understandable that MLRs could be significantly volatile. For example, APCo's specific MLR is influenced not only by its load, but by load variations of the

[48] Staff's May 18, 2010 Post-hearing Brief at 24.

[49] Consumer Counsel's May 18, 2010 Post-hearing Brief at 20 (citing Ex. 64 (Norwood direct) at 19).

[50] Staff's May 18, 2010 Post-hearing Brief at 23 (citing *Application of Appalachian Power Company, For an expedited increase in base rates*, Case No. PUE-1994-00063, 1996 S.C.C. Ann. Rept. 255, 256, Final Order (May 24, 1996)); Consumer Counsel's May 18, 2010 Post-hearing Brief at 20.

[51] *Application of Appalachian Power Company, For an expedited increase in base rates*, Case No. PUE-1994-00063, 1996 S.C.C. Ann. Rept. 255, 256, Final Order (May 24, 1996).

[52] We also note that Indiana Michigan Power Company ("I&M") – an affiliate of APCo that also operates under the Interconnection Agreement – recently agreed to use a five-year average MLR as approved by the Indiana Utilities Regulatory Commission. *See, e.g.*, Staff's May 18, 2010 Post-hearing Brief at 24 n.76 (citing *Petition of Indiana Michigan Power Company, an Indiana Corporation, For Authority to Increase its Rates and Charges*, Cause No. 43306, 2009 Ind. PUC LEXIS 107 at *172-73, 273 P.U.R.4th 310, Opinion (Mar. 4, 2009)).

[53] *See, e.g.*, Ex. 64 (Norwood direct) at Ex. SN-3; Ex. 100 (Carr direct) at 41, Graph.

[54] Staff's May 18, 2010 Post-hearing Brief at 23-24.

other AEP-East companies. That is, APCo's MLR is impacted by diverse factors stretching across the *entire* AEP-East footprint, including economic cycles, weather patterns, usage patterns, and customer migration.[55]

Staff's proposed five-year average MLR utilizes actual data through October 2009.[56] Subsequent to the filing of Staff's testimony, however, the record in this case was expanded by the Company to include actual MLR data through February 2010, which results in a higher five-year average MLR and a larger revenue requirement as compared to using October 2009 data. We find that it is reasonable, based on the record in this case, to use the most recent five-year average in the record – *i.e.*, through February 2010 – to establish the Company's MLR. This finding results in an MLR for APCo of 32.44% and reduces the Company's requested rate increase by approximately $15.0 million.[57]

Capacity Equalization Rate

The Capacity Equalization Rate "is the *price* charged" for APCo's capacity deficiency, and it consists of: (1) "the Capacity Investment Rate ('Investment Rate'), which is based on the gross installed cost of the surplus members' generating units and a FERC-approved annual carrying charge of 16.49%;" and (2) "the Fixed Operating Rate ('Operating Rate'), which is based on the operating costs and one-half of the maintenance costs of the surplus members' units."[58]

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[55] *See, e.g.*, Ex. 100 (Carr direct) at 31-41. We find that, based on the record in this case, the Company's proposed MLR is not reasonably predictable.

[56] Staff's proposed five-year average also adjusts for the loss of Century Aluminum, a former 300 megawatt customer in APCo's West Virginia jurisdiction. APCo did not oppose specific recognition of Century Aluminum in this case. Moreover, both APCo and Staff supported accounting adjustments to recognize the loss of Century Aluminum in the instant case. *See, e.g.*, Staff's May 18, 2010 Post-hearing Brief at 81.

[57] This MLR is determined by (1) using actual MLRs as shown by Consumer Counsel witness Norwood, which were updated through February 2010 by Company witness Nelson (resulting in a five-year average of 33.04%), and (2) adjusting for the loss of Century Aluminum (reducing the five-year average MLR by 0.6%). *See, e.g.*, Ex. 64 (Norwood direct) at Ex. SN-3; Ex. 108 (Nelson rebuttal) at 16; Ex. 100 (Carr direct) at Appendix B, pages 5-6.

[58] Staff's May 18, 2010 Post-hearing Brief at 22, 25 (emphasis in original) (citing Ex. 100 (Carr direct) at 32-33).

First, we find that Staff's proposed Investment Rate is reasonable for this purpose: (1) "[p]ursuant to the terms of the Interconnection Agreement, the Investment Rate to be used for an entire calendar year is fixed at the affiliates' plant investments as of December 31 of the previous year;" (2) "[t]hus, the Investment Rate for 2010 will be based on those investments as of December 31, 2009;" and (3) "Staff calculated its Investment Rate based on investment data as of that date, which was provided by the Company."[59] Second, we do not find the Company's proposed Operating Rate, which is based on forecasts, to be reliable for setting rates herein. Rather, we find that Staff's proposed actual October 2009 Operating Rate, which is the most recent actual Staff-audited Operating Rate and uses actual October 2009 data, is reasonable and shall be used to calculate the Capacity Equalization Rate for purposes of this proceeding.[60] These findings result in a Capacity Equalization Rate of $12.73 per kW and reduce the Company's requested rate increase by approximately $12.8 million.[61]

Cook Accidental Outage Insurance Proceeds

As explained by the Company, "[b]oth units of the Cook Nuclear Plant ("Cook") are owned by I&M, another AEP-East Zone operating company," and "Cook Unit 1 experienced an accident on September 20, 2008 and remained out of service until December 18, 2009."[62] Although Cook Unit 1 has resumed production, it "is not expected to return to full power until the fall of 2011."[63] I&M "maintains accidental outage insurance on the Cook facility . . . in addition to property insurance [and has] received $184.4 million in accidental outage policy

[59] *Id.* at 25-26 (citing Ex. 100 (Carr direct) at 40).

[60] *See, e.g., id.* at 25.

[61] Ex. 100 (Carr direct) at 42.

[62] Company's May 18, 2010 Post-hearing Brief at 48 (citing Ex. 100 (Carr direct) at 22-23, 28).

[63] Staff's May 18, 2010 Post-hearing Brief at 32 (citing Ex. 100 (Carr direct) at 22-23).

proceeds through December 2009 and an additional $72.1 million of property insurance proceeds through September 2009."[64] Conversely, AEP has "continued to charge [APCo] 'full price' for Cook's installed capacity cost and certain operating and maintenance expense through the AEP-East pool capacity equalization mechanism."[65]

Staff asserts that the Commission should reduce APCo's "proposed revenue requirement [in this proceeding] by $14.7 million, which is half of [APCo's] Virginia jurisdictional MLR share of the [Cook insurance] proceeds."[66] We conclude that it is not appropriate at this time to deem insurance proceeds received by I&M to be allocable for rate setting purposes in Virginia, which does not preclude consideration of such matters in future proceedings.

Mountaineer Carbon Capture and Sequestration Demonstration Project

As described by Consumer Counsel, the Company is undertaking the Mountaineer Carbon Capture and Sequestration Demonstration Project at its "Mountaineer coal-fired plant in West Virginia in an effort to test and prove whether carbon capture and sequestration [('CCS')] is a viable commercial technology for coal-fired electric generation plants in the event carbon emissions are regulated," and this "is the first CCS project being undertaken at an in-service coal plant."[67] Specifically, this is a "validation project" intended to test CCS technology at a level that is not commercial in scale.[68] The Company asserts that "[c]ustomers of utilities in the U.S. and abroad will benefit from the work we are doing at our Mountaineer plant," but that the "first

[64] *Id.* at 31-32 (citing Ex. 100 (Carr direct) at 25-26).

[65] *Id.* at 32 (citing Ex. 100 (Carr direct) at 23-24).

[66] *See id.* at 31-33 (citing Ex. 100 (Carr direct) at 24-25, 27).

[67] Consumer Counsel's May 18, 2010 Post-hearing Brief at 24-25 (citing Tr. 465 (LaFleur)).

[68] Ex. 123 (AEP Selected to Receive DOE Funds); Staff's May 18, 2010 Post-hearing Brief at 14.

use of any technology comes at a higher cost than subsequent uses."[69] The Company concludes that "it is most prudent to gain knowledge now that will allow compliance with [greenhouse gas ('GHG')] controls, whether in the form of state or federal legislation or via regulatory action."[70] APCo seeks to include approximately $74 million in rate base, and requests both a return on rate base and recovery of expenses, for this project.[71]

It is reasonable for AEP to evaluate and explore options regarding potential federal legislation or regulation regarding GHG emissions. We do not find, however, that it was reasonable for APCo to incur the Mountaineer CCS project costs and then seek recovery from Virginia ratepayers. For example: (i) although AEP asserts that this demonstration project will benefit customers of all of AEP's operating companies and of all utilities in the United States, APCo's ratepayers (and not shareholders) are being asked to pay for all of the costs incurred by AEP for this project; and (ii) as stated by Consumer Counsel, "AEP is undertaking no other [CCS] initiatives at any of its other subsidiaries' plants," and "APCo and its customers are being asked to shoulder the entire financial burden and risk associated with AEP's [CCS] research and development."[72] Accordingly, we deny the Company's request for cost recovery of the

[69] *Id.*

[70] Company's May 18, 2010 Post-hearing Brief at 65 (citing Ex. 121 (LaFleur rebuttal) at 7).

[71] *See, e.g.*, Consumer Counsel's May 18, 2010 Post-hearing Brief at 25 (citing Tr. 373); Staff's May 18, 2010 Post-hearing Brief at 14.

[72] *See, e.g.*, Consumer Counsel's May 18, 2010 Post-hearing Brief at 24-29; Staff's May 18, 2010 Post-hearing Brief at 13-15. VML/VACO also asserts that the Commission should deny the costs associated herewith. VML/VACO's May 18, 2010 Post-hearing Brief at 9. Furthermore: (1) this project significantly increases operation and maintenance expenses at the Mountaineer plant; (2) this project decreases the efficiency of the Mountaineer facility, which results in increased fuel costs; (3) the CCS technology decreases the Mountaineer plant's operating capacity, which further increases APCo's capacity deficit position within the AEP-East pool and, thus, increases APCo's capacity equalization charges; and (4) the potential benefits to Virginia ratepayers currently are speculative at best. *See, e.g.*, Consumer Counsel's May 18, 2010 Post-hearing Brief at 24-29; Staff's May 18, 2010 Post-hearing Brief at 13-15.

Mountaineer CCS demonstration project under the facts presented herein.[73] This finding reduces the Company's requested rate increase by approximately $9.8 million.

<u>December 2009 Storm Costs</u>

The Company stated that it "incurred substantial costs from storms in December 2009 that totaled approximately $26.8 million in incremental distribution operations and maintenance costs."[74] We will allow the Company to "defer on its books this incremental distribution storm restoration expense, until such time as a request for recovery is made and subsequently ruled upon by the Commission."[75] This finding does not constitute approval or rejection of all or part of these costs.

<u>PJM Ancillary Fees</u>

We reject APCo's projection of PJM ancillary fees. These fees are based on variables that have proven to be volatile in the past (such as the amount of hours that AEP's generating plants run and market prices).[76] We do not find that the Company's projection of future PJM ancillary fees "reasonably can be predicted to occur during the rate year."[77] Rather, we find that it is reasonable for the revenue requirement established herein to reflect actual PJM ancillary fees as occurred during the twelve months ended October 31, 2009, and that such level of fees

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[73] In addition, although there was evidence that this CCS project could also *increase* APCo's fuel and capacity equalization charges, we do not address in this case whether an approved level of such charges should be reduced to remove the impact of the Mountaineer CCS project. *See, e.g.*, Consumer Counsel's May 18, 2010 Post-hearing Brief at 25; Ex. 100 (Carr direct) at 63-64.

[74] Company's May 18, 2010 Post-hearing Brief at 67.

[75] *Id.*

[76] *See, e.g.*, Staff's May 18, 2010 Post-hearing Brief at 19-21 (citing Ex. 41 (Schedule of Actual v. Projected December 2009 Results); Ex. 112 (Rate Year Forecast Compared to Available Actual to Date Total Company); Ex. 100 (Carr direct) at 47; Ex. 108 (Nelson rebuttal) at 19).

[77] Va. Code § 56-235.2 A.

provides the Company with a reasonable opportunity to recover its costs. This finding reduces the rate increase requested in the Company's Application by approximately $7.4 million.

<u>Employee Incentive Plans</u>

AEP has an Annual Incentive Plan ("AIP") and a Long-Term Incentive Plan (collectively, "Incentive Plans"). As explained by Staff: (1) "[a]ward calculations for the Incentive Plans are based in large part on AEP earnings and shareholder return;" (2) "[i]ndeed, AEP earnings performance ultimately determines the AIP payouts in any given year;" (3) "[t]he primary goals of the Incentive Plans are to increase shareholder value;" (4) "[t]he benefits of incentivizing [earnings per share] and stock price growth accrue primarily to AEP's shareholder[s];" and (5) "because these incentives are driven by *AEP* earnings and stock prices, they may actually provide incentives to take certain actions that are not necessarily in the best interests of [*APCo*] or its ratepayers."[78] The Company seeks to collect 100% of the costs of the Incentive Plans from ratepayers.

The Company has not shown that 100% of the Incentive Plan expenses serve to benefit ratepayers. We will not, however, reject all of these costs; rather, as recommended by Staff, we find that 50% of such expenses are just and reasonable for ratemaking purposes in this case.[79] This finding reduces APCo's requested rate increase by approximately $4.2 million.

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[78] Staff's May 18, 2010 Post-hearing Brief at 26-27 (emphasis in original) (citations omitted). Indeed, Consumer Counsel asserts that AEP has been incented to take actions that it knew would hurt APCo and would benefit AEP. *See, e.g.*, Consumer Counsel's May 18, 2010 Post-hearing Brief at 10-13 (Confidential) (citations omitted).

[79] *See, e.g.*, Staff's May 18, 2010 Post-hearing Brief at 26-27; Tr. 883 (Carr). In addition, we find that APCo failed to make an appropriate adjustment to remove the portion of American Electric Power Service Corporation ("AEPSC") employees' incentive compensation expense that was attributable to AEP exceeding its earnings per share targets. *See, e.g.*, Ex. 100 (Carr direct) at 55. This additional adjustment is reflected in Staff's Other Operating Expense Adjustments referenced below.

Environmental Expenses

We reject APCo's projection of environmental expenses. As explained by Staff:

> [The Company] incurs expense to operate its environmental control equipment. These expenses include the handling and disposal of gypsum and the consumption of urea, limestone, trona, polymer, and lime hydrate. The Company incurs additional expense to consume emission allowances, which are used to offset emissions of regulated pollutants.[80]

We find that the Company's forecasts of these environmental expenses have proven to be unreliable and inaccurate.[81] We do not find that the Company's projections of future environmental expenses "reasonably can be predicted to occur during the rate year."[82] Rather, we adopt Staff's proposed expense level for this purpose, which uses actual data and limited forecasts that we find reasonably can be predicted to occur during the rate year.[83] Staff evaluated and audited individual components of this expense and made reasonable recommendations on each.[84] The difference between the Company's and Staff's proposals "results primarily from the Company's forecasts for urea, limestone, and polymer."[85] We further find that Staff's recommended level of environmental expenses provides the Company with a reasonable opportunity to recover its costs. This finding reduces the rate increase requested in the Company's Application by approximately $5.3 million.

[80] Staff's May 18, 2010 Post-hearing Brief at 16 (citing Ex. 100 (Carr direct) at 43).

[81] *See, e.g., id.* at 16-19 (citing Tr. 1215 (Waldo); Ex. 41 (Schedule of Actual v. Projected December 2009 Results); Ex. 100 (Carr direct) at 43-46; Ex. 108 (Nelson rebuttal) at 20).

[82] Va. Code § 56-235.2 A.

[83] *See, e.g.*, Staff's May 18, 2010 Post-hearing Brief at 16-19 (citing Tr. 1215 (Waldo); Ex. 41 (Schedule of Actual v. Projected December 2009 Results); Ex. 100 (Carr direct) at 43-46; Ex. 108 (Nelson rebuttal) at 20).

[84] *See id.*

[85] *Id.* at 17 (citing Ex. 100 (Carr direct) at 46).

Rate Base

We reject the Company's proposed rate year average adjustments to rate base, which include projected future costs for items such as plant in service, construction work in progress ("CWIP"), accumulated depreciation, and accumulated deferred income taxes. We agree with Staff that APCo's predictions of these significant rate base components are "based on unreliable and inaccurate assumptions."[86] We do not find that the Company's projected "future costs . . . reasonably can be predicted to occur during the rate year."[87] Rather, we find that it is reasonable for the rate base established herein to reflect Staff's proposed rate base, which contains "[r]ecent, actual information, normalized or annualized when necessary and adjusted for reasonably predictable future changes."[88]

We also find, contrary to APCo's assertions, that the rate base approved herein provides the Company with a reasonable opportunity to recover its costs. The approved rate base includes known costs, plus future costs (such as CWIP related to distribution projects) that we conclude reasonably can be predicted to occur during the rate year. In addition, APCo's contention that the approved rate base will not permit recovery of costs associated with capital investment in scrubbers for its Amos coal plant is misplaced.[89] First, the rate base that *APCo* proposed does not include these scrubbers.[90] Second, the Amos scrubbers provide further example of how the

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[86] *Id.* at 9.

[87] Va. Code § 56-235.2 A. *See, e.g.,* Staff's May 18, 2010 Post-hearing Brief at 8-13 (citing Ex. 100 (Carr direct) at 74-76).

[88] Staff's May 18, 2010 Post-hearing Brief at 8.

[89] Company's May 18, 2010 Post-hearing Brief at 74-75. In addition, in a footnote on Attachment 2 of its post-hearing brief, the Company "requests recognition of the Amos 2 scrubber and its expenses." *Id.* at Attach. 2 n.3. We recognize that the Company may seek to include Amos 2 scrubbers in subsequent rate cases if appropriate, but such recognition does not modify our rate base findings for purposes of the instant proceeding.

[90] *See, e.g.,* Staff's May 18, 2010 Post-hearing Brief at 10 (citing Tr. 1160 (Allen)).

Company's projected future costs of such rate base components are not reasonably predictable. Specifically, "[i]n the space of just ten months, a $530 million construction project had its in-service dates moved from: (a) March 2010 and December 2010 to (b) 2012, and (c) back to the first quarters of 2010 and 2011."[91] Finally, the rate base and associated revenue growth adjustment that we approve herein does not decrease – but, rather, *increases* – the Company's proposed revenue requirement.[92]

The rate base and associated revenue adjustment approved herein increases the Company's rate request by approximately $3.5 million.[93]

<u>Deferred Fuel Balance</u>

Consumer Counsel "recommended an adjustment to the deferred fuel balance to reflect an updated estimated fuel balance," and the Company agreed with the recommended adjustment.[94] We find that Consumer Counsel's proposed adjustment, which uses APCo's "revised forecast of rate year fuel cost deferrals . . . for determining the 13-month average deferral fuel balance to be included in working capital in this case," is reasonable and shall be

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[91] Ex. 100 (Carr direct) at 11.

[92] *See, e.g.*, Staff's May 18, 2010 Post-hearing Brief at 10. In addition, our approval reflects consistent treatment of rate base and customer growth, which the Company and Staff agree is needed to avoid a mismatch between revenue and rate base. *See, e.g., id.* at 12 (citing Ex. 100 (Carr direct) at 15-21); Company's May 18, 2010 Post-hearing Brief at 75.

[93] *See, e.g.*, Staff's May 18, 2010 Post-hearing Brief at 12, 16 (citing Ex. 100 (Carr direct) at 15-21; Ex. 103 (Carr revised statements) at Revised Statement VII-A). This amount does not include changes to the deferred fuel balance, which are discussed below.

[94] *See, e.g.*, Consumer Counsel's May 18, 2010 Post-hearing Brief at 35-36 (citing Ex. 64 (Norwood direct) at 33-34); Company's May 18, 2010 Post-hearing Brief at 75-76 (citing Tr. 384 (Nelson); Ex. 64 (Norwood direct) at 33-34).

approved.[95] This finding reduces the Company's requested rate increase by approximately $2.4 million.

Next, the Committee asserts that the "Commission should exclude from revenue requirement the costs of APCo's wind purchased power costs associated with the Camp Grove and Fowler Ridge Projects," which are part of the Company's renewable energy portfolio standard ("RPS") program under § 56-585.2 B of the Code.[96] The Committee states, among other things, that "APCo has not shown that its proposed inclusion of [these] costs in the deferred fuel component of rate base complies with Va. Code § 56-585.2 E."[97] The Company opposes such adjustment,[98] which would reduce its requested rate increase by approximately $1.2 million.[99] We find that APCo has not satisfied – nor even attempted to satisfy – the statutory standards under § 56-585.2 E of the Code for recovery of these costs. Specifically, and as we similarly found in APCo's prior fuel factor proceeding:

> [T]he Company has not met its burden under [the plain language of § 56-585.2 E of the Code] (a) to establish what portion – if any – of the Camp Grove and Fowler Ridge costs represent 'incremental costs of the RPS program,' and (b) to allocate and recover such costs based on demand and excluding large industrial rate classes. Accordingly, we reject the Company's request to include ... the RPS program costs attendant to Camp Grove and Fowler Ridge.[100]

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[95] Consumer Counsel's May 18, 2010 Post-hearing Brief at 36 (citing Ex. 64 (Norwood direct) at 33-34). This reduces APCo's deferred fuel adjustment from $31.9 million to $13.8 million. *Id.*

[96] Committee's May 18, 2010 Post-hearing Brief at 31 (typeface modified).

[97] *Id.* at 39.

[98] Company's May 18, 2010 Post-hearing Brief at 76-77.

[99] *See, e.g.*, Ex. 100 (Carr direct) at 79.

[100] *Application of Appalachian Power Company, To revise its fuel factor pursuant to Va. Code § 56-249.6*, Case No. PUE-2009-00038, 2009 S.C.C. Ann. Rept. 462, 466, Order Establishing Fuel Factor (Aug. 3, 2009) (footnote omitted). The Company may defer these carrying costs on its books pending a subsequent request for recovery of the same.

In sum, the two findings above, which decrease the deferred fuel component of rate base, collectively reduce the Company's requested rate increase by approximately $3.6 million.

Accumulated Deferred Income Taxes and Accumulated Deferred Investment Tax Credits

Accumulated Deferred Income Taxes ("ADIT") and Accumulated Deferred Investment Tax Credits ("ADITC") are components of rate base and are related to separate operating expenses that the Commission has permitted APCo to recover herein.[101] The Company proposes to functionalize the rate base impact of ADIT/ADITC based on APCo's functional ledgers.[102] Staff, however, proposes to functionalize the rate base impact of these items in a manner that is similar to the method by which the related operating expenses are functionalized.[103] We adopt Staff's recommendation and find that it is reasonable to functionalize the rate base impact of ADIT/ADITC based on the same functionalization of related expenses. This treatment also avoids a ratemaking mismatch and permits recovery of appropriate expenses and return on rate base. This finding reduces the Company's requested rate increase by approximately $3.6 million.

Overtime Pay

We find that the Company's proposed overtime pay expense is reasonable.

Capitalization of Executive Compensation

We find that the Company's proposed expensing of executive compensation is reasonable.

[101] *See, e.g.*, Staff's May 18, 2010 Post-hearing Brief at 15.

[102] *See, e.g.*, *id.* (citing Tr. 879-880 (Carr)); Company's May 18, 2010 Post-hearing Brief at 78-79 (citing Ex. 24 (Kelly rebuttal) at 3-5).

[103] *See, e.g.*, Staff's May 18, 2010 Post-hearing Brief at 15; Tr. 879-880 (Carr).

Umbrella Trust Plan

The Umbrella Trust Plan funds payments for certain executive employee benefits administered by AEPSC and was established to dedicate funds for these benefits in the event of a bankruptcy or change in control of AEP.[104] In addition: (1) "[t]ypically, the gains on the plan assets offset all or a portion of the cost of those benefits;" (2) "from 2004 through the 2008 test year, [APCo] experienced a loss only in the test year;" and (3) "[t]his aberration in 2008 was due primarily to losses in the stock market."[105] Accordingly, we find that the Company's request to include one-half of the abnormal test year loss as a rate year expense is unreasonable. Rather, we conclude that it is reasonable to reflect a normalized level of Umbrella Trust Plan results. Specifically, we find that it is reasonable to use a five-year average of such results – which reflects both (i) gains from 2004 through 2007, and (ii) losses from 2008.[106] This finding reduces the Company's requested rate increase by approximately $1.3 million.

Other Operating Expense Adjustments

Staff proposed a series of additional operating expense adjustments – some of which increased, and some of which decreased, the Company's revenue requirement.[107] We find that these adjustments are reasonable and shall be approved. This finding reduces the Company's requested rate increase by approximately $5.1 million.

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[104] *See, e.g.*, Staff's May 18, 2010 Post-hearing Brief at 29.

[105] *Id.* at 29-30 (citing Tr. 1031-32 (Hoersdig); Ex. 100 (Carr direct) at 58).

[106] *Id.* at 30.

[107] *See, e.g., id.* at 34-36 (citing Ex. 100 (Carr direct) at 48-49; Ex. 103 (Carr revised statements) at Revised Statement VII-A).

Jurisdictional and Class Cost of Service Studies

We find that APCo's proposed jurisdictional cost of service study, as subsequently updated by the Company, is reasonable.[108] The Company's jurisdictional cost of service study "was uncontested by the other parties in this proceeding and was consistent with the study filed and approved by the Commission in the Company's 2008 base rate case" (Case No. PUE-2008-00046).[109]

Next, we find that the Company's proposed class cost of service study reasonably allocates Virginia jurisdictional costs among APCo's retail customers. The Company appropriately "determined the Virginia retail class cost of service through the standard three-step approach of functionalization, classification and allocation."[110] Moreover, "the Company's jurisdictional, functional, and recommended functionalized class cost of service studies are generally consistent with comparable studies conducted by [APCo] and Staff in the Company's last base rate case, Case No. PUE-2008-00046" – which were adopted by the Commission.[111]

Revenue Allocation

We herein approve an annual revenue requirement increase for APCo of approximately $61.5 million. For purposes of allocating this increase among customer classes, the Company notes that "each party [in this case] argues for different changes" to revenue allocation among

[108] *See, e.g.*, Company's May 18, 2010 Post-hearing Brief at 87.

[109] *Id.*

[110] *Id.*

[111] Staff's May 18, 2010 Post-hearing Brief at 73 (citing Ex. 104 (Roberts direct) at 6-10). In addition, we decline to adopt at this time the "minimum system" approach for allocating certain distribution costs. *See, e.g.*, Kroger's May 18, 2010 Post-hearing Brief at 2-4; Committee's May 18, 2010 Post-hearing Brief at 39-42; Staff's May 18, 2010 Post-hearing Brief at 73-74; Company's May 18, 2010 Post-hearing Brief at 92-93. Rather, we have found that APCo's traditional class cost of service methodology, as previously approved by this Commission, remains reasonable for purposes of this proceeding.

customer classes, and that "[a]ll recommend a smaller share of the [rate increase in this case] be allocated to the rate schedule(s) under which they take most or all of their service."[112] We conclude that Staff's proposed "Alternative 2" revenue apportionment, modified such that all customer classes move toward rate of return parity, is reasonable for establishing rates in this proceeding.[113] We find that this result, among other things, avoids unnecessary rate shock and reasonably promotes (i) gradualism in rates, (ii) rate stability and predictability, and (iii) historic continuity.[114]

Schedule GS (General Service)

The Company proposes to implement a new rate schedule, Schedule GS, which would replace Schedules MGS (Medium General Service) and LGS (Large General Service). Schedules MGS and LGS "are both generally applicable to customers with demands greater than 25 kilowatts but less than 1,000 kilowatts, with low load customers benefiting from service under

[112] Company's May 18, 2010 Post-hearing Brief at 88. *See also* Kroger's May 18, 2010 Post-hearing Brief at 3-4; Committee's May 18, 2010 Post-hearing Brief at 46-51; Wal-Mart's May 18, 2010 Post-hearing Brief at 3-5; Steel Dynamic's May 18, 2010 Post-hearing Brief at 5-7.

[113] *See, e.g.*, Staff's May 18, 2010 Post-hearing Brief at 74-77. This results in a specific revenue increase for each customer class as follows:

Customer Class	Revenue Increase
Residential	$ 39,000,043
Small General Service (SGS)	$ 2,020,218
Medium General Service (MGS)	$ 3,025,244
Large General Service (LGS)	$ 5,166,130
Large Power Service (LPS)	$ 11,182,233
Sanctuary Worship Service (SWS)	$ 656,477
Outdoor Lighting (OL)	$ 422,377
Total	$ 61,472,722

[114] The rate design within each class shall be implemented consistent with APCo's proposals in this case – except where modified herein by the Commission – and reduced to reflect the decreased revenue requirements as also approved herein. In addition, for the residential class, the reduced revenue requirement shall be applied to the proposed rates for energy consumption.

MGS and high load customers benefiting from service under LGS."[115] As explained by Staff, "if a MGS customer's usage characteristics change over time, it may benefit from migrating to LGS, and vice versa," and, according to APCo, "if all identified customers that could benefit by switching schedules were to do so, the Company 'would lose about $770,000 based on present rates.'"[116]

Staff asserts that "[a]s proposed, Schedule GS will adversely affect low load factor customers currently receiving service under Schedules MGS and LGS."[117] Wal-Mart opposes this new schedule, asserting that it (i) is unjustified, (ii) inappropriately collects only 21% of demand-related costs through demand charges, and (iii) creates new revenue instability.[118] VML/VACO also opposes this schedule, stating that "elimination of Schedules MGS and LGS will adversely affect the Public Authorities and governmental customers."[119] Wal-Mart and Kroger further contend that the class rates of return for Schedules MGS and LGS must be equalized prior to replacing such schedules with GS; since LGS has a higher relative rate of return than MGS, these parties assert that the new blended GS rate will permanently disadvantage LGS customers if rates of return are not equalized.[120]

Finally, Staff recommends that Schedule GS "be offered on a voluntary basis, in conjunction with" Schedules MGS and LGS, which "will give the Company an appropriate

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[115] Staff's May 18, 2010 Post-hearing Brief at 78.

[116] *Id.* at 78-79 (citing Ex. 78 (Bethel direct) at 14).

[117] *Id.* at 79.

[118] *See, e.g.*, Wal-Mart's May 18, 2010 Post-hearing Brief at 7-9.

[119] VML/VACO's May 18, 2010 Post-hearing Brief at 13.

[120] *See, e.g.*, Kroger's May 18, 2010 Post-hearing Brief at 10-12; Wal-Mart's May 18, 2010 Post-hearing Brief at 5.

amount of time to examine the effects of Schedule GS on customers."[121] We adopt Staff's recommendation and approve Schedule GS on a voluntary basis. APCo has not established that it is reasonable at this time to eliminate Schedules MGS and LGS as proposed in this case.[122]

Schedule LGS (Large General Service)

The Company's proposed rate design for Schedule LGS (i) "would recover approximately 65% of demand-related costs through $/kW demand charges,"[123] and (ii) includes a new energy charge designed to recover certain demand-related costs.[124] Kroger asserts that demand charges should recover at least 80% – not 65% – of demand-related costs.[125] Wal-Mart and Kroger further oppose APCo's new energy charge as an improper means through which to collect demand-related costs.[126] Staff recommends that this schedule be modified to collect 70% of demand-related costs through demand charges, which was required by the Commission as part of the approved settlement in APCo's prior rate case (Case No. PUE-2008-00046).[127] We adopt Staff's recommendation and find that it is reasonable to "retain[] the level of demand costs that the Company recovers through $/kW demand charges at 70%."[128] This finding also eliminates the need for APCo's new LGS energy charge, which we therefore reject.

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[121] Staff's May 18, 2010 Post-hearing Brief at 79.

[122] In addition, as requested by Kroger and APCo, we clarify that the two-tier energy charge in Schedule GS does not constitute a declining block rate. *See, e.g.*, Kroger's May 18, 2010 Post-hearing Brief at 12-14; Company's May 18, 2010 Post-hearing Brief at 90.

[123] Staff's May 18, 2010 Post-hearing Brief at 78.

[124] *See, e.g.*, Kroger's May 18, 2010 Post-hearing Brief at 7-8; Wal-Mart's May 18, 2010 Post-hearing Brief at 5.

[125] *See, e.g.*, Kroger's May 18, 2010 Post-hearing Brief at 5-7.

[126] *See, e.g.*, *id.* at 7-10; Wal-Mart's May 18, 2010 Post-hearing Brief at 5-7.

[127] Staff's May 18, 2010 Post-hearing Brief at 78.

[128] *Id.* (footnote omitted).

Schedule LPS (Large Power Service)

The Committee asserts that: (1) "APCo is proposing a 'cost shift' from demand to energy charges in its LPS rate design;" (2) "[t]here is no basis . . . for the Company's proposed rate design for LPS;" (3) "Staff neither concurs with or opposes APCo's proposed rate design;" and (4) "APCo . . . offered no rebuttal to [the Committee's testimony on this issue]."[129] We find that APCo has not established that its proposed cost shift from the LPS demand charges is just and reasonable. These demand and energy charges shall be designed consistent with the cost allocations reflected in the Company's previously approved Schedule LPS.

Schedule GS-TOD (General Service Time-of-Day)

We adopt Staff's proposals (i) to increase the maximum normal demand for General Service Time-of-Day rates from 500 kW to 1,000 kW, and (ii) to remove this schedule's current limitation of 500 customers.[130]

Experimental – ATOD (Advanced Time-of-Day) Schedule

The Commission approved APCo's Advanced Time-of-Day Schedule on an experimental basis in 1997. We adopt Staff's proposal that, given the passage of time, this schedule should no longer be deemed experimental and that all references to such as "experimental" should be removed from the tariff.[131]

Schedule NMS (Net Metering Service Rider)

We approve APCo's proposed revisions to its Net Metering Service Rider, which are designed to reflect recent statutory amendments.[132]

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[129] Committee's May 18, 2010 Post-hearing Brief at 51-53.

[130] *See* Staff's May 18, 2010 Post-hearing Brief at 79.

[131] *See id.* at 80.

[132] *See id.*

Schedule EDR (Economic Development Rider)

We approve APCo's proposed addition of an Economic Development Rider, which is designed to encourage economic development in the Company's service area.[133]

Credit and Collections

We approve the Company's proposed changes to its credit and collections program, which include, among other things: (i) suspending APCo's current credit and collections program that allows it to require additional deposit amounts if a residential customer exhibits an extended pattern of delinquency or if the deposit on hand is inadequate given the size of a customer's monthly bill; (ii) changing deposits to an amount that is equal to two times the average monthly usage of a customer rather than an amount equal to the customer's estimated bill for the two highest consecutive months of usage; (iii) allowing payments for deposits to be extended up to six months in cases of hardship; and (iv) allowing customers who participate in the Company's budget billing program to spread their settlement payments over the next twelve months of the budget year rather than paying the settlement over three months.[134]

Other Rate Schedules

The Commission approves the Company's proposed rate designs for residential service (Schedules RS, RS-E, RS-TOD), sanctuary worship (Schedule SWS), small general service (Schedules SGS and SGS-TOD), medium general service (Schedule MGS), large power service time-of-day (Schedule LPS-TOD), standby service (Schedule SBS), and outdoor lighting (Schedule OL).[135]

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[133] *See id.* (citing Ex. 104 (Roberts direct) at 33-34).

[134] Ex. 13 (Waldo direct) at 11-12.

[135] *See* Staff's May 18, 2010 Post-hearing Brief at 77-78, 80.

Accordingly, IT IS HEREBY ORDERED THAT:

(1) The Company's Application is granted in part and denied in part as set forth in this Final Order.

(2) The Company shall forthwith file revised tariffs and terms and conditions of service with the Commission's Division of Energy Regulation, in accordance with this Final Order, effective for bills rendered on and after August 1, 2010.

(3) The Company shall determine, using the methodology prescribed by the General Assembly (2010 Va. Acts of Assembly Chaps. 1 and 2), whether customer refunds are due. For each customer where application of this methodology results in a refund, the Company shall provide such refund within sixty (60) days of the issuance of this Final Order.

(4) Interest upon the ordered refunds shall be computed from the date payments of monthly bills were due to the date each refund is made at the average prime rate for each calendar quarter, compounded quarterly. The average prime rate for each calendar quarter shall be the arithmetic mean, to the nearest one-hundredth of one percent, of the prime rate values published in the *Federal Reserve Bulletin* or in the Federal Reserve's Selected Interest Rates (Statistical Release H.15) for the three (3) months of the preceding calendar quarter.

(5) The refunds ordered herein may be credited to current customers' accounts. Refunds to former customers shall be made by check mailed to the last known address of such customers when the refund amount is $1 or more. The Company may offset the credit or refund to the extent of any undisputed outstanding balance for the current or former customer. No offset shall be permitted against any disputed portion of an outstanding balance. The Company may retain refunds to former customers when such refund is less than $1. The Company shall maintain a record of former customers for which the refund is less than $1, and such refunds shall be

promptly made upon request. All unclaimed refunds shall be subject to § 55-210.6:2 of the Code.

(6) The Company shall deliver to the Commission's Divisions of Public Utility Accounting and Energy Regulation a report showing either that refunds are not required or that all refunds have been made pursuant to this Final Order, detailing the costs of the refunds and the accounts charged.

(7) The Company shall bear all costs incurred in effecting the refunds ordered herein.

(8) This case is dismissed.

AN ATTESTED COPY hereof shall be sent by the Clerk of the Commission to all persons on the official Service Lists in these matters. The Service Lists are available from the Clerk of the State Corporation Commission, c/o Document Control Center, 1300 East Main Street, First Floor, Tyler Building, Richmond, Virginia 23219. A copy shall also be sent to the Commission's Office of General Counsel and Divisions of Energy Regulation, Public Utility Accounting, and Economics and Finance.

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

Case No. 10-0699-E-42T

APPALACHIAN POWER COMPANY
and WHEELING POWER COMPANY,
both dba AMERICAN ELECTRIC POWER

COMMISSION ORDER ON THE
APPLICATION FOR A RATE INCREASE.

March 30, 2011

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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 30th day of March 2011.

CASE NO. 10-0699-E-42T

APPALACHIAN POWER COMPANY and
WHEELING POWER COMPANY, dba AMERICAN
ELECTRIC POWER, public utilities.
Joint Application for Rate Increases on Notice with Proposed Effective Dates and Changes in Tariff Provisions, Pursuant to W.Va. Code, §24-2-4a and Approval of a Transmission Rate Adjustment Clause Rider.

COMMISSION ORDER

As part of the Joint Stipulation, the parties recommended that the utilities receive a $60 million rate increase. Based upon an analysis of the Joint Stipulation and the evidence in this case, the Commission modifies the Joint Stipulation by lowering the rate increase to $51.12 million as provided in this Order.

I. INTRODUCTION

A. Overview of Ratemaking

Ratemaking is a difficult and complicated process. It does not lend itself to easy explanation. That is even more the case during these periods of unsettled financial times such as this nation and this State have seen and are currently experiencing. Those times have been marked by high unemployment, financial volatility, unsettled housing markets, increased sensitivity to the level of government spending, cutbacks in basic government services, and little or no increases in funding for entitlement programs. It is against that backdrop that this Commission is handed repeated requests for rate increases by public utilities and asked to rationalize those requests against the economic uncertainty that the citizens and ratepayers are experiencing.

Many utility customers believe that the price of utility services should mirror their personal financial situation and should be determined solely by the yardstick of "affordability" for the lowest income recipients among the utility users. This is a sensitive issue, and one which this Commission has addressed. See, for instance, West Virginia-American Water Company, Case No. 03-0353-W-42T (Order dated

January 2, 2004) at 29, in which the Commission held that affordability could be one of the factors to be considered in evaluating the level of requested rates in a rate case, but could not be the sole determining factor. That is because the Commission's task is also defined and constrained by State statutes and State and federal constitutional limitations. Regardless of the "public appeal" or attractiveness of such an approach, the Commission is not free to require utilities to provide their utility service at a level below the lowest reasonable cost to the utility of providing that service.[1]

Our role is to establish that lowest fair and reasonable level of rates and charges consistent with the costs to utilities of providing that service. To the extent that there are citizens of the State who may have difficulty paying for those services, the Commission attempts to ameliorate that impact within the authority granted to it by statute and Constitutional limitations by appropriate rate design, by encouraging the Legislature to address the underlying societal problem through encouraging and supporting utility rate support programs financed by taxpayers and to some extent ratepayers, by allowing charitable and public support for special rate and weatherization programs and, most importantly, by paying particular heed to the level of and propriety of the costs that the utilities include in their rates.

Public pressure for "below cost" rates is enormous (and enticing). It also clouds the ratemaking process. Our task in ratemaking is further complicated by the difficult and somewhat arcane terms and processes that form the framework of our ratemaking efforts and that we use to carry out our constitutional and statutory charge, terms such as "cost of service," "deferred income tax adjustments," "revenue requirement," "rate base," "rate of return," "cost allocation," "cost of capital" and "rate design." We know that the customers are frustrated and incensed by rate increases and that customers frequently do not appreciate (or, for that matter, in many instances care about) the difficulties and costs incurred by utilities in providing that utility service.

In this case, for instance, customers of Appalachian Power Company (APCo) and Wheeling Power Company (WPCo), both public utilities and both operating as American Electric Power (collectively "APCo/WPCo" or the "Companies"), have filed protests containing in excess of 8,000 names against the original rate request of approximately $155 million filed by APCo/WPCo. Even after the parties to this case, representing all classes of affected customers, including residential, commercial and industrial customers, after extensive discovery and settlement negotiations, recommended in a Joint Stipulation and Agreement for Settlement (Joint Stipulation), not the requested $155 million, but rather $60 million, customers of APCo/WPCo continued to file petitions containing nearly 3,500 names opposing the rate increase with the Commission.

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[1] See Discussion, "Ratemaking Guidance" at 14, infra.

Given the public's interest and involvement in this case, the Commission has tried to make the process understandable to all customers of APCo/WPCo, including those who have actively participated in the process by filing protests or attending public comment hearings. Further, in this Order we attempt to address the rate process in basic terms.

Public utilities file rate cases with the Commission to change their rates because that is the only way they are permitted to change their rates under the law. Neither APCo/WPCo nor any other regulated public utility in this State is free to change its rates on its own initiative. The West Virginia Code requires a utility to file a rate case with the Commission and receive the prior approval of the Commission before that utility can change its rates and charges and its revenues (and even then only after a significant suspension period). W.Va. Code §24-2-4a.

In these rate case proceedings, the Commission Staff is a party, represents the public interest and makes a recommendation to the Commission. The Consumer Advocate Division (CAD) is specifically designated by statute to represent the interests of West Virginia residential customers. Other parties intervene, including groups of industrial and commercial customers, individual large customers, affected associations and public interest groups, such as West Virginia Energy Users Group; Kroger Company; Steel of West Virginia, Inc.; South Bluefield Neighborhood Association; Wal-Mart Stores East, LP and Sam's East, Inc.; and Independent Oil and Gas Association of West Virginia. These Intervenors participate actively in the case to have their individual interests represented and protected. Typically, other than the utility, none of those parties favors rate increases, and all do their best through the adversary process to limit the rate increases.

B. Ratemaking Process

During a rate proceeding, the Commission and the parties examine and explore all aspects of the requested rate increase, and after that examination and based on the evidence presented, the Commission sets the utility's revenue requirement or cost of service. This is a costly and time-consuming process. The revenue requirement or cost of service is the total annual revenue required by the utility to cover the anticipated cost of providing service to its customers, including a fair return on its investment. That fair return on investment is an essential part of the process, and utilities are legally entitled to a fair return. That revenue requirement is determined by examining historical costs for a recent prior twelve-month period and adjusting those costs for known and measurable changes that the utility will experience. The formula for the development of that revenue requirement to be collected from ratepayers is relatively simple to state but extremely complex to apply:

Revenue Requirement equals the operating expenses plus depreciation plus taxes plus the amount determined by the Commission that represents an opportunity to earn a reasonable return on rate base.

In the calculation of the revenue requirement, the utility's expenses, taxes and depreciation are the "costs" associated with providing utility service; the return on rate base is the rate of return applied against rate base; rate of return is generally perceived as the utility's cost of capital; and the rate base is the original depreciated cost (not current market value) of investments made by the utility to provide service (or, in other words, the capital the utility has invested in utility plant and working capital in order to provide service to its customers). The determination of the cost of service and revenue requirement for a large utility is difficult. There are literally thousands of calculations used in establishing a utility's revenue requirement and considerable effort by the parties and the Commission is involved in assessing that revenue requirement.

In the current rate case, the Companies filed for and presented evidence in support of their initial request for approximately a $155 million rate increase. Staff, CAD and Intervenors to the case (mostly comprised of industrial and commercial customers, all of whom opposed the increase) undertook extensive discovery and investigation and presented their own evidence and arguments as to a recommended revenue requirement and rate increase for the Companies. Staff, CAD and the Intervenors, based on their investigations, initially presented evidence to support recommendations for a rate increase ranging from approximately $41 million to $57 million.[2]

The parties, following discovery and review of the evidence, presented the Joint Stipulation to the Commission. In the Joint Stipulation, the parties agreed among themselves (and recommended to the Commission as reasonable) a $60 million base rate increase for the Companies. As we discuss later in this Order, the Joint Stipulation is an agreement among the parties to the Commission about what they consider to be a reasonable resolution of the case. It does not represent a final resolution that the Commission must accept, but is merely a recommendation to the Commission for a resolution that the stipulating parties would accept. The parties in the Joint Stipulation agreed on a final revenue requirement, but only agreed upon a few of the components that go into the calculation of the revenue requirement.

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[2] The voluminous record in this case consists of the APCo/WPCo Rule 42T filing, the testimony and exhibits of eighteen witnesses on the behalf of APCo/WPCo, four witnesses on behalf of Staff, four witnesses on behalf of CAD, five witnesses collectively on behalf of the Intervenors, and the record at the evidentiary hearing in this proceeding. In addition, the Commission has considered the comments made at the public comment hearings and in the many letters of protests filed in the case. The evidentiary record in this case consists of over 3,600 pages.

In evaluating the requested rate increase and the proposed Joint Stipulation, the Commission is mindful that we are considering the underlying causes and justification for the APCo/WPCo rate case application in the context of other important conditions, including the current economic climate and the history of recent rate increases for APCo/WPCo.

C. The Current Economic Climate

The Commission considered the rate increase and the proposed Joint Stipulation based on all of the evidence presented in the case. In doing that, however, we did not check our knowledge of the real world and regulatory experience at the front door of the Commission. In arriving at our Order in this case, we viewed the evidence in the light of the current economic crisis affecting the ratepayers and APCo/WPCo. The State and nation are facing the worst economic crisis since the Great Depression. Beginning in December 2007, the country entered into what has been termed the "Great Recession,[3]" one of the deepest and longest lasting recessions in United States history. Although that recession officially ended in June 2009, economic recovery has been slow, and the effects of the economic crisis may linger for years. The unemployment rate, which is a key economic indicator, peaked near 10 percent and, while showing some improvement, has not improved dramatically, particularly for the residents of the State. Direct Testimony of Staff Witness Randall R. Short at 13 (hereinafter the prefiled testimony of witnesses will be cited by witness last name, exhibit number or other identification as entered in the record, and page number, such as "Short, Ex. RRS-D at 3").

The impact of the Great Recession on American life and the lives of West Virginians continues. According to a May 2010 U.S. Congressional study, "Economic Overview and Outlook: West Virginia," that was prepared by the Joint Economic Committee, West Virginia's unemployment rate continued to rise between May 2008 and May 2010, rising from 4 percent to 8.9 percent.[4] Moreover, the recession has had a pernicious effect on West Virginians because of the State's ongoing poverty level. According to the 2000 Census, 17.9 percent of the State's population had an income at or below 100 percent of the federal poverty level, ranking it forty-seventh out of the fifty

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[3] A recent Bloomsberg Report article entitled, "'Great Recession' Gets Recognition as Entry in AP Stylebook," indicates the term "Great Recession" has been officially adopted to describe the longest and deepest economic decline in seven decades of U.S. history. Schlisserman, Courtney, *'Great Recession' Gets Recognition as Entry in AP Stylebook,* Bloomberg Anywhere, http://www.bloomberg.com/apps/news?pid=newsarchive&sid=ayojB2KWQG4k (February 23, 2010).

[4] Joint Economic Committee, *Understanding the Economy: State-by-State Snapshots (May Data), Economic Overview and Outlook: West Virginia,* United States Congress, http://jec.senate.gov/public/index.cfm?a=Files.Serve&File_id=45b13b8e-71be-4cc9-a7c4-14c1d6085751 (June 22, 2010).

states. According to the U.S. Census Bureau's most recent data in the study, Poverty: 2008 and 2009 American Community Survey, 17.7 percent of the State's population had an income at or below 100 percent of the federal poverty level, a slight improvement. The Companies' proposed rate increase would have an impact on all customers, but particularly so on the State's poor. As reported in this proceeding, low income households can pay as much as 20 percent or more of their annual household income to heat their homes and to be supplied with electric service. Alexander, Ex. BRA-D at 4, 5.

The Commission received hundreds of letters and petitions signed by thousands of customers protesting the proposed rate increase, emphasizing the current dismal economic situation and expressing the perception that the Companies file repeated and excessive rate requests. Protestants spoke at public hearings, voicing their feelings about the unfairness of burdening the State ratepayers with a rate increase during these difficult economic times (references to the transcripts of hearings will be by date of hearing and page number, such as "Tr. 11/16/10 at 27"). Tr. 11/16/10 at 27. There was extensive public comment about the difficult choices made by many State residents who stated that they often must decide between paying for food, medicine or electricity because of the economy. Tr. 11/16/10 at 22-24.

The Commissioners presided over public comment hearings in Wheeling, Beckley, Huntington and Charleston, and as a result of the public comments in those proceedings, the Commission is keenly aware of the potential impact of the proposed rate increase on the State ratepayers. The President and Chief Operating Officer of APCo, Mr. Charles Patton, acknowledged

> [T]he reality is that any increase in rates is significant and it does have a dramatic impact on our customers. You can't sit in the public hearings, and I've sat in them, and you hear representatives of our constituents . . . talk about their struggles in payment and not be impacted by those claims, which we know many are legitimate.

Tr. 12/15/10 at 44.

Notwithstanding recent APCo/WPCo rate increases, Mr. Patton testified at the December 15, 2010 hearing about the levels of APCo and WPCo rates proposed in the Joint Stipulation as compared to the national average, which is roughly 12 cents per kilowatt hour. Tr. 12/15/10 at 45. In his Direct Testimony, Mr. Patton testified that the current APCo/WPCo West Virginia residential and industrial rates are lower than the rates of most other electric companies in the United States while its electric service is comparable to that available in the region and the nation and superior in comparison to the rest of the world. He testified that only 10 out of 175 major electric companies in the U.S. have residential rates that are lower than APCo's West Virginia rates and only 31 of those 175 major electric utilities have industrial rates lower than APCo's West Virginia rates. Patton, CRP No. 1, Direct Testimony at 19 and CPR Ex. No. 2 attached to testimony.

II. RECENT APCO/WPCO RATE HISTORY

As discussed, the public comments (and to some extent the evidence of the Intervenors) in this case have focused on the size and frequency of the Companies' rate requests. Rate requests are not static or disconnected events and are frequently related because of construction projects or other matters affecting the long-term operations of a utility and its need for rate increases.

To properly balance the interests of utilities and ratepayers, the Commission always reviews the evidence in a rate proceeding and the impact of its decision in the context of a utility's rate history. We will begin with a brief explanation and overview of the process and APCo/WPCo's prior ratemaking efforts over the past six or seven years.

Much has been made publicly about the frequency and magnitude of APCo/WPCo rate filings. In that public discourse, however, what is often not made clear is the nature and justification for those rate filings. APCo/WPCo requests rate increases in two different types of rate proceedings, (i) Expanded Net Energy Costs (ENEC) proceedings that have been combined with a special Construction Work in Progress (CWIP) surcharge mechanism since 2006 and (ii) base rate proceedings. The Commission will provide an overview of APCo/WPCo's recent rate increases to provide a background and context for the requested rate increase in this case.

A. APCo/WPCo ENEC Proceedings

The ENEC proceedings were initially begun in 1976 to recover fuel costs (costs which are impacted by a national and international energy market over which APCo/WPCo has little or no control). The ENEC proceedings have been since modified to include some other energy cost components. Monongahela Power Company and the Potomac Edison Company, dba Allegheny Power, Case No. 09-1485-E-P (Order dated December 29, 2009) fn 1 at 1.

ENEC proceedings differ from base rate proceedings. For most utilities, all of the operating expenses of the utility are considered in periodic base rate proceedings. For electric utilities, the ENEC proceeding for APCo/WPCo and the First Energy operating companies (formerly Allegheny Energy) focus on the recovery of fuel costs, purchased power and net purchased transmission costs and revenue. Fuel costs represent the prices the utilities must pay for coal to run their coal-fired generation. For APCo/WPCo, since 2006, the Commission has also considered the surcharges for certain identified major construction work in progress projects including a major transmission line investment project and the addition of flue gas scrubbers for sulfur removal at the Mountaineer and Amos generation plants.

Coal costs incurred in the generation of electricity are the single greatest expense in the ENEC process. Additional cost components considered in the ENEC include purchased power costs and some transmission costs related to wholesale transactions. The intent of the ENEC is to allow the utility only the coal and other ENEC costs incurred, nothing more or less. Therefore, each year the ENEC rate is trued-up. Generally speaking, if revenues from ENEC rates are less than actual costs that the Commission finds to be reasonable and prudently incurred, the difference is referred to as the allowable underrecovery. The utility is generally entitled to receive additional revenues from its customers in the next year's ENEC when rates are designed to make up for that allowable under recovery. If ENEC revenues are more than actual costs that the Commission finds are reasonable and prudently incurred, the difference is referred to as an overrecovery, and the Commission will usually reduce or offset the new ENEC rates to return the amount of the overrecovery to customers.

The costs involved in these ENEC proceedings tend to be more significant than base rate cases and, as indicated, are filed only by major electric utilities. ENEC costs are typically the most volatile costs for the electric utility (and constitute the largest part of customer rates for an electric utility). Leaving those rates unchanged, except for occasional changes made in base rate proceedings, could and likely would lead to grossly unfair rates by embedding extremely high (or low) cost components in base rates. For several years, however, because of a period of stability in the coal markets, the ENEC rate filings were discontinued (from approximately 1999 to 2005). See, Appalachian Power Company, dba American Electric Power, Case No. 99-0409-E-GI.

In 2006, the Commission considered and granted APCo/WPCo and the Allegheny Energy Companies, Monongahela Power Company and The Potomac Edison Company, approval to resume ENEC rate reviews in proceedings beginning in 2007.

Much of the public outcry about recent APCo/WPCo rate increases stems not from base rate cases (APCo/WPCo's last rate case in 2005 actually resulted in a decrease of base rates), but rather, and most specifically, from the requested ENEC rate increase in the 2009 ENEC proceeding. That 2009 ENEC case (Case No. 09-0177-E-GI) was filed on March 9, 2009, and was what can only be described as a regulatory "perfect storm."

In the 2009 ENEC case (Appalachian Power Company and Wheeling Power Company, Case No. 09-0177-E-GI), APCo/WPCo requested an ENEC increase of $442 million. This exceptionally large increase was driven by significant increases in actual 2008 ENEC costs (primarily skyrocketing 2008 coal costs), estimated 2009 coal costs and decreased off-system sales resulting from the impact of the recession that lowered industrial demand for electricity.

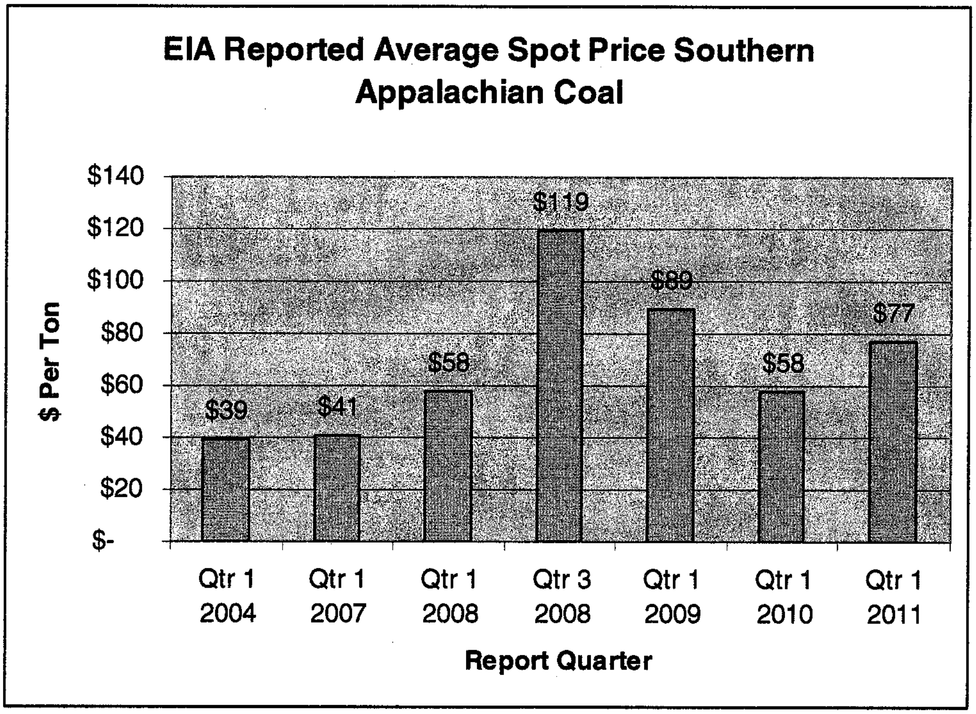
That request was the largest rate case ever filed in West Virginia and generated a tremendous public protest and outcry. Recognizing the devastating effect such a large increase would have on customers if implemented in one step, all parties to that proceeding recommended that the costs be closely examined and, just as importantly, that the rate recovery in that case be spread over two or three years to ease the impact on ratepayers.

The Commission issued its Order in the 2009 ENEC on September 30, 2009, that resulted in new ENEC and surcharge rates approved for all service on and after October 1, 2009.

The Commission decision in the 2009 ENEC required a longer phase-in (approximately four years) than the phase-in requested by any party. The Commission's approach was designed to eliminate by June 30, 2013, the underrecovery balance (that was growing and would continue to grow). The longer phase-in period benefited the public by spreading out over time smaller increases that would otherwise have been one enormous increase. Unfortunately, it has resulted in filings for rate increases each year to recover the phased-in increases. Some have perceived these filings as new and distinct filings when, in fact, they are a follow up to the 2009 filing and decision.

The Commission emphasizes that the 2009 filing and decision reflects the impact on customers of (i) the tremendous run up in coal prices, (ii) the impact of the recent economic crisis that slowed the demand for off-system sales of energy, and (iii) the fact that the 2009 ENEC was being spread over four years to ease the impact on all customers. The subsequent ENEC rate increases resulted largely from the earlier phase-in approved in the 2009 ENEC case.

The cost of coal at AEP generation stations is affected by a number of factors. AEP may have coal quality specifications that do not match averages for all coal sold in the market. In some cases, long-term or medium-term contracts may cause AEP coal costs to lag behind spot prices as these prices move either up or down. Over time, however, the general direction and levels of spot coal prices are a good barometer of the general movement in the cost of coal that we allow in electricity rates in the annual ENEC cases described above. The following table graphically illustrates the relative stability of the average price of Southern Appalachian low sulfur coal until 2008 and the extreme run-up in coal prices in 2008. It also shows that there was a temporary downturn in coal prices beginning with the fourth quarter of 2008 as the economy fell into recession. While coal prices dropped in 2009, reaching first quarter 2008 levels for a short period of time around the first quarter of 2010, they have again increased upward, although not to a level that approaches the high level reached in mid 2008.



The data for this chart reflects average prices. On a more granular level, the data show that spot prices reached as high as $140 per ton in 2008.

In that 2009 ENEC proceeding, the Commission addressed the affect of the 2008/2009 economic downturn on rate filings made by APCo/WPCo in the ENEC proceedings. The Commission acknowledged the impact of the economy and regulatory changes in setting rates:

> The Commission, in this case, faces the difficult regulatory task of reacting to the dynamic changes impacting utilities, particularly the coal-fired electric utilities in this State, and at the same time attempting to balance those impacts with future factors yet to be incurred by that industry. We are called upon, to some extent, to divine the unknown while balancing the interests of customers (current and future), the State's economy and the utilities. This has become increasingly difficult in this current era of financial stress, tight money markets, a depressed economy, high rates of unemployment, volatility of coal prices and coal availability, extreme environmental uncertainty, and almost certain escalating costs facing coal-fired generation.

Commission 2009 ENEC Order (dated September 30, 2009) at 2.

The rate increase in the APCo/WPCo 2009 ENEC proceeding was largely attributable to the increased costs of coal and other electricity production costs resulting from economic conditions in the year 2008, including dramatic increases for energy costs, including coal, with coal prices peaking at more than $140 a ton in July 2008 and then declining to a then current price at the time of the 2009 proceeding of about $50 a ton. This dramatic and volatile coal market was complicated by the reduction in revenues in 2009 for off-system sales.

In APCo/WPCo's most recent 2010 ENEC proceedings, the Commission approved a stipulated rate increase of $95,476,845. While it does not seem publicly known, because of the hoped-for softening of the coal market, this rate was significantly lower than the $165 million overall rate increase projected for 2010 by APCo/WPCo in the 2009 ENEC proceeding. Commission 2009 ENEC Order, Finding of Fact No. 5.

B. Base Rate Proceeding

The current case is not an ENEC case; it is a base rate proceeding. In APCo/WPCo's last base rate case, Appalachian Power Company and Wheeling Power Company, both dba American Electric Power, Case No. 05-1278-E-PC-PW-42T (2005 Rate Case), the Commission approved a Joint Stipulation as a resolution of that rate proceeding. Pursuant to the Joint Stipulation in that case, the parties agreed, among other things, that (i) the Companies' current base rates would be reduced by $18,433,000 on an annual basis and would be based on a return on equity of 10.5 percent, effective July 28, 2006, (ii) expenditures related to the Wyoming-Jackson Ferry 765 kV line and a construction surcharge for the retrofit of scrubbers at the Mountaineer plant and Units 1, 2 and 3 of the John Amos plant would be recovered in future ENEC proceedings, (iii) the ENEC proceedings would be reinstated with annual ENEC proceedings to resume in 2007, and two agreed upon ENEC rates were to stand in effect until July 1, 2007, or further Order of the Commission, which were projected to produce additional annual revenues of $56.01 million, and (iv) a Century Aluminum Rate Mechanism would be established. The Commission's Order in APCo/WPCo's 2005 Rate Case, Case No. 05-1278-E-PC-PW-42T, approved the stipulation of the parties that required the Companies to file a new rate case no later than June 30, 2010. That requirement was inserted in the Joint Stipulation in 2005 to insure that the Commission would have the opportunity to revisit APCo/WPCo's base rates after all of the planned additions for environmental and other improvements were made and to insure that those rates were fair and reasonable.

Prior to the 2005 Rate Case, the Companies had not filed a base rate case since the early to mid-1990s, and at the public comment hearings, Steven H. Ferguson, APCo/WPCo's Director of Regulatory Services, stated for the record that base rates, reflecting the portion of the utility rates covering the costs of providing day-to-day service, have actually decreased since 1984. Tr. 11/04/10 at 14, 15.

In considering this APCo/WPCo rate case, the Commission considered the evidence presented in this case in the context of the underlying causes for the APCo/WPCo recent rate increase requests. The APCo/WPCo ENEC rate increase requests resulted from the higher coal costs and 2008/2009 economic downturn as discussed previously. The current base rate increase is driven by a number of factors, many of which could not be anticipated or predicted at the time of the 2005 Rate Case.

In his prefiled direct testimony, Mr. Patton addressed the underlying causes for the filing of the current base rate case. Patton, CRP No. 1, Direct Testimony at 2-4. At the evidentiary hearing, he also addressed the significant disparity between the original rate filing in this case ($155 million) and the amount recommended by the parties in the Joint Stipulation ($60 million). In his prefiled direct testimony, he stated that APCo/WPCo filed its rate case because (i) APCo/WPCo had agreed to file a new rate case no later than June 30, 2010, pursuant to the Stipulation approved in the last rate case and (ii) APCo/WPCo earnings were at levels below those authorized in the 2005 Rate Case. At the December 15, 2010 evidentiary hearing, he testified that APCo/WPCo earnings were at levels of 6 percent to 7 percent annualized for 2010, compared to 10.5 percent authorized in the last rate case. Tr. 12/15/10 at 70.

In his prefiled direct testimony, Mr. Patton identified other reasons for the decline in the APCo/WPCo earnings, including (i) increased environmental regulation costs; (ii) the increased costs from the regional transmission organization (RTO); (iii) the more demanding North American Electric Reliability Corporation (NERC) reliability requirements; (iv) the shifting priorities in national energy policy; and (v) the costs associated with aging utility infrastructure. Mr. Patton addressed APCo/WPCo's efforts to control operational costs including: salary freezes in 2009, work-force reductions, deferral of maintenance, a plan to place generating units in the AEP eastern fleet in "extended startup status," efficiency measures, automated meter reading program (AMR), and paperless billing. Despite these efforts at cost containment, Mr. Patton stated APCo/WPCo's combined rate of return has been significantly below the 10.5 percent level authorized in the 2005 Rate Case because of decreases in revenue associated with decreased industrial load, the increase in operation and maintenance (O&M) costs since 2006, and increased costs because of compliance with environmental requirements. Patton, CRP No. 1, Direct Testimony at 3-10.

In addition, Mr. Patton addressed the effect of the costs related to the winter storm damage in 2009 resulting in expenses of $22.8 million. Further, he testified about the effect of the Virginia State Corporation Commission (VSCC) Order dated July 15, 2010, in AEP's Virginia base rate proceeding, in which the VSCC denied cost recovery for the carbon capture and sequestration (CCS) project at APCo's Mountaineer plant in Mason County, West Virginia. Id. at 3.

From the testimony of Charles Patton, it is clear that a multitude of factors contributed to the increase in base rate costs for APCo/WPCo, resulting in increased revenue requirements. It is also clear that the factors combined to create a further significant increase in electric utility rates at a time when the average West Virginia ratepayer has already absorbed or will be requested to absorb a series of past and planned ENEC increases.

With these significant and weighty factors in mind, the Commission must consider the recommendation of the Joint Stipulation, its justness and fairness and whether it allows the APCo/WPCo the opportunity to earn sufficient revenues, balanced with the interests of the State and ratepayers. This consideration, however, is not limited to the Joint Stipulation. It includes consideration of the numerous issues affecting revenue requirements and the Commission decision on the reasonableness of individual revenue requirement cost components. Whether a party continued to recommend a particular ratemaking treatment of a particular cost item or modified its recommendation because of the Joint Stipulation is not a factor in the Commission decision on how a particular item should be treated for determining revenue requirements in this case.

III. PROCEDURAL BACKGROUND

On May 14, 2010, APCo/WPCo tendered for filing revised tariff sheets, to become effective June 13, 2010, reflecting a system average rate increase of approximately 13.8 percent annually, or a net increase in current rates of $155,463,299, comprised of a $223,778,770 increase in base rates and a $68,315,471 decrease in the Construction Surcharge and ARS Surcharge, for furnishing electric utility service to approximately 481,141 customers in twenty-four counties in West Virginia. APCo/WPCo also requested approval of a proposed Transmission Rate Adjustment Clause Rider.

CAD, the West Virginia Energy Users Group (WVEUG), the Kroger Company (Kroger), Wal-Mart Stores East, LP and Sam's East, Inc. (collectively Wal-Mart), the South Bluefield Neighborhood Association (SBNA) and Steel of West Virginia, Inc. (SWVI) were granted intervenor status and are parties in the proceeding.

The Commission suspended the effective date of the tariff sheets filed by APCo/WPCo, and deferred the use of the rates and charges stated in the filing until 12:01 a.m., March 31, 2011. (Orders dated June 11, 2010, and June 25, 2010.)

At the evidentiary hearing held December 15, 2010, the parties to the proceeding, except SBNA, presented a Joint Stipulation as the parties' agreed recommendation about the issues in this base rate proceeding.

It is not necessary to repeat the entire procedural history of this case, but a complete record of the procedural background in this proceeding is attached and incorporated in this Order as Appendix A.

IV. DISCUSSION

A. Ratemaking Guidance

Before we begin a review of the APCo/WPCo rate case, it is appropriate to review the regulatory framework within which the Commission must function. The Commission is a creature of statute and may act only to the extent authorized by statute. Eureka Pipe Line Company v. Public Service Commission 137 S.E. 2d 200 (W.Va. 1964); Wilhite v. Public Service Commission 149 S.E. 2d 273 (W.Va. 1966); Casey v. Public Service Commission 457 S.E. 2d 543 (1995). In a rate case, the Commission must act within the boundaries of its legal authority and must fulfill its statutory duties in a manner consistent with constitutional constraints. The Commission must also adhere to legal principles established in case law.

The Supreme Court of Appeals of West Virginia and the Supreme Court of the United States of America have both held that utility rates must allow a public utility the opportunity to earn a level of revenues sufficient to attract capital in the competitive market, balanced with interests of the public in receiving fair and reasonable rates. Bluefield Water Works and Improvement Company v. Public Service Commission, 320 U.S. 679 (1923); Federal Power Commission v. Hope Natural Gas Company, 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).

When the Commission exercises its ratemaking authority pursuant to Chapter 24 of the West Virginia Code, the Commission is not absolutely bound by the doctrines of *stare decisis* or *res judicata* because ratemaking is a legislative function. Central West Virginia Refuse Inc. v. Public Service Commission, 438 S.E. 2d 596 (W. Va. 1993). The West Virginia Supreme Court has held that the Public Service Commission may employ such methods for determining utility rates as it deems suitable but the end result must guarantee West Virginia consumers good service at fair rates and enable utilities an opportunity to earn a competitive return for their stockholders upon their investment in West Virginia. VEPCO v. Public Service Commission, 242 S.E. 2d 698 (W.Va. 1978).

B. Joint Stipulations

The West Virginia Code contemplates the use of Joint Stipulations in Commission proceedings. W.Va. Code §24-1-9(f). This Commission has stated repeatedly that it values stipulations and the efforts of parties to reach stipulated results.

For instance, in Bluefield Gas Company, Case No. 09-0681-G-42T (Order dated January 28, 2010) at 3, the Commission recognized the important role of Stipulations in the ratemaking process:

> The Commission values stipulations and appreciates the efforts of parties to reach reasonable and just settlements in rate and other proceedings. Stipulations are a significant assistance to the Commission in carrying out its statutory duties and frequently resolve many cases in a prompt, fair, reasonable and expedited fashion based on the arms-length negotiations of the parties. This can reduce litigation costs for the benefit of all parties and the ratepayers.

Id. at 2, 3.

As stated by the Commission at the outset of the December 15, 2010 evidentiary hearing, when reviewing the proposed Joint Stipulation the Commission is not bound by the terms of the Joint Stipulation and must reach a reasoned end result based on the record and a consideration of its statutory duties. Tr. 12/15/10 at 24, 25.

As helpful and useful as Joint Stipulations are to the Commission to carry out its statutory duties, the Commission is not bound to accept a Joint Stipulation. The Commission treats a Joint Stipulation as a proposal by the parties to the Joint Stipulation of a reasonable settlement of the case, in the eyes of those parties, to resolve all or some of the issues to be decided by the Commission in that particular case. We do not consider the substance of the settlement among the parties embodied by the Joint Stipulation as binding on the Commission when it is submitted to the Commission. We have so held. In Virginia Electric and Power Company and Utilicorp United, Inc., Case No. 85-553-E-PC (Order dated January 6, 1987), approving and clarifying Joint Stipulation and Agreement for Settlement at 3, 4, the Commission interpreted stipulation language prepared by the parties to the effect that "(i)t is expressly understood by the parties that this Joint Stipulation is conditional and nonseverable and shall have no force or effect unless adopted in its entirety by the Commission, either expressly or by operation of law pursuant to West Virginia Code §24-1-9." The Commission held that language was binding only upon the parties and that the Commission retained the authority to accept, reject or modify any stipulation which is presented to it.[5]

The filing of the Joint Stipulation by the parties does not alter or obviate the statutory duties of the Commission under W.Va. Code §§24-1-1(b) and 24-2-3. In a rate case, such as this case, the Commission must evaluate the proposed Joint Stipulation

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[5] The Joint Stipulation presented in this rate proceeding at ¶ 41 contains language acknowledging the Commission's authority by stating "(t)he Stipulating Parties acknowledge that it is the Commission's prerogative to accept, reject, or modify any stipulation. However, in the event that this Agreement is modified or rejected by the Commission, it is expressly understood by the Stipulating Parties that they are not bound to accept this Agreement as modified or if rejected, and may avail themselves of whatever rights are available to them under law and the Commission's *Rules of Practice and Procedure*."

independently, in light of the record, to make a determination that the proposed provisions result in fair and reasonable rates that balance the interests of all parties, the ratepayers and the State, as required by law. Monongahela Power Company and The Potomac Edison Company, dba Allegheny Power, Case No. 09-1352-E-42T (Order dated June 25, 2010).

In evaluating the justness and reasonableness of the terms of the Joint Stipulation, the Commission acknowledges that the parties, through a vigorous litigation process including extensive audit, discovery and negotiation efforts, have presented a position on various issues, and in most cases a recommended revenue requirement and rate increase that they believe is both fair and reasonable. The parties do not attend those settlement discussions with a pre-determined commitment to raise rates. On the contrary, the CAD, charged by statute to represent the interests of the residential ratepayer, seeks to ensure the lowest possible rate increase. The CAD in this case, however, determined that the revenue requirement and the negotiated terms of the proposed Joint Stipulation are in the best interests of the residential customer. The Intervenors, on behalf of the commercial and industrial customers, negotiated terms of the Joint Stipulation favorable, or at least acceptable, to their interests. APCo/WPCo, CAD and Staff agreed that the revenue requirement is adequate for the utility and is also in the public interest. The Commission respects the value of the Joint Stipulation in this ratemaking proceeding and will take that Joint Stipulation into consideration in our decision-making process.

C. The Modification of Joint Stipulations

As is acknowledged in the Joint Stipulation, the Commission reserves the right to accept, modify or reject a stipulation. Recognizing that the Joint Stipulation represents an overall settlement that the parties have agreed is fair and reasonable, the Commission will test that settlement by considering the merits of each parties' evidence on individual issues and determining how we would resolve each of those issues. The results of that evaluation of issues will be compared to the stipulated revenue requirement to help us determine if the Joint Stipulation, as presented, is a fair, balanced, and reasonable resolution of this rate case.

We understand that in arriving at the Joint Stipulation, the parties evaluated certain risks of litigation, the strength of their respective positions, and a host of other factors and may have compromised certain positions in arriving at the settlement embodied in the Joint Stipulation. Nonetheless, we cannot, given our statutory charge, accept a stipulation proposal urged by the parties based solely on the fact that the parties agree that it is fair and reasonable. We must make that evaluation based on the record in the case, including the evidence related to the stipulation.

What then is the test for determining whether to accept a Stipulation? First and foremost, the settlement embodied by the Stipulation must be reasonable. Reasonableness is a touchstone of regulation and the term "reasonable" or "reasonableness" is scattered throughout the West Virginia Code provisions relating to the Commission. See, for instance, fn. 1 to Virginia Electric and Power Company and Utilicorp, Inc., Case No. 85-553-E-PC (Order dated December 12, 1986) at 8, in which this Commission recognized the ubiquity and application of the "reasonableness" standard in Chapter 24 of the West Virginia Code.

We have recognized that stipulations result in expedited proceedings and lower processing costs, but that is not a standard for our review. It is a result of a good stipulation.

The Commission has not often rejected or modified a stipulation, and we do so with some reluctance when all of the parties have agreed to the stipulation. We have sent orders back to our Administrative Law Judges where there is little in the record to support the stipulation other than the bald statements of counsel. We have, however, on rare occasion, rejected portions of a stipulation. See, Jefferson County PSD, Case Nos. 06-0413-PSD-T-PC; 07-0294-PSD-PC; and 08-0322-PSD-S-PC (Order dated January 14, 2009).

In West Virginia-American Water Company, Case No. 07-0998-W-42T (Order dated March 18, 2008), the Commission adopted an Amended Joint Stipulation. The Commission issued two procedural Orders in that case articulating the Commission position regarding proposed Joint Stipulations in rate cases. In the Commission Procedural Order dated December 21, 2007, the Commission reiterated its prior positions:

> Stipulations, particularly in rate cases, may take different forms, ranging from (i) fully resolved, detailed agreements where all parties agree on a single cost of service calculation and stipulate to a compromise resolution of each and every issue in a case, to (ii) settlements in which each party agrees to the same revenue requirement but states its firm belief in its own cost of service calculations and analysis of individual issues. Often in rate case settlements, parties may modify their original positions on different issues, but reach the same overall revenue requirement recommendation although they do not reach full agreement on each issue. Typically, however, stipulations include some discussion of the parties' original positions and set forth how the parties modified their positions in order to reach an agreed-upon revenue requirement. While each of these various forms may be presented to the Commission, there should be some analysis of the issues supporting the stipulation rather than "illustrative" calculations of "one of many ways" to arrive at the stipulated revenue requirement.
>
> The Commission is well aware that parties can and frequently do arrive at a revenue requirement in different ways either during the

> assessment of their respective positions during the development of the case or as a result of the negotiation process. Accordingly, the Commission appreciates parties' reluctance to be bound in future cases by their agreement on substantive issues in one settled case. A disclaimer in that regard is a part of virtually every settlement agreement filed at this Commission and the Commission respects that disclaimer. That practice allows the development of settlements in contested cases without prejudice to any party entering into the settlement. However, in this case, the parties' failure to acknowledge the reasonableness of their own modifications from their original positions within the context of a settlement makes the Commission's assessment of the fairness and reasonableness of a settlement more difficult.

West Virginia American Water, Case No. 07-0998-W-42T at 2, 3 (emphasis added).

In the procedural Order entered December 7, 2007, in West Virginia American Water Company, Case No. 07-0998-W-42T, the Commission provided its general expectations in rate cases in which the parties file a Joint Stipulation:

> Furthermore, the Commission advises the parties that it will not depart in this case from its historical practice of requiring parties to a rate stipulation to file all of the testimony in the case and to demonstrate the reasonableness of their compromise. The Commission expects the parties supporting the Stipulation to move all pre-filed testimony into the record as well as present evidence at the hearing explaining how their separate positions are now reconciled to the Stipulation. The Commission also expects the parties to provide some explanation of how they revised their cost of service and rate of return calculations to reach the settlement in the Stipulation. This is a significant rate case, and the Commission applauds and encourages the efforts of the parties to fashion and present an overall settlement. Having said that, however, the Commission is mindful of its ongoing obligation to independently assess the fairness and reasonableness of the Stipulation, and urges the parties to the Stipulation to present a full discussion of the Stipulation. The Commission is not suggesting that the details of privileged settlement discussions need to be spread on the record, only that the parties demonstrate that the resulting settlement is fair and reasonable.

Id. at 3. See also Beckley Water Company, Case No. 08-0404-W-42T (Order dated December 19, 2008) at 2, 3, in which the Commission stated "a rate case stipulation must contain explanation that goes beyond a simple recitation of the final revenue requirements."

While not controlling, we have also looked for guidance for addressing stipulations to the holdings of other jurisdictions, and find that the guidance in those jurisdictions is consistent with the holdings that we have made in earlier cases and in this proceeding.[6]

With these principles in mind, the Commission adopts key provisions of the Joint Settlement on which all parties agreed and on issues that were not major contested issues in the case. The Commission, however, has considered the recommended rate increase of $60 million and, based on its analysis of the various issues, concludes that the rate increase should be lowered to $51.12 million.

Prior to agreeing on the additional revenue requirement in the Joint Stipulation, the parties asserted various positions regarding their recommendations for an increase in APCo/WPCo's base rates in the pre-filed testimony and exhibits in this proceeding. APCo/WPCo initially requested a rate increase of $155,463,299, with a return on equity of 11.75 percent, representing a 13.8 percent increase. Staff recommended an overall rate

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[6] Public utility commissions in other jurisdictions have adopted different standards of review for the approval of settlements in rate cases. See generally, Re The Detroit Edison Company, 251 P.U.R. 4th 369 (2006) (Michigan); Re Consolidated Edison Company of New York, Inc. 261 P.U.R. 4th 1 (2007) (New York); Re Kentucky-American Water Company, 261 P.U.R. 4th 470 (2007) (Kentucky); Re Rocky Mountain Power, 275 P.U.R. 4th 446 (2009) (Utah) (reasonable and in the public interest); Re Aguila, Inc. dba Aguila Networks, 247 P.U.R. 4th 437 (2006) (Iowa) (reasonable in light of record, consistent with law, and in the public interest); Re Aqua Virginia, 252 P.U.R. 4th 495 (2006) (Virginia) (no presumption of reasonableness apart from the evidence); Re Orange and Rockland Utilities, Inc. 276 P.U.R. 4th 369 (2009) (New York) (proper balance of ratepayer and utility interests, conformity with social economic and environmental policies of the State, and in the public interest); Re Avistor Corporation, 275 P.U.R. 4th 494 (2009) (Idaho) (reasonable, in the public interest, and in accordance with law or regulatory policy); and, Re Vectron Energy Delivery of Ohio, Inc., 240 P.U.R. 4th 548 (2005); Re Ohio-American Water Company, 269 P.U.R. 4th 398 (2008); Re Ohio-American Water Company, 269 P.U.R. 4th 398 (2008); Re Duke Energy Ohio, Inc., 275 P.U.R. 4th 506 (2009) (Ohio) (satisfaction of three-prong test for reasonableness: 1) product of serious bargaining among capable, knowledgeable parties, 2) beneficial to ratepayers and the public interest, and 3) not violation of important regulatory principle or practice). The commissions have modified or rejected a proposed settlement based on their applicable standard of review. Re Indiana Michigan Power Company, 273 P.U.R. 4th 310 (2009) (Michigan) (settlement approved, as modified, for the purpose of satisfying the public interest and because of lack of evidence, applying the standard of review of determining if rates were reasonable and just, properly balancing the interests of the utility, the customers and the overall public interest). Re Carolina Water Services, Inc., 253 P.U.R. 4th 143 (2006) (South Carolina) (settlement rejected because of lack of evidence because the Commission could not make independent determination as to whether public interest was served by the settlement or whether the proposed rates were just and reasonable).

increase of $41,645,702 after making a correction in its calculations filed as its direct testimony that initially had indicated an increase of $43,684,588. CAD recommended an overall rate increase of $41,214,177 based on a 9 percent return on equity and an overall rate increase of $56,563,488, based on a 10 percent return on equity. WVEUG did not recommend a specific revenue requirement, but recommended that the Commission approve a return on equity of 9.5 percent. The parties also addressed other issues including changes to the Companies' tariffs and related to certain policies. The CAD, in particular, presented recommendations for the residential customers to mitigate the impact of the proposed rate increase.

Under the proposed Joint Stipulation, the parties recommended that APCo/WPCo receive a $60 million rate increase. In the Joint Stipulation, presented as Joint Exhibit No. 1 at the December 15, 2010 evidentiary hearing, the parties agreed in summary (the following is not a word-for-word duplication of the Joint Stipulation) that:

(a) The Companies should receive an increase in current base rates to produce an additional $60 million of annual revenue, or a total annual West Virginia retail rate revenue requirement (excluding surcharges) of $1.167 billion. Joint Stipulation, Joint Exhibit No. 1 at ¶ 19.

(b) The stipulated revenue requirement reflects moving the current Construction Surcharges, other than Amos Unit 1 and the Musser Surcharge, into base rates. Id. ¶ 20.

(c) The overall cost of service attached as Attachment A to the Joint Stipulation is reasonable although the stipulating parties do not necessarily agree with each and every item in the Cost of Service. Id. ¶ 21.

(d) The Companies are entitled to use the 10.5 percent return on equity authorized by the Commission in the 2005 rate case for the calculation of AFUDC. Id. ¶ 22.

(e) The 2009 extraordinary storm expenses up to $18.2 million could be amortized or deferred over a period of eight years. Id. ¶ 23.

(f) The federal income tax related to the catch-up deduction (§ 481 adjustment) taken on the federal income tax return related to the change in tax accounting for the definition of units of property assets could be deferred. These deferred federal income taxes could be recorded by debiting Account 410 Deferred Federal Income Tax Expense and crediting Account 282-Deferred Federal Income Tax Liability. The parties agreed that deferred federal income tax would reverse as the related assets are depreciated for book purposes. The parties agreed that all annual future tax deductions related to units of property will be treated as flow-through deductions for ratemaking purposes. Id. ¶ 24.

(g) The cost allocation and rate design in accordance with Attachment B attached to the Joint Stipulation could be approved. Id. ¶ ¶ 25, 26, 27, 28, 29 and 30.

(h) A transmission cost tracking and surcharge mechanism would not be instituted in this proceeding. Id. ¶ 31.

(i) No Regional Transmission Expansion Plan (RTEP) costs would be included in the Companies' base rates and the Companies would seek recovery of RTEP costs in ENEC proceedings, with the parties' understanding that each party is free to advocate its position in future ENEC proceedings as to the level of RTEP costs. Id. ¶ 32.

(j) Certain tariff language modifications would be approved. Id. at ¶ 33.

(k) Certain customer payment issues would be resolved as recommended. Id. ¶ 34, 35 and 36.

(l) The Companies would provide in the next ENEC proceeding certain information related to firm and interruptible loads used to develop demand and energy allocation factors, kW and kWh billing determinates for each special contract customer broken out by firm and interruptible service subject to an appropriate confidentiality agreement in the next ENEC proceeding. Id. ¶ 37.

(m) The Companies would make an annual donation of $250,000 to the Dollar Energy Fund by December 31, 2011, for calendar year 2011 and by December 31, 2012, for calendar year 2012. Id. ¶ 38.

The Joint Stipulation presented at the hearing is attached and incorporated in this Order as Appendix B.

D. Testimony at Hearing

At the December 15, 2010 hearing, the parties filed the Joint Stipulation and presented witnesses to testify generally how the Joint Stipulation differed from the initial positions, how the Joint Stipulation resolved the contested issues in this proceeding and why they considered the Joint Stipulation to be fair and reasonable.

At the December 15, 2010 hearing, Mr. Patton, the President and Chief Operating Officer of APCo/WPCo, presented the Joint Stipulation as Joint Exhibit No. 1.

Tr. 12/15/10 at 41. Mr. Patton summarized the differences between APCo/WPCo's initial proposed rate increase and the settlement amount in the Joint Stipulation. Mr. Patton noted APCo/WPCo initially requested a rate increase of approximately $155 million, representing a 13.8 percent increase, whereas the settlement rate increase of $60 million represented a 5.36 percent increase. Id. at 45. He stated APCo/WPCo's residential rate increase was initially 17 percent while the settlement residential rate increase was just slightly over 5 percent. Id. at 45, 46. Mr. Patton further testified that the primary reasons for the differences between the two figures could be explained by cost reductions, based on corrections to the initial APCo/WPCo numbers presented in its filing with adjustments related to a reduction in the number of employees, and by moving the tracker for transmission charges to the ENEC proceeding. Id. at 63-65. He also stressed that APCo/WPCo had not been earning the authorized rate of return of 10.5 percent, but in fact had been earning between 6 percent and 7 percent. Id. at 70.

Mr. Steven H. Ferguson, Director of Regulatory Services at APCo, testified regarding the key elements of the Joint Stipulation at the December 15, 2010 hearing. Tr. 12/15/10 at 77-88. He testified that Attachment A included in the Joint Stipulation was APCo/WPCo's illustrative cost of service representing the parties' positions, with the understanding that not all parties arrived at the final result to Attachment A in the same way. Id. at 78. As we have stated, this is not unique. The Commission has also required the parties in other proceedings to state more than "there are a hundred ways to calculate the revenue requirement." This requirement to provide evidence of a reasonable calculation of the revenue requirement is not a "make weight" undertaking. It allows the Commission to assess the reasonableness of the Joint Stipulation. In a perfect case, all parties would agree on a single recommendation and manner of calculating the revenue requirement. That is not the situation in this case. As discussed below, because each party calculated the revenue requirement in a different manner, the Commission must examine each of those calculations and the record in the case in assessing the fairness and reasonableness of the Joint Stipulation.

Mr. Ferguson testified regarding the difference between APCo/WPCo's proposed rate increase and the Joint Stipulation rate increase. He attributed the differences in the rates to reductions in costs related to actual costs as compared to proposed costs for APCo/WPCo's severance package and West Virginia share of the 2009 storm damage. Id. at 92-94. Mr. Ferguson testified at the hearing that the illustrative cost of service revenue requirement attached to the Joint Stipulation represented APCo/WPCo's method of arriving at the stipulated rates. Id. at 93-95. He explained the items listed in APCo/WPCo's illustrative cost of service revenue requirement. Id. at 95-118.

Responding to questions from the Commissioners regarding executive compensation, Mr. Ferguson testified that APCo/WPCo's proposed executive compensation costs were consistent with the compensation levels for executives in utilities or other industries across the country. Id. at 118, 119. Mr. Ferguson testified that executive compensation constituted a small, almost insignificant, percentage of the overall rates the customer is charged. Id. at 119.

CAD witness Byron Harris testified about the Joint Stipulation for the CAD positions and issues in the proceeding. Mr. Harris testified that APCo/WPCo's original revenue increase request of $155 million disproportionately allocated the revenue increase to the residential customers. Id. at 128. He testified that the recommended $60 million revenue increase in the Joint Stipulation resulted in a decent outcome for residential customers. Id. at 129. He testified that the parties agreed to set the customer charge for residential customers at $5 per month and retain the declining block structure of Schedule RS, that benefited residential customers. Id. at 129-131. Mr. Harris testified the Joint Stipulation included the recommendations of CAD witness Alexander to assist the "working poor" or "near poor" customers and low income customers that benefited residential customers. Id. at 132-134. He testified that the Joint Stipulation included favorable provisions for the residential customers regarding the Average Monthly Payment Plan, the deferred payment plan for customers whose service had been terminated, and information that APCo/WPCo agreed to track regarding customer credit and collection practices. Id. He stated the Joint Stipulation proposed revenue increase, allocation and rate design, and policy changes will benefit the residential customers. Id. at 134. He stated that the Joint Stipulation was reasonable and in the public interest. Id. Upon cross-examination by WVEUG counsel, he also testified that the revenue allocation in Attachment B of the Joint Stipulation represented a compromise between WVEUG and the CAD. Id. at 135.

Staff Witness Oxley testified regarding the Staff revenue requirement calculation. Although it was not attached to the Joint Stipulation, Staff, at the hearing, presented Staff Exhibit No. 1, showing the Staff revenue requirement calculation for the Joint Stipulation. Id. at 142, 143; Staff No. 1. Staff originally recommended a rate increase of $41.6 million, as shown in prefiled direct testimonies of Staff Witnesses. Id. at 146. Staff explained the various Staff adjustments to that revenue requirement, including an adjustment to going-level revenues related to test year bank amortization; the transfer of RTEP costs to the ENEC; the storm damage and eight-year amortization of the storm damage; short-term debt and long-term debt; the Staff recommendation of a return on equity to 10 percent; Staff's adoption of the CAD federal income tax rate of 22.39 percent; amortization of employee severance costs; inclusion of investment projects for Amos No. 2 reheater project and Amos No. 2 turbine modifications; inclusion of APCo/WPCo's direct incentive plan costs, and an adjustment to test year non-ENEC generation expenses. Id. at 144-152. Staff also testified that the Joint Stipulation represented a reasonable resolution of the (i) issues presented in the proceeding and (ii) parties' position in the rate case. Id. at 152.

E. Post-Hearing Exhibits

At the December 15, 2010 evidentiary hearing, the Commission suggested that the Joint Stipulation represented a "black box settlement" in that the parties agreed to a final revenue requirement amount, but the proposed Joint Stipulation did not fully address each of the parties' recommendations on certain issues. Id. at 93, 94. The Commission did not request disclosure of the give and take settlement process, but because of the magnitude to the APCo/WPCo rate case and the tremendous sensitivity to the request, the Commission asked each party for a post-hearing exhibit to show how each party arrived at the settlement number of $60 million compared to its initial revenue requirement and rate increase recommendation. Tr. 12/15/10 at 120, 121. The Commission requested the post-hearing exhibits in order to fully evaluate the Joint Stipulation and to compare the settlement embodied in the Joint Stipulation with all of the evidence presented in the case.

The Commissioners requested on the record that APCo/WPCo, Staff and CAD provide a Commission Request Exhibit after the hearing, detailing the parties' different cost of service recommendations and, specifically, requested a detailed explanation as to how executive compensation is accounted for in the parties' recommendations. Id. at 102, 120, 121. The exhibit that had been presented by Staff witness Oxley in support of the Stipulation already contained the detail required by the Commission so Staff was not asked to provide an additional exhibit.

On December 17, 2010, CAD filed its post-hearing Commission Request Exhibit as Commission Request - CAD, reflecting CAD's calculation of the cost of service in the settlement, including a return on equity of 10 percent.

On December 30, 2010, APCo/WPCo filed the Commission Request Exhibits No. 1 and 2. In the Commission Request Exhibit No. 1, APCo/WPCo provided an analysis of the Joint Stipulation rates, explaining the differences between APCo/WPCo proposed revenue requirements and the revenue requirements agreed upon by the parties. The Exhibit showed the revenue deficiency calculation for settlement analysis, including a series of line item adjustments. According to APCo/WPCo's Commission Request No. 1, the Joint Stipulation weighted cost of capital is 7.75 percent, the return on equity is 10.5 percent, the rate base as adjusted is $2,518,700,000, the return on rate base is $195,200,000 and the total requested revenue increase is $60 million. We had expected that the Companies would continue to support their development of the $60 million rate increase as had been filed with the Joint Stipulation, but would provide more detail as to the adjustments on specific issues necessary to arrive at the $60 million increase. Unfortunately, APCO/WPCO Commission Request Exhibit No. 1 differed from the APCo/WPCo illustrative cost of service included as Attachment A of the Joint Stipulation and presented some difficulties in analyzing this case. In effect, the Companies departed from their illustrative cost of service giving us two APCo/WPCo proposals as to adjustments that could support a $60 million rate increase.

In APCo/WPCo's Commission Request Exhibit No. 2, APCo/WPCo explained its views on executive compensation in response to the Commission's request at hearing to address this issue. APCo/WPCo asserted that the compensation levels provided to its executive positions are market competitive and set at levels designed to attract, retain, and fairly remunerate human talent needed to perform the necessary functions of the positions. The Companies asserted that executive compensation levels are in the middle of the spectrum for compensation for comparable positions throughout the country. The Companies noted the base levels of executive compensation were not contested issues, although the issue of incentive compensation was a contested issue in the proceeding. The Companies stated they took into consideration the emergence of incentive executive compensation as a contested issue as an operative factor in the overall negotiated settlement. The Companies stated this factor influenced the overall settlement numbers to which the Companies agreed. The Companies stated three of the specific adjustments included on the Commission Request Exhibit No. 1 (net payroll savings, incentive adjustment and adjusted production O&M) reflected in part reductions to the levels of executive compensation in the Companies' original filing. This was an apparent contradiction to the initial position taken by the Companies in the illustrative cost of service filed with the Joint Stipulation.

On January 13, 2011, the Companies filed a Motion for Extension, requesting a one week extension to file rates reflecting the proposed Joint Stipulation, and on January 21, 2011, the Companies filed the rates reflecting the rate increase and rate design settlement reached in the Joint Stipulation.

In reviewing the fairness and justness of a Stipulation in a recent rate case, the Commission held that the Commission's obligation to balance the interest of all Parties, the ratepayers and the State can only be satisfied by a review of <u>all</u> of the evidence, not just the evidence submitted in favor of the joint stipulation. <u>Monongahela Power Company and The Potomac Edison Company dba Allegheny Power</u>, Case No. 09-1352-E-42T (Order dated June 25, 2010). Therefore, in addition to the evidence presented at the December evidentiary hearing, the Commission considered the entire record, including witnesses' pre-filed and hearing testimony and the exhibits presented in this rate case. We will review various revenue requirement components and develop a revenue requirement based on that review. We will then determine if our independent analysis of the evidence supports the Joint Stipulation.

V. DISCUSSION OF REVENUE REQUIREMENTS AND RATE DESIGN

The issues in this proceeding included significant revenue requirements differences between the Companies' position and the recommendations of Staff, CAD, and WVEUG. There are also significant issues between the Companies' position and the recommendations of Staff, CAD, and WVEUG relating to Class Cost of Service, Rate Design, and Tariff Terms and Conditions of Service.

The revenue requirements issues can be divided into several main categories: Rate of Return, Rate Base, Operation and Maintenance Expenses, and Income Taxes. Each of these main categories contains a number of sub-categories. In the following sections of this Order, we will address each main and sub-category, highlight the issues contained therein, and discuss the Commission findings, conclusions and decisions.

VI. RATE OF RETURN

A. Capital Structure

Capital structure, that is, the relative percentage of debt and equity within APCo/WPCo's total capital, is not a significant issue in this case. The following table summarizes the capital structure as filed by the Companies and the capital structure recommended by Staff.

	Original Companies' Filing	Companies' Rebuttal Filing	Original Staff Recommendation
	Percent of Total Capital	Percent of Total Capital	Percent of Total Capital
Long-term debt	53.4%	53.0%	53.0%
Short-term debt	3.7%	4.5%	4.5%
Preferred equity	0.3%	0.3%	0.3%
Subtotal	57.4%	57.8%	57.8%
Common equity	42.6%	42.2%	42.2%

The Companies originally proposed a capital structure consisting of 53.4 percent long-term debt, 3.7 percent short-term debt, 0.3 percent preferred equity and 42.6 percent common equity, based on a thirteen-month test year average. The CAD initially adopted the Companies capital structure, reserving the right to review the issue further in its rebuttal case. The Staff used a quarterly averaging approach and a more recent time period to derive a recommended capital structure of 53 percent long-term debt, 4.5 percent short-term debt, 0.3 percent preferred equity and 42.2 percent common equity.

In rebuttal testimony, the Companies accepted the measurement period used by the Staff, but continued to argue for a monthly average calculation. APCo/WPCo's proposal of a thirteen-month average to determine capital structure did not result in a significant difference from the Staff recommended capital structure. Although there remains some differences in the average cost rate for debt capital (as will be discussed later in this Order), the Companies' use of a thirteen-month average capital structure results in relative percentages of capital that are almost identical to the Staff recommended capital structure. In fact, as shown in the table above, rounded to three decimal places the capital structure percentages in the Companies' rebuttal and the Staff recommended capital structure percentages are identical.

The Commission is not required to use any particular averaging or projection methodology, or time period, to derive a reasonable capital structure for the purpose of developing an overall rate of return in a rate proceeding. In the past, the Commission has pointed out that we are not bound to either a test year capital structure or a projected capital structure. Rather we review historic, projected and hypothetical capital structures to arrive at a structure that is reasonable, fairly balances the interests of the customers and the utility and produces the lowest reasonable revenue requirements while maintaining the financial integrity and flexibility of the utility. Hope Gas, Inc., dba Dominion Hope, Case No. 08-1783-G-42T (Order dated November 20, 2009) at 7; West Virginia-American Water Company, Case No. 84-008-W-42T (Order dated January 25, 1985) at 17; Appalachian Power Company, Case No. 83-897-E-42T (Order dated December 28, 1984) at 3.

The Commission has reviewed the methodology and the time periods used by the parties to derive a capital structure, and we find that it is reasonable to use the Staff-proposed capital structure in this proceeding.

B. Cost of Debt and Preferred Equity

The changes in the time period used to measure the cost of debt produce some relatively minor differences between the Companies' original filing, rebuttal filing and the Staff recommendation. The following table summarizes the cost rates and weighted cost rates for debt and preferred equity as originally proposed by the Companies, from the Companies rebuttal, and the Staff recommendation.

	Original Companies' Filing			Companies' Rebuttal Filing			Original Staff Recommendation		
	Percent of Total Capital	Cost Rate	Wtd. Cost Rate	Percent of Total Capital	Cost Rate	Wtd. Cost Rate	Percent of Total Capital	Cost Rate	Wtd. Cost Rate
Long-term debt	53.4%	6.42%	3.43%	53.0%	5.97%	3.16%	53.0%	5.85%	3.10%
Short-term debt	3.7%	0.89%	0.03%	4.5%	0.25%	0.01%	4.5%	0.50%	0.02%
Preferred equity	0.3%	4.35%	0.01%	0.3%	4.35%	0.01%	0.3%	4.35%	0.01%
Subtotal	57.4%		3.47%	57.8%		3.18%	57.8%		3.13%

The Commission determines that the Staff derivation of an average cost rate for debt and preferred equity is reasonable. The Staff data includes a slightly lower cost rate for long-term debt as compared the Companies' filing and a relatively significant higher cost rate for short-term debt. Given the lower total weighted cost contained in the Staff recommendation, and considering the rebuttal testimony and exhibits of the Companies that likewise lowered the weighted cost of debt from the level included in the original filing, it is reasonable to reject the original weighted cost rate as filed in favor of a lower total weighted cost of debt and preferred equity. We will use the Staff-recommended cost rates for these elements of Cost of Capital.

C. Return on Equity

The Commission is faced with a fairly wide range of return on equity recommendations from witnesses for the Companies, Staff, and WVEUG, both in prefiled testimony and in the revenue requirements provided to the Commission in support of the Joint Stipulation. Each witness in prefiled testimony provided clear exhibits for the data underlying their positions and clear testimony supporting their analysis of the data and recommendations regarding the return on equity that the Commission should grant the Companies in this proceeding. To their credit, each witness provided a detail of all data, including individual results that were higher and lower than their recommended range of reasonableness for return on equity (outliers). They then explained their position about outliers that might bias the data and that should be excluded. Not unexpectedly, Staff and WVEUG rebutted the Companies and suggested that some of the methods used biased the requested return on equity upward. Also as expected, the Companies rebutted the Staff and WVEUG and suggested that their methods tended to bias their recommendation downward.

Some of the best testimony came from witness Avera for the Companies when he acknowledged that alternative methods for evaluating the expected return by stockholders may produce wide results but defended the methods and stated "[I]nterpreting the results of these methods requires care and practical judgment." Avera, WEA No. 1, Direct Testimony at 24. The Commission completely agrees that results must be evaluated and judged carefully and practically, and we undertake that task now, based on our practical judgment of the methods used by the expert witnesses, the current market conditions, the data presented by the witnesses and the return on equity contained in the Joint Stipulation. As we have stated in the past, there is no absolute, one correct answer to be derived from the mass of data related to return on equity presented in this, or any, rate case record. The fair result lies within a zone of reasonableness that is framed by our judgment and application of regulatory principals and policies that have been used by this Commission and previous Commissions.

Each of the witnesses generally used two widely-accepted methodologies to evaluate data and arrive at a return on equity recommendation. Those are the Discounted Cash Flow (DCF) method and the Capital Asset Pricing Model (CAPM). Each method used actual available data such as actual stock prices, dividend payouts, interest rates on various securities and historical returns achieved in the stock market. Some projections are also involved, such as projected growths in dividends and earnings of a number of companies that are chosen as a proxy group comprised of publicly traded corporations with similar risks of the Companies. All of this empirical and projected data are wrapped up in analyses that require judgment as to the reasonableness of the component parts, including the identity of the proxy corporations and the evaluation of the data they provide. For their DCF and CAPM analyses, the methods employed by the witnesses are similar, but there are differences in the judgment portion of their analyses, giving rise to a fairly wide range of recommendations.

Dr. Avera, the witness for the Companies, added another method which he called Expected Earnings. This method, which concedes the application of judgment to unknown market analysts employed by Value Line, uses the projections of earnings made by those market analysts. The witness for the Companies also factored his recommendation upward to include an adder of 0.15 percentage points (15 basis points) to his final recommendation to account for flotation costs.

The range of recommendations and the specific points within those ranges chosen by each witness are:

Companies (William A. Avera)			
DCF	9.8%	to	13.0%
CAPM	10.2%	to	10.3%
Expected Earnings	10.9%	to	11.5%
Overall	10.6%	to	12.6%
Recommendation	11.75%		
Staff (Randall R Short)			
DCF	8.7%	to	9.7%
CAPM	5.0%	to	6.9%
Overall	8.5%	to	9.5%
Recommendation	9.0%		
WVEUG (Richard A. Baudino)			
DCF	8.3%	to	10.4%
CAPM	7.2%	to	8.8%
Overall	9.0%	to	9.7%
Recommendation	9.5%		

We note that in some cases the above ranges include mid-points or averages to arrive at the low and high data based on variability within the underlying data and evaluation methods employed by the witnesses. Although we understand that returns on equity included in the various revenue requirement calculations supporting the Joint Stipulation are necessarily a function of the settlement and the totality of the revenue requirement calculation, the parties utilized numbers of 10 percent (Staff) and 10.5 percent (CAD and APCo/WPCo) in that calculation.

The Commission further understands that some of variability in the ranges recommended by witnesses is a result of the unusual circumstances in the current capital markets. Staff's lower CAPM numbers include the effects of extremely low interest rates on short-term government securities that we are not inclined to accept for purposes of weighting a reasonable return on equity at this time. However, we appreciate that the witness has recognized the past inclination and preference of the Commission to consider short-term government securities and included the data in his exhibits. As a matter of fact, we commend all of the witnesses for presenting the low and high data within their exhibits even though they then applied their judgment to disregard some of the data in arriving at their final recommendations. This enables the Commission to fully evaluate the underlying data supporting a return on equity recommendation and not be hostage to incomplete data by referencing, but not showing, excluded data simply because a witness thought it fell outside of a range of reasonableness.

For purposes of our review of the Joint Stipulation and associated revenue requirements, the Commission focused mostly on the DCF data and then to some extent on the CAPM data in this proceeding. We have reviewed the Expected Earnings data, but do not rely heavily on that particular data or methodology. We have found in the past that investor expectations for a proxy group of comparable risk companies are reasonably captured in the DCF data. The CAPM data and methodology is also reasonable although it adjusts for risk in a different way through the development of the "beta factor" and risk premium. Both of these methods are more comprehensive than the Expected Earnings methodology and allow the Commission to test and qualitatively evaluate the underlying data and assumptions. We also accepted the recommendations of witnesses that some of the data should not be weighted very heavily, or at all, to the extent they are unrealistically high or low. However, we apply our own judgment with regard to what data may be unrealistically biasing the final answer (as opposed to data that simply reflect the realities of the market and investor acceptance of the realities for particular companies within the proxy groups).

In evaluating the recommendation of all of the witnesses, we applied our judgment to the data presented by that witness. For example, Dr. Avera excluded four companies from his Value Line utility proxy group analysis because they had cost of equity estimates of 4.7 percent, 7.1 percent, 7.7 percent and 7.2 percent. Excluding these companies resulted in his Value Line data averaging 10.6 percent. The same data had companies with indicated equity returns of 14.4 percent and 13 percent, which were arguably more of an outlier than some of the companies he excluded from his analysis. Excluding none of the companies in the Value Line group, we would arrive at an average of 9.7 percent indicated return on equity instead of his 10.6 percent number. If we exclude only the company with an indicated return on equity of 4.7 percent, we would arrive at an average of 10 percent indicated return on equity instead of his 10.6 percent number. Finally, if we exclude all of the companies he recommended, but also excluded the 14.4 percent and 13 percent companies, we arrive at an indicated return on equity of 10.1 percent instead of his 10.6 percent. In his entire utility proxy group DCF analysis, Dr. Avera excluded fourteen companies that he considered to be low outliers and four companies that he considered to be high outliers. There were eight data points with indicated returns on equity in excess of 13 percent that he did not consider to be high outliers. While the Commission agrees that some judgment is involved in determining if outliers are so outrageous that they completely taint the data and should be eliminated, applying our judgment, we would not have excluded some of the data that caused his recommended ranges to be as high as they are.

Another problem we have with the data relied on by Dr. Avera is the non-utility proxy group. The range that he arrived at for his utility proxy group was 10 percent to 12 percent. For his non-utility proxy group, the range was 11.6 percent to 13 percent. The non-utility group included thirty-two data points that were greater than fifteen percent that he did not consider to be outliers to be excluded from his averages, and a large number of data points between 13 percent and 15 percent. In our judgment, the range of 11.6 percent to 13 percent produced by the non-utility proxy group should be discounted for purposes of evaluating a range of reasonableness from Dr. Avera's data.

As mentioned earlier, we have considered, but do not rely on, the expected earnings approach that is part of Dr. Avera's overall recommendation. That approach produced a return on equity range of 10.9 percent to 11.5 percent. We do not give these data the weight that Dr. Avera did in arriving at his ranges for return on equity.

Finally, we do not adopt Dr. Avera's proposed upward adjustment to reflect flotation costs.

Taking all of these factors into consideration, we have viewed the data presented by Dr. Avera, but arrived at a different determination regarding the range that is reasonably derived from that data.

We find that the overall range recommended by Dr. Avera is high. His minimum level of 10.6 percent is, in our opinion, too high and not supported by the evidence at the low end of a range, although it is not unreasonable as a recommendation based on his evidence. Our evaluation of his data and methods produces what the Commission considers a more reasonable range of 9.7 percent to 11.8 percent. His recommendation of 11.75 percent, which includes the flotation cost adder, may be within, but very near the upper end of, the range of reasonableness that we derive from our analysis of his data and methods.

On the other hand, we find that the upper end of the range recommended by Mr. Short is too low. Our evaluation of the data presented by Mr. Short, applying

Commission methods for deriving a range of reasonableness, produces a range of 8.5 percent to 10 percent. His final recommendation is very near the low end of the range, but within the range supported by our evaluation of his testimony and methods.

Likewise, we find that the upper end of the range recommended by Mr. Baudino is too low, and we would evaluate the data presented by Mr. Baudino to produce a range of 9 percent to 10.2 percent. His recommendation is reasonably within, and near the mid-point of the range supported by his testimony and our evaluation of his testimony and methods. Mr. Baudino recommended a return on equity of 9.5 percent based on the results of his two CAPM analyses and DCF analysis. Baudino, WVEUG-2, Direct Testimony at 3. Mr. Baudino recommended an ROE range between 9 percent to 9.7 percent, adopting an ROE based on the top of the range of results for his DCF analysis. Id. at 28. His recommendation in the upper half of the range was based on the similarity of results for the DCF Method 1 and Method 3 and also reflected his finding that the bulk of the APCo/WPCo capital expenditure program is behind them and that the Companies are in the process of improving their financial metrics. Id. at 28. Mr. Baudino applied historic results to show investor expectations in developing his CAPM analyses. Id. at 24-28.

In Dr. Avera's rebuttal testimony, he showed that if forward-looking methodology were applied to Mr. Baudino's CAPM analyses, it resulted in CAPM cost of equity estimates for his proxy group of 10.7 percent and 10.98 percent. Nov. WEA No. 1, Rebuttal Testimony at 5.

Taking all of the evidence presented by all of the witnesses into consideration, we determine that a return on equity range of reasonableness for the Companies in this proceeding is 9.1 percent to 10.9 percent. The majority agrees that it is reasonable to set rates in this case based on a return on equity at 10 percent, at the mid-point of that range.[7]

The Commission has noted in the past that return on equity is more art than science and there is no single "correct" answer. We have considered evidence on the current market conditions, circumstances of the Companies and their customers, and empirical return on equity data in the record. Applying our individual judgment to the

[7] Although not controlling upon the Commission decision regarding return on equity, there seems to be growing public interest in comparing West Virginia to other states. Appalachian Power and Wheeling Power are utilities wholly-owned by American Electric Power (AEP). AEP also has utilities in surrounding states and the regulatory authorities in those states have authorized the following returns on equity in current rates: Kentucky (Kentucky Power, 10.5 percent, Case No. 2009-00459); Virginia (Appalachian Power, 10.5 percent, Case No. PUE-2009-00030); Ohio (Columbus Southern Power, 17.6 percent, Case No. 10-1261-EL-UNC, 2011; Note: this return allowed in a partially deregulated market); Indiana (Indiana Michigan Power, 10.5 percent, Case No. 433-06, 2009); and Michigan (Indiana Michigan Power, 10.35 percent, U-16180, 2010).

evidence, we do not reach a unanimous decision regarding the 10 percent return on equity. Based on the evidence supporting a wide range for return on equity, the majority believes that a 10 percent equity return is reasonable and reflects the business and financial risks for AEP and its shareholders, which include the uncertain future costs and operating restrictions that carbon-based generation is facing, the economic doldrums that threaten industrial load that helps to support the fixed costs of the utility and the uncertainties of a fluctuating stock market.

We have heard arguments made that a 10 percent return on equity is excessive as compared to the interest that persons are earning on pass-book savings accounts or even certificates of deposit and government bonds. We acknowledge that interest rates on medium- to long-term government bonds are in the range of 2.5 to 4.5 percent. Interest on certificates of deposit is, in many cases, 1 percent or less. Interest on pass-book saving accounts has dropped to near zero. However, comparing these interest rates to a return on equity is not a valid or meaningful comparison.

People that invest in government bonds and certificates of deposit are interested first, and foremost, in the security of their invested funds. They accept low interest rates because they know that when the securities mature, every dollar invested will still be there. A $10,000 investment in a long-term CD in 2007 can be cashed out at $10,000 today. A similar investment in a five-year government bond in 2007 will be cashed-out for $10,000 at maturity. This cash value protection comes at a price, and that price is the lower interest rate that can be earned from these secure, nearly risk-free investments, compared to alternative investments.

There is risk for loss of investment value in the stock market. In some cases that risk is low and mitigated by dividends and in other cases it can be very high. People that invest in the stock market expect a higher return on their investment to compensate them for the risk of loss in value. Investors in electric utility stock are not immune from risk. In early 2007, the price for AEP stock was $50 per share. Then, the stock price fell, dropping to $28 by October 2008 and eventually to $25 in early 2009. Anyone who had invested in AEP at $50 per share in 2007 would have seen the value of that investment cut in half by March 2009. A $10,000 investment made at the high point of the market in 2007 would have been worth $5,000 in March 2009. The price has recovered somewhat, and today, it is around $36 per share. Thus, there have been significant gains for stockholders that purchased at the low point in early 2008; nevertheless, that $10,000 investment made in 2007 would have a current value of only $7,200.

There is a plus side to stock market investments. Normally, for high quality stocks, what goes down [often] comes back up. Moreover, for a utility stock like AEP there is an annual benefit from dividends that historically have been constant and predictable. Customers that invested $10,000 in 2007 expecting to receive about $320 per year in dividends, or about 3.2 percent, received those dividends even as the market value of their investment dropped.

All of these risk/reward factors are considered by the Commission. We must determine the relative safety and certainty of dividends and the potential for roller coaster rides up and down in value that could severely restrict cash flow to an investor that needed to cash-out stock for day-to-day living expenses during a market downturn. These factors define the risk to the stockholder and determine the reasonableness of a return on equity. The risks are real and ever present as evidenced in the stock price declines in 2007/2008. Thus, a credible evaluation of a particular return on equity decision is not as simple as saying that government bonds are paying 4.5 percent, or certificates of deposit are paying 1 or 2 percent, and using those facts alone to attack the reasonableness of a return on equity of 10 percent.

D. Overall Rate of Return

Based on the capital structure and capital cost rates approved herein, including a return on equity of 10 percent, we approve an overall rate of return of 7.36 percent.

VII. RATE BASE

A. Rate Base Adjustments for Year-End and Post-Test Year Plant Additions

1. Amos Unit 2

APCo/WPCo proposed an adjustment of $23.9 million total company or $10.2 million on a WV jurisdictional basis to provide for a full inclusion in rate base (terminal treatment) for a reheater replacement project on Amos Unit 2 that was completed and placed in service in February 2010, after the end of the test year in this case. See, Adjustment No. 75 – EPIS and Fawcett, JDF No. 1, Direct Testimony at 5, 12-14. Staff and CAD both oppose this adjustment because it departs from the use of an average test year rate base and includes investment that was not in plant in service at all during the test year.

The Companies also proposed a second adjustment of $7.7 million total company or $3.3 million on a WV jurisdictional basis to provide for terminal treatment of a turbine modification project at Amos Unit 2 that went into service in February 2010. Fawcett, JDF No. 1, Direct Testimony at 14. Staff and CAD both oppose this adjustment for reasons similar to their opposition to the Amos Unit 2 reheater project.

The CAD opposition to these adjustments in its prefiled testimony is consistent with its opposition to terminal treatment of the scrubber projects that have been previously granted special ratemaking treatment through the construction surcharge mechanism first established in Case No. 05-1278-E-PC-PW-42T. The Staff did not oppose terminal treatment for projects that it could identify as being related to those special ratemaking treatment projects; however, Staff did oppose other terminal treatment and post-test year plant additions adjustments proposed by the Companies. The Commission, for purposes of calculating a revenue requirement, adopts the Staff recommendations regarding the Staff-identified scrubber projects that were afforded special ratemaking treatment in the construction surcharge. In allowing this adjustment, the Commission wants to clarify that the construction surcharge mechanism was intended to be an exception to traditional AFUDC accounting by the Companies and traditional use of average test year rate base. In this case, we will not expand the special treatment that we intended for the scrubber installations to any plant investment that the Companies tag as non-revenue producing plant additions or additions related to the quality of the environment. This approach opens the door for wholesale departure from our traditional average test year rate base ratemaking.

The Companies propose a departure from our historical use of average test year plant in service rate base for projects that, at best, may be tangentially related to the environmental projects that we have allowed special ratemaking treatment since 2006. Just because the scrubber retrofit provided a propitious time to do other plant modifications on Amos Unit 2 does not mean that the special ratemaking treatment should be provided for other plant additions, renewals or replacements. We are not denying recovery; we are only saying that we never intended that all plant investment that the Companies choose to label as "environmentally-related" will be afforded special ratemaking treatment in this case. We cannot ascertain from the evidence in this case whether either of these projects was reflected in the surcharge mechanism approved in Case No. 05-1278-E-PC-PW-42T. If they were, then the Companies have received an unintended CWIP allowance through the surcharge and customers will benefit from lower AFUDC on these projects. If they were not, then disallowance of this adjustment does not place the Companies in any worse position. They have accumulated AFUDC pursuant to our System of Accounts and the rate base that we will allow in this case conforms to our historical average rate base policy with regard to these projects.

2. Wheeling Project

The Wheeling project is somewhat different because it is clearly unrelated to the special ratemaking treatment established by the Commission in Case No. 05-1278-E-PC-PW-42T. The project is described as a significant rehabilitation project to replace all of the old underground cable in the network and remove and replace the overhead transformer installations with underground equipment. Fawcett, JDF No. 1, Direct Testimony at 14, 15. The project was not completed and in service during any portion of test year 2009, was only 88 percent complete by the end of June 2010, with full completion of the project not expected until November 2010. Id. The only justification for the adjustment is that it meets a "non-revenue producing, non-expense reducing" criteria that the Commission has from time to time used for allowing departure from historical average test year rate base.

The Companies have not provided sufficient reasons and have not met their burden of convincing the Commission that there is a compelling reason to depart from the historical average test year approach and to move outside of the test year to include rate base items such as the Amos Unit 2 reheater, turbine modification projects, or the downtown Wheeling distribution system upgrades.

3. Other Rate Base Adjustments Departing from an Average Test Year Rate Base

We note that there may be similar adjustments to those discussed above that depart from an average test year rate base for projects other than the scrubbers, but which were not eliminated by Staff. We will not refine our analysis of the reasonableness of the revenue increase in the Stipulation by separately discussing and disallowing such adjustments. To the extent there are such adjustments for non-scrubber projects we place the Companies on notice that the revenue requirement and rate increase herein ordered is not a confirmation of the acceptance of adjustments to depart from an average test year rate base in the future.

We also note that there were several significant rate base adjustments proposed by the Companies in their rebuttal testimony. We find that the testimony and exhibit adjusting rate base did not really rebut any specific direct testimony, but instead was used as an opportunity to significantly modify the original filing of the Companies. This modification to the original filing is contrary to the Commission's rate filing rules. The Companies are supposed to file all of the financial data that they intend to rely to support their requested rate increase with the initial filing of a rate case. Specifically, Rule 42 of the Commission Rules for the Construction and Filing of Tariffs requires that: "Each utility, at the time it files a tariff or application for initial rates or changes in rates shall present the proposed tariff, schedules and exhibits upon which it intends to rely in support of its application or filing" (emphasis added). The late-filed rate base adjustments clearly include significant data that the Companies want to rely upon to support the rate increase, but it was not part of the initial filing. While we may grant waiver of our rules, we do not find that such a waiver would be reasonable for the significant adjustments that were put into the record much too late in the case to allow for a complete record on the reasonableness of the adjustments.

We find that the exhibits and explanation of the adjustments proposed at the rebuttal stage of the case do not demonstrate the full nature of the adjustments and whether they are specifically for the scrubbers at Amos, or are simply "related" to the scrubber projects. The limited testimony filed described the adjustment:

> There is an understatement in APCo's CWIP balance in rate base because some projects related to the installation of pollution control equipment at APCo's Amos Units 1 & 2 were not coded as environmental work orders, although they should have been.

Brubaker Nov. JLB No. 1, Rebuttal Testimony at 17. Emphasis added.

The exhibit supporting the proposed adjustment does not clearly show that the new late-filed proposed rate base adjustment is for the scrubbers. In fact, it appears to show just the opposite and indicates that this new adjustment would simply have modified the Amos reheater and turbine modification projects which we discussed above and determined should not be allowed. For example, the sparse description of the adjustment indicated that it included additions for: Am 1& 2 Balanced Draft C; Am 1842 Boiler Modifications; Am 1 & 2 Controls Moderni; and Am 1& 2 SO3 Mitigation S. Except for the last listed project, these do not appear to be direct investments in the Amos scrubbers.

We find that the late-filed adjustments fail to meet any reasonable burden of proof that would allow us to find that they are reasonable or correct. We do not include these adjustments in rate base.

B. Adjustment to Include Deferred Storm Damage Expenses in Rate Base

The Companies proposed to defer and amortize the extraordinary storm damage costs it experienced in late 2009. The Staff and CAD both recommend a storm damage increment in O&M expenses in this case, although at a different level and calculated differently from the Companies' request. Staff opposed the proposed inclusion of deferred storm damage costs in rate base. The Companies' adjustment added $11.4 million to its requested rate base. The Companies did not provide specific argument or cite Commission precedent with regard to the rate base treatment of storm damage. The Companies offered some testimony suggesting its request was "the precise treatment which this Commission accorded Allegheny Power in 1994 in connection with a comparable major storm expense." Ferguson, Nov. SHF No. 1, Rebuttal Testimony at 11. However, we believe that statement is limited to the Operation and Maintenance treatment of extraordinary storm damage expense (one-fifth allowed for ratemaking purposes) and does not address the issue regarding inclusion in rate base. The Companies' only argument for including a portion of the storm damage costs in rate base was that "any extended period of time to carry such a burden should allow for a return component." Id.

We note that the approach taken by Staff provides for an average of extraordinary storm-related costs over a ten-year period and includes that level in rates in this proceeding. Because the costs experienced in 2009 were high, this calculation is the equivalent of taking one-tenth of the 2009 costs. We do not believe that Staff intended to reflect an amortization of those specific 2009 costs over a ten-year period. The Staff and the Companies similarly averaged the more "normal" storm-related repair costs over a three-year period to arrive at an average for such "normal" expenditures. For this second adjustment there is no rate base component proposed by the Companies. The Companies, however, want to treat extraordinary storm-damage costs different from the treatment of the three-year average of "normal" storm costs by setting up a rate base account for the extraordinary storm-related costs. The Commission will allow an increment in rates to reflect a portion of the extraordinary 2009 storm-related costs in rates, but will not allow a rate base component for such costs at the same time.

Normally, ratemaking is a process by which a test year is used to derive an expected continuing level of investment, revenue units, and expenses and to use that data to develop rates that will recover an expected revenue requirement for the first full year those rates are in effect. When the test year is an anomaly, adjustments may be necessary to adjust for going-level costs that are not reflected in the test year or to exclude test year costs that are extraordinary and non-recurring. The storm-related costs experienced in December 2009 fall into the category of test year expenses that are extraordinary and non-recurring. The Commission will not eliminate the storm-related costs at going level; but we will allow an amount equal to one-seventh of the identified extraordinary storm-related costs in determining the revenue requirements in this case. The Companies may consider this to be an allowance of the specific 2009 costs that they may recover. This treatment and consideration of the rate increment allowed herein as being an identifiable and continuing rate allowance is conditioned, however, on not including any perceived "unrecovered" amount in rate base. If we thought that providing this guarantee to the Companies would require a rate base allowance, we would adopt the Staff approach of treating extraordinary storm-related costs the same as we treat fluctuating levels of costs that are normalized using an averaging process.

C. Accumulated Deferred Income Tax Adjustments

There are some significant differences among the parties with regard to the Accumulated Deferred Income Taxes (ADITS) that should be included in rate base.

The Companies identified the bulk of this difference as related to $22.8 million deferred federal income tax liability related to prepaid pension assets that are another rate base issue. The Companies argue that there is an unbreakable link between the deferred federal income tax liability related to the pension assets and the treatment of the pension assets themselves for rate base purposes. We do not agree. The Companies admit that they received a tax benefit from the pension contributions. Regardless of how the pension assets for rate base purposes are treated, the tax benefit has accrued and will not go away. This is not different from our decision in Hope Gas, Case No. 08-1783-G-42T. The ADITS related to the pension contributions made will continue to be included in rate base in this case.

D. Inclusion of Pension Fund Assets in Rate Base

The Companies proposed that the amounts placed in their Pension Funds as prepayments be included in rate base. Staff and CAD proposed that the so-called Prepaid Pension Asset not be included in rate base.

The Commission will not include the amounts recorded by the Companies as Prepaid Pension Assets in Rate Base. We do not agree with the Companies' arguments that these Pension Assets represent payments by the Companies upon which they are entitled to earn a return in the same manner as we provide a return on Utility Plant in Service that is used and useful for the provision of utility service. We recognize that pension accounting is a complex area and that providing funds to build up pension assets that will provide for future pension benefits that have been promised to employees is an important and prudent thing to do. We cannot presume, however, that because pension costs are "prepaid" in the sense that money is deposited into a separate pension fund, the pension assets represent prepaid expenses that either require or deserve rate base treatment. We must be careful of including any and all prepayments in rate base. Prepayments should be subject to the same review as any other investment or expense of a utility. Inclusion of prepayments in rate base should not be used for a utility to find a convenient place to deposit funds and then expect to earn a return on those funds.

E. Cash Working Capital

Cash working capital is a specific measurement of the difference in timing between when expenses are incurred for providing service to customers and when expenses are actually paid, in cash. If the cash payment of an expense precedes the actual cash collections from customers, there is a positive working cash requirement because company-supplied cash is needed to meet the cash payment, pending receipt of funds from customers. This represents a working cash requirement that we include in rate base. If the cash payment for an expense is not made until the cash to make that payment is received from customers, there is a zero working cash requirement. Finally, if the cash payment for an expense is made after the cash to make the payment is received from customers, there is a negative cash working cash requirement. This working cash requirement, even though negative, is still part of the rate base calculation and reduces rate base. It is the combination of positive and negative cash working capital requirements that eventually determines whether the Commission will allow a positive or negative working cash increment in rate base.

There is a large difference between the cash working capital component of rate base as proposed by the Companies and the recommendations of the Staff and CAD. The rate base filed by the Companies included a cash working capital component of $30.4 million. The Staff cash working capital component of rate base was a negative $28.8 million. The CAD proposed a cash working capital component of negative $14.7 million, but indicated that it believed that its adjustment was understated and that the negative cash working capital should be greater than the negative $14.7 million included in the CAD proposed rate base. The difference in cash working capital related to the lead/lag studies that were used by the parties. By far, the biggest area of disagreement involved the determination of the lag time calculated between the service date related to utility property tax payments and the actual cash payments made to the State.

The Staff determined that the tax related to service provided in a calendar year would be paid in two installments with the first installment not being due until September 1, two years following the end of the calendar year. As an example, Staff testified that "for the tax year of 2008, the utilities first half payment will be due on September 1, 2010, and the second half payment will not be due until March 1, 2011." We agree with the Staff evaluation of the lag between an annual service period and the payment of the property tax related to that annual period.

Although the Companies offered rebuttal to the Staff position, we find that the rebuttal actually supports the Staff treatment of property taxes in its lead/lag study. The timeline Mr. Pyle attached to his testimony shows that a tax return covering property in service in 2009 is filed in early 2010. MAP No. 1, Direct Testimony of Mark A. Pyle and MAP No. 3 attached to that testimony. Although it shows a number of intervening steps, including the date for the tax value determination by the State, the lien date, and the dates that accrued tax liabilities are recorded on the books, the Exhibit clearly shows that the first cash payment is made immediately before September 1, 2011. Assuming an August 31 payment date, this is 607 days after the end of the 2009 calendar year, which is the payment lag used by the Staff in its lead/lag study. The second payment is made six months later, which is also consistent with the Staff calculations.

There are several other differences between the cash working calculations made by the Companies and the Staff and CAD. The Companies included non-cash items such as depreciation expense and return on equity in their calculation of cash working capital. The Staff and CAD excluded these non-cash items. The Commission agrees with the Staff and CAD treatment.

The non-cash items do not fit into the cash working capital formula used by the Commission and should, therefore, be excluded. By including depreciation in its cash working capital calculation, the Companies have overstated their requested rate base by $10 million. By including the total return on equity and an assumed zero payment lag for this item, the Companies have overstated rate base by $6.3 million. We note that, although we do not consider the total return on equity as a cash working capital component, we have, in the past, considered including dividends in the cash working capital increment calculation. The lead/lag study applied to common dividends normally shows a payment lag in excess of the revenue receipt lag because common dividends are usually paid quarterly and usually fifteen days, or more, after the end of the quarter. Thus, the payment of dividends will usually lag behind receipt of cash from customers to pay those dividends. It is likely that if the Companies had not made their erroneous total return on equity working cash calculation, and they or any other party had calculated a cash working capital requirement related to common dividends, there would have been an additional offset to rate base, not reflected in any of the data before the Commission and we would arrive at a cash working capital component even less than the Staff recommendation.

As a final, but minor, issue, the Companies argue that average bank balances that must be maintained should be factored into the working capital component of rate base. We find that the Companies made a reasonable argument in support of including these balances in rate base. The Companies' rebuttal states that:

> Because the Companies' CWC studies have reflected check float as a reduction of cash working capital, the actual bank cash balances must be included in CWC in order to recognize the financing costs associated with this asset. Since the Companies cannot control when checks will clear through the banking system, and given the various minimum balance requirements imposed by banks, the Companies must maintain certain levels of available cash in their bank accounts.

We do not find that any and all bank balances should be included in the working capital component of rate base. The balances should be small and should not be interest bearing, or, if they do bear interest, offsets to the revenue requirements to reflect the interest earned would have to be made. The level of oversight that must be taken to assure that a utility is not receiving a regulated rate of return of excessive or unnecessary bank balances makes this a questionable item to include in rate base. For the purpose of this case, we find that the balances are reasonably small, the Companies have supported the inclusion of $400,000 for average cash bank balances in rate base and exclusion of these balances from rate base has not been sufficiently supported by Staff.

We do not agree with the other objections of the Companies to the cash working capital calculations made by Staff and we adopt the Staff-recommended cash working capital component except for the inclusion of an additional $400,000 for average bank balances.

VIII. OPERATION AND MAINTENANCE EXPENSES

A. Non-ENEC Generation Expenses

The Companies made a going-level adjustment of $1,483,511 to West Virginia jurisdictional costs to increase test year non-ENEC generation O&M expenses to a three-year, inflation-adjusted average cost. The description of the adjustments states that it is unrelated to the Amos and Mountaineer Scrubber projects or the Mountaineer Carbon Capture and Storage Project. Staff opposed the adjustment, stating that it creates a mismatch between revenue units and expense units of the test year.

The Companies have provided no evidence supporting their adjustment, other than to show that an inflation-adjusted three-year average of O&M expenses for the categories they chose to adjust with their going-level adjustment number 13 is higher than the test year level of expenses. The math that compares an inflation-adjusted three-year average to the test year level of expenses is not evidence that the resulting average is proper for setting rates for the future. We have not accepted general going-level adjustments that simply assume that inflation was an appropriate basis for making going-level adjustments to expenses. We have also not accepted a general going-level adjustment based on an average of costs unless it can be demonstrated that the test year level is not representative of the level of expenses that is expected in the future. We agree with Staff that such an adjustment requires careful consideration of the relationship between revenue units, expense units that are being adjusted, and other average expense and rate base items that make up the totality of the test year revenues, expenses and capital-related costs. The Companies have not provided any such analyses or justification for the proposed adjustment. We will not allow the adjustment for determining going-level expenses.

B. Estimated 2010 PJM Expenses

The Companies proposed an adjustment of $10.8 million to reflect a going-level of certain expenses incurred related to their transactions with PJM. The Companies also proposed a tracking mechanism whereby the PJM costs could be adjusted through a surcharge mechanism rather than being an issue for revenue requirement in a base rate case. Staff made a similar adjustment, but for a lesser amount of $10.1 million. Staff did not initially address the surcharge mechanism, but later supported the CAD opposition to the surcharge. The CAD did not address the adjustment, but opposed the surcharge mechanism.

In its rebuttal, the Companies suggested that the issue of the appropriate level of the PJM charges should be considered as part of the ENEC proceeding. Other parties seemed satisfied with that suggestion.

The Commission notes that there is some confusing testimony filed by CAD indicating that somehow the Companies intend to remove internal transmission revenue requirements from the ratemaking jurisdiction of the Commission and transfer that authority to the Federal Regulatory Energy Commission (FERC). The CAD saw the surcharge mechanism as part of that attempt.

The Commission establishes rates for West Virginia retail customers based on fully-integrated production, transmission and distribution revenue requirements as established by this Commission. Included in those revenue requirements are the costs for internally-generated power supply from the APCo plants, purchased power, credits for sales to affiliates and non-affiliates, internal transmission and distribution costs on lines owned by APCo/WPCo, and net purchased and sold transmission from affiliates and non-affiliates. Even though we have moved consideration of some elements of power supply costs and transmission credits to the ENEC proceedings, we have never ceded our jurisdiction over rates to retail customers to the FERC. The Commission will not allow

APCo/WPCo transmission expense for use of their own lines to provide retail service flowing through PJM transactions to be used to circumvent Commission authority over retail rates. To the extent such transmission costs, less transmission revenue are related to use of the transmission system of APCo/WPCo for serving retail load, we will not allow net transmission costs for the retail customers to exceed our determination regarding the level of transmission costs reasonably necessary to serve retail load.

We will allow the PJM cost issue to be transferred to the ENEC proceedings. We believe that, unlike an automatic surcharge mechanism, the Commission will have the opportunity to review the effects of the PJM charges and credits in each ENEC proceeding. Based on that review, the Commission will make whatever adjustments are necessary to assure that the generation costs related to the provision of retail service reflect only the transmission-related revenue requirement components that are consistent with the rate base, rate of return, and operating cost decisions made by the Commission in base rate cases.

C. Uncollectibles

The Companies proposed an adjustment of $116,554 to reflect actual account balances written off during the test year. The Staff adjusted for uncollectibles using a three-year weighted average of actual net write offs compared to revenue to arrive at a rate for uncollectibles that could be applied to going-level and proforma revenues. We agree with the Staff approach. The Commission has determined in the past that for ratemaking purposes, the use of a three-year average is appropriate when there are fluctuations that occur between the years as long as the average is developed and represented as a ratio or percentage rate, relative to revenue levels. The use of an average rate for uncollectibles will normalize the peaks and valleys that occur over time while still maintaining the relationship between revenue levels and expense levels.

D. Amortization of Extraordinary Storm-Related Costs

The Companies proposed an adjustment of $4.6 million to amortize for ratemaking purposes the extraordinary maintenance expenses they experienced because of the winter storm that began in December 2009. The Companies later, in their rebuttal testimony, corrected an error in their original estimates of the extraordinary costs that resulted in a decrease in the annual amount they requested be built into their revenue requirements.

We discussed the treatment of the unrecovered extraordinary costs above in the rate base section of the Order. Staff proposed that we determine an average of extraordinary storm-related costs over a ten-year period and include that average level in rates in this proceeding. Because the costs experienced in 2009 were so extraordinary, the Staff determination of a ten-year average of similar extraordinary costs is the equivalent of simply taking one-tenth of the 2009 costs. The Commission will adopt the Staff approach, but use a shortened time frame. The increment that we will allow is based on one-seventh of the extraordinary costs, as corrected by the Companies in their rebuttal testimony.

E. Costs of Carbon Capture and Storage Demonstration Project

The Commission first examined the issue of a possible treatment of carbon dioxide (CO_2) emissions through the use of Carbon Capture and Storage (CCS) in Appalachian Power Company d/b/a American Electric Power, Case No. 06-0033-E-CN (Order dated March 6, 2008) (IGCC Order). That case involved an Application by APCo to construct a 629 megawatt (MW) Integrated Gasification Combined Cycle (IGCC) power plant at APCo's Mountaineer power plant site near New Haven, Mason County, West Virginia, on a 70-acre tract of land owned by APCo. The IGCC plant was designed, and the certificate was sought, to increase APCo's base generating capacity.

As a part of the discussion of the Certificate of Convenience and Necessity (CCN) Application, the parties addressed extensively the appropriateness and the necessity for including within that Application (and the Order of the Commission) a specific provision for treating CO_2 through the use of CCS. We will not repeat here all of the arguments and evidence presented in the case. Suffice it to say that the CAD argued that APCo should include within the IGCC plant design equipment to make the IGCC plant carbon capture ready and estimated that the CCS equipment would cost between $80 million and $200 million. APCo on the other hand, argued that the CCS technology was not currently technologically feasible, that CO_2 legislation and regulation could significantly change the cost of IGCC, that the development of CO_2 technology is ongoing and evolving, and that the Commission should instead approve APCo's plan to "leave space" to retrofit the plant for CCS technology.

The Commission approved the proposed construction of the IGCC, subject to a list of conditions set forth in the IGCC Order (IGCC Order) at 83, including reconciling any differences between the IGCC Order and an Order of the VSCC, which had been asked to approve and absorb a 50 percent funding of the IGCC plant. In its conclusions of law in the IGCC Order, this Commission stated that the IGCC plant was a clean coal facility within the meaning of W.Va. Code §24-2-1g. The Commission, however, as to carbon capture specifically held:

> 14. Based on expected cost, developing technologies, and likely reduced Plant output among other factors, the Commission concludes that retrofitting the Plant for carbon capture would be a major modification of the certificated Project and APCo must first obtain a certificate of convenience and necessity for that work.

IGCC Order at 79.

After the entry of the IGCC Order, the VSCC, in Case No. PUE-2007-00068 (Order dated April 14, 2008), disapproved the necessary funding contribution by Virginia to the construction of the IGCC plant, and although the matter remained open on this Commission's docket under a Petition for Rehearing request filed by APCo, we ultimately dismissed the case by Order dated May 29, 2008.

There was no separate filing, either during or following the IGCC proceeding, seeking approval for the construction and installation of the CCS facility at the Mountaineer plant nor has that facility been the subject of a CCN proceeding or a request for a rate increase from this Commission, until now. In this case, APCo, Staff and CAD included both the cost to date of expenditures for the construction of a CCS facility at the Mountaineer Plant and some operating costs for the CCS facility at the Mountaineer Plant in its requested revenue allowance in this case. WVEUG, on the other hand, urged that the Commission disallow those costs. In our review of this issue, we are troubled. Those costs and expenses are <u>not</u> insignificant. In this case, APCo has requested a number of adjustments to reflect additional rate base above the average test year amount for the CCS facility. It has also requested going-level depreciation expenses and going-level operating expenses for the CCS facilities. On a net basis, APCo included a West Virginia jurisdictional CCS rate base of $30.9 million in its filing. It also included $4.3 million in depreciation expense and $6 million for operating expenses for CCS on a West Virginia jurisdictional basis.

The Commission is sympathetic to the efforts of APCo to perfect and further develop CCS technology and recent developments regarding nuclear generation and other alternatives to coal-fired generation have not diminished the attractiveness of CCS. The simple fact is, however, that APCo has proceeded to develop its CCS project at the Mountaineer Plant without further input or authorization from the Commission. It has characterized its current CCS efforts at Mountaineer as "Project Title: Mountaineer Carbon Dioxide Capture and Storage Demonstration" (see below).

Based on current development of CCS at the Mountaineer Plant, it is clear that the costs for CCS are significant. Recent estimates for the cost of carbon capture at the Mountaineer Plant vary in range from $400 million to $600 million for partial CCS at Mountaineer, based on information in a recent Department of Energy release that indicated:

- **American Electric Power Company, Inc. (Columbus, OH):** *Project Title: Mountaineer Carbon Dioxide Capture and Storage Demonstration.* American Electric Power (AEP) will design, construct and operate a chilled ammonia process that is expected to effectively capture at least 90 percent of the CO_2 (1.5 million metric tons per year) in a 235 megawatt flue gas stream at the existing 1,300 megawatt Appalachian Power Company (APCo) Mountaineer Power Plant near New Haven, WV. The captured CO_2 will be treated, compressed, and then transported by pipeline to proposed injection sites located near the capture facility. During the operation phase, AEP plans to permanently store the entire amount of captured CO_2 in two separate saline formations located approximately 1.5 miles below the surface. The project team includes AEP, APCo, Schlumberger Carbon Services, Battelle Memorial Institute, CONSOL Energy, Alstom, and an advisory team of geologic experts. (DOE share: $334 million; project duration: ten years).

See, http://www.energy.gov/8356.htm.

We are troubled by the inclusion of the CCS capital costs and operating expenses in the cost of service applicable to the West Virginia ratepayers for a number of reasons. First, as discussed by APCo/WPCo in its case, the VSCC, in a recent APCo rate case before that body in Case No. PUE-2009-00030, disallowed the recovery of all CCS costs and expenses. In fairness, in reviewing the VSCC's order, it might be argued that the VSCC might have considered allowing some of the expenses if it had been allocated in some fashion other than including 50 percent of the **total** CCS cost to Virginia and 50 percent of the **total** cost to West Virginia. See, VSCC Order at 20. Also, refer to the testimony of Charles Patton at the December 15, 2010 evidentiary hearing discussing the Virginia Commission ruling. Tr. 12/15/11 at 74, 75.

APCo has seen fit to pursue this CCS project at the Mountaineer Plant and seeks full recovery from the West Virginia ratepayers. We are concerned about the future of CCS and the enormous potential that it might hold for West Virginia and our natural resources. Given all of that, and given the "pilot project" nature of the CCS project to date, we believe that a fair treatment of the capital and operating expenses is to allow a portion of the operating expenses, but to exclude amounts booked in Account 103, "Experimental Electric Plant" from rate base.

Account 103 provides for plant constructed as a research, development or demonstration plant which is being operated for a period of time in an experimental status. This seems to describe the present status of the CCS facility. However, Account 183, Preliminary Survey and Investigations, is charged with expenditures for "preliminary investigations, etc., made for the purpose of determining the feasibility of utility projects under contemplation." Account 183 also provides that if construction results from the preliminary investigation, the amounts booked in Account 183 will be charged to the "appropriate utility plant account."

At this point, we believe that the CCS investment is somewhere between Account 183 and Account 103. We believe that the operation of the plant is experimental as described in Account 103. However, we believe that this experimental operation is being used solely as a mechanism to gather information in contemplation of expanding the CCS beyond the demonstration phase. If this experiment results in construction, as described in Account 183, than it would be appropriate to book the CCS investment to the "appropriate utility plant account."

We do not include Account 183 in rate base, and given the circumstances of the Carbon Capture and Storage demonstration project, we will not include it in APCO/WPCo's rate base. We consider the project as a continuing preliminary investigation. In the future, we may consider it as used and useful plant in service and include it in rate base. Any such inclusion, however, would be considered only for a reasonable share allocable to APCo and APCo's West Virginia jurisdictional operations. We believe that all AEP companies should be sharing in the cost of this facility rather than it being the responsibility of only APCo, simply because it happens to be a 100 percent owner of the plant that was chosen by AEP for the demonstration project.

We do not, however, wish to accumulate operating costs, which may dwarf the actual investment in the CCS demonstration project, in Account 108. Inasmuch as the CCS project is operating at a nominal level and is in fact sequestering some of the CO_2 from the Mountaineer Plant, we are willing to allow a proportionate share of those expenses to be included in operating expenses in this case. To be fair, as discussed above, we believe that this operating cost also needs to be shared among all AEP operating companies. We do not agree with the recommendation of WVEUG that a 21 percent allocator for APCo/WPCo is reasonable. We prefer to allocate the cost based on the relative load of APCo/WPCo to the total AEP load. We realize that this allocation could be done on a peak load basis, or a total load basis. Either method could be argued to be reasonable. More importantly, the allocation could be made for all AEP operating companies or only the AEP-East operating companies. For purposes of this case, we will accept an allocated share for APCO/WPCo based on their average coincidental peak load relative to the sum of the total coincidental peak loads of the AEP-East operating companies. We will consider alternatives to this allocation approach in the future, but only on a prospective basis. Because the peak load information is not a part of the record in this case, we take administrative note of coincidental peak load data filed in the recent Transmission Equalization Case at the FERC. American Electric Power Service Corporation, Case No. ER-09-1279. In that case, AEP provided exhibits that reflected the coincidental peak loads of the AEP-East companies, for an extended period of time. The reasonable average allocator for APCo/WPCo based on that data is 32 percent. Therefore, we will use an allocator of 32 percent to determine a fair share of the operating costs of the CCS facilities to include in the revenue requirements for the Companies in this case.

We recognize that a sharing of the CCS cost among AEP operating companies is not something that this Commission can mandate. Our jurisdiction is limited to the cost recovery question, and we have resolved that by concluding that only a proportionate share of the CCS costs should be borne by APCo/WPCo. Cooperation between AEP operating companies, and cooperation among the various State Regulatory Commissions is needed if a fair sharing of the CCS costs is to be accomplished. We believe this can, and should, be done.

We note that this issue is not dissimilar from the issues that arose over twenty years ago with regard to compliance with the federal Clean Air Act Amendments of 1990 (CAAA). At that time, there was discussion about system-wide compliance within a large utility holding company system, like AEP, how alternative compliance plans could result in different cost responsibilities within the holding company system, appropriate sharing of compliance costs and sharing of the sulfur emissions credits that were an integral part of the CAAA sulfur emission reduction requirements. While for AEP the operating agreement in place provided for some cost sharing depending on the compliance choices, there was no provision for sharing of the emission credits. A major issue developed at that time regarding scrubber installation versus shifting to low sulfur coal at the Gavin Plant of Ohio Power Company. West Virginia had an interest in that decision because APCo shared in the capital cost of the Gavin plant, but there was no provision for sharing of credits that would be obtained if the scrubber alternative was chosen. The importance of AEP recognition of the fairness of sharing both costs and credits, as well as cooperation and dialogue between states, was evident. The National Regulatory Research Institute issued a report on CAAA compliance that, among other things addressed the need for this cooperation.[8] The result of the dialogue between AEP, and the AEP State Commission at that time was a joint agreement regarding compliance and appropriate sharing of the sulfur credits created by installing scrubbers on Gavin, and other AEP power plants.

We have revisited the Clean Air Act Amendments of 1990 to point out that large multi-state holding companies have had "sharing" issues in the past and they were worked out cooperatively. We believe that a reasonable sharing of the CCS investment and operating costs likewise can, and should, be worked out.

F. Executive Compensation

The issues of payroll and payroll-related costs for APCo and its affiliates and parent are a flash point of contention and have received considerable scrutiny and public comment. Before discussing the specifics of those issues, the Commission wishes to make clear its concern with the magnitude and the continuing escalation of these payroll

[8] The [Ohio] Commission has been active with periodic meetings with other state commissions that regulate operating companies of American Electric Power (AEP). The Commission has been trying to at least have open lines of communication with respect to the implication of the Act and believes that even if some general agreement on how AEP should be treated relative to its compliance cannot be reached, that at least having these lines of communication open and active is likely to improve the process. NRRI 92-17, "Regulatory Policy Issues and the Clean Air Act: An Interim Report on the State Implementation Workshops, the National Regulatory Research Institute," August 1992.

costs that the Companies ask the Commission to include in cost of service and to pass to West Virginia customers.

There may be a question about whether, or to what extent, the Commission can limit the payroll increases that the Companies and their affiliates pay to their employees. There is not, however, any question that the Commission can and must exclude those increases from revenue requirement if the Commission finds that the increases are unfair or unreasonable under current conditions.

West Virginia has not been immune to the unemployment and under-employment conditions that mark the economy throughout the country. In fact, the work force of this State is frequently the first to feel the effects of recession and the last to recover. Many West Virginia families are faced with the burden of escalating household expenses while attempting to hold families together in the face of reduced household incomes, incomes that are frequently augmented by limited, stagnant or declining government support programs. Some of these families and individuals are unemployed, and those that are fortunate enough to have a job that provides reduced compensation, with little or no benefits, as compared to jobs that they may have held in the past. It is in this context that the Commission has been asked to approve additional annual pay raises, annual cash bonus compensation, stock bonuses to highly-paid senior officials, and annual escalations in the cost of benefits to utility employees, often related to the increases in pay and bonuses.

In considering the payroll adjustments, we are not disallowing or removing all prior pay increases from the payroll base for purposes of calculating the level of payroll and related adjustments to include in the case. We are, however, imposing a very watchful eye on the amount to be included as an adjustment in this case for current additions to that payroll and have specifically approved the Staff approach that disallows all parent company and affiliated bonuses flowing to APCo/WPCo.[9]

G. Non-executive Bonuses, Payroll and Severance

The issue of bonuses to non-executive employees of APCo/WPCo (direct bonuses) was addressed at length by all parties. As discussed above, we are disallowing all parent

9 This Commission is mindful of the public comments at hearing regarding executive pay and salary increases in the current economic climate. Consistent with the Order entered in Hope Gas, Inc., dba Dominion Hope, Case No. 08-1783-G-42T, November 30, 2009, in which the Commission allowed incentive compensation for direct Hope employees, but disallowed expenses related to affiliated service company charges for incentive compensation and non-officer earnings-related bonuses, the Commission adjustment to the APCo/WPCo request is based on recognition that utility employee salary increases and bonuses, to a certain extent, are not justifiable "in the midst of protracted economic turmoil," as stated in the Hope case. Id. at 36.

company and affiliated bonuses. We find that some limitation on the level of non-executive direct bonuses allowed for ratemaking purposes is reasonable and necessary.

We realize utility employees are concerned about their financial futures, and we have nothing in the record to suggest that these employees do not work hard at their jobs. We do, however, believe that West Virginia rate payers cannot be called upon to support ever increasing salaries, wages, bonuses, and benefit packages when it appears to the Commission that utility management is unable or unwilling to exercise substantial and significant restraint.

Other than the 2005 Rate Case (Case No. 05-1278-E-PC-PW-42T) that resulted in a decrease in APCo's base rates, this is the first base rate increase request from the APCo since 1993. To some extent, much of the publicity about high salaries and bonuses being paid to senior management, while attention getting, is not accurate. The simple fact is that much of the increase in compensation has not been included in the APCo/WPCo revenue requirements in a rate case adjudicated by this Commission. That does not mean, however, that APCo has not awarded its employees a rather generous array of pay and benefit increases since the last rate case which it then seeks to embed in this case, along with a further increase to those pay and benefit allowances.

The Commission hopes and expects those difficult financial times will pass and wants to make it clear that it is not denigrating the good work that utility employees perform. We are suggesting, however, that during these difficult times in our State, APCo must not expect the ratepayers to support annual pay increases and bonuses at the rate they have received in the past when ratepayers are suffering financial hardships. Some belt-tightening is appropriate. The direct non-executive bonuses should not be allowed for ratemaking purposes at the levels requested by the Companies. We will allow one-half of the requested non-executive direct bonuses.

Staff agreed with the methodology used by Companies to annualize base payroll for employees of APCo/WPCo (referred to herein as "direct" costs) but did not agree with the final adjustment. The major difference between the Companies' adjustment and the Staff is that Staff utilized a more current time period reflecting major changes in employment because of significant work force reductions that took place in 2010. The Companies made no adjustment for the severance of employees but instead proposed a modest upward adjustment for direct payroll expenses of $368,172. Staff, however, proposed a significant decrease for direct payroll expense, $4,662,708. Sprinkle, TDS-D at 5, 6. There were also differences between the Companies' adjustments and Staff relating to projected direct pay increases, projected direct overtime pay, and projected direct health insurance costs. Sprinkle, TDS-D at 6-10.

CAD also recommended similar decreases to going-level payroll because of the reduction in the number of employees. The CAD downward adjustment to the requested direct payroll was $5 million and the downward adjustment to payroll-related employee savings plan contributions was $246,000. White, CAD 4, Direct Testimony at 2-9 and Ex. DLW-2 attached to the testimony.

The work force reductions that took place in direct employee levels for APCo/WPCo also affected employment levels of affiliates which, in turn, affected the Staff calculation of going-level charges from affiliated, mostly AEP Service Corporation (AEPSC). Staff calculated significantly lower going-level costs from affiliates than those requested by the Companies. Staff recommended that the Commission reduce the going-level cost of affiliate labor by $3,354,614. Sprinkle, TDS-D at 10, 11.

For purposes of assessing the Joint Stipulation, the Commission will adopt the recommendations of the Staff and CAD to reflect the effect of work force reductions on going-level payroll costs.

As an offset to its adjustment to reflect lower going level payroll, the CAD proposed an upward adjustment to expenses of $2.4 million on a West Virginia jurisdictional basis to provide for one-fourth of the projected costs of severance packages offered to APCo and WPCo employees ("direct severance costs"). Staff did not make a similar adjustment and did not address the post-test year severance costs that might be incurred by the Companies.

The Companies did not object to the suggested allowance of one-fourth of projected severance costs; however, they did rebut the underlying amounts included in the CAD calculation. The Companies argued that the CAD erred by not including involuntary severance costs in the calculation. The total amount of the involuntary severance costs presented in the rebuttal testimony was $1.2 million to total APCo before allocation to West Virginia jurisdictional operations. The Companies also objected to the CAD calculation that assumed that a portion of the severance costs should be capitalized. The Companies testified that capitalization of severance costs is prohibited by Statement of Financial Accounting Standards (SFAS) 88. Finally, the Companies argued that the CAD had not properly allocated the test year severance costs between West Virginia and Virginia in its adjustment. Overall, the Companies provided calculations in their rebuttal showing that with their modifications to the CAD calculation, the $2.4 million CAD addition to expenses for severance costs should be $3.9 million.

The Companies also argued that there were severance costs granted to AEP Service Company employees after the test year (AEPSC severance costs). They objected to the Staff going-level payroll adjustment because it did not include an offset to reflect any allowance for severance costs paid to Service Corporation employees. They claimed that the West Virginia jurisdictional share of severance costs billed from AEPSC was $9.4 million.

The Commission notes that both of these adjustments are difficult to evaluate because of the timing and manner they were presented in the case. These costs are non-recurring in nature and would normally be excluded from going-level ongoing expenses. However, because it appears that the test year contains only a *de minimis* level of severance costs, it is not necessary to make a downward adjustment to exclude them as non-recurring costs. The question is whether it is reasonable to go outside the test year to pick up a non-recurring cost and then allow some portion of that cost as an adjustment to revenue requirements in this case. The Companies now propose to add $3.9 million for an amortized portion of direct severance costs in this case, even though they did not make such an adjustment at the time of their original filing. Unlike other late-filed adjustments this particular adjustment is responsive to direct testimony filed by the CAD and rebuts the calculation made by the CAD in its direct case. We are inclined to consider, and allow, some adjustment for direct severance costs. The AEPSC severance costs present a different problem. An adjustment for these costs was not originally requested by the Companies and the amount of record evidence supporting the AEPSC severance costs is limited, at best. This makes our evaluation of the reasonableness of the AEPSC severance costs more problematic than direct severance costs. In fact, we do not even have any indication in the record whether any of these severance costs were incurred in the test year or whether they are entirely post-test year costs. Nevertheless, it is necessary to address and resolve the issue of both direct and AEPSC severance costs.

We do not agree with the Companies that capitalization of severance costs is prohibited by SFAS 88. It may not make any sense to capitalize severance costs and, instead it may be reasonable to expense all severance costs, but not for the reasons given by the Companies. Severance costs do not represent payroll related to current services performed. They represent, instead, costs for employees to cease working. As such, it may be difficult to quantify what, if any, portion of severance costs should be capitalized. However, to the extent that it is difficult to assign severance costs to plant or expense accounts, it is equally difficult to determine why severance costs should be associated with production, transmission, distribution or administrative costs for purposes class cost of service studies or even jurisdictional allocations. The CAD and Companies appear to have solved this later question by assuming an allocation based on an average functional assignment of severance costs and, therefore, an average jurisdictional allocation factor. This may be reasonable, but it may also have been reasonable to assume a similar average functional assignment between plant and expense accounts for purposes of capitalizing some portion of the severance costs, which is effectively what the CAD did. As we have indicated, we are not sure that it makes any sense to capitalize severance costs, but that was proposed by the CAD and was not reasonably rebutted by the Companies.

We have a bigger problem with the AEPSC severance costs because the record is void of any evidence on how severance costs, paid to employees for not working, were assigned to APCo and WPCo. We could assume that a broad general allocator that fairly assigned the costs among all of the operating utility companies and other subsidiaries of

AEP was used, but that is not an assumption that is supported by any evidence in the record.

We believe that it is reasonable to allow some portion of the severance costs in revenue requirements in this case. We do not believe that a four-year amortization is reasonable for two reasons. First, an amortization assumes a finding of reasonableness of a cost that can then be recovered over some specified amortization period. We cannot determine that the total amounts quantified by the Companies in their rebuttal are reasonable. Second, even if we could determine a reasonable level of costs for future recovery, we believe that a four-year recovery period is too short. We find that it is reasonable to allow $2.1 million in revenue requirements in this proceeding. Compared to the original CAD total direct severance cost recommendation, $2.1 million represents a 4.7 year recovery period. Compared to the Companies rebuttal for direct severance costs, $2.1 million represents a 7.4 year recovery period. We consider one-seventh of the severance costs to be a more reasonable allowance in this case than the one-fourth recommended by the CAD. If we ultimately determine that all of the AEPSC severance costs referenced in the Companies' rebuttal are reasonable and should have been included in our allowance, than the annual $2.1 million may represent a recovery period of as much as twelve years.

We are not finding at this time that any particular level of severance costs represents a reasonable and prudent expense allocable to West Virginia jurisdictional operations. We will consider that issue in a future proceeding if the Companies file a rate case and include a request for a severance cost allowance in that case. We believe that the fair answer, as supported by the CAD evidence and the limited evidence presented by the Companies is higher than the original recommendation of the CAD, and we do not believe that a $2.1 million allowance is unreasonable for purposes of setting an annual revenue requirement in this case.

H. AEP Stock-Based Bonuses and Supplemental Executive Retirement Bonuses

The Staff and CAD proposed a number of going-level adjustments to Supplemental Executive Retirement Plan (SERP) costs, AEP Service Corporation long-term incentive bonuses and certain other executive compensation from Operation and Maintenance Expenses. The total adjustments proposed by Staff reduced O&M expenses by $2,833,000 and the total reduction proposed by the CAD was $2,771,000. The Companies opposed these adjustments.

While the Companies may be correct when they argue that supplemental retirement adders and long-term incentive bonuses are highly prevalent and substantial components of a market competitive compensation program, we do not agree that these costs should be passed on to ratepayers. If the Human Resources Committee believes that it is necessary to pay long-term incentive bonuses, and provide for supplemental executive retirement, it should do so recognizing that the costs may be paid for by stockholders, not ratepayers.

The level of executive compensation at AEP has been widely and publicly discussed and the Commission believes that there needs to be some clarification of that compensation (and indirectly that discussion). The total executive compensation package to the Chief Executive Officer of AEP exceeded $7 million in 2009. None of that compensation has yet been included in the APCo/WPCo rates although a significant portion of it is within the test year. Approximately $5.8 million of this number was for bonuses and compensation other than base salary. The total of the bonuses and supplemental compensation for all the top level executives of AEP was significantly higher than $7 million.

We have decided that it is appropriate to exclude all top executive bonuses and supplemental compensation, including that of the CEO, from expenses in this case because of the magnitude of that compensation and our belief that level of compensation, particularly given current economic conditions, is unreasonable. We also feel, however, that it is important to explain why our adjustment for the ratepayers of APCo/WPCo is significantly less than the total compensation of the entire group of top executives, or even that of the CEO alone. This is a matter that is not fully explained in the public discourse on "excessive executive compensation." The fact of the matter is that much of the bonuses and supplemental compensation are not allocated to APCo/WPCo.

If we examine this allocation, ratepayers can get a better feel for the level of that compensation. To determine the amount of the adjustment to West Virginia jurisdictional expenses and test the reasonableness of the adjustments proposed by the CAD and Staff, we must consider how the total AEP costs are allocated among seven operating companies in AEP-East, four operating companies in AEP-West and other AEP subsidiaries. Although the allocation of various categories of cost varies, APCo/WPCo generally are allocated only about 20 percent of AEP Service Corporation costs, including executive pay. West Virginia and Virginia then share in that APCo/WPCo portion of those costs with about 45 percent being allocated to West Virginia. In other words, only about 9 percent (45 percent of 20 percent) of the total AEP executive base compensation, bonuses and supplemental compensation is actually included in the expenses of APCo/WPCo. While we have not excluded the base salary level of top executives, those salaries are a small share of the total executive compensation, and the smaller base salary level allocated to West Virginia represents only about 9 percent of the total amounts paid.

Based on the average 9 percent allocator, the CEO bonus and supplemental compensation of $5.8 million charged to expenses of APCo/WPCo in the test year would have been approximately $522,000. This amount is disallowed for ratemaking purposes in this Order, and no portion is included in rates to be paid by West Virginia customers. As discussed above, the total adjustment to disallow executive bonuses and supplemental compensation that we are adopting in this case equals over $2.8 million. This adjustment reflects the disallowance of the CEO bonus and supplemental compensation along with that of all top executives of AEP.

I. Employee Medical Insurance and Other Payroll-Related Benefits

Staff and CAD proposed a number of adjustments to reduce payroll-related costs, mostly because of their recommendations regarding a lower level of going-level payroll. The most significant of these downward adjustments was for employee medical insurance, where the Staff variance from the Companies was approximately $1.3 million.

The Commission finds that the proposed payroll-related adjustments made by the Staff and CAD that reflect the change in work force and payroll costs at going-level are reasonable and shall be adopted in the final revenue requirements calculation approved herein.

J. Income Taxes

1. Effective Income Tax Rate

Staff proposed an effective federal income tax rate of 16.8 percent. CAD proposed an effective federal income tax rate of 27 percent. Staff derived its recommended effective rate using a five-year average of the years 2005 through 2009 and including the losses of all members of the consolidated group. The CAD also used a five-year average, but used the years 2004 through 2008. CAD also adopted adjustments to the 2004 tax calculation to eliminate the effect of a large AEP tax loss related to the disposition of a generation unit in the United Kingdom. See Pyle, Nov. MAP No. 1, Rebuttal Testimony at 4. The CAD calculation did not include 2009 which was the year that a large tax loss was incurred related to a tax accounting change related to the use of different units of property for tax purposed versus book purposes to determine whether new plant should be capitalized or expensed.

The Companies opposed the Staff calculation for a number of reasons. The Companies did not agree with the use of loss companies other than the parent company for purposes of deriving a consolidated tax savings or effective tax rate. The Companies argued that the Commission had rejected the use of loss companies, other than the parent company, in the last contested Appalachian Power Company base rate case in 1991. The Companies also disagreed with the calculation of a large negative effective tax rate in 2009 that was related to the tax accounting change for units of property. Although the Companies did not agree with the use of an effective tax rate that included loss companies other than the parent, they did provide a calculation of an alternative to the Staff numbers that excluded the 2009 tax loss related to the units of property tax accounting change.

The effective federal income tax rate as presented by the CAD, Staff, and Companies (not agreed-upon but presented as an alternative but only for the years 2004 through 2009) are:

	Effective Federal Income Tax Rate				
	2005	**2006**	**2007**	**2008**	**2009**
Companies	28.7%	25.1%	30.7%	27.3%	18.4%
CAD	28.7%	25.1%	30.7%	27.2%	
Staff	27.9%	26.4%	30.7%	26.9%	-27.8%

The Commission has, for many years, adopted the use of a consolidated tax rate to reflect the effective income tax rates for companies that file as part of a consolidated group. The Commission has explained its reasoning and refined its methodology in a number of cases since the 1991 APCo rate case. The Companies are correct that the present methodology of the Commission is different than that used in 1991 for APCo. After the 1991 APCo Case, the Commission considered the effective tax rate issue and reconsidered the use of loss companies other than the parent company to calculate an effective income tax rate. In both Mountaineer Gas Company, Case No. 93-0005-G-42T and Hope Gas, Inc., Case No. 93-0004-G-42T, the Commission stated a preference for calculating the consolidated tax savings by including the losses of both the parent and the affiliates within the group. More recently, the Commission has addressed its reasoning, legal authority, and justification for its effective federal income tax rate methodology in Monongahela Power Company, Case No. 06-0960-E-42T, (Orders dated May 22, 2007, and December 12, 2008); West Virginia-American Water Company, Case No. 08-0900-W-42T (Order dated March 25, 2009); Hope Gas Inc., dba Dominion Hope, Case No. 08-1783-G-42T (Order dated November 20, 2009).

The Companies presented the rebuttal testimony of Robert W. Hriszko, explaining three different federal income tax methodologies. The "stand alone" method was described by Mr. Hriszko as one that disregards the membership of a utility within a consolidated tax group entirely. The parent company loss adjustment (PCLA) method calculates an effective tax rate using only the tax losses of the parent company. The third method described, the method used by the Commission in recent cases and recommended by the Staff and CAD in this case, is described by Mr. Hriszko as the consolidated tax adjustment method (CTA), which includes all loss companies to calculate and effective income tax rate. Mr. Hriszko testified that the CTA method is not appropriate for calculating cost of service for ratemaking purposes because it is arbitrary, inequitable and violates fundamental ratemaking principles. Hriszko, Nov. RWH No. 1, Rebuttal Testimony at 4-7.

The Commission has reviewed all of the evidence, testimony and arguments and considered cases cited by the Companies, various Court decisions on this issue and prior decisions of this Commission. The Commission does not agree that the CTA method is arbitrary, inequitable or violates fundamental ratemaking principles. We have addressed this issue at length in recent cases, and we will not belabor this Order by repeating all of the Commission findings and conclusions in those cases. We will adopt the applicable reasoning and discussions from previous orders herein, and refer specifically to Monongahela Power Company, Case No. 06-0960-E-42T (Orders dated May 22, 2007, and December 12, 2008); West Virginia-American Water Company, Case No. 08-0900-W-42T (Order issued March 25, 2009); Hope Gas Inc., dba Dominion Hope, Case No. 08-1783-G-42T (Order issued November 20, 2009).

The Commission will not depart from the CTA method in this case. We will continue to exclude accelerated depreciation of utility companies from the calculation to be consistent with normalization requirements of the Internal Revenue Service. We also agree with the Companies with regard to the large tax deduction created in 2009 related to a tax accounting change and catch-up of that change reflected in the 2009 taxable income. By excluding the effect of that tax accounting change, the large negative effective tax rate calculated by Staff is eliminated. We do not adopt the methodology chosen by the Companies to normalize the five-year average effective tax rate whereby the Companies arrived at an alternative CTA-based effective tax rate of 26 percent. However, without adopting the exact methodology used by the Companies, considering the range of effective tax rate numbers for various years and the reasonableness of an effective tax rate on a going-forward basis, we determine that the 26 percent rate is a reasonable number to use in this case.

The calculation of an effective income tax rate that reflects not only parent company losses but also losses of other members of the consolidated group is consistent with the decisions made by the Commission in a number of recent cases.

2. Normalization of Additional Deductions to Taxable Income Related to Differences in Units of Property for Book Purposes and Tax Purposes

The determination of when plant should be expensed or capitalized is controlled by an accounting mechanism referred to as "retirement units," or sometimes, "units of property." In describing electric plant accounting and differentiating when work orders should be charged to expense or capitalized, the Uniform System of Accounts for Electric Utilities requires:

> For the purpose of avoiding undue refinement in accounting for additions to and retirements and replacements of electric plant, all property will be considered as consisting of (1) retirement units and (2) minor items of property. Each utility shall maintain a written property units listing for use in accounting for additions and retirements of electric plant and apply the listing consistently.

In 2009, the Companies adopted a different list of property units for purposes of tax accounting than they use for maintaining their regulated books. This gave rise to a temporary timing difference between capitalization of plant additions for tax purposes and book purposes. As has always been the case, the Commission is faced with the question of whether to flow-through the tax effects of these temporary timing differences or normalizing (deferring) them.

Staff agreed that amounts taken as a "catch up provision" related to pre-2009 tax returns should be normalized, but Staff calculated lower current income taxes for ratemaking purposes in this case because it proposed to flow-through the tax benefits of the 2009 difference between book and tax expenses created by the use of different property units for tax and book purposes. Staff explained its tax treatment of this item as follows:

> The Companies have normalized the tax impact associated with a change in the deductibility of costs for repairs and replacements of property. The change which broadened the definition of a unit of property was instituted in 2009 and included a catch up provision applicable to prior years. Staff's tax calculation normalizes the catch up provision for the tax accounting change and reduces Rate Base for the full impact of the associated tax deferral due to the tax deduction taken. Staff recommends and has reflected flow through treatment for the vintage 2009 tax deduction taken by the APCo. The flow through vintage 2009 deduction is $37.4 million and the normalized catch up deduction taken in 2009 is $224.9 million on a total APCo basis or $16.2 and $97.1 million applicable to the West Virginia jurisdiction.

The Companies originally proposed to normalize both the catch up tax effect of this accounting change and the 2009 timing difference. The Companies opposed the proposed flow through of the tax benefit of the 2009 deduction as proposed by Staff. The Companies argued that the deduction they were taking is the equivalent of an acceleration of depreciation. While not arguing that we were required to normalize, they did argue that normalization is preferred because flow-through of the tax benefit creates intergenerational inequities by benefiting current ratepayers at the expense of future ratepayers. The Companies also argued that changing its tax accounting and normalizing the resulting timing differences was a strategy employed to meet cash flow needs and that flow-through of the benefits would defeat the purpose of that strategy.

The Commission is not required to normalize the effects of the timing differences created by the change in accounting for tax capitalization of plant additions. However, we are not precluded by any statutory or ratemaking restrictions from normalizing these timing differences. If we do not normalize, the lower future depreciation expense that the Companies will have for tax purposes will result in higher income taxes that customers will have to pay in the future. If we approve the normalization requested by the Companies, those higher taxes will be offset by the reversal of the timing differences in the future. We note that normalization of the 2009 deduction will increase current income taxes and revenue requirements, but there will be an offset to revenue requirements in the form of a deferred income tax negative rate base component. This deferral will grow so that at some point in the future it will likely fully offset the higher current taxes created by the adoption of a normalization ratemaking approach for this tax deduction.

The Commission will normalize the tax timing difference related to the difference between book and tax property units. We put the Companies on notice that we may or may not continue normalization, and that a determination thereon will be done on a case-by-case basis. We could adopt a flow-through approach in the future. If a flow-through approach were to be adopted in the future, the accumulated deferred income taxes at that point in time would continue to be used as a rate base offset until they were fully reversed and credited to the benefit of customers.

K. Motion for Protective Treatment

On November 17, 2010, the Companies filed a letter indicating that it would file a motion for protective treatment for information in the pre-filed direct testimony and exhibits of CAD witness, Ralph C. Smith, filed on November 10, 2010, concerning the Companies' incentive compensation program. The Companies stated the information was made available to CAD during the discovery process pursuant to a protective agreement between CAD and the Companies.

On November 29, 2010, the Companies filed a Motion for Protective Order, seeking protective treatment of portions of the direct testimony of CAD witness Ralph C. Smith. The Motion seeks protective treatment of portions of Exhibit LA-2 related to the Companies' incentive compensation plans. The Companies do not seek protective treatment of pages 48-49 of Mr. Smith's direct testimony that was also filed as confidential, after reviewing the information and determining that it is not confidential. The Companies also filed a confidential version of Exhibit LA-2 that is currently under seal with the Executive Secretary's office.

On December 1, 2010, the Commission entered an Order requiring parties to file a response or objection to the Motion on or before Monday, December 6, 2010, by 4:00 p.m. The Commission required an earlier response than the ten-day response under the Commission Rules of Practice and Procedure in light of the impending hearing date of December 13, 2010. No response or objection was filed in response to the December 1, 2010 Order.

The Commission concludes that it is not necessary to rule on the Companies' motion at this time. No entity has requested copies of the information for which protective treatment is sought. The documents are currently under seal with the Executive Secretary's office. The Commission will continue to maintain the confidentiality of the documentation that is the subject of the Companies' motion. Upon a filing, if any, of a West Virginia Freedom of Information Act (FOIA) request pursuant to W.Va. Code §29B-1-1 *et seq.* for the information, the Commission will notify the Companies. At that time, the Commission will provide the Companies with the opportunity to present arguments as to why protective treatment should be afforded the information and whether the information should be given permanent protective treatment.

IX. SUMMARY

This rate increase filing, coupled with other recent rate increases, has understandably caused significant public outcry. If the Commission task was to gauge the level of public protest in making its decision, the result would be simple - it would allow no rate increase. However, the Commission is obligated to perform its duties according to statutory guidelines from the Legislature and the State and United States Constitution.

The Commission was created to regulate utilities in the interest of the using and consuming public. By statute, the Commission is obligated to regulate the rates of public utilities in order to "provide the availability or adequate, economical and reliable utility services throughout the State." W.Va. Code §24-1-1(a)(1). The West Virginia Code summarizes the duties of the Commission as follows:

> The Legislature creates the public service commission to exercise the legislative powers delegated to it. The public service commission is charged with the responsibility for appraising and balancing the interests of current economy and the interests of the utilities subject to its jurisdiction in its deliberations and decisions.

W.Va. Code §24-1-1(b).

The Commission cannot simply disallow rates because they represent an increase. That action would not be balanced, as required by the statute, and would be contrary to the Commission's obligation to ensure adequate and reliable utility service. The Commission is very sensitive to the economic impact of rate increases upon the public; however, it is also aware that in order to ensure adequate and reliable utility service, it must allow sufficient rate increases to allow the utility to meet increased costs in providing adequate utility service. This reality was recognized by every party to the stipulation who recommended a rate increase greater than the increase provided in this Order. Those parties represent a broad array of interests including residential, commercial and industrial customers.

The Commission understands that it will be criticized by allowing any rate increase. Nonetheless, the rate increase of $51.12 million (shown on Appendix C) allowed by this Order is the lowest reasonable increase to cover increased costs, and to attract capital necessary to ensure adequate and reliable electric service in the future.

FINDINGS OF FACT

1. The Companies originally requested increased revenues of $155,463,299 (comprised of $223,778,770 increases in base rates and $68,315,471 decreases in the Construction Surcharge and ARS Surcharge) or an approximately 13.8 percent increase annually. The Companies also requested approval of a proposed Transmission Rate Adjustment Clause Rider. Joint Application at 1-6.

2. The Companies satisfied all public notice, mailing, posting and publication requirements with respect to the filing of its joint rate case and the scheduled public and evidentiary hearings. Affidavits of Publication filed September 10, 2010, and December 22, 2010.

3. The CAD, WVEUG, Kroger, Wal-Mart, SBNA and SWVI were granted intervenor status in the proceeding. (Orders dated June 11, 2010, June 25, 2010, September 13, 2010, and November 22, 2010).

4. Public comment hearings were held on November 4, 2010, in Wheeling; November 8, 2010, in Huntington; November 9, 2010, in Beckley; and, November 16, 2010, in Charleston. The Commission has considered the comments made at the public comment hearings and in the letters of protests with 8,000 signatures filed in the case.

5. The Commission convened the evidentiary hearing on December 13, 2010, during which it accepted public comment and reconvened the hearing on December 15, 2010, during which it accepted the testimony of two witnesses on behalf of the Companies, one CAD witness, and one Staff witness. At the December 15, 2010 evidentiary hearing, the Commission admitted the direct rebuttal and revised testimonies of the Companies witnesses, CAD witnesses, SWVI witness, Wal-Mart witness, WVEUG witnesses, and Staff witnesses.

6. At the December 15, 2010 hearing, all the parties, except SBNA, filed and presented to the Commission the Joint Stipulation and its Attachment A, representing the Companies' illustrative cost of service, and its Attachment B, representing the revenue allocation settlement of $60 million.

7. The intervenor SBNA did not sign, but did not object to the Joint Stipulation.

8. At the December 15, 2010 hearing, the Commission admitted Staff Exhibit No. 1, representing the Staff illustrative cost of service. The Commission requested that the Companies, Staff and CAD file a schedule showing the original filing and details as to how the parties arrived at their recommended illustrative cost of service. Tr. 12/15/10 at 120, 121. The Commission specifically requested that the parties include specifics

regarding executive compensation in the parties' illustrative cost of service recommendations. Id. at 20.

9. On December 17, 2010, CAD filed Commission Request Exhibit/CAD, containing CAD's cost of service recommendation in response to the Commission's request at the December 15, 2010 hearing.

10. On December 30, 2010, the Companies filed Commission Request Exhibit No. 1, containing the Companies' cost of service recommendation and Commission Request Exhibit No. 2 containing the Companies' position on executive compensation.

11. On January 21, 2011, on behalf of the Stipulating parties, the Companies filed rates reflecting the settlement reached in the Joint Stipulation.

12. The parties acknowledge the Commission's authority to accept, reject or modify any Stipulation. The parties agreed in the event the Joint Stipulation is modified, the parties are not bound to accept the Agreement, as modified or if rejected by the Commission, and may avail themselves of whatever rights are available under the law and the Commission's Rules of Practice and Procedure. Joint Stipulation and Agreement. ¶ 41.

Capital Structure

13. The Companies proposed a capital structure consisting of 53.4 percent long-term debt, 3.7 percent short-term debt, 0.3 percent preferred equity and 42.6 percent common equity, based on a thirteen-month test year average. Avera, WEA No. 1, Direct Testimony at 57; Reitter, MDR No. 1, Direct Testimony at 3, and Ex. MDR No. 2 attached to testimony.

14. Staff proposed a quarterly averaging approach and a more recent time period to derive a recommended capital structure of 53 percent long-term debt, 4.5 percent short-term debt, 0.3 percent preferred equity and 42.2 percent common equity. Short, Staff RS-D at 3, 4, 19, 20, 21 and Ex. RRS – 1, Schedule 1 attached to testimony.

15. In its rebuttal, the Companies recommended a capital structure of 53 percent long-term debt, 4.5 percent short-term debt, 0.3 percent preferred equity and 42.2 percent common equity. That is almost identical to the Staff-recommended capital structure. The Companies continued to use a thirteen-month average period to determine the capital structure recommended in its rebuttal testimony, but used the Staff-recommended more recent time period. Reitter, Nov. MDR No. 1, Rebuttal Testimony at 1, 2 and MDR Exhibit 2 attached to testimony.

16. WVEUG witness Baudino accepted the Companies' recommended capital structure in his analysis in making a recommendation of 9.5 percent return on equity. Baudino, WVEUG 2, Direct Testimony at 28, 29.

17. Companies' witness Avera based his recommendation for long-term debt, short-term debt and preferred equity on his finding that increased fuel costs, including coal and gas, financial and regulatory pressures, and the downward economic trend experienced by the utility industry between 2008 and 2009 impacted the investors' risk assessment of the utilities. Avera, WEA No. 1, Direct Testimony at 11-16.

Cost of Debt and Preferred Equity

18. The Companies initially proposed a cost rate of 6.4 percent and a weighted cost rate of 3.43 percent for 53.4 percent of total capital for long-term debt; a cost rate of 0.89 percent and a weighted cost rate of 0.03 percent for 3.7 percent of total capital for short-term debt; and a cost rate of 4.35 percent and a weighted cost rate of 0.01 percent for 0.3 percent of total capital for preferred equity. Order at 27. Reitter, MDR No. 1, Direct Testimony at 4, 5 and MDR Ex. No. 2 attached to testimony.

19. Staff proposed a cost rate of 5.85 percent and a weighted cost rate of 3.1 percent for 53 percent of total capital for long-term of total capital; a cost rate of 0.5 percent and a weighted cost rate of 0.02 percent for 4.5 percent of total capital for short-term debt; and a cost rate of 4.35 percent and a weighted cost rate of 0.01 percent for 0.3 percent of total capital for preferred equity. Short, Staff RS-D at 19-21.

20. In its rebuttal testimony, the Companies recommended a cost rate of 5.97 percent and a weighted cost rate of 3.16 percent for 53 percent of total capital for long-term debt; a cost rate of 0.25 percent and a weighted cost rate of 0.01 percent for 3.7 percent of total capital for short-term debt; and a cost rate of 4.35 percent and a weighted cost rate of 0.01 percent for 0.3 percent of total capital for preferred equity. Reitter, Nov. MDR No. 1, Rebuttal Testimony and MDR Rebuttal Ex. 2 attached to testimony.

Return on Equity

21. The Companies initially recommended an 11.75 percent return on equity in its rate filing, Staff recommended a 9 percent return on equity, and WVEUG recommended a 9.5 percent return on equity. Avera, WEA No. 1, Direct Testimony at 5; Short, Staff RS-D at 41; Baudino, WVEUG 2, Direct Testimony at 3, 28.

22. Dr. Avera testified that interpretation of cost of equity data requires care and practical judgment. Avera, WEA No. 1, Direct Testimony at 24.

23. The Companies recommendation of an 11.75 percent return on equity is based on Dr. Avera's analysis and testimony. Avera, WEA No. 1, Direct Testimony at 62.

24. The Staff recommendation of 9 percent return on equity is based on Mr. Short's analysis and testimony. Short, Staff RS-D at 41.

25. WVEUG witness Baudino's recommendation of 9.5 percent return on equity is based on Mr. Baudino's analysis and testimony. Baudino, WVEUG 2, Direct Testimony at 3, 28.

26. At the December 15, 2010 hearing, Staff filed a Commission Request exhibit as Staff 1, that included a return on equity of 10 percent. Staff 1.

27. On December 17, 2010, CAD filed its post-hearing Commission Request exhibit as Commission Request Exhibit – CAD in which CAD included a return on equity of 10 percent. Commission Request Exhibit – CAD.

28. The Companies filed its Commission Request Exhibit as Commission Request No. 1 –APCO/WPCo on December 30, 2010, including a return on equity of 10.5 percent. Commission Request No. 1 – APCO/WPCo.

29. In the Joint Stipulation, the parties did not adopt a specific return on equity, but agreed that the Companies could use the return on equity of 10.5 percent authorized in Case No. 05-1278-E-PC-PW-42T for the calculation of AFUDC. Joint 1, Joint Stipulation ¶ 22.

30. The capital structure and capital cost rates, including a return on equity of 10 percent approved by the Commission, results in an overall rate of return of 7.36 percent.

Amos Unit 2

31. APCo/WPCo proposed an adjustment of $23.9 million total company or $10.2 million on a WV jurisdictional basis to provide for a full inclusion in rate base (terminal treatment) for a reheater replacement project on Amos Unit 2 that was completed and placed in service in February 2010, after the end of the test year in this case. Adjustment No. 75 – EPIS and Fawcett, JDF-D at 5, 12-14.

32. Staff and CAD opposed the Companies' adjustment for a reheater replacement project at Amos Unit 2 because it departs from the use of an average test year rate base and includes investment that was not in plant in service at all during the test year. Oxley, Staff ELO-D at 7, 8 and Ex. TDS-1, Schedule 2 exhibit attached to Sprinkle, Staff TDS-D; CAD 2, Direct Testimony of Ralph C. Smith at 24, 25, 26, 27.

33. The Companies proposed an adjustment of $7.7 million total company or $3.3 million on a WV jurisdictional basis to provide for terminal treatment of a turbine modification project at Amos Unit 2 that went into service in February 2010. Fawcett, JDF-D at 14.

34. Staff and CAD opposed the Companies' adjustment related to Amos No. 2 turbine modifications for reasons similar to their opposition to the Amos Unit 2 reheater project. Oxley, Staff ELO-D at 7, 8; CAD 2, Direct Testimony of Ralph C. Smith at 27, 28.

35. Staff did not oppose terminal treatment for work orders that it could identify as the scrubber additions that the Commission had approved for special ratemaking surcharge treatment in Case No. 05-1278-E-PC-PW-42T.

Wheeling Project

36. The Companies proposed an adjustment for the Wheeling project, a rehabilitation project replacing all of the old underground cable and removing and replacing the overhead transformer installations with underground equipment in the Wheeling network. The Wheeling project was not completed and in service during any part of test year 2009 and was only 88 percent complete by the end of June 2010, with full completion of the project not expected until November 2010. Fawcett, JDF-D at 14, 15.

37. The Commission has not approved special ratemaking treatment for the Wheeling project in Case No. 05-1278-E-PC-PW-42T or other proceeding.

Other Rate Base Adjustments

38. In rebuttal testimony, the Companies modified their initial filing with the addition of several adjustments that were not included in the Companies' initial filing, including a rate base adjustment for projects that were related to the installation of pollution control equipment at Amos Units Nos. 1 and 2 that the Companies stated should have been coded as environmental work orders, but were not. Brubaker, Nov. JLB No. 1, Rebuttal Testimony at 17.

Deferred Storm Damage in Rate Base

39. The Companies proposed to defer the extraordinary storm damage costs it experienced in late 2009 with an adjustment that added $11.4 million to its requested rate base. Ferguson, SHF No. 1, Direct Testimony at 15, 16; Nov. SHF No. 1, Rebuttal Testimony at 10, 11. Staff opposed the proposed inclusion of deferred storm damage costs in rate base. Sprinkle, Staff TDS-D at 15.

Federal Income Tax Accumulated Deferred Income Tax Adjustments

40. The Companies identified an Accumulated Deferred Income Taxes (ADITS) as a rate base issue, most of which is related to $22.8 million deferred federal income tax liability related to prepaid pension. Pyle, MAP No. 1, Direct Testimony at 23-25.

Inclusion of Pension Fund Assets in Rate Base

41. The Companies proposed that the amounts placed in their pension funds as prepayments be included in rate base. Company 2, Statement B, Schedule 6. Staff and CAD recommended that the prepaid pension asset not be included in rate base. Sprinkle, Staff TDS-D at 22; Smith, CAD 2, Direct Testimony at 34.

Cash Working Capital

42. The rate base filed by the Companies included a cash working capital component of $30.4 million. Company 2, Statement B.

43. Staff recommended a negative $28.8 million cash working capital component of rate base. Sprinkle, Staff TDS-D at 20.

44. The CAD recommended a cash working capital component of negative $14.7 million, but indicated that it believed that its adjustment was understated and that the negative cash working capital should be greater than the negative $14.7 million included in the CAD proposed rate base. White, CAD 4, Direct Testimony at 11.

45. The difference in the parties' recommendations for the cash working capital component of rate base is related to the inclusion of non-cash items in the lead/lag studies used by the parties.

46. The Companies must maintain certain levels of available cash in their bank accounts because they cannot control when checks will clear through the banking system and because of the minimum balance requirements imposed by banks.

O&M Expenses

Non-ENEC Generation Expenses

47. The Companies did not provide evidence to support their $1,483,511 adjustment to increase test year non-ENEC generation O&M expenses to a three-year, inflation-adjusted average. Order at 41.

Estimated 2010 PJM Expenses

48. The parties recommend that the issue of the appropriate level of expenses related to the Companies' transactions with PJM should be considered as part of the next ENEC proceeding. Joint Stipulation at 7; Ferguson, Nov. SHF No. 1, Rebuttal Testimony at 9.

49. The Commission sets rates for West Virginia retail customers based on fully-integrated production, transmission and distribution revenue requirements as established by this Commission. Included in those revenue requirements are the costs for internally-generated power supply from the APCo plants, purchased power, credits for sales to affiliates and non-affiliates, internal transmission and distribution costs on lines owned by APCo/WPCo, and net purchased and sold transmission from affiliates and non-affiliates.

Uncollectibles

50. The Companies proposed an adjustment of $116,554 to reflect actual account balances written off during the test year. Company 2, Statement A, Schedule 2 at 4.

51. The Staff adjusted for uncollectibles using a three-year weighted average of actual net compared to revenue to arrive at a rate for uncollectibles that could be applied to going-level and proforma revenues. Sprinkle, Staff TDS-D at 13, 14.

Amortization of Extraordinary Storm-Related Costs

52. The Companies calculated the December 2009 storm costs for West Virginia to be approximately $18 million. Ferguson, Tr. 12/1/11 at 93; Brubaker, Nov. JLB No. 1, Rebuttal Testimony at 15; Joint Stipulation at 6.

Costs of Carbon Capture and Storage Demonstration Project

53. It is clear that the costs of CCS at the Mountaineer Plant are significant. Recent estimates for the cost of carbon capture at the Mountaineer Plant vary in range from $400 million to $600 million for partial CCS at Mountaineer, based on information in a recent Department of Energy release. Order at 45.

54. The VSCC, in a recent APCo rate case before that body disallowed the recovery of all CCS costs and expenses. VSCC Case No. PUE-2009-00030.

55. Account 103, Experimental Electric Plants, provides for plant constructed as a research, development or demonstration plant which is being operated for a period of time in an experimental status.

56. Account 183, Preliminary Survey and Investigations, is charged with expenditures for "preliminary investigations, etc., made for the purpose of determining the feasibility of utility projects under contemplation." Account 183 also provides that if construction results from the preliminary investigation, the amounts booked in Account 183 will be charged to the "appropriate utility plant account."

57. APCo has seen fit to pursue the CCS project without seeking a CCN or without seeking further consent from this Commission and seeks full recovery from the West Virginia ratepayers.

58. The Commission has concerns about the future of CCS but appreciates the enormous potential that it might hold for West Virginia and our natural resources.

Non-executive Bonuses, Payroll and Severance

59. The Staff recommended that all direct employee bonuses be disallowed in this case. Sprinkle, Staff TDS-D at 11.

60. Staff agreed with the Companies' method of annualizing base payroll for APCo/WPCo employees direct costs, except Staff used a more recent time period reflecting the Companies' severance of employees in 2010. Staff initially proposed a decrease for direct payroll expense of $4,662,708. Sprinkle, Staff TDS-D at 5 and Ex. TDS-1, Schedule 3.

61. The Companies made no adjustment for the severance of employees in 2010 in initially proposing an adjustment for direct payroll expenses of $368,172. Company 1, Statement G, Companies' Adjustment 35-P-L.

62. CAD initially recommended similar decreases to going-level payroll because of the severance of employees. The CAD downward adjustment to the requested direct payroll was $5 million and the downward adjustment to payroll-related employee savings plan contributions was $246,000. White, CAD 4, Direct, DLW-2, Ex. attached to testimony.

63. The Staff recommendation for direct payroll expense took into account the affect of the 2010 work force reductions on the affiliates, primarily the AEP Service Corporation, in recommending that the Commission reduce the going level cost of affiliate labor by $3,354,614, as shown in Sprinkle, Staff TDS-D at 6 and Ex. TDS-1, Schedules 2, 3.

64. CAD proposed an upward adjustment to expenses of $2.4 million on a West Virginia jurisdictional basis to provide for one-fourth of the projected costs of severance packages offered to APCO/WPCO employees as direct severance costs.

White, CAD 4, Direct, DLW-3 Ex. 3 attached to testimony. White, CAD 4, Direct, DLW-3, Ex. attached to testimony.

65. The Companies objected to the capitalization of severance costs in CAD's proposal on the ground that the SFAS 88 prohibits the capitalization of severance costs. Brubaker, Nov. JLB No. 1, Rebuttal Testimony at 11, 12.

66. The Companies' calculation of severance for direct payroll expense included a West Virginia jurisdictional share of severance costs billed from AEP Service Corporation of $9.4 million.

67. CAD and Staff proposed adjustments to reduce payroll-related costs related to their recommendations for lower level of going-level payroll, including employee medical insurance, that have been included in the Commission approved payroll expenses.

AEP Stock-based Bonuses/Supplemental Executive Retirement Bonuses

68. AEP costs billed by the Service Corporation are allocated among seven operating companies in AEP-East, four operating companies in AEP-West and other AEP subsidiaries. APCo/WPCo are generally allocated 20 percent of AEP Service Corporation costs, including the costs of executive compensation. West Virginia and Virginia, in turn, share in the 20 percent allocation, with 45 percent of the 20 percent being allocated to West Virginia. The result is that West Virginia pays nine percent of total AEP Service Corporation costs, including executive compensation costs.

69. AEP executive bonuses and supplemental compensation of $2.8 million is included in APCo/WPCo test year expenses.

Income Taxes

Effective Income Tax Rate

70. The Commission has, for many years, adopted the use of a consolidated tax rate to reflect the effective income tax rates for companies that file as part of a consolidated group.

71. The Commission has explained its reasoning for the use of a consolidated tax rate, and refined its methodology in a number of cases since the 1991 APCo rate case. The present methodology of the Commission is different than that used in 1991 for APCo.

Normalization of Additional Deductions to Taxable Income Related to Differences in Units of Property for Book Purposes and Tax Purposes

72. The determination of when plant should be expensed or capitalized is controlled by an accounting mechanism referred to as "retirement units," or sometimes, "units of property."

73. In describing electric plant accounting and in differentiating whether work orders should be charged to expense or capitalized, the Uniform System of Accounts for Electric Utilities requires:

> For the purpose of avoiding undue refinement in accounting for additions to and retirements and replacements of electric plant, all property will be considered as consisting of (1) retirement units and (2) minor items of property. Each utility shall maintain a written property units listing for use in accounting for additions and retirements of electric plant and apply the listing consistently.

Electric Rule 2.4.

74. In 2009, the Companies adopted a different list of property units for purposes of tax accounting than they use for maintaining their regulated books. This gave rise to a temporary timing difference between capitalization of plant additions for tax purposes and book purposes. Pyle, MAP No. 1, Direct Testimony at 20, 21-25.

75. If the tax effects of the timing differences created by the change in accounting for tax capitalization of plant additions are not normalized, the lower future depreciation expense that the Companies will have for tax purposes will result in higher income taxes that customers will have to pay in the future. If the tax effects are normalized, those higher taxes will be offset by the reversal of the timing differences in the future.

76. Normalization of the 2009 deduction will increase current income taxes and revenue requirements, but there will be an offset to revenue requirements in the form of a deferred income tax negative rate base component.

Motion for Protective Treatment

77. On November 29, 2010, the Companies filed a Motion for Protective Order requesting protective treatment of portions of the direct testimony of CAD witness Ralph C. Smith that is currently filed under seal with the Executive Secretary's Office.

78. On December 1, 2010, the Commission issued an Order requiring parties to file a response or objections to the Companies' Motion for Protective Order on or before December 6, 2010, by 4:00 p.m. No response was filed. No entity has requested copies of the information for which protective treatment is sought.

CONCLUSIONS OF LAW

1. Utility rates must allow a public utility the opportunity to earn a level of revenues sufficient to attract capital in the competitive market, balanced with the interests of the public in receiving fair and equitable rates. Bluefield Water Works and Improvement Company v. Public Service Commission, 320 U.S. 679 (1923); Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591, 64 S. Ct. 281 (1944).

2. The Commission values stipulations in rate and other proceedings because they resolve many cases in a prompt, fair, reasonable and expedited fashion. Bluefield Gas Company, Case No. 09-0681-G-42T (Order dated January 28, 2010) at 2, 3; Monongahela Power Company and The Potomac Edison Company, dba Allegheny Power, Case No. 09-1352-E-42T (Order dated June 25, 2010).

3. The Commission has the authority to accept, modify or reject a stipulation. Virginia Electric and Power Company and Utilicorp United, Inc., Case No. 85-553-E-PC (Order dated January 6, 1987), Joint Stipulation at 41.

4. The filing of the Joint Stipulation by the parties does not alter or obviate the statutory duties of the Commission under W.Va. Code §§24-1-1(b) and 24-2-3.

5. In a rate case, such as this case, the Commission must evaluate the proposed Joint Stipulation independently, in light of the record, to make a determination that the proposed provisions result in fair and reasonable rates that balance the interests of all parties, the ratepayers and the State, as required by law. Monongahela Power Company and The Potomac Edison Company, dba Allegheny Power, Case No. 09-1352-E-42T (Order dated June 25, 2010).

6. The Commission requires that a stipulation in a rate case contain some explanation that goes beyond the recitation of the final revenue requirement. In a rate case, the parties must present sufficient evidence in order for the Commission to independently assess whether the settlement is fair and reasonable, including all prefiled testimony and evidence at hearing in support of the stipulation. West Virginia-American Water Company, Case No. 07-0998-W-42T (Orders dated December 7, 2007, and December 21, 2007). See also, Beckley Water Company, Case No. 08-0404-W-42T (Order dated December 19, 2008).

7. The Commission concludes that the Joint Stipulation provisions relating to the revenue requirement, AFUDC rate, 2009 storm damage amortization, flow-through of

certain new tax deductions and specifically paragraphs 19, 21, 22, 23 and 24 of the Joint Stipulation are not reasonable and are not approved by the Commission.

8. The Commission concludes that the remaining provisions in the Joint Stipulation are fair and reasonable and should be adopted, including the rate design of the Joint Stipulation, except to the extent that the rates agreed to in the Joint Stipulation must be modified to reflect the lower revenue requirement approved herein. The Joint Stipulation is approved, as modified by the Commission.

Capital Structure

9. The Commission is not bound to either a test year capital structure or a projected capital structure, and may, depending on the economic or other circumstances, review historic, projected and hypothetical capital structures to arrive at a structure that is reasonable, fairly balances the interests of the customers and the utility and produces the lowest reasonable overall revenue requirements, while maintaining financial integrity and flexibility for the utility. Hope Gas, Inc., dba Dominion Hope, Case No. 08-1783-G-42T (Order dated November 20, 2009) at 7; West Virginia-American Water Company, Case No. 84-008-W-42T (Order dated January 25, 1985) at 17; Appalachian Power Company, Case No. 83-897-E-42T (Order dated December 28, 1984) at 3.

10. The Staff-proposed capital structure is reasonable and is adopted by the Commission.

Cost of Debt and Preferred Equity

11. The Staff recommended cost rates for debt and preferred equity are reasonable and are adopted by the Commission.

Return on Equity

12. The Commission should apply its own judgment in evaluating the cost of capital data to arrive at a reasonable return on equity.

13. The Commission concludes that the return on equity recommendation of the Companies' witness Avera in the range of 10.6 percent and 12.6 percent is too high. The Commission finds his data and methods support a more reasonable range of return on equity of 9.7 percent to 11.8 percent.

14. The Commission, in applying its own judgment to the testimony of Dr. Avera, concludes that some of the outlier data should not have been excluded from his DCF analysis and, thus, the Commission determines a different return on equity range from Dr. Avera's data.

15. The Commission considers but does not rely on Dr. Avera's non-proxy group to arrive at a return on equity range and discounts the range of 11.6 percent to 13 percent return on equity produced by the non-proxy group.

16. The Commission concludes that the return on equity recommendation of Staff witness Short in the range of 8.5 percent to 9.5 percent return on equity is too low. The Commission finds that his data and methods support a more reasonable range of return on equity of 8.5 percent to 10 percent.

17. The Commission concludes that the return on equity recommendation of the WVEUG witness Baudino in the range of 9 percent to 9.7 percent is too low. The Commission finds that his data and methods support a more reasonable range of return on equity of 9 percent to 10.2 percent.

18. The Commission concludes that a return on equity of 10 percent, which is within the Commission determined range of reasonableness of 9.1 percent to 10.9 percent, is reasonable based on a review and analysis of the return on equity data in the record.

19. The return on equity component of AFUDC is a significant element that impacts future rate base value that will ultimately be supported by rates. Therefore, the Commission has modified the Joint Stipulation to allow an AFUDC rate of 10 percent.

20. It is reasonable to adopt an overall rate of return of 7.36 percent, based on the capital structure and capital cost rates, including a return on equity of 10 percent, approved by the Commission in this proceeding.

Amos Unit 2

21. The Commission has held that departures from the average rate base should be rejected except in unusual circumstances. West Virginia- American Water Company, Case No. 84-008-W-42T (Order dated October 19, 2004); Appalachian Power Company, Case No. 83-697-E-42T (Order dated September 28, 1984).

22. It is reasonable to allow terminal treatment for the Amos scrubbers because the Commission had identified the construction of the scrubbers as capital costs that should be placed in rates through an annual surcharge mechanism, which is a departure from the normal CWIP/AFUDC and average test year rate base regulatory model followed by the Commission because the Stipulation approved by the Commission in the Companies' last rate case provided that the Companies' costs related to the Wyoming-Jackson Ferry 765 kV line and a construction surcharge for the retrofit of scrubbers at the Mountaineer plant and Units 1, 2 and 3 of the John Amos plant could be recovered in rates (in future ENEC proceedings). Appalachian Power Company and Wheeling Power

Company, dba American Electric Power, Case No. 05-1278-E-PC-PW-42T (Order dated July 26, 2006).

Other Base Rate Adjustments

23. Rule 42 requires that each utility, at the time it files a tariff or application for initial rates or changes in rates, shall present the proposed tariff, schedules and exhibits upon which it intends to rely in support of its application or filing. Rule 42 of the Commission Rules for the Construction and Filing of Tariffs, 150 C.S.R. 2.

24. The adjustments filed by the Companies in their rebuttal testimony that were not included in the Companies' initial Rule 42 filing do not meet Rule 42 requirements, are unreasonable, and will be denied by the Commission.

25. Because the Companies have not met the burden of proof to establish justification to depart from the historical average test year approach and to move outside of the test year to include rate base items such as the Amos Unit 2 reheater, turbine modification projects, or the downtown Wheeling distribution system upgrades, the Amos Unit. 2 reheater, turbine modification project and the Wheeling project will not be included in rate base.

Deferred Storm Damage in Rate Base

26. When the test year is not reflective of normal operations, adjustment may be necessary to include costs that are not reflected in the test year or to exclude test year costs that are extraordinary and non-recurring.

27. The Commission will make an expense adjustment equal to one-seventh of the identified extraordinary 2009 storm-related costs as an identifiable and continuing rate allowance but does not and will not include any perceived "unrecovered" amount in rate base.

Federal Income Tax Accumulated Deferred Income Tax Adjustments

28. It is reasonable to include the ADITS related to the pension contributions in rate base. Hope Gas, Inc., dba Dominion Hope, Case No. 08-1783-G-42T (Order dated November 20, 2009) at 25.

Inclusion of Pension Fund Assets in Rate Base

29. It is reasonable that the Companies' prepaid pension assets are not included in rate base. Hope Gas, Inc., dba Dominion Hope, Case No. 08-1783-G-42T (Order dated November 20, 2009) at 25.

Cash Working Capital

30. It is reasonable to allow required bank balances in the cash working capital component of rate base if the balances are maintained at the lowest required level and are non-interest bearing, or, if the bank balances bear interest, there should be offsets to the revenue requirements to reflect the interest earned.

31. The $400,000 for average cash bank balances meets the criteria for inclusion in the cash working capital component of rate base and will be allowed.

32. Depreciation charges do not represent a cash requirement and should not be included in the lead lag study analysis of cash working capital.

33. The lag between the service period for utility property taxes and payment as calculated by Staff is reasonable and supports the Staff negative cash working capital component for utility property taxes.

34. Total return on equity is not a cash working capital component and should not be used in the lead lag study.

35. Because APCo/WPCo provided no analysis of payment lags for dividends, the Commission will not include dividends in the lead lag analysis of cash working capital.

O&M Expenses

Non-ENEC Generation Expenses

36. A comparison of an inflation-adjusted three-year average of O&M expenses to the test year level of expenses is not evidence that the resulting average is proper for setting rates for the future. Greenbrier County Public Service District No. 2, Case No. 07-0072-PSD-42T, Order August 29, 2007 at 13 (discussing history of Commission policy on this issue); Appalachian Power Company, Case No. 91-026-E-42T, Order, November 1, 1991.

37. A general going-level adjustment to non-ENEC generation O&M expenses that assumes that inflation is an appropriate basis for making going-level adjustments to expenses is not reasonable. Id.

38. A going-level adjustment of the non-ENEC generation O&M expenses requires careful consideration of the relationship between revenue units, expense units that are being adjusted, and other average expense and rate base items that make up the totality of the test year revenues, expenses and capital-related costs. Contel of West Virginia, Inc., Case No. 89-206-T-42T, Commission Order May 18, 1990.

Estimated 2010 PJM Expenses

39. Even though the Commission considers some elements of power supply costs and transmission credits in ENEC proceedings, the Commission has jurisdiction to set rates, including the transmission component of rates, for retail customers. §201(b)(1) of the Federal Power Act, §16 U.S.C.S. 824(b)(1).

40. The Commission will not allow APCo/WPCo transmission expense for use of their own lines to provide retail service flowing through PJM transactions to be used to circumvent Commission authority over retail rates.

41. In the ENEC proceedings the Commission will have the opportunity to review the effects of the PJM charges and credits. The Commission may make whatever adjustments are necessary to assure that the generation costs related to the provision of retail service reflect only the transmission-related revenue requirement components that are consistent with the rate base, rate of return, and operating cost decisions made by the Commission in base rate cases.

Uncollectibles

42. In calculating an uncollectibles expense, it is appropriate to use a three-year average of actual net write offs compared to revenue when fluctuations occur between the years as long as the average is developed and represented as a ratio or percentage rate, relative to revenue levels. The use of an average rate for uncollectibles normalizes the peaks and valleys that occur over time while still maintaining the relationship between revenue levels and expense levels. West Virginia-American Water Company, Case No. 03-0353-W-42T, Order January 2, 2004 at 82, 83; West Virginia-American Water Company, Case No. 08-0900-W-42T at 56, 57.

Amortization of Extraordinary Storm-Related Costs

43. The Commission adopts the Staff approach of averaging the extraordinary storm costs, but uses a shortened time frame and allows an expense based on one-seventh of the extraordinary 2009 storm costs.

Costs of Carbon Capture and Storage Demonstration Project

44. Given the "pilot project" nature of the CCS project to date, a fair treatment of the capital and operating expenses is to allow a portion of the operating expenses, but to not include amounts booked by the Companies in Account 103, "Experimental Electric Plant" in rate base at this time.

45. The operation of the CCS plant is experimental as described in Account 103. This experimental operation, however, is being used solely as a mechanism to gather information in contemplation of expanding the CCS beyond the demonstration phase. If this experiment results in construction, as described in Account 183, then it would be appropriate to book the CCS investment to the "appropriate utility plant account."

46. The CCS project is a continuing preliminary investigation. In the future, we may consider it as used and useful plant in service and include it in rate base. Any such inclusion, however, would be considered only for a reasonable share allocable to APCo and APCo's West Virginia jurisdictional operations.

47. It is reasonable that all AEP companies share in the cost of the CCS facility rather than it being the responsibility of only APCo/WPCo.

48. The CCS project is operating at a nominal level and is in fact sequestering some of the CO_2 from the Mountaineer Plant, and it is reasonable for the Commission to allow a proportionate share of those expenses to be included in operating expenses in this case.

49. The allowed CCS cost will be based on an allocated share for APCO/WPCo based on their average coincidental peak load relative to the sum of the total coincidental peak loads of the AEP-East operating companies. The Commission will consider alternatives to this allocation approach in the future, but only on a prospective basis.

50. The reasonable average allocator for APCo/WPCo is 32 percent, based on the recent Transmission Equalization Case at the FERC. American Electric Power Service Corporation, Case No. ER-09-1279. The 32 percent allocator is reasonable to determine a fair share of the operating costs of the CCS facilities to include in the revenue requirements for the Companies in this case.

51. Although the Commission does not have jurisdiction to mandate a sharing of the CCS cost among AEP operating companies, cooperation between AEP operating companies, and cooperation among the various State Regulatory Commissions is appropriate if a fair sharing of the CCS costs is to be accomplished.

Non-executive Bonuses, Payroll and Severance

52. Because of difficult economic times, and for other reasons set forth in the Order, ratepayers should not be required to support bonuses that the Companies have given their employees. It is reasonable to allow one-half of the requested non-executive direct bonuses in the revenue requirement in this case.

53. For purposes of assessing the Joint Stipulation, the Commission will adopt the recommendations of the Staff and CAD to reflect the effect of work force reductions on going-level payroll costs.

54. The adjustments for direct severance costs and AEPSC severance costs are difficult to evaluate because of the timing and manner they were presented in the case. In addition, these are costs that are non-recurring in nature and would normally be excluded from going-level ongoing expenses.

55. Severance costs do not represent payroll related to current services performed but rather represent costs for employees to cease working. As such, it may be difficult to quantify what, if any, portion of severance costs should be capitalized.

56. Because AEPSC severance costs were not originally requested by the Companies, the evidence in support of the adjustment is inadequate and does not address how severance costs were assigned to APCo and WPCo, does not indicate whether these severance costs were incurred in the test year or whether they are entirely post-test year costs, the Commission cannot determine whether the adjustment is reasonable.

57. It is reasonable to allow $2.1 million in revenue requirements in this proceeding for severance costs.

58. The Commission allowance of $2.1 million for severance costs should not be construed as a Commission determination that any particular level of severance costs represents a reasonable and prudent expense allocable to West Virginia. If the Companies seek to recover any further severance costs in a future rate case, the Commission will consider that issue in that future proceeding.

AEP Stock-based Bonuses/Supplemental Executive Retirement Bonuses

59. The Commission will disallow all top executive bonuses and supplemental compensation allocated to APCo/WPCo, amounting to $2.8 million in the test year, because the level of executive compensation is unreasonable and in light of current economic conditions affected by the recent recession.

Income Taxes

Effective Income Tax Rate

60. The consolidated tax adjustment method adopted by the Commission is reasonable and has been approved in prior cases. Monongahela Power Company, Case No. 06-0960-E-42T (Orders dated May 22, 2007, and December 12, 2008); West Virginia-American Water Company, Case No. 08-0900-W-42T (Order dated March 25,

2009); Hope Gas Inc., dba Dominion Hope, Case No. 08-1783-G-42T (Order November 20, 2009).

61. The Commission will not depart from the CTA method in this case. The Commission will continue to exclude accelerated depreciation of utility companies from the calculation to be consistent with normalization requirements of the Internal Revenue Service.

62. The Commission will exclude the effect of the large tax deduction created in 2009 related to a tax accounting change and catch-up of that change reflected in the 2009 taxable income, and thereby eliminate the large negative effective tax rate calculated by Staff.

63. The Commission will approve a 26 percent average effective tax rate as reasonable in consideration of the range of effective tax rate numbers for various years and the reasonableness of an effective tax rate on a going-forward basis. This approval should not be construed as adoption of the Companies methodology to normalize the five-year average effective tax rate to arrive at an alternative CTA-based effective tax rate.

64. Determination of an effective income tax rate that reflects not only parent company losses but also losses of other members of the consolidated group is consistent with the Commission decisions in a number of recent cases. Mountaineer Gas Company, Case No. 93-0005-G-42T and Hope Gas, Inc., Case No. 93-0004-G-42T; Monongahela Power Company, Case No. 06-0960-E-42T (Orders dated May 22, 2007, and December 12, 2008); West Virginia-American Water Company, Case No. 08-0900-W-42T (Order dated March 25, 2009); Hope Gas Inc., dba Dominion Hope, Case No. 08-1783-G-42T (Order dated November 20, 2009).

Normalization of Additional Deductions to Taxable Income Related to Differences in Units of Property for Book Purposes and Tax Purposes

65. The Commission is not required to normalize the effects of the timing differences created by the change in accounting for tax capitalization of plant additions, nor is the Commission precluded by any statutory or ratemaking restrictions from normalizing these timing differences.

66. Normalization of the tax timing difference related to the difference between book and tax property units is reasonable in this case. If we do not normalize, the lower future depreciation expense that the Companies will have for tax purposes will result in higher income taxes that customers will have to pay in the future.

67. If the Commission adopts a flow-through approach in the future, the accumulated deferred income taxes at that point in time would continue to be used as a rate base offset until they were fully reversed and credited to the benefit of customers.

Motion for Protective Treatment

68. The Commission will continue to maintain the confidentiality of the documents for which protective treatment is sought, that are segregated and under seal in the Executive Secretary's office, until such future time, if any, that the Commission receives a Freedom of Information Act request for the documents. At such time, the Commission will notify the Companies.

ORDER

IT IS THEREFORE ORDERED that the Joint Stipulation and Agreement for Settlement filed on December 14, 2010, and attached hereto as Attachment B, is hereby approved by the Commission, except paragraphs 19, 21, 22, 23 and 24, which are modified as provided in this Order.

IT IS FURTHER ORDERED that APCo/WPCo file a new tariff within ten days adopting the rate design agreed to in the Joint Stipulation, but reflecting the lower revenue requirement approved in this Order, prorated across all rate schedules and rates contained therein, except for customer charges, which may remain as stipulated.

IT IS FURTHER ORDERED that the documents for which protective treatment is sought will remain segregated and under seal in the Executive Secretary's office, until such future time, if any, that the Commission receives a Freedom of Information Act request for the documents. At such time, the Commission will notify the Companies.

IT IS FURTHER ORDERED that upon 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.

Commissioner Palmer has filed a separate opinion, concurring in part and dissenting in part.

A True Copy, Teste: Sandra Squire
Sandra Squire
Executive Secretary

ASH/rt/klm
100699cg.doc

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 30th day of March 2011.

CASE NO. 10-0699-E-42T

APPALACHIAN POWER COMPANY and
WHEELING POWER COMPANY, dba AMERICAN
ELECTRIC POWER, public utilities.
Joint Application for Rate Increases on Notice of Proposed Effective Dates and Changes in Tariff Provisions, Pursuant to W. Va. Code, §24-2-4a and Approval of a Transmission Rate Adjustment Clause Rider.

DISSENTING OPINION OF COMMISSIONER PALMER

By Commission Order entered on March 30, 2011, a majority of the Commission modified the proposed Joint Stipulation and Agreement for Settlement (Joint Stipulation) filed by the parties to this proceeding, by approving a $51.12 million base rate increase for Appalachian Power Company and Wheeling Power Company (the Companies) instead of the $60 million base rate increase agreed to by the parties. For the reasons set forth below, I respectfully dissent from the majority's decision to calculate rates based on an approved return on equity of 10 percent because I believe that the evidence instead supports a return on equity of 9.5 percent.

The Commission has before it a fully developed record consisting of testimony and evidence filed by the Companies and the other parties, and a Joint Stipulation that all parties agree presents a reasonable resolution of the issues in this case. The majority decision fully evaluates the evidence to determine whether the Joint Stipulation results in fair and reasonable rates that balance the interests of the parties, the ratepayers and the State. With the exception of return on equity, I agree that the evidentiary record supports the majority's decisions on all issues presented in this case, including the range of reasonableness for a return on equity, as well as the general discussion of capital structure and rate of return.

In my evaluation of the appropriate level of return on equity in this case, I rely on established law and Commission policy that utility rates should allow a public utility a level of revenues that provide for reasonable expenses and an opportunity for net earnings sufficient to attract capital in the competitive financial marketplace, balanced with the interests of the consuming public in receiving fair and reasonable rates. Bluefield Water Works and Improvement Company v. Public Service Commission, 320 U.S. 679 (1923); Federal Power Commission v. Hope Natural Gas Company, 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). The balancing of competing interests is especially crucial when determining the reasonable return on equity component of an overall rate of return authorized for a utility.

Typically, a utility base rate proceeding presents the Commission with conflicting testimony, analysis and recommendations as to the determination of an appropriate return on equity. When confronted with a wide range of recommendations in the past, the Commission has noted that, "[A]ll 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 trends and data that is susceptible to interpretation, but the ultimate answer regarding investor expectations must rely heavily on the judgement of the Commission." Appalachian Power Company, Case No. 91-026-E-42T (Commission Order, November 1, 1991) at p. 4.

In this case, the evidentiary record addressing the appropriate rate of return on equity for the Companies is voluminous and includes the testimony and evaluations of three witnesses: William Avera for the Companies; Randall Short for the Staff; and Richard Baudino for the West Virginia Energy Users Group. The evidence presents several formulae for objective evaluation of both investor expectations and risk associated with holding utility common stock. The three witnesses evaluated the formulae using similar, but not identical inputs. Given current market conditions, I believe that the Commission should regard the formulae as the underpinning, but not the absolute answer, for determining a reasonable return on equity.

I find the evaluation presented by Mr. Baudino on the return on equity component of rate of return to be persuasive because Mr. Baudino properly considers the impact of the Great Recession on investor expectations. I agree with Mr. Baudino's conclusion that Appalachian Power Company and Wheeling Power Company remain attractive to investors because they are low-risk electric utilities with solid investment grade ratings. WVEUG 2, Direct Testimony Richard A. Baudino, at 9.

Investors do not make decisions in a vacuum. Rather, investors evaluate as much information as possible including potential returns on a wide range of investment options, the current state of the economy, future expectations as to economic activity and the stability of the enterprise in question. Today, economic downturn has significantly reduced the level of earnings a typical investor expects to make as compared to the level he or she expected to make in years gone by. It is reasonable, therefore, to assume that, just like investors in other markets, investors in electric public utilities have lower expectations than in the past. The evidence indicates that despite decreased investor expectations, the Companies and similarly situated utilities remain attractive to investors because of the low-risk nature of their operations and solid investment grade ratings.

I agree with the majority that a reasonable range for a return on equity in this proceeding is 9.1 to 10.9 percent. I conclude, however, that in the current economy, a fair balancing of the interests of the Companies and the ratepayers requires that the Commission use a return on equity in the lower half of the reasonable range. Therefore, taking into account current economic conditions and corresponding investor expectations for a low-risk electric utility with a solid investment grade rating, a return on equity rate of 9.5 percent is fair and reasonable and would result in base rates that would allow the Companies to earn an appropriate return on investment while protecting the interests of the consuming public.

Based on all of the foregoing, I conclude that the Commission should have approved a return on equity of 9.5 percent and a base rate increase of $44.2 million.

RBP/tt

APPENDIX A

PROCEDURAL HISTORY
Case No. 10-0699-E-42T

On May 14, 2010, Appalachian Power Company (APCo) and Wheeling Power Company (WPCo), both public utilities and both operating as American Electric Power (collectively "APCo/WPCo" or the "Companies"), tendered for filing revised tariff sheets, to become effective June 13, 2010, reflecting a system average rate increase of approximately 13.8 percent annually, or a net increase in current rates of $155,463,299, comprised of a $223,778,770 increase in base rates and a $68,315,471 decrease in the Construction Surcharge and ARS Surcharge, for furnishing electric utility service to approximately 481,141 customers in twenty-four counties in West Virginia. APCo/WPCo also requested approval of a proposed Transmission Rate Adjustment Clause Rider.

The Commission Consumer Advocate Division (CAD), the West Virginia Energy Users Group (WVEUG), the Kroger Company (Kroger), Wal-Mart Stores East, LP and Sam's East, Inc. (collectively Wal-Mart), the South Bluefield Neighborhood Association (SBNA) and Steel of West Virginia, Inc. (SWVI) were granted intervenor status in the proceeding. Orders dated June 11, 2010, June 25, 2010, September 13, 2010, and November 22, 2010.

On June 10, 2010, the Commission Staff filed a motion to dismiss the filing as insufficient; or, in the alternative, if APCo/WPCo agreed to a tolling, a motion to implement further case processing.

The Commission suspended the effective date of the tariff sheets filed by APCo/WPCo and deferred the use of the rates and charges stated therein until 12:01 a.m., March 31, 2011. Orders dated June 11, 2010, and June 25, 2010.

On June 17, 2010, APCo/WPCo filed a Response to the Staff motion to dismiss, requesting a twenty-day tolling of the statutory decision due date and the adoption of a procedural schedule agreed upon by the Companies, Staff, CAD and WVEUG.

On June 25, 2010, the Commission issued an Order that, among other things, granted the APCo/WPCo motion to toll the statutory decision period and established a new suspension date of 12:01 a.m., March 31, 2011. The Order further required APCo/WPCo to immediately comply with the publication and notice requirements of Tariff Rule 23, using a modified Tariff Form 8 stating the suspension date and adopted the following procedural schedule:

Deadline to file petitions to intervene	-	August 3, 2010
Companies direct testimony due	-	July 23, 2010
Staff and other parties' testimony due	-	November 10, 2010
Rebuttal testimony of all parties due	-	November 24, 2010
Commencement of Evidentiary Hearing	-	December 13, 2010

On July 23, 2010, the Companies filed the direct testimony and exhibits of Charles R. Patton, Steven H. Ferguson, William E. Avera, Marc D. Reitter, Jeffrey D. LaFleur, James D. Fawcett, Phillip A. Wright, David B. Weiss, Larry C. Foust, Dennis W. Bethel, Diana L. Gregory, Jay Joyce, Andrew R. Carlin, Jeffrey L. Brubaker, and Mark A. Pyle.

On October 15, 2010, the Commission issued a Procedural Order scheduling public comment hearings for November 4, 2010, in Wheeling; November 8, 2010, in Huntington; November 9, 2010, in Beckley; and November 16, 2010, in Charleston, West Virginia, and, further directing APCo/WPCo to publish notice of public comment and evidentiary hearings in each county in which they provide service. The public comment hearings were conducted as scheduled. Commissioners Michael A. Albert, Ryan B. Palmer and Jon W. McKinney presided at the public comment hearings.

APCo/WPCo filed affidavits of publication, indicating that it properly published notice of its filing, as required by the June 25, 2010 Order, and that it satisfied all public notice requirements of the public comment and evidentiary hearings in this proceeding as required by the October 15, 2010 Order. Affidavits of publication filed September 10, 2010, and December 22, 2010.

On October 22, 2010, the Companies filed corrections to the pre-filed direct testimony and exhibits of Charles R. Patton, Jeffrey L. Brubaker, Steven H. Ferguson, and Dennis W. Bethel.

On November 10, 2010, the Staff filed the direct testimony and exhibits of Thomas D. Sprinkle, Edwin L. Oxley, Randall Short, and Earl E. Melton, as well as the Staff Rule 42 Exhibits for APCo and WPCo. CAD filed the direct testimony and exhibits of Byron L. Harris, Deanna Lynne White, Ralph C. Smith, and Barbara R. Alexander. WVEUG filed the direct testimony and exhibits of Stephen J. Baron and Richard A. Baudino. Kroger filed the direct testimony and exhibits of Kevin C. Higgins. SWVI filed the direct testimony and exhibits of Dennis W. Goins. Wal-Mart filed the direct testimony and exhibits of Steve W. Chriss.

On November 17, 2010, the Companies filed a letter indicating that they would soon file a motion for protective treatment of information in the pre-filed direct testimony and exhibits of CAD witness, Ralph C. Smith concerning the Companies' incentive compensation program, and a redacted version of those documents. The Companies stated this information was made available to CAD during the discovery process pursuant to a protective agreement between CAD and the Companies.

On November 23, 2010, CAD filed the rebuttal testimony and exhibits of Byron L. Harris, Deanna Lynne White, and Ralph C. Smith, and Kroger filed the rebuttal testimony and exhibits of Kevin C. Higgins.

On November 24, 2010, the Companies filed the rebuttal testimony and exhibits of Steven H. Ferguson, William E. Avera, Marc D. Reitter, Jay Joyce, Andrew R. Carlin, Jeffrey L. Brubaker, Mark A. Pyle, Robert W. Hriszko, Jeffrey D. Lafleur, James D. Fawcett, Hugh E. McCoy, Larry C. Foust, and David M. Roush.

On November 24, 2010, Staff filed the rebuttal testimony and exhibits of Randall Short and Edwin L. Oxley. WVEUG filed the rebuttal testimony of Stephen J. Baron.

On November 29, 2010, the Companies filed a Motion for Protective Order requesting protective treatment of portions of the direct testimony of CAD witness Ralph C. Smith. The Motion sought protective treatment of portions of Exhibit LA-2 related to the Companies' incentive compensation plans. The Companies stated they did not seek protective treatment of pages 48 or 49 of Mr. Smith's direct testimony, also filed as confidential, after reviewing the information and determining that it was not confidential. The Companies also filed a confidential version of Exhibit LA-2 that is currently under seal with the Commission Executive Secretary's office.

On December 1, 2010, the Commission issued an Order, directing the parties wishing to file a response to the Companies' motion for protective order to file a response on or before December 6, 2010. No response was filed.

On December 6, 2010, Staff filed a motion for leave to amend and file the amended direct testimony of Thomas D. Sprinkle.

On December 10, 2010, the Companies filed a letter indicating that the parties, except SBNA, have been engaged in negotiations respecting a settlement in this proceeding. On behalf of the stipulating parties, the Companies stated they intended to file a Joint Stipulation and Agreement for Settlement (Joint Stipulation) to resolve issues in the pending rate proceeding. On behalf of the stipulating parties, the Companies requested an amended procedural schedule for the evidentiary hearing.

On December 10, 2010, the Commission entered an Order, establishing the procedure for the evidentiary hearing in this matter in light of the December 10, 2010 filing and the Joint Stipulation expected to be filed in the case. The Order scheduled the hearing to begin Monday, December 13, 2010, as published, and to resume Wednesday, December 15, 2010, for the presentation of the proposed Joint Stipulation.

Mr. Steven H. Ferguson, Director of Regulatory Services at APCo, testified regarding the key elements of the Joint Stipulation at the December 15, 2010 hearing. Id. at 77-88. He testified that Attachment A included in the Joint Stipulation was the Companies' illustrative cost of service representing the parties' positions, with the understanding that not all parties will get to the final result to Attachment A in the same way. Id. at 78. Mr. Ferguson testified regarding the difference between the Companies' proposed rate increase and the Joint Stipulation rate increase. He attributed the differences in the rates to reductions in costs related to actual costs as compared to proposed costs for the Companies' severance package and West Virginia share of the 2009 storm damage. Id. at 92-94. Mr. Ferguson testified that the illustrative cost of service revenue requirement attached to the Joint Stipulation represented the Companies' method of arriving at the stipulated rates. Id. at 93-95. He explained the items listed in the Companies' illustrative cost of service revenue requirement. Id. at 95-118.

Responding to questions from Commissioners McKinney and Palmer regarding executive compensation, Mr. Ferguson testified that the Companies' proposed executive compensation costs were consistent with the compensation levels for executives in utilities or other industries across the country. Id. at 118, 119. Mr. Ferguson testified that executive compensation constituted a small, almost insignificant, percentage of the overall rates the customer is charged. Id. at 119.

CAD witness Byron Harris testified regarding the Joint Stipulation resolution of the CAD positions and issues in the proceeding. Mr. Harris testified that the Companies' initial proposed revenue increase had a disproportionate allocation of the revenue increase to the residential customers. Id. at 128. He testified that the $60 million revenue increase resulted in a decent outcome for residential customers, compared to the Companies' initial proposal. Id. at 128, 129. Mr. Harris testified that the Joint Stipulation at paragraphs 34 and 36 included the recommendations of CAD witness Alexander to assist the working poor or near poor customers and low income customers. Id. at 132-134. He testified that the Joint Stipulation also included the recommendations of CAD witness Alexander regarding service delay of reconnection, removing obstacles to customers getting on the Average Payment Plan, and having the Companies track information regarding customer collection and credit practices. Id. Mr. Harris stated the Joint Stipulation proposed revenue increase, the allocation, and the policy changes will benefit the residential customers. Id. at 134. He stated that the Joint Stipulation was reasonable and in the public interest. Id. Upon cross-examination by WVEUG counsel, Mr. Williamson, Mr. Harris testified that the revenue allocation in Attachment B of the Joint Stipulation represented a compromise between WVEUG and the CAD. Id. at 135.

Staff Witness Edwin Oxley testified regarding the Staff revenue requirement calculation and presented Staff Exhibit No. 1, showing the Staff revenue requirement calculation for the Joint Stipulation. Id. at 142, 143; Staff Exhibit No. 1. Mr. Oxley stated that Staff recommended a rate increase of $41.6 million, as shown in prefiled direct testimonies of Staff Witnesses. Id. at 146. Mr. Oxley explained the various Staff adjustments shown in Staff Exhibit No. 1 related to adjusted going level revenues related to test year bank amortization; the transfer of RTEP costs to the ENEC; the storm damage and eight-year amortization of the storm damage; short-term debt and long-term debt; the Staff recommendation of a return on equity to 10 percent; Staff's adoption of the CAD federal income tax rate of 22.39 percent; amortization of employee severance costs; inclusion of investment projects for Amos No. 2 reheater project and Amos No. 2 turbine modifications; inclusion of the Companies' direct incentive plan costs, and an adjustment to 2009 non-ENEC expenses. Id. at 144-152. Mr. Oxley testified that the Joint Stipulation represented a reasonable resolution of the issues presented in the proceeding. Id. at 152. Mr. Oxley testified that the Joint Stipulation represented a reasonable resolution of the parties' position in the rate case. Id. at 152.

The Commission asked the Companies, Staff and CAD to provide a Commission Request Exhibit after the hearing detailing how executive compensation is accounted for in the parties' revenue requirement recommendations and detailing the parties positions on other items in their cost of service. Id. at 120, 121.

On December 17, 2010, CAD filed its post-hearing Commission Request Exhibit-CAD, reflecting CAD's illustrative calculation of the cost of service in the settlement, including a return on equity of 10 percent.

On December 30, 2010, APCo/WPCo filed the Commission Request Exhibits No. 1 and 2. In the Commission Request Exhibit No. 1, the Companies provided an analysis of the Joint Stipulation rates, explaining the differences between the Companies proposed revenue requirements and the revenue requirements agreed upon by the parties. The Exhibit showed the revenue deficiency calculation for settlement analysis, including a series of line item adjustments. According to the Companies' Commission Request No. 1, the Joint Stipulation weighted cost of capital is 7.75 percent, the return on equity is 10.5 percent, the rate base as adjusted is $2,518,700, the return on rate base is $195,200 and the total requested revenue increase is $60 million.

In the Companies' Commission Request Exhibit No. 2, the Companies explained its views on executive compensation. The Companies asserted that the compensation levels provided to its executive positions are market competitive and set at levels designed to attract, retain, and fairly remunerate human talent needed to perform the necessary functions of the positions. The Companies asserted that its executive compensation levels are in the middle of the spectrum for compensation for comparable positions throughout the country. The Companies noted the base levels of executive compensation was not a contested issue, although the issue of incentive compensation was a contested issue in the proceeding. The Companies stated they took into consideration the emergence of incentive executive compensation as a contested issue as an operative factor in the overall negotiated settlement. The Companies stated this factor influenced the overall settlement numbers to which the Companies agreed. The Companies stated three of the specific adjustments included on the Commission Request Exhibit No. 1 (net payroll savings, incentive adjustment and adjust production O&M) reflected in part reductions to the levels of executive compensation in the Companies' original filing. The Companies acknowledged the issue of executive compensation evoked a visceral reaction from some members of the public and holders of public office. The Companies asserted, however, they must pay market prices for the executive talent it needs to fulfill the corporate responsibilities to its shareholders.

On January 13, 2011, the Companies filed a Motion for Extension, requesting a one week extension to file rates to implement the proposed Joint Stipulation.

On January 14, 2011, the Commission granted the Companies' Motion for Extension and ordered the Stipulating parties to file the Stipulated rates on or before January 21, 2011.

On January 21, 2011, the Companies filed the rates reflecting the settlement reached in the Joint Stipulation.

PUBLIC SERVICE COMMISSION OF WEST VIRGINIA
CHARLESTON

CASE NO. 10-0699-E-42T

APPALACHIAN POWER COMPANY and
WHEELING POWER COMPANY,
public utilities.

Joint Application for Rate Increases on Notice with Proposed Effective Dates and Changes in Tariff Provisions, Pursuant to W.Va. Code, §24-2-4a, and Approval of a Transmission Rate Adjustment Clause Rider.

JOINT STIPULATION AND AGREEMENT FOR SETTLEMENT

Pursuant to *W. Va. Code* 24-1-9(f) and Rule 13.4 of Title 150, Series 1, *Rules of Practice and Procedure*, the following parties to this proceeding (hereinafter "the Stipulating Parties"), Appalachian Power Company ("APCo") and Wheeling Power Company ("WPCo") (collectively "the Companies"), the Staff of the Public Service Commission of West Virginia ("the Staff"), the Consumer Advocate Division of the Public Service Commission of West Virginia ("the CAD"), E.I. du Pont de Nemours and Company, Huntington Alloys Corporation, Bayer CropScience, Bayer MaterialScience, PPG Industries, Inc., Air Products & Chemicals, Inc., Alcan Rolled Products, EQT Corporation, and Globe Metallurgical, referred to collectively as West Virginia Energy Users Group ("WVEUG"), The Kroger Co. ("Kroger"), Wal-Mart Stores East, LP and Sam's East, Inc. ("Walmart"), and Steel of West Virginia, Inc. ("SWVA, Inc.") join in this Joint Stipulation and Agreement for Settlement ("this Agreement"), and request that the Commission approve and adopt it, in its entirety and without modification, as the full and final resolution of all issues in the instant proceeding. The only other party to this proceeding, South Bluefield Neighborhood Association, did not participate in settlement discussions, despite being invited to participate, and is not a signatory to this Agreement. In support of this Agreement, the Stipulating Parties make the following representations:

Procedural History

1. On May 14, 2010, the Companies filed their Application to increase base rates, request approval of a Transmission Rate Adjustment Clause, and make changes in classifications, charges, rules and regulations, and other tariff provisions. The Application was supported by seven volumes, including Rule 42 data, workpapers, proposed tariffs, a class cost of service study, and 2009 annual reports of the Companies and their parent, American Electric Power Company, Inc. ("AEP").

2. On June 10, 2010, the Staff moved to dismiss the application, alleging that the Companies did not comply with several filing requirements. Alternatively, the Staff advised that it would agree to tolling the statutory time period to process this matter if the Companies wanted to file a corrective Tariff Rule 42 financial exhibit. The CAD and WVEUG filed subsequent letters in support of the Staff's motion.

3. On June 11, 2010, the Commission suspended the revised tariff sheets and use of the filed rates and charges until March 11, 2011.

4. On June 17, 2010, the Companies filed a response to the Staff's motion, which included additional Rule 42 documentation responsive to the concerns identified by the Staff. In their response, the Companies informed the Commission that they had reached an agreement with the Staff, the CAD, and WVEUG to toll the statutory suspension period by twenty days and they proposed a new procedural schedule.

5. On June 25, 2010, the Commission issued an Order which, among other things, suspended the use of the rates and charges stated in the Companies' revised tariff sheets until March 31, 2011 and approved the proposed procedural schedule.

6. At various dates various entities filed petitions to intervene, which were granted by the Commission.

7. On July 23, 2010, the Companies filed the direct testimony and exhibits of Charles R. Patton, Steven H. Ferguson, William E. Avera, Marc D. Reitter, Jeffrey D. LaFleur, James D. Fawcett, Phillip A. Wright, David B. Weiss, Larry C. Foust, Dennis W. Bethel, Diana L. Gregory, Jay Joyce, Andrew R. Carlin, Jeffrey L. Brubaker, and Mark A. Pyle.

8. On October 22, 2010, the Companies filed corrections to the direct testimony and exhibits of Charles R. Patton, Jeffrey L. Brubaker, Steven H. Ferguson, and Dennis W. Bethel.

9. The Companies provided public notice in substantial compliance with the Commission's directions.

10. In the course of the discovery phase of this proceeding, numerous requests for information were filed by various parties and responded to by the parties to whom they were addressed.

11. The Commission conducted public comment hearings on November 5, 2010 in Wheeling, on November 8, 2010 in Huntington, on November 9, 2010 in Beckley, and on November 16, 2010 in Charleston. The Companies, the Staff, and the CAD appeared at each of those hearings.

12. On November 10, 2010, the Staff filed the direct testimony and exhibits of Thomas D. Sprinkle, Edwin L. Oxley, Randall R. Short, and Earl E. Melton, as well as Staff Rule 42 Reports for APCo and WPCo; the CAD filed the direct testimony and exhibits of Byron L. Harris, Deanna Lynne White, Ralph C. Smith, and Barbara R. Alexander; WVEUG filed the direct testimony and exhibits of Stephen J. Baron and Richard A. Baudino; The Kroger Co. filed the direct testimony and exhibits of Kevin C. Higgins; Steel of West Virginia filed the direct testimony and exhibits of Dennis W. Goins; and Wal-Mart filed the direct testimony and exhibits of Steve W. Chriss.

13. On November 23, 2010, the CAD filed the rebuttal testimony and exhibits of Byron L. Harris, Deanna Lynne White, and Ralph C. Smith and Kroger filed the rebuttal testimony and exhibits of Kevin C. Higgins.

14. On November 24, 2010, the Companies filed the rebuttal testimony and exhibits of Steven H. Ferguson, William E. Avera, Marc D. Reitter, Jay Joyce, Andrew R. Carlin, Jeffrey L. Brubaker, Mark A. Pyle, Robert W. Hriszko, Jeffrey D. Lafleur, James D. Fawcett, Hugh E. McCoy, Larry C. Foust, and David M. Roush.

15. On November 24, 2010, the Staff filed the rebuttal testimony and exhibits of Randall R. Short and Edwin L. Oxley and WVEUG filed the rebuttal testimony of Stephen J. Baron.

16. On December 6, 2010, the Staff filed a motion for leave to amend and the amended direct testimony of Thomas D. Sprinkle.

17. Since November 17, 2010, the Stipulating Parties have engaged in settlement discussions concerning all aspects of the instant proceeding, and have now

reached agreement on a comprehensive series of proposals to recommend to the Commission as a fair and just settlement of all of the issues in this proceeding.

18. The substantive elements of the proposed settlement, which are hereby submitted for the Commission's approval, and which resolve all of the issues in this proceeding, are set forth in particular below and in the attachments hereto.

Base Rates

19. The Stipulating Parties agree that, effective March 31, 2011, the Companies' current base rates shall be increased to produce an additional $60 million of revenue on an annual basis. The Stipulating Parties agree that the Companies' new base rates shall be designed to generate a total annual West Virginia retail rate revenue requirement (excluding surcharges) of $1.167 billion.

20. The stipulated revenue requirement reflects the impact of rolling into base rates the Musser Surcharge as well as current Construction Surcharges other than that associated with the Amos Unit No. 1 Flue Gas Desulfurization facilities.

21. Attachment A hereto, which is incorporated herein by reference, provides the Companies' illustrative cost of service showing a derivation of the Companies' annual West Virginia retail rate revenue requirement. Although none of the Stipulating Parties necessarily agrees with each and every item in this cost of service, all of the Stipulating Parties agree that the overall cost of service is reasonable and should be adopted by the Commission.

22. The Stipulating Parties have not reached an agreement on a specific return on equity ("ROE"), but they acknowledge that for the calculation of AFUDC, the

Companies shall be entitled to use the ROE authorized by the Commission in the Companies' last base rate case, Case No. 05-1278-E-PC-PW-42T.

23. The Stipulating Parties agree that it is reasonable to permit the Companies to defer and amortize their 2009 extraordinary storm expenses, up to $18.2 million over a period of eight years.

24. The Stipulating Parties agree that the Companies shall record deferred federal income taxes related to the catch-up deduction (§481 Adjustment) taken on the federal income tax return related to the change in tax accounting for the definition of units of property assets. These deferred federal income taxes shall be recorded by debiting Account 410-Deferred Federal Income Tax Expense and crediting Account 282-Deferred Federal Income Tax Liability. The Deferred Federal Income Tax Liability shall reverse as the related assets are depreciated for book purposes. All annual future tax deductions related to the units of property shall be treated as flow-through deductions for ratemaking purposes and shall not have any deferred federal income taxes recorded for ratemaking purposes.

Allocation and Rate Design

25. The Stipulating Parties agree that the rate increase stipulated in this Agreement will be allocated among customer classes, rate schedules, and special contracts in accordance with Attachment B hereto, which is incorporated herein by reference.

26. The Stipulating Parties agree that the customer charge for residential customers shall be set at $5.00 per month and that the declining block structure of Schedule RS shall be retained.

27. The Stipulating Parties agree to a combination of rate schedules MGS and LGS into a single rate schedule GS and the design of rates under rate schedule GS to reflect the equivalent of a demand charge of 80% of full demand costs. The customer charge component of the GS rates shall be set at the following levels for different delivery voltages: $21 for secondary, $100 for primary, $250 for subtransmission, and $350 for transmission.

28. The Companies agree to withdraw their proposal to combine rate schedules LCP and IP into a single rate schedule LPS.

29. The Stipulating Parties agree that the demand charges in the rates designed for Schedule LCP shall reflect 80% of full demand costs and that the demand charges in the rates designed for Schedule IP shall reflect 90% of full demand costs.

30. The Stipulating Parties agree to submit to the Commission by January 14, 2011, a complete set of rates reflecting the settlement reached in this Agreement.

Transmission Tracker

31. The Stipulating Parties agree that a transmission cost tracking and surcharge mechanism shall not be instituted in this proceeding.

Regional Transmission Expansion Plan ("RTEP") Costs

32. The Stipulating Parties agree that no RTEP costs are included in the Companies' base rates and that the Companies shall seek recovery of RTEP costs in future ENEC proceedings, with the understanding that each party is free to advocate in the ENEC whatever substantive position it chooses on the level of RTEP costs to be recovered. On that basis, the Companies agree to withdraw from this case their proposal for recovery of RTEP costs through their base rates.

Tariff Language Modifications

33. The Stipulating Parties agree to the modifications which the Companies proposed to the language of their Tariffs with the following exceptions: (a) the Companies agree to withdraw their proposed modifications to the limitation of liability provisions of their Tariffs; (b) the Companies agree to withdraw the following proposed addition to their Tariff Terms & Conditions: "Where service has been disconnected at the customer's request to allow for service upgrade, the customer must contact the Company by 1:30 PM so as to be reconnected on the same day. If the customer contacts the Company after 1:30 PM, a one time fee may be charged if service cannot be reconnected by 5:00 PM."; and (c) the Stipulating Parties agree to the Companies' proposed Tariff modification on remote disconnection with an added express provision conditioning remote disconnection upon prior personal contact with the customer as directed under Rule 4.8.1 of the Commission's Electric Rules.

Customer Payment Issues

34. The Companies agree to allow residential customers who are not current in their payments the option of enrolling in the Average Monthly Payment Plan, provided an agreeable deferred payment plan of up to twelve months can be established pursuant to the Commission's Rules.

35. The Companies agree to allow residential customers whose service has been terminated to include arrearages, customer deposits, and reconnection fees into a deferred payment plan, provided an agreeable plan can be established pursuant to the Commission's Rules.

36. The Companies agree to track the following metrics regarding their credit/collections policies:

a. The number of past due accounts per billing period;
b. The dollar amount of past due accounts per billing period;
c. For those past due accounts, the length of time over which the amount past due accrued expressed as 31-60 days, 61-90 days, and over 90 days;
d. The number of disconnection notices issued per month;
e. The number of disconnections per month for any reason other than at the request of the customer or the abandonment of the premises;
f. The number of residential reconnections following disconnection without consent per month (requests for service by new customers are excluded);
g. The number of payment plans negotiated broken down by duration of plan and the amounts associated with each duration.
h. With regard to payment plans for residential customers, the following information:
    1. The number of payment plans that were completed;
    2. The number of payment plans that were renegotiated;
i. The monthly number of deposits, the amount of deposits billed and the amount of deposits paid.

Miscellaneous

37. The Companies agree to provide, in response to a discovery request made in their next ENEC case and subject to an appropriate confidentiality agreement, firm and interruptible loads (kW and kWh) used to develop demand and energy allocation factors and, with the consent of the customers involved, the kW and kWh billing determinants for each special contract customer broken out by firm and interruptible service. No stipulating party is agreeing at this time that any of this information should be accorded permanent confidential treatment by the Commission, and each party reserves the right to

make whatever argument it deems appropriate regarding confidentiality in the ENEC proceeding.

38. The Companies agree to make an annual donation of $250,000 to the Dollar Energy Fund by December 31, 2011 for calendar year 2011 and by December 31, 2012 for calendar year 2012. These donations will be in addition to any other commitments which the Companies have made for donations to the Dollar Energy Fund for 2011 and/or 2012.

General Matters

39. The Stipulating Parties agree to the admission by stipulation of the Companies' filing and the filed testimony and exhibits of all witnesses.

40. The Stipulating Parties agree to waive their right to conduct in this proceeding any examination of the witnesses of any other party to this Agreement, except that the parties may ask clarifying questions concerning this Agreement of any witness offered in support of this Agreement.

41. This Agreement is entered into subject to the acceptance and approval of the Commission. It results from a review of any and all filings in this proceeding, of the Stipulating Parties' filed testimony and exhibits, and of extensive discovery requests and responses, and considerable detailed settlement negotiations. It reflects substantial compromises by the Stipulating Parties and the withdrawal of their respective positions asserted in this case to the extent they are inconsistent with the substantive terms of this Agreement. It is being proposed to expedite and simplify the resolution of this proceeding. It is made without any admission or prejudice to any positions which any party might adopt during subsequent proceedings. The Stipulating Parties adopt this

Agreement as being in the public interest, without adopting any of the compromise positions set forth herein as ratemaking principles applicable to future proceedings, except as expressly provided herein. The Stipulating Parties acknowledge that it is the Commission's prerogative to accept, reject, or modify any stipulation. However, in the event that this Agreement is modified or rejected by the Commission, it is expressly understood by the Stipulating Parties that they are not bound to accept this Agreement as modified or if rejected, and may avail themselves of whatever rights are available to them under law and the Commission's *Rules of Practice and Procedure*.

WHEREFORE, the Stipulating Parties, on the basis of all the foregoing, respectfully request that the Commission make appropriate Findings of Fact and Conclusions of Law adopting and approving this Joint Stipulation and Agreement for Settlement in its entirety, including the attachments hereto.

Respectfully submitted this 14th day of December, 2010.

APPALACHIAN POWER COMPANY and WHEELING POWER COMPANY

By: Oliver C. Lu

STAFF OF THE PUBLIC SERVICE COMMISSION OF WEST VIRGINIA

By: Leslie J. Anderson

CONSUMER ADVOCATE DIVISION OF THE PUBLIC SERVICE COMMISSION OF WEST VIRGINIA

By:__________________________________

WEST VIRGINIA ENERGY USERS GROUP

By: __________________________________

THE KROGER CO.

By: __________________________________

David H WV Bar #8813

WAL-MART STORES EAST, LP AND SAM'S EAST, INC.

By: __________________________________

STEEL OF WEST VIRGINIA, INC.

By:__________________________________

CONSUMER ADVOCATE DIVISION OF THE PUBLIC SERVICE COMMISSION OF WEST VIRGINIA

By: ______________________________

WEST VIRGINIA ENERGY USERS GROUP

By: ______________________________

THE KROGER CO.

By: ______________________________

WAL-MART STORES EAST, LP AND SAM'S EAST, INC.

By: ______________________________

STEEL OF WEST VIRGINIA, INC.

By: Dxenopoulos

Damon E. Xenopoulos, Esq.

Appalachian Power Company and Wheeling Power Company
Case No. 10-0699-E-42T
Companies' Illustrative Cost of Service

	$000's
Weighted Cost of Capital	7.75%
Rate Base	$2,551,000
Return on Rate Base	198,000
Federal taxes	54,000
State Taxes	5,000
Operation and Maintenance Expense	995,000
Depreciation Expense	117,000
Taxes Other Than Income	55,000
Other	(8,000)
Total Expenses	1,218,000
Total Expense and Rate Base	1,416,000
Going Level Revenues	1,292,000
Less System Sales	(225,000)
Less Other Revenue	(24,000)
Construction Surcharge	68,000
ENEC Bank Feedback	(4,000)
ARRS (Musser) *	-
Going Level Retail Revenues	1,107,000
Revenue Increase/(Decrease)	60,000
Retail Rate Revenue Requirement	$1,167,000

* Less than 1,000

Appalachian Power Company and Wheeling Power Company
Case No. 10-0699-E-42T
Revenue Allocation Settlement

	Settlement Proposal Based Adjusted Average of WVEUG-CAD Proposals	
	Dollars	Percent
Residential	$ 33,832,482	6.97%
Small General Service	$ 1,163,326	5.39%
Medium General Service	$ 5,858,492	4.84%
Large General Service	$ 4,011,020	4.30%
Large Capacity Power	$ 6,081,142	3.74%
Industrial Power TOD	$ 4,110,687	3.64%
Sanctuary Worship Service	$ 428,474	5.83%
School Service	$ 1,482,048	5.50%
Outdoor Lighting	$ 515,981	5.36%
Street Lighting	$ 182,930	5.36%
Special Contracts	$ 2,333,418	3.11%
Total West Virginia	$ 60,000,000	5.36%

Commission-Authorized Base Rate Increase

	$ 000
Staff Recommended Base Rate Increase	41,645
Commission Adjustments:	
Adjust reserve for depreciation to reflect West Virginia authorized depreciation expenses.	2,035
Adjust return on equity to 10.0% (Overall rate of return to 7.36%)	12,798
Adjust effective federal income tax rate to 25.6%	755
Remove PJM transmission costs that are moved to ENEC from O&M expenses.	(10,831)
Adjust cash working capital to include compensating bank balances.	35
Correct estimated storm damage expense and provide for a seven year average of extraordinary storm damage expenses	329
Allow ½ of Direct Employee Bonuses	1,778
Normalize effect of 2009 tax deduction related to differences between book and tax units of property capitalization policy.	6,840
Adjust revenue to eliminate credits flowed through to customers from deferred overrecoveries (ENEC bank).	4,214
Exclude return and depreciation on Mountaineer carbon capture and storage project.	(6,460)
Adjust operating costs for Mountaineer carbon capture and storage project to reflect 68 percent allocation to AEP-East operating companies.	(4,124)
Allow $2.1 million for employee severance payments.	2,108
Total Commission Authorized Base Rate Increase	51,122