BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company, d/b/a	)	
AmerenUE's Tariffs to Increase Its Annual	)	**Case No. ER-2008-0318**
Revenues for Electric Service	)	Tariff Nos. YE-2008-0605

REPORT AND ORDER

Issue Date: January 27, 2009

Effective Date: February 6, 2009

KAWC EXHIBIT
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APPEARANCES

Thomas M. Byrne, Managing Assoc. General Counsel, and **Wendy K. Tatro**, Asst. General Counsel, Ameren Services Company, P.O. Box 66149, 1901 Chouteau Ave., St. Louis, Missouri 63103;

James B. Lowery, Attorney at Law, Smith Lewis, LLP, P.O. Box 918, Suite 200, City Centre Building, 111 South Ninth St. Columbia, Missouri 65205-0918; and

James M. Fischer, Attorney at Law, Fischer & Dority, 101 Madison, Suite 400, Jefferson City, Missouri 65101.

For Union Electric Company, d/b/a AmerenUE.

Kevin Thompson, General Counsel, **Steven Dotthiem**, Chief Deputy General Counsel, **Steven Reed**, Chief Litigation Attorney, **Nathan Williams**, Deputy General Counsel, **Sarah Kliethermes**, Assistant General Counsel, and **Eric Dearmont**, Assistant General Counsel, P.O. Box 360, 200 Madison Street, Jefferson City, Missouri 65102

For the Staff of the Missouri Public Service Commission.

Lewis Mills, Public Counsel, P.O. Box 2230, 200 Madison Street, Suite 650, Jefferson City, Missouri 65102

For the Office of the Public Counsel and the Public.

Shelley Ann Woods, Assistant Attorney General, P.O. Box 899, Jefferson City, Missouri 65102

For the Missouri Department of Natural Resources.

Stuart W. Conrad, Attorney at Law, Finnegan, Conrad & Peterson, L.C., 3100 Broadway, Suite 1209, Kansas City, Missouri 64111, and

David Woodsmall, Attorney at Law, Finnegan, Conrad & Peterson, L.C., 428 East Capitol, Suite 300, Jefferson City, Missouri 65101

For Noranda Aluminum, Inc.

Michael C. Pendergast, Vice President and Associate General Counsel, Laclede Gas Company, 720 Olive Street, Room 1520, St. Louis, Missouri 63101.

For Laclede Gas Company.

H. Todd Iveson, Assistant Attorney General, and **Robert Carlson**, Assistant Attorney General, P.O. Box 899, Jefferson City, Missouri 65102.

For The State of Missouri.

Henry B. Robertson, Attorney at Law, Great Rivers Environmental Law Center, 705 Olive Street, Suite 614, St. Louis, Missouri 63101.

For Missouri Coalition for the Environment and Missourians for Safe Energy.

Diana Vuylsteke, Attorney at Law, Bryan Cave, LLP, 211 N. Broadway, Suite 3600, St. Louis, Missouri 63102.

For Missouri Industrial Energy Consumers.

Lisa C. Langeneckert, Attorney at Law, Sandberg, Phoenix & Von Gontard, P.C., One City Centre, 15th Floor, St. Louis, Missouri 63101-1880.

For Missouri Energy Group.

John B. Coffman, Attorney at Law, John B. Coffman, LLC, 871 Tuxedo Blvd, St. Louis, Missouri 63119-2044.

For AARP

Michael A. Evans, Attorney at Law, Hammond, Shinners, Turcotte, Larrew and Young, P.C. 7730 Carondelet Ave., Suite 200, St. Louis, Missouri 63105.

For International Brotherhood of Electrical Workers Locals 2, 309, 649, 702, 1439, 1455, AFL-CIO and International Brotherhood of Operating Engineers Local 148, AFL-CIO.

Rick D. Chamberlain, Attorney at Law, Behrens, Taylor, Wheeler & Chamberlain, 6 N.E. 63rd, Suite 400, Oklahoma City, Oklahoma 73102, and

Koriambanya S. Carew, Attorney at Law, Baker Sterchi Cowden & Rice, LLC, 2400 Pershing Road, Suite 500, Kansas City, Missouri 64108.

For The Commercial Group.

<u>DEPUTY CHIEF REGULATORY LAW JUDGE</u>: Morris L. Woodruff

REPORT AND ORDER

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The Missouri Public Service Commission, having considered all the competent and substantial evidence upon the whole record, makes the following findings of fact and conclusions of law. The positions and arguments of all of the parties have been considered by the Commission in making this decision. Failure to specifically address a piece of evidence, position, or argument of any party does not indicate that the Commission has failed to consider relevant evidence, but indicates rather that the omitted material was not dispositive of this decision.

Summary

This order allows AmerenUE to increase the revenue it may collect from its Missouri customers by approximately $162.6 million, based on the data contained in the True-up Reconciliation filed by the Missouri Public Service Commission Staff on January 9, 2009.

Procedural History

On April 4, 2008, Union Electric Company, d/b/a AmerenUE filed tariff sheets designed to implement a general rate increase for electric service. The tariff would have increased AmerenUE's annual electric revenues by approximately $251 million. The tariff revisions carried an effective date of May 4, 2008.

By order issued on April 7, 2008, the Commission suspended AmerenUE's tariff until March 1, 2009, the maximum amount of time allowed by the controlling statute.[1] In the same order, the Commission directed that notice of AmerenUE's tariff filing be provided to interested parties and the public. The Commission also established April 28 as the deadline for submission of applications to intervene. The following parties filed applications and were allowed to intervene: Noranda Aluminum, Inc.; The State of Missouri; The International Brotherhood of Electrical Workers Locals 2, 309, 649, 702, 1439, and 1455, AFL-CIO and International Union of Operating Engineers Local 148 AFL-CIO (collectively the Unions); The Missouri Industrial Energy Consumers (MIEC);[2] The Missouri Energy Group (MEG);[3] The Missouri Department of Natural Resources; Laclede Gas Company; The Consumers Council of Missouri; AARP; The Commercial Group;[4] and Missouri

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[1] Section 393.150, RSMo 2000.

[2] The members of MIEC are Anheuser-Busch Companies, Inc.; BioKyowa, Inc.; The Boeing Company; Chrysler; Doe Run; Enbridge; Explorer Pipeline; GKN Aerospace; General Motors Corporation; Hussmann Corporation; JW Aluminum; Monsanto; Pfizer; Precoat Metals; Proctor & Gamble Company; Nestlé Purina PetCare; Solutia; and U.S. Silica Company.

[3] The members of MEG are Barnes–Jewish Hospital; Buzzi Unicem USA, Inc.; and SSM HealthCare.

[4] The members of the Commercial Group are JCPenney Corporation and Wal-Mart Stores East, LP.

Coalition for the Environment and Missouri Nuclear Weapons Education Fund, d/b/a Missourians for Safe Energy.

On May 29, 2008, the Commission established the test year for this case as the 12-month period ending March 31, 2008, with certain pro forma adjustments through September 30, 2008, trued-up as of September 30, 2008. In its May 29 order, the Commission established a procedural schedule leading to an evidentiary hearing.

In September, the Commission conducted fourteen local public hearings at various sites around AmerenUE's service area. At those hearings, the Commission heard comments from AmerenUE's customers and the public regarding AmerenUE's request for a rate increase.

In compliance with the established procedural schedule, the parties prefiled direct, rebuttal, and surrebuttal testimony. The evidentiary hearing began on November 20, and continued on November 21, 24 and 25, as well as December 1-4 and December 10-12. The parties indicated they had no contested true-up issues and Commission cancelled the true-up hearing scheduled for January 6 and 7, 2009. The parties filed post-hearing briefs on January 8. Based on the true-up reconciliation filed by Staff on January 5, 2009, AmerenUE's rate increase request has been reduced to $187,829,805. That same reconciliation indicates that each party has taken positions that will allow AmerenUE a rate increase of at least $66 million.

The Partial Stipulations and Agreements

During the course of the evidentiary hearing, various parties filed two nonunanimous partial stipulations and agreements resolving several issues that would otherwise have been the subject of testimony at the hearing. No party opposed those partial stipulations and agreements. As permitted by its regulations, the Commission treated the unopposed partial stipulations and agreements as unanimous.[5] After considering both stipulations and agreements, the Commission approved them as a resolution of the issues addressed in those agreements.[6] The issues that were resolved in those stipulations and agreements will not be further addressed in this report and order, except as they may relate to any unresolved issues.

During the course of the hearing, the Office of the Public Counsel, Noranda, MIEC, MEG, and the Commercial Group filed a third non-unanimous stipulation and agreement that would have resolved various class cost of service and rate design issues. The Commission's Staff opposed that non-unanimous stipulation and agreement and as provided in the Commission's rules, the Commission will consider that stipulation and agreement to be merely a position of the signatory parties to which no party is bound.[7] The issues that were the subject of that stipulation and agreement shall be determined in this report and order.

Overview

AmerenUE is an investor-owned utility providing retail electric service to large portions of Missouri, including the St. Louis Metropolitan area. AmerenUE has approximately 1.2 million retail electric customers in Missouri, more than 1 million of which

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[5] Commission Rule 4 CSR 240-2.115(C).

[6] The Commission issued an *Order Approving Stipulation and Agreement as to All FAC Tariff Rate Design Issues* and an *Order Approving Stipulation and Agreement as to Off-System Sales Related Issues* on December 30, 2008.

[7] Commission Rule 4 CSR 240-2.115(2)(D).

are residential customers.[8] AmerenUE also operates a natural gas utility in Missouri but the rates it charges for natural gas are not at issue in this case.

AmerenUE began the rate case process when it filed its tariff on April 4, 2008. In doing so, AmerenUE asserted it was entitled to increase its retail rates by $250.8 million per year, an increase of approximately 12.1 percent.[9] AmerenUE set out its rationale for increasing its rates in the direct testimony it filed along with its tariff on April 4. In addition to its filed testimony, AmerenUE provided work papers and other detailed information and records to the Staff of the Commission, Public Counsel, and to the intervening parties. Those parties then had the opportunity to review AmerenUE's testimony and records to determine whether the requested rate increase was justified.

This is a complex case with many issues and it is easily understandable why the parties could, in fact, disagree on a multitude of those issues. Fortunately, the parties were able to resolve their differences on many issues. Where the parties disagreed, they prefiled written testimony for the purpose of raising those issues to the attention of the Commission. All parties were given an opportunity to prefile three rounds of testimony – direct, rebuttal, and surrebuttal. The process of filing testimony and responding to the testimony filed by other parties revealed areas of agreement that resolved some issues and areas of disagreement that revealed new issues. On November 12, the parties filed a Joint Statement of Issues listing the issues they asked the Commission to resolve.

As previously indicated, a number of the identified issues were resolved by the approved partial stipulations and agreements and will not be further addressed in this report and order. The remaining issues will be addressed in turn.

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[8] Voss Direct, Ex. 1, Page 2, Lines 21-22.

[9] Voss Direct, Ex. 1, Page 3, Lines 17-18.

Conclusions of Law Regarding Jurisdiction

AmerenUE is a public utility, and an electrical corporation, as those terms are defined in Section 386.020(43) and (15), RSMo (Supp. 2008). As such, AmerenUE is subject to the Commission's jurisdiction pursuant to Chapters 386 and 393, RSMo.

Section 393.140(11), RSMo 2000, gives the Commission authority to regulate the rates AmerenUE may charge its customers for electricity. When AmerenUE filed a tariff designed to increase its rates, the Commission exercised its authority under Section 393.150, RSMo 2000, to suspend the effective date of that tariff for 120 days beyond the effective date of the tariff, plus an additional six months.

Conclusions of Law Regarding the Determination of Just and Reasonable Rates

In determining the rates AmerenUE may charge its customers, the Commission is required to determine that the proposed rates are just and reasonable.[10] AmerenUE has the burden of proving its proposed rates are just and reasonable.[11]

In determining whether the rates proposed by AmerenUE are just and reasonable, the Commission must balance the interests of the investor and the consumer.[12] In discussing the need for a regulatory body to institute just and reasonable rates, the United States Supreme Court has held as follows:

> Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the services are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment.[13]

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[10] Section 393.150.2, RSMo 2000.

[11] *Id.*

[12] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603, (1944).

[13] *Bluefield Water Works & Improvement Co. v. Public Service Commission of the State of West Virginia*, 262 U.S. 679, 690 (1923).

In the same case, the Supreme Court provided the following guidance on what is a just and reasonable rate:

> What annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.[14]

The Supreme Court has further indicated:

> '[R]egulation does not insure that the business shall produce net revenues.' But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[15]

In undertaking the balancing required by the Constitution, the Commission is not bound to apply any particular formula or combination of formulas. Instead, the Supreme Court has said:

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[14] *Id.* at 692-93.

[15] *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944) (citations omitted).

> Agencies to whom this legislative power has been delegated are free, within the ambit of their statutory authority, to make the pragmatic adjustments which may be called for by particular circumstances.[16]

Furthermore, in quoting the United States Supreme Court in *Hope Natural Gas,* the Missouri Court of Appeals said:

> [T]he Commission [is] not bound to the use of any single formula or combination of formulae in determining rates. Its rate-making function, moreover, involves the making of 'pragmatic adjustments.' ... Under the statutory standard of 'just and reasonable' it is the result reached, not the method employed which is controlling. It is not theory but the impact of the rate order which counts.[17]

The Rate Making Process

The rates AmerenUE will be allowed to charge its customers are based on a determination of the company's revenue requirement. AmerenUE's revenue requirement is calculated by adding the company's operating expenses, its depreciation on plant in rate base, taxes, and its rate of return multiplied by its rate base. The revenue requirement can be expressed as the following formula:

Revenue Requirement = E + D + T + R(V-AD+A)
Where: E = Operating expense requirement
D = Depreciation on plant in rate base
T = Taxes including income tax related to return
R = Return requirement
(V-AD+A) = Rate base
For the rate base calculation:
V = Gross Plant
AD = Accumulated depreciation
A = Other rate base items

All parties accept the basic formula. Disagreements arise over the amounts that should be included in the formula.

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[16] *Federal Power Commission v. Natural Gas Pipeline Co.* 315 U.S. 575, 586 (1942).

[17] *State ex rel. Associated Natural Gas Co. v. Pub. Serv. Comm'n*, 706 S.W. 2d 870, 873 (Mo. App. W.D. 1985).

The Issues

1. Rate of Return

Introduction:

This issue concerns the rate of return AmerenUE will be authorized to earn on its rate base. Rate base includes things like generating plants, electric meters, wires and poles, and the trucks driven by AmerenUE's repair crews. In order to determine a rate of return, the Commission must determine AmerenUE's cost of obtaining the capital it needs.

a. Capital Structure

Findings of Fact:

The relative mixture of sources AmerenUE uses to obtain the capital it needs is its capital structure. All parties agree that AmerenUE's actual capital structure should be used for purposes of establishing its rates in this case. In his rebuttal testimony, AmerenUE's witness, Michael G. O'Bryan described AmerenUE's actual capital structure as of March 31, 2008 as:

Long-Term Debt	45.532%
Short-Term Debt	00.722%
Preferred Stock	01.737%
Common Equity	52.009%[18]

That structure is slightly different from the actual capital structure as of March 31, 2008 that O'Bryan described in his supplemental direct testimony. At that time, O'Bryan indicated the common equity component made up 50.928% of the structure.[19] In his rebuttal testimony, O'Bryan explained that the adjustment to common equity had occurred because he had previously adjusted the March 31 common equity balance to remove any

[18] O'Bryan Rebuttal, Ex. 8, Schedule MGO-RE1.

[19] O'Bryan Supplemental Direct, Ex. 7, Schedule MGO-E5.

earnings related to unregulated subsidiaries. AmerenUE had historically made that adjustment to remove any earnings related to unregulated subsidiaries, so that unregulated earnings would not have an impact on the company's regulated capital structure. [20] As of March 31, AmerenUE no longer owned the subsidiaries, so the adjustment was no longer necessary.[21] As a result, O'Bryan's adjustment to common equity in his rebuttal testimony was intended simply to correct a mistake in his description of the actual capital structure contained in his supplemental direct testimony.

If the retained earnings had already been removed from AmerenUE's March 31 capital structure, as they should have been since the company no longer owned the unregulated subsidiaries, O'Bryan's original adjustment to remove costs that were not there would be unnecessary, and would understate the proportion of common equity in AmerenUE's actual capital structure. O'Bryan's decision to reverse his previous adjustment would increase AmerenUE's revenue requirement by $7.6 million.[22]

In his surrebuttal testimony, Staff's witness, Stephen Hill, accused O'Bryan of improperly adding back to the capital structure the retained earnings of unregulated subsidiaries that he had previously correctly removed from the capital structure.[23] Hill and O'Bryan agree that the retained earnings of the unregulated subsidiaries do not belong in the capital structure. The real question is whether those retained earnings are in fact in AmerenUE's capital structure as of March 31, 2008.

Hill does not offer any independent evidence or calculation to show that retained

[20] O'Bryan Rebuttal, Ex. 8, Page 8, Lines 1-6.

[21] O'Bryan Supplemental Direct, Ex. 7, Page 3, Lines 20-21.

[22] Weiss Rebuttal, Ex. 12, Page 16, Lines 8-14.

[23] Hill Surrebuttal, Ex. 205, Page 8, Lines 4-8.

earnings of unregulated subsidiaries are in the March 31, 2008 capital structure described by O'Bryan in his rebuttal testimony. Instead, he seizes on a line in O'Bryan's rebuttal testimony that says AmerenUE's UES month-end March 2008 accounts were corrected to a zero balance subsequent to the filing of O'Bryan's supplemental direct testimony.[24] Hill reasons that if the retained earnings were not removed from the account until after O'Bryan filed his supplemental direct testimony, then they must have still been in the account at the time O'Bryan originally calculated the capital structure he reported in his supplemental direct testimony. Therefore, O'Bryan would still need to make his adjustment to remove the retained earnings from the capital structure.

Considering it is worth $7.6 million, the parties paid amazingly little attention to this issue. Neither Hill nor O'Bryan were effectively cross-examined about this issue at the hearing, and neither Staff nor AmerenUE effectively addressed the issue in their briefs.

Hill's position is understandable as a matter of bare logic. However, it does not account for the likelihood that O'Bryan in fact used the corrected account balance when he reported the revised capital structure in his rebuttal testimony, even though he does not report that fact in his testimony. Given the paucity of evidence on this issue, the Commission finds O'Bryan's representations to be more credible than the theory offered by Hill. Accordingly, the Commission finds that the correct capital structure is that described by O'Bryan in his rebuttal testimony.

Conclusions of Law:

There are no additional conclusions of law for this issue.

Decision:

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[24] O'Bryan Rebuttal, Ex. 8, Page 8, Lines 12-13.

The Commission finds that AmerenUE's actual capital structure as of March 31, 2008, is

Long-Term Debt	45.532%
Short-Term Debt	00.722%
Preferred Stock	01.737%
Common Equity	52.009%

b. Return on Equity

Introduction:

Determining an appropriate return on equity is without a doubt the most difficult part of determining a rate of return. The cost of long-term debt and the cost of preferred stock are relatively easy to determine because their rate of return is specified within the instruments that create them. In contrast, in determining a return on equity, the Commission must consider the expectations and requirements of investors when they choose to invest their money in AmerenUE rather than in some other investment opportunity. As a result, the Commission cannot simply find a rate of return on equity that is unassailably scientifically, mathematically, or legally correct. Such a "correct" rate does not exist. Instead, the Commission must use its judgment to establish a rate of return on equity attractive enough to investors to allow the utility to fairly compete for the investors' dollar in the capital market, without permitting an excessive rate of return on equity that would drive up rates for AmerenUE's ratepayers. In order to obtain guidance about the appropriate rate of return on equity, the Commission considers the testimony of expert witnesses.

Four financial analysts offered recommendations regarding an appropriate return on equity in this case. Dr. Roger A. Morin testified on behalf of AmerenUE. Dr. Morin is

Emeritus Professor of Finance at Robinson College of Business, Georgia State University, and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry at Georgia State University. He holds a Ph.D. in Finance and Econometrics from the Wharton School of Finance, University of Pennsylvania.[25] He recommends the Commission allow AmerenUE a return on equity of 10.9 percent if AmerenUE is allowed to establish a fuel adjustment clause.[26] If AmerenUE is not allowed to establish a fuel adjustment clause, Dr. Morin recommends a return on equity of 11.15 percent.[27]

Stephen G. Hill testified on behalf of Staff. Hill is self-employed as a financial consultant, specializing in financial and economic issues in regulated industries. He has earned a Masters in Business Administration from Tulane University.[28] Hill recommends the Commission allow AmerenUE a return on equity of 9.5 percent, assuming the company is not allowed to establish a fuel adjustment clause.[29] If AmerenUE were allowed to establish a fuel adjustment clause, Hill's recommended return on equity would drop to below 9.375 percent.[30]

Michael Gorman testified on behalf of MIEC. Gorman is a consultant in the field of public utility regulation.[31] He holds a Masters in Business Administration with a concentration in Finance from the University of Illinois at Springfield.[32] Gorman

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[25] Morin Direct, Ex. 3, Page 1, Lines 8-18.

[26] Morin Direct, Ex. 3, Page 65, Lines 7-16.

[27] Morin Direct, Ex. 3, Page 71, Lines 10-13.

[28] Hill Direct, Ex. 203, Page 1, Lines 7-15.

[29] Hill Direct, Ex. 203, Page 44, Lines 10-12.

[30] Hill Direct, Ex. 203, Page 44, Lines 2-4.

[31] Gorman Direct, Ex. 600, Page 1, Line 5.

[32] Gorman Direct, Ex. 600, Appendix A, Page 1, Lines 10-12.

recommends the Commission allow AmerenUE a return on equity of 10.2 percent.[33] That rate of return is based on AmerenUE's current level of risk without a fuel adjustment clause. If AmerenUE were allowed to establish a fuel adjustment clause, Gorman would reduce his recommendation by 20 or 25 basis points, resulting in a recommended rate of return of 9.95 or 10.0 percent.[34]

Finally, Billie Sue LaConte testified on behalf of MEG. LaConte is a consultant in the field of public utility economics and regulation.[35] She holds a M.B.A. in finance from the John M. Olin School of Business at Washington University, St. Louis, Missouri. LaConte recommends the Commission allow AmerenUE a return on equity of 10.2 percent without a fuel adjustment clause, or 10.0 percent if a fuel adjustment clause is established.[36]

Findings of Fact:

A utility's cost of common equity is the return investors expect, or require, to make an investment in that company.[37] Financial analysts use variations on three generally accepted methods to estimate a company's fair rate of return on equity. The Discounted Cash Flow (DCF) method assumes the current market price of a firm's stock is equal to the discounted value of all expected future cash flows. The Risk Premium method assumes that all the investor's required return on an equity investment is equal to the interest rate on a long-term bond plus an additional equity risk premium to compensate the investor for the risks of investing in equities compared to bonds. The Capital Asset Pricing Method (CAPM) assumes the investor's required rate of return on equity is equal to a risk-free rate of

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[33] Gorman Direct, Ex. 600, Page 2, Lines 5-7.

[34] Transcript, Page 543, Lines 1-9, and Page 548, Lines 2-25.

[35] LaConte Direct, Ex. 650, Page 1, Line 4.

[36] LaConte Direct, Ex. 650, Page 2, Lines 3-4.

[37] Gorman Direct, Ex. 600, Page 10, Lines 4-5.

interest plus the product of a company-specific risk factor, beta, and the expected risk premium on the market portfolio. No one method is any more "correct" than any other method in all circumstances. Analysts balance their use of all three methods to reach a recommended return on equity. In the words of Dr. Morin, what financial analysts do is a "scientific art", based on a solid economic foundation, but still dependent upon the analyst's judgment.[38]

Before examining the analyst's use of these various methods to arrive at a recommended return on equity, it is important to look at another number. For the first nine months of 2008, the average return on equity awarded to electric utilities in this country was 10.51 percent, as reported by Regulatory Research Associates. That figure was up from an average of 10.36 percent for calendar year 2007.[39] That overall average number includes all electric utilities, some of which are "wires only" utilities in restructured states that provide only distribution services and do not own generation assets. Such utilities tend to be less risky and generally receive lower authorized returns on equity. If the "wires only" utilities are eliminated from the average, the average allowed return on equity for integrated utilities, such as AmerenUE, was 10.62 percent. For Midwest integrated electric utilities[40], that average return on equity rose to 10.71%.[41]

The Commission mentions the average allowed return on equity not because the Commission should, or would slavishly follow the national average in awarding a return on

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[38] Transcript, Page 385, Lines 16-23.

[39] Ex. 60.

[40] "Integrated" or "vertically-integrated" is an industry-specific term commonly used to refer to utilities that own their own generation, transmission and distribution system. An electric utility that only owns a distribution system or possibly owns some transmission in connection with a distribution system is commonly referred to as a "wires only" company.

[41] Morin Rebuttal, Ex. 4, Page 5, Lines 5-18.

equity to AmerenUE. However, AmerenUE must compete with other utilities all over the country for the same capital. Therefore, the average allowed return on equity provides a reasonableness test for the recommendations offered by the return on equity experts.

In AmerenUE's last rate case, the Commission bemoaned the tendency of return on equity witnesses to race to extreme positions instead of offering a balanced analysis that could aid the Commission in its evaluation of the proper return on equity.[42] In this case, the experts have generally done a better job of offering a balanced analysis and the parties are to be commended. Other than Mr. Hill's recommended 9.5 percent return on equity, the recommendations of the other parties are separated by only 70 basis points, and all of those recommendations are within 50 basis points of the reported average return on equity for either vertically-integrated utilities or all utilities.

In evaluating the recommendations of the experts, the Commission will look first at the recommendation offered by Michael Gorman, the witness for MIEC. Gorman utilized a constant growth DCF model to arrive at an average return on equity of 11.86 percent.[43] He also utilized a two-stage DCF model that showed an average return on equity of 9.73 percent.[44] Gorman's use of a multi-stage DCF indicated an average return on equity of 9.89 percent.[45] Gorman also used a Risk Premium model to arrive at a return on equity in a range between 10.25 percent and 10.66 percent, with a midpoint estimate of 10.46 percent.[46] Gorman's use of a Capital Asset Pricing Model (CAPM) showed an estimated

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[42] *In the Matter of Union Electric Company d/b/a AmerenUE's Tariffs Increasing Rates for Electric Service*, Report and Order, Case No. ER-2007-0002, May 22, 2007, Page 42.

[43] Gorman Direct, Ex. 600, Page 18, Lines 9-16.

[44] Gorman Direct, Ex. 600, Page 26, Lines 8-15.

[45] Gorman Direct, Ex. 600, Page 27, Lines 16-22.

[46] Gorman Direct, Ex. 600, Page 31, Lines 1-2.

range of return on equity of 10.63 percent to 10.64 percent, with a midpoint of 10.63 percent.[47]

The results of Gorman's various methods are summarized in the following chart:

Method	Resulting Return on Equity
Constant Growth DCF	11.86%
Two-Stage Growth DCF	9.73%
Multi-Stage DCF	9.89%
Risk Premium	10.46%
CAPM	10.63%
Average of Five Methods	10.51%

However, Gorman chose to ignore the results of his constant growth DCF model in making his recommended return on equity. The results upon which he did rely are summarized in this chart:

Method	Resulting Return on Equity
Two-Stage Growth DCF	9.73%
Multi-Stage DCF	9.89%
Risk Premium	10.46%
CAPM	10.63%
Average of Four Methods	10.2%

[47] Gorman Direct, Ex 600, Page 36, Lines 6-10.

Gorman then recommended a return on equity of 10.2 percent, which is the midpoint of his estimated return on equity range of 9.81 percent to 10.55 percent.[48]

Gorman explains that he decided to ignore the results of his constant growth DCF because he found the results unreasonable and believes they represent an inflated return for AmerenUE.[49] The average 3-5 year growth rates for his three proxy groups are 6.80 percent, 7.25 percent, and 8.03 percent. He believes these growth rates are too high to be a rational estimate of the proxy groups' long-term sustainable growth, because they would exceed the growth rate of the overall US economy.[50]

For his two-stage growth DCF model, Gorman uses a published nominal 5-year and 10-year Gross Domestic Product growth rate of 5.0 percent and 4.8 percent to limit the long-term growth estimate of his proxy groups.[51] However, Gorman used these 5 and 10 year growth estimates improperly to model the historical long-term growth of the economy as a whole.[52] If instead, Gorman had used the 6.0 percent estimate of long-term US GDP growth found in Morningstar's *Stocks, Bond, Bills and Inflation 2008 Yearbook Valuation Edition*, his two-stage DCF model would have been raised by approximately 100-120 basis points, putting his estimates in the 10.7 percent to 10.9 percent range.[53] Making the same adjustment to his multi-stage DCF model would raise the results of that model into the 10.9 percent to 11.1 percent range.[54]

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[48] Gorman Direct, Ex. 600, Page 37, Lines 1-6.

[49] Gorman Direct, Ex. 600, Page 18, Lines 19-20.

[50] Gorman Direct, Ex. 600, Page 18-9, Lines 19-23, 1-13.

[51] Gorman Direct, Ex. 600, Page 25, Lines 14-22.

[52] Morin Rebuttal, Ex. 4, Page 39-40, Lines 22-23, 1-3.

[53] Morin Rebuttal, Ex 4, Page 40, Lines 11-21.

[54] Morin Rebuttal, Ex. 4, Page 41, Lines 1-5.

The Commission will not attempt to recalculate Gorman's two-stage and multi-stage DCF models using different inputs, but the problems with those models illustrate the desirability of considering his model that produces a relatively high return on equity as a balance to his DCF models that show a relatively low return on equity. In that way, the possibly unreasonable impact of one model is counterbalanced by other models. There simply is no good reason to ignore the results of Gorman's constant growth DCF.

As previously indicated, if the result of Gorman's constant growth DCF model is included with the results of his other models, the average result is 10.51 percent. That result should be further adjusted upward because the proxy groups Gorman uses are all, on average, less risky than AmerenUE in that they have average bond ratings two grades higher than the bond ratings assigned to AmerenUE by two widely-used credit rating agencies – Standard & Poor and Moody's.[55]

In the recent Empire rate case, the Commission faced the exact same scenario and noted the difference between a BBB- rating and a BBB+ rating can add between 25 and 50 basis points to a reasonable return on equity.[56] Ultimately, the Commission settled on a 25 basis point upward adjustment to Gorman's recommended return on equity to recognize the increased risk.[57]

[55] Gorman Direct, Ex. 600, Schedule MPG-3.

[56] *In the Matter of The Empire District Electric Company's Tariffs to Increase Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company*, Report and Order, Case No. ER-2008-0093 July 30, 2008, Page 20.

[57] *In the Matter of The Empire District Electric Company's Tariffs to Increase Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company*, Report and Order, Case No. ER-2008-0093 July 30, 2008, Page 21.

AmerenUE is a much different utility from Empire in that AmerenUE has a higher portion of equity in its capital structure[58]. Less debt proportionately means that the utility is less risky. Accordingly, the Commission finds that in this case a 20 basis point adjustment of ROE is necessary to recognize the difference for utility bond ratings. That brings Gorman's recommended return on equity up to 10.71 percent.

One more adjustment to Gorman's recommended return on equity is appropriate. Gorman used an annualized quarterly dividend payment in calculating his DCF analyses.[59] AmerenUE as well as the overwhelming majority of traditional vertically-integrated electric utilities pay dividends quarterly, not annually. This distinction is important because the conventional DCF model does not account for the compounding of interest (earnings) investors receive and expect in the real world. So, it is more appropriate to use a quarterly DCF model.

At the hearing, Dr. Morin further explained that the use of the annual DCF model is appropriate in jurisdictions that use a forward test year to avoid being overly generous to the company. However, in a jurisdiction such as Missouri that uses a historical test year, the quarterly test year is more appropriate.[60] Morin indicated the difference between the quarterly and the annual DCF model would "definitely "add 20 basis points to a return on equity recommendation.[61] However, Morin's analysis does not contemplate the greater amount of equity in AmerenUE's capital structure referenced by the Commission earlier.

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[58] In the Empire Report and Order, the Commission found that the percentage of common equity in Empire's capital structure was 50.78 percent. *In the Matter of The Empire District Electric Company's Tariffs to Increase Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company*, Report and Order, Case No. ER-2008-0093 July 30, 2008, Page 10.

[59] Gorman Direct, Ex. 600, Page 27, Lines 13-14.

[60] Transcript, Page 433-434, Lines 19-25, 1-12.

[61] Transcript, Page 435, Lines 2-6.

Therefore, the Commission finds that only a five basis point adder is appropriate in this case.

Before finishing the analysis of Mr. Gorman's testimony, the Commission takes notice that this is the second consecutive case where the Commission has made an upward adjustment for return on equity using the quarterly dividends DCF model. Since Ameren does pay quarterly dividends, it is appropriate for this Commission to require the PSC Staff to use the quarterly dividend method when calculating return on equity using the DCF model in future rate cases. Moreover, if Staff does not agree with that approach in succeeding rate cases, Staff needs to make a more compelling argument grounded in economic reality as to why the Commission should relieve them of this obligation.

The Commission finds Gorman's recommended return on equity using the DCF model as adjusted above is the most appropriate return on equity for AmerenUE. Therefore, Ameren's authorized return on equity should be 10.76 percent. However, the Commission's analysis does not end there.

That return on equity is also supported by a necessary adjustment to Gorman's bond yield plus risk premium analysis. That analysis is based on the difference between a utility's required return on common equity investments and bond yield.[62]

In his direct testimony, Gorman used a 22-year average of authorized electric return and Treasury bond yields to calculate an indicated risk premium of 5.08 percent.[63] Gorman's decision to begin his historical analysis with 1986 data is purely arbitrary and he offers no compelling reason for doing so. A careful review of this data demonstrates his

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[62] Gorman Direct, Ex. 600, Page 28, Lines 12-13.

[63] Gorman Direct, Ex. 600, Schedule MPG-14.

range and average risk premium are remarkably lower due to events that occurred 15-20 years ago.

The Commission finds that the use of more recent data when calculating a company's historical equity risk premium is helpful. The Commission makes no finding as to where that cut-off line should be, but finds the following analysis is worth noting in the context of Mr. Gorman's testimony. Using Gorman's data to calculate the average risk premium for the last ten years yields an average risk premium of 5.56 percent. Excluding 1999 data from that average yields a 5.68 percent risk premium. The averages for the most recent five-year period and three-year periods are 5.66 percent and 5.58 percent, respectively.

Further, in making these calculations, Gorman does not account for the fact that, in recent years, vertically-integrated electric utilities like AmerenUE have been awarded an average ROE substantially higher than the average for all electric utilities.

Therefore, the Commission finds the upper range of Gorman's risk premium estimates to be his most valid. If the five-year average indicated risk premium of 5.66 percent is added to the 5.1 percent 30-year Treasury bond yield used by Gorman in his Risk Premium analysis, the result is a return on equity of 10.76 percent.

As previously indicated, there is no precisely "correct" return on equity for AmerenUE. The Commission's manipulation of Gorman's recommendation is not intended to calculate a "correct" return. Rather it is intended to demonstrate the area in which a reasonable return is to be found. After a close examination, the recommendations of two of the other financial experts are also in the same range as the modified recommendation from Gorman.

Dr. Morin recommends a return on equity of 10.9 percent, which is slightly above the 10.76 percent return the Commission has found to be reasonable. However, Dr. Morin's recommendation includes an upward adjustment of approximately 30 basis points to allow for flotation costs.[64] Flotation costs are associated with stock issues. Those costs can either be expensed and recovered at the time the stock is issued, or they can be recovered over a longer period through the use of a flotation allowance, such as Morin incorporated in his return on equity recommendations.[65] However, Morin conceded that AmerenUE did not incur any flotation costs during the test year.[66] He also was unaware of whether this Commission has expensed flotation costs in the past, but concedes that if flotation costs were expensed they should not be recovered again through a flotation adjustment.[67]

AmerenUE contends flotation costs could not have been expensed in many years because before it filed its last previous rate case in 2006, it had not filed a rate case in 20 years.[68] However, the absence of a rate case does not mean AmerenUE did not recover its costs during that period, nor does it mean it should be able to reach back to retroactively recover those costs in this case. Presumably, since AmerenUE chose not to file a rate case during that 20-year period, it was recovering at least a reasonable return on equity during that time.

Since the record does not clearly indicate whether AmerenUE's flotation costs have been expensed in the past, Morin's 30 basis point flotation adjustment must be removed

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[64] Morin Direct, Ex. 3, Page 63, Lines 11-16.

[65] Transcript, Page 393, Lines 4-19.

[66] Transcript, Page 393, Lines 4-6.

[67] Transcript, Page 402, Lines 1-5.

[68] Transcript, Page 462, Lines 3-8.

from his return on equity recommendation. That reduces his return on equity recommendation to 10.6 percent, which is slightly lower than the 10.76 percent return the Commission has found to be reasonable. However, Morin also used the annual DCF model rather than the quarterly DCF model that the Commission found to be appropriate when discussing Gorman's recommendation. The Commission made only a 5 basis point adjustment to Gorman's recommendation, but Morin insisted a 20 basis point adjustment is appropriate.[69] A 20 basis point upward adjustment brings Morin's recommendation back to 10.8 percent, which is very close to the 10.76 percent the Commission has found to be reasonable.

MEG's witness, Billie Sue LaConte, utilized three methods to analyze an appropriate return on equity for AmerenUE and found that a return on equity in the range of 10.1 percent to 10.6 percent would be appropriate.[70] At the hearing, LaConte agreed that anything within her range would be a reasonable return on equity.[71] Thus, the top end of LaConte's recommendation is within 16 basis points of the rate the Commission has found to be reasonable.

Ms. LaConte frequently testifies before this Commission on rate design issues,[72] and some of her points are well taken. However, a comparison of Ms. LaConte's return on equity analysis to that offered by Dr. Morin and Mike Gorman reveals that she did not provide quite the same detailed analysis as either of those two witnesses. This limits her

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[69] Transcript, Page 435, Lines 2-6.

[70] LaConte Direct, Ex. 650, Page 14, Lines 2-4.

[71] Transcript, Page 295, Lines 22-24.

[72] Transcript, Page 285, Lines 10-13.

credibility on the issue and the Commission does not find her testimony persuasive enough to require a reduction in the rate of return the Commission has found to be reasonable.

The final return on equity expert witness is Stephen Hill for the Commission's Staff. Hill recommended a return on equity of 9.5 percent, which is 70 basis points lower than any other recommendation offered in this case, and more than 100 basis points lower than the average allowed return on equity for all electric utilities throughout the country. Hill's recommendation would give AmerenUE the lowest return on equity authorized for any integrated electric utility in the country for 2008.[73] Mr.Hill does not argue that AmerenUE is, in fact, the least risky of all those utilities.

Hill generally testifies on behalf of consumer advocates,[74] but even Public Counsel in this case did not support his extremely low recommendation. Dr. Morin's rebuttal, surrebuttal, and live testimony convincingly explain all the problems with Hill's recommendation, and the Commission will not waste its time recounting those deficiencies. It is enough to say that based on Morin's testimony, the Commission specifically finds that Hill's return on equity recommendation in this case is not credible, and the Commission will give it no further consideration.

Should the Commission adjust AmerenUE's return on equity downward in the event a fuel adjustment clause is awarded?

In this Report and Order, the Commission is authorizing AmerenUE to implement a fuel adjustment clause for the first time. Several parties contend the allowed return on equity should be adjusted downward to recognize the decreased risk AmerenUE will face because it now has a fuel adjustment clause.

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[73] Ex. 60.

[74] Transcript, Page 490, Lines 7-14.

There is no dispute that the implementation of a fuel adjustment clause will reduce the level of operating risk AmerenUE will face. The question is whether the analysts' recommendations already take that decreased risk into account.

Fuel adjustment clauses are commonly used around the country,[75] so most of the comparable companies included in the proxy groups used by the various return on equity analysts already have fuel adjustment clauses in place. Moreover, the overwhelming majority of the jurisdictions where traditional vertically-integrated utilities like AmerenUE operate (including our neighboring states of Arkansas, Kansas and Oklahoma) allow for the 100 percent pass-through of fuel and purchased power costs, which are the most significant costs AmerenUE faces. This Report and Order will not allow AmerenUE to pass-through 100 percent of those costs, meaning AmerenUE will retain more risk than most comparable companies.

AmerenUE's witness, Dr. Morin, testified that if AmerenUE did not receive a fuel adjustment clause he would have to increase his return on equity recommendation by 25 basis points to compensate AmerenUE for the higher financing costs and increased risk it would face.[76] That possible upward adjustment does not, however, mean a similar downward adjustment must be made for the presence of a fuel adjustment clause.

As indicated, most of the companies included in the proxy groups used by the analysts to estimate an appropriate return on equity for AmerenUE already operate under a fuel adjustment clause. That means the analysts are measuring and evaluating AmerenUE against companies with a level of risk that takes into account their use of a fuel adjustment clause. Therefore, while an upward adjustment may have been appropriate if a fuel

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[75] Lyons Rebuttal, Ex. 42, Schedule MJL-RE8.

[76] Morin Direct, Ex. 3, Page 68, Lines 6-14.

adjustment clause were not allowed, no corresponding reduction is necessary because a fuel adjustment clause will be in place.

Generic Return on Equity Case

Billie Sue LaConte, the witness for MEG, advised the Commission to consider opening a generic return on equity case to better deal with future rate cases. Such a case would have no effect on AmerenUE's current rate case, but it might make the Commission's task easier in future rate cases. At the same time, it would also bring some certainty to utilities and other parties as they participate in those future rate cases. The concept of a generic case was supported at the hearing by other witnesses and parties.

The Commission is interested in learning more about the concept of a generic return on equity case and plans to hold a roundtable or open a working case to consider that concept. Moreover, this Commission finds that discussion of a generic return on equity should included the quarterly DCF issue previously discussed in this Report and Order.

Conclusions of Law:

In assessing the Commission's ability to use different methodologies to determine just and reasonable rates, the Missouri Court of Appeals has said:

> Because ratemaking is not an exact science, the utilization of different formulas is sometimes necessary. ... The Supreme Court of Arkansas, in dealing with this issue, stated that there is no 'judicial mandate requiring the Commission to take the same approach to every rate application or even to consecutive applications by the same utility, when the commission in its expertise, determines that its previous methods are unsound or inappropriate to the particular application' (quoting *Southwestern Bell Telephone Company v. Arkansas Public Service Commission,* 593 S.W. 2d 434 (Ark 1980).[77]

Furthermore,

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[77] *State ex rel. Assoc. Natural Gas Co. v. Public Service Commission,* 706 S.W. 2d 870, 880 (Mo. App. W.D. 1985).

> Not only can the Commission select its methodology in determining rates and make pragmatic adjustments called for by particular circumstances, but it also may adopt or reject any or all of any witnesses' testimony.[78]

In another case, the Court of Appeals recognized that the establishment of an appropriate rate of return is not a "precise science":

> While rate of return is the result of a straight forward mathematic calculation, the inputs, particularly regarding the cost of common equity, are not a matter of 'precise science,' because inferences must be made about the cost of equity, which involves an estimation of investor expectations. In other words, some amount of speculation is inherent in any ratemaking decision to the extent that it is based on capital structure, because such decisions are forward-looking and rely, in part, on the accuracy of financial and market forecasts.[79]

Section 386.266, RSMo (Supp. 2008), the statute that allows the Commission to order AmerenUE to implement a fuel adjustment clause, allows the Commission to modify a company's allowed return on equity to reflect the implementation of a fuel adjustment clause. Specifically, subsection 7 of that statute provides that the Commission may:

> take into account any change in business risk to the corporation resulting from implementation of the adjustment mechanism in setting the corporation's allowed return in any rate proceeding, in addition to any other changes in business risk experienced by the corporation.

That section does not, however, require the Commission to make any adjustment to allowed return on equity when it allows a company to implement a fuel adjustment clause.

Decision:

Based on the evidence in the record, on its analysis of the expert testimony offered by the parties, and on its balancing of the interest of the company's ratepayers and shareholders, as fully explained in its findings of fact and conclusions of law, the

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[78] *Id.*

[79] *State ex rel. Missouri Gas Energy v. Public Service Commission*, 186 S.W.3d 376, 383 (Mo App. W.D. 2005).

Commission finds that 10.76 percent is a fair and reasonable return on equity for AmerenUE. The Commission finds that this rate of return will allow AmerenUE to compete in the capital market for the funds needed to maintain its financial health. As one final check on reasonableness, the 10.76% return on equity is within 15 basis points of the national average return on equity for electric utility companies.

2. Vegetation Management and Infrastructure Inspection Expenses

Introduction:

In 2006, AmerenUE experienced extensive service outages due to severe thunderstorms in the summer and ice storms in the winter. In response to concerns that AmerenUE and other electric utilities had failed to properly maintain their electric distribution systems, the Commission promulgated new rules designed to compel Missouri's electric utilities to do a better job of maintaining their electric distribution facilities to enhance the reliability of electric service to customers. Those rules, entitled Electrical Corporation Infrastructure Standards[80] and Electrical Corporation Vegetation Management Standards and Reporting Requirements,[81] became effective on June 30, 2008.

The rules establish specific standards requiring electric utilities, including AmerenUE, to inspect and replace old and damaged infrastructure, such as poles and transformers. In addition, electric utilities are required to more aggressively trim tree branches and other vegetation that encroaches on transmission lines. In promulgating the stricter standards, the Commission anticipated utilities would have to spend more money to comply. Therefore, both rules include provisions that allow the utility a means to recover to

[80] Commission Rule 4 CSR 240-23.020.

[81] Commission Rule 4 CSR 240-23.030.

the extra costs it incurs to comply with the requirements of the rule. In general, this issue concerns whether and how AmerenUE will be allowed to recover those costs.

This is a complicated and confusing issue that the Commission will address in pieces by answering the specific questions offered by the parties in the Statement of Issues filed before the start of the hearing. Once the specific pieces are addressed, the overall picture will come into focus.

a. Vegetation Management

What level of vegetation management expense is appropriate for recognition in AmerenUE's revenue requirement in this case?

Findings of Fact:

The determination of this number is the starting point for other decisions to follow. Staff proposes the amount be set at the company's actual expenditures during the test year, trued-up through September 30, 2008.[82] What that amount may be is not clearly revealed in the record. Initially, Staff indicated the test year level of vegetation management costs should be set at $45,666,000,[83] which is a number derived from the supplemental direct testimony of AmerenUE's witness, Gary Weiss.[84] However, since Weiss' testimony was filed on June 16, 2008, that number would not be trued-up through September 30, 2008. At the hearing, Staff's witness indicated his belief that the trued-up number might have been $49.7 million.[85]

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[82] Transcript, Page 1673, Lines 6-12.

[83] Beck Surrebuttal, Ex. 218, Page 4, Lines 8-9.

[84] Weiss Supplemental Direct, Ex. 11, Page 20, Lines 8-9.

[85] Transcript, Page 1673, Lines 13-19. That number is also found in Zdellar's workpapers entered into evidence as Ex. 240.

AmerenUE proposes the base amount for vegetation management be set at the average amounts included in AmerenUE's budgets for 2009 and 2010.[86] In Ron Zdellar's rebuttal testimony, he says that number is $49 million.[87] However, in his corrected surrebuttal testimony, the number has become $54.1 million.[88]

Whatever the exact numbers, the important determination at this point is the principle of whether an actual test year amount or a prospective budgeted amount should be used. Public Counsel, and presumably Staff, oppose the use of budgeted cost numbers, because they believe such numbers are not known and measurable.[89]

AmerenUE's expenditures on vegetation management have increased each quarter of 2008, as the company ramps up its compliance with the Commission's vegetation management rules.[90] Therefore, a projected budget amount is more likely to properly measure the company's actual expenditures in the coming years.

AmerenUE has made good progress in meeting its prior commitments and the requirements of the Commission's rule by attaining the required four and six-year tree trimming cycles as of November 14, 2008.[91] The Commission wants to encourage the company to continue making progress and allowing an amount in rates that is likely to match the company's actual expenditures is the best way to achieve that goal. Therefore, the Commission will include $54.1 million as the base amount of vegetation management costs for the calculation of rates in this case.

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[86] Transcript, Page 1610, Lines 20-24.

[87] Zdellar Rebuttal, Ex. 16, Page 9, Lines 1-2.

[88] Ex. 76.

[89] Robertson Surrebuttal, Ex. 408, Page 4, Lines 10-11.

[90] Zdellar Surrebuttal, Ex. 17, Page 3, Lines 21-22.

[91] Transcript, Page 1608, Lines 17-20.

Should AmerenUE's revenue requirement in this case include a three year amortization of vegetation management expense from January 1, 2008 to June 30, 2008 that is in excess of the $45 million annual level that was included in AmerenUE's revenue requirement for Case No. ER-2007-0002?

Should AmerenUE's revenue requirement in this case include a three year amortization of vegetation management expense from July 1, 2008 to September 30, 2008 that is in excess of the $45 million annual level that was included in AmerenUE's revenue requirement for Case No. ER-2007-0002?

These two questions are interrelated so the Commission will address them together.

Findings of Fact:

In answering the previous question, the Commission determined AmerenUE's rates going forward should allow the company to recover $54.1 million per year from ratepayers for vegetation management expenses. In AmerenUE's last rate case, the Commission approved a stipulation and agreement that allowed the company to recover $45 million per year, and, in fact, established a one-way tracker that required the company to spend that amount of money on vegetation management, but did not track or require future consideration of any additional spending over $45 million.[92]

The Commission's new vegetation management rule includes a provision that allows an electric utility to recover expenses it incurs to comply with the rule to the extent those costs exceed the amount allowed in the utility's existing rates.[93] Between January 1, 2008, and September 30, 2008, AmerenUE spent an additional $2.9 million for vegetation

[92] Transcript, Pages 1626-1627, Lines 18-25, 1-15.

[93] Commission Rule 4 CSR 240-23.020(4).

management, beyond what it was able to recover in its existing rates.[94] AmerenUE asks that it be allowed to amortize that amount over three years and recover it in the rates to be established in this case.

Staff opposes AmerenUE's attempt to recover these additional expenditures for two reasons: first, because the one-way tracker from the last rate case does not allow AmerenUE to track and recover expenditures above $45 million; and second, because AmerenUE's additional expenditures are related to its prior commitment to improve its vegetation management practices, and not because of the implementation of the new vegetation management rule.[95]

Staff does not identify, and the Commission does not find, anything in the one-way tracker implemented in AmerenUE's last rate case that would preclude the company from utilizing the clear provisions of the rule to recover the additional expenses it incurred to comply with the vegetation management rule. Thus, to the extent AmerenUE incurred additional costs to comply with the rule, it should be allowed to recover those costs in this case.

The question of whether AmerenUE's additional expenditures were caused by its compliance with the new rule is complicated by the fact that the new rule did not go into effect until June 30, 2008. Thus, AmerenUE's increased expenditures for the period of January 1, 2008 to June 30, 2008, undeniably occurred before the rule went into effect.

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[94] Exhibit 76, Page 12, Lines 5-6.

[95] Beck Rebuttal, Ex. 217, Page 7, Lines 1-9.

However, AmerenUE began complying with the Commission's rule on January 1, 2008, six months before the rule went into effect.[96] It did so because it anticipated that the rule would be effective on January 1, and in fact, the rule would have been effective on that date except the Commission missed the deadline for submission of its rulemaking to the secretary of state and had to restart the rulemaking process. Staff's witness, however, agreed that AmerenUE's decision to begin complying with the rule before it became effective was a good practice that benefited the company's ratepayers.[97]

The Commission finds that AmerenUE's decision to begin complying with requirements of the rule benefited the reliability of AmerenUE's electric system and thus benefited the company's ratepayers. The fact that those costs were incurred before the rule went into effect does not affect AmerenUE's ability to recover those costs under the terms of the rule.

However, that determination does not necessarily mean that AmerenUE incurred those costs because of the rule. As Staff points out, in a previous case,[98] AmerenUE made a commitment to increase its spending on vegetation management to improve the reliability of its electric system. In particular, AmerenUE agreed to implement a four-year tree-trimming cycle in urban areas and a six-year cycle in rural areas by the end of 2008.[99] Staff contends AmerenUE's extra spending was to comply with that earlier commitment and not to comply with the rule.

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[96] Zdellar Surrebuttal, Ex. 17, Page 2, Lines 6-8.

[97] Transcript, Page 1682, Lines 20-23.

[98] Commission Case No. EW-2004-0583.

[99] Zdellar Surrebuttal, Ex. 17, Page 4, Lines 8-18.

"The rule requires AmerenUE to take steps above and beyond its earlier commitment. The rule also sets a minimum clearance distance, requires mid-cycle inspections, customer education efforts, and requires notice be given before trimming. None of those requirement existed before AmerenUE began complying with the new rules and all impose additional costs on the company.[100]

Furthermore, the existence of the $45 million one-way tracker in the previous rate case actually supports AmerenUE's position. The $45 million was established in the last rate case as the amount AmerenUE would be required to spend to comply with the commitments it had made at that time. It is reasonable to assume it actually spent that amount to comply with those earlier commitments. However, after AmerenUE began complying with the rule on January 1, 2008, it spent more than the $45 million it was required to spend under the tracker. Therefore, the Commission concludes the extra $2.9 million spent above $45 million was the amount AmerenUE spent to comply with the rule. Under the terms of the rule, AmerenUE is entitled to recover that amount from ratepayers, and it may do so by amortizing $2.9 million over three years and recovering it in rates.

Should accounting authority be granted for vegetation management expense incurred from October 1, 2008 to February 28, 2009, in excess of the $45 million annual level that was included in AmerenUE's revenue requirement for Case No. ER-2007-0002, with this cost being deferred for treatment in AmerenUE's next rate case?

Findings of Fact:

AmerenUE is requesting an accounting authority order to allow it to accumulate and defer the additional costs of complying with the vegetation management rule it will incur

[100] Zdellar Surrebuttal, Ex. 17, Page 4, Lines 19-23.

during the period of October 1, 2008 through February 28, 2009.[101] That period is between the end of the true-up for this case and the beginning of new rates that will go into effect at the end of this case. The Commission has just found that extra expenses incurred before October 1 can be recovered in this case. Similarly, extra expenses incurred after February 28 would be deferred for future consideration in the tracking mechanism that will be considered later in this order. However, extra expenses AmerenUE incurs during this gap could not be considered and recovered in a future rate case unless an accounting authority order is authorized.

Staff opposed granting of the requested accounting authority for the same reason it opposed allowing AmerenUE to recover the extra expenses it incurred through September 30, 2008. For the same reasons it rejected Staff's arguments regarding those costs, the Commission rejects Staff's arguments regarding the requested accounting authority order. AmerenUE is authorized to accumulate and defer the additional costs of complying with the vegetation management rule it will incur during the period from October 1, 2008, through February 28, 2009.

Should a tracker be implemented for vegetation management expense that exceeds the level of vegetation management expense the Commission recognized in AmerenUE's revenue requirement in this case? Should such a tracker be implemented for the one-year period of March 1, 2009 to February 28, 2010?

Findings of Fact:

AmerenUE asks the Commission to implement a two-way tracking mechanism for vegetation management and infrastructure inspection and repair expenses. The tracker

[101] Zdellar Surrebuttal, Ex. 17, Page 12, Lines 8-10.

would set a base level of vegetation management and infrastructure inspection and repair costs. Actual expenditures would then be tracked around that base level with the creation of a regulatory liability in any year where AmerenUE spends less than the target amount, and a regulatory asset where the company spends more than the target amount. The assets and liabilities would then be netted against each other and considered in AmerenUE's next rate case.[102]

Staff supports the idea of a two-way tracking mechanism. However, Staff would place a ten percent cap on expenditures,[103] and would limit the operation of the tracker to only one year, March 1, 2009, through February 28, 2010.[104]

The Commission finds a ten percent cap on the tracker to be appropriate. Without a cap, the tracker would essentially give AmerenUE a blank check to spend however much it wants on vegetation management with assurance that any expenditure will likely be recovered from ratepayers. Of course, any such expenditure would still be subject to a prudence review in the next rate case, but a prudence review is not a complete substitute for a good financial incentive. If AmerenUE finds it must increase its vegetation management spending to a level more than ten percent above its budgeted amount, it has the option of coming to the Commission for accounting authority to defer those costs for consideration in a future rate case.[105]

Public Counsel opposes the implementation of any tracking mechanism. Public Counsel's witness argues "the use of tracker mechanisms subvert the regulatory rate model

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[102] Zdellar Rebuttal, Ex. 16, Pages 7-8, Lines 15-22, 1-2.

[103] Transcript, Page 1684, Lines 7-22.

[104] Beck Surrebuttal, Ex. 218, Page 6, Lines 22-23.

[105] Transcript, Page 1703, Lines 14-25.

process and should be used in very limited instances."[106] Public Counsel further explains that tracker mechanisms violate the "matching principle" of regulation by moving revenues or expenses away from the time in which they were incurred, to be recovered from future ratepayers who may not have benefited from the expenditures.[107] They also reduce the utility's business risk at the expense of ratepayers, and they reduce the utility's incentive to minimize its expenses.[108]

Staff also suggests the tracker be limited to one year. Staff provided no testimony or other evidence to support such a restriction. The Commission finds that the tracker shall remain in effect until new rates are established in the next rate case.

Public Counsel's general concerns about the overuse of tracking mechanisms are valid. The Commission does not intend to allow the overuse of tracking mechanisms in this case, or in future rate cases. However, the tracker proposed by AmerenUE in this case is appropriate. This is a limited tracker that will have only a limited effect on AmerenUE's business risk. With the cap proposed by Staff, the tracker can increase AmerenUE's vegetation management costs by no more than approximately five million dollars. Furthermore, because the vegetation management rule is still very new, no one can know with any certainty how much AmerenUE will need to spend to comply with the rule's provisions. The tracker will ensure AmerenUE does not over-recover for its actual expenditures, as much as it will ensure it does not under-recover those expenditures. Thus, the risk for ratepayers, as well as for AmerenUE, is reduced by operation of the tracking mechanism.

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[106] Robertson Surrebuttal, Ex. 408, Page 10, Lines 4-5.

[107] Robertson Surrebuttal, Ex. 408, Pages 10-11, Lines 17-21, 1.

[108] Robertson Surrebuttal, Ex. 408, Page 11, Lines 1-21.

In addition, Public Counsel is concerned AmerenUE will have fewer electrical outages on its system in the future because of the work that it is doing to comply with the vegetation management rule.[109] As a result, AmerenUE will likely have fewer outage related expenses. Public Counsel points out that any reduction in outage related expenses will not be included in the tracker.[110]

Public Counsel's concerns are unwarranted. The Commission certainly hopes AmerenUE's increased spending on vegetation management will result in a reduction in outage related expenses. That will mean AmerenUE's electric system has become more reliable, a result that will certainly benefit the utility's customers. Any reduction in outage related expenses will, of course, be reflected in a reduced cost of service in AmerenUE's next rate case. In the same rate case, the Commission will consider any adjustments, up or down, that result from application of the tracking mechanism the Commission will approve in this case. Thus, balance will be maintained and ratepayers will not be harmed by operation of the tracking mechanism.

b. Infrastructure Inspection and Repair.

What level of infrastructure inspection and repair expense is appropriate for recognition in AmerenUE's revenue requirement in this case?

Findings of Fact:

AmerenUE proposes it be allowed to recover $23.9 million in this case for infrastructure inspection and repair costs.[111] Staff would limit AmerenUE's recovery under these provisions to the amount spent for inspections, but would eliminate expenditures for

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[109] Transcript, Page 1622, Lines 19-22.

[110] Transcript, Page 1618, Lines 3-8.

[111] Zdellar Surrebuttal, Ex. 17, Page 12, Lines 14-15.

repairs made as a result of those inspections.[112] The Commission finds that AmerenUE's rates already allow for recovery of the expenditures required to repair its electric system. The fact those repairs may occur following an inspection does not mean the repairs would not eventually have been made anyway and there is no reason to believe the repairs would be more costly simply because they were made after an inspection. Thus, to allow recovery under this provision as an increased cost of complying with the rule could result in a double recovery of those costs.[113]

AmerenUE's witness, Ron Zdellar, offered vague assurances AmerenUE would be able to separate repair costs resulting from inspections from repair costs resulting from a system failure or a customer report of problems,[114] thus avoiding the double counting problem. However, the Commission is not convinced, and finds that the risk of double recovery precludes AmerenUE's attempt to recover repair costs under this provision. Therefore, the Commission finds that AmerenUE shall recover $10.7 million as the cost of conducting infrastructure inspections. That amount is the average of AmerenUE's forecast expense for 2009 and 2010.[115]

Should AmerenUE's revenue requirement in this case include a three year amortization of infrastructure inspection and repair expense from January 1, 2008 to June 30, 2008?

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[112] Beck Surrebuttal, Ex. 218, Page 11, Lines 23-24.

[113] Beck Surrebuttal, Ex. 218, Page 11, Lines 24-28.

[114] Zdellar Surrebuttal, Ex. 17, Pages 10-11, Lines 17-21, 1-2.

[115] Exhibit 240.

Should AmerenUE's revenue requirement in this case include a three year amortization of infrastructure inspection and repair expense from July 1, 2008 to September 30, 2008?

Should accounting authority be granted for infrastructure inspection and repair expenses incurred from October 1, 2008 to February 28, 2009, with these costs being deferred for treatment in AmerenUE's next rate case?

Findings of Fact:

AmerenUE again proposes a three-year amortization and recovery in rates of the $8.0 million in infrastructure inspection and repair expenses it incurred to comply with the Commission's rule from January 1, 2008, through September 30, 2008.[116] For the compliance costs incurred from October 1, 2008, through February 28, 2009, AmerenUE requests an accounting authority order to defer those costs for consideration in its next rate case.

Staff again opposes recovery of the amount incurred before the rule went into effect on June 30, 2008. For the reasons previously described regarding the vegetation management rule, the Commission rejects that position.

Conclusions of Law:

For the costs AmerenUE incurred from July 1, 2008 through September 30, 2008, Staff again opposes AmerenUE's proposal to amortize and recover those costs in this case. Staff instead advises the Commission to grant AmerenUE accounting authority to defer recognition of the costs incurred from July 1, 2008 through February 28, 2009 for

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[116] Exhibit 76.

consideration in AmerenUE's next rate.[117] In its brief, Staff suggests those costs simply be added to the tracking mechanism for consideration in AmerenUE's next rate case.

Staff takes that position because of its interpretation of a provision of the Commission's Infrastructure Standards Rule, 4 CSR 240-23.020.[118] Section (4) of that rule allows a utility to request an accounting authority order to recover compliance costs in its next general rate case, "filed after the effective date of this rule". AmerenUE filed this before the rule became effective, so Staff contends the costs incurred from July 1, 2008, through September 30, 2008 cannot be recovered in this case and must instead be deferred until AmerenUE's next rate case.

Staff's interpretation of the rule is overly technical and nonsensical. The intent of the rule is simply to indicate costs may be deferred until the next rate case. The Commission did not intend to limit a utility's ability to recover costs incurred within the update period of a pending rate case.

AmerenUE may amortize its infrastructure inspection costs incurred from January 1, 2008, through September 30, 2008, to comply with the Commission's Infrastructure Standards rule over three years and recover those costs in this case. Furthermore, AmerenUE is granted accounting authority to defer its infrastructure inspection costs incurred between October 1, 2008, and February 28, 2009, to comply with the Commission's Infrastructure Standards rule.

AmerenUE also proposed to recover or defer its cost of infrastructure repairs. For the reasons previously stated, the Commission finds that recovery or deferral of those repair costs is not appropriate.

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[117] Beck Surrebuttal, Ex. 218, Page 11, Lines 1-3.

[118] Beck Surrebuttal, Ex. 218, Page 11, Lines 5-19.

In his surrebuttal testimony for AmerenUE, Ron Zdellar indicated the cost of infrastructure inspection and repairs for the period of January 1, 2008, through September 30, 2008, was $8.6 million. Exhibit 240, drawn from Zdellar's work papers, breaks that down into $3.7 million for inspections and $4.9 million for repairs for the January through September period. In his corrected surrebuttal testimony, which is exhibit 76, Zdellar reduces that amount to a total of $8.0 million for infrastructure inspection and repair. Unfortunately, the record does not contain a breakdown of that total amount between repairs and inspections. Since the Commission has determined AmerenUE should not be allowed to defer and recover those repair costs, the Commission must devise a way to remove those costs from the total.

The Commission will assume Zdellar's corrected amount will retain the same ratio of repair costs to inspection costs as that in the number contained in his surrebuttal testimony. The number in the surrebuttal testimony was 43 percent inspection costs and 57 percent repair cost. Applying the same ratio to the $8.0 million number in exhibit 76 shows inspection costs of $3.44 million and repair costs of $4.56 million. Thus, the Commission will allow AmerenUE to amortize $3.44 million in inspection costs over 3 years and recover them in the rates to be established in this case.

Should a tracker be implemented for infrastructure inspection and repair expense that exceeds the level of infrastructure inspection and repair expense the Commission recognizes in AmerenUE's revenue requirement in this case? Should such a tracker be implemented for the one-year period of March 1, 2009 to February 28, 2010?

Findings of Fact:

AmerenUE proposes a single tracking mechanism that would track both vegetation management expenses and infrastructure inspection expenses. The Commission has previously approved a tracker for vegetation management expenses and for the same reasons, will approve the tracking mechanism to also apply to infrastructure inspection expenses as previously described.

Conclusions of Law Regarding Vegetation Management and Infrastructure Inspection and Repair:

Commission Rule 4 CSR 240-23.020 establishes standards requiring electrical corporations, including AmerenUE, to inspect its transmission and distribution facilities as necessary to provide safe and adequate service to its customers. Specifically, 4 CSR 240-23.020(3)(A) establishes a four-year cycle for inspection of urban infrastructure and a six-year cycle for inspection of rural infrastructure.

Commission Rule 4 CSR 240-23.020(4) establishes a procedure by which an electric utility may recover expenses it incurs because of the rule. Specifically, that section states as follows:

> In the event an electrical corporation incurs expenses as a result of this rule in excess of the costs included in current rates, the corporation may submit a request to the commission for accounting authorization to defer recognition and possible recovery of these excess expenses until the effective date of rates resulting from its next general rate case, filed after the effective date of this rule, using a tracking mechanism to record the difference between the actually incurred expenses as a result of this rule and the amount included in the corporation's rates ... .

Commission Rule 4 CSR 240-23.030 establishes standards requiring electrical corporations, including AmerenUE, to trim trees and otherwise manage the growth of vegetation around its transmission and distribution facilities as necessary to provide safe and adequate service to its customers. Specifically, 4 CSR 240-23.030(9) establishes a four-year cycle for vegetation management of urban infrastructure and a six-year cycle for vegetation management of rural infrastructure. The vegetation management rule also includes a provision that would allow AmerenUE to ask the Commission for authority to accumulate and recover its cost of compliance in its next rate case.[119]

Decision:

The Commission's decision regarding vegetation management and infrastructure inspection expenses can be summarized as follows:

1. AmerenUE shall recover in its base rates $54.1 million for vegetation management costs, and $10.7 million for infrastructure inspection costs.

2. AmerenUE shall amortize over three years and recover in rates $2.9 million for vegetation management expenses beyond what it was able to recover in prior rates. AmerenUE shall amortize over three years and recover in rates $3.44 million in infrastructure inspection costs beyond what it was able to recover in prior rates.

3. AmerenUE shall establish a tracking mechanism to track future vegetation management and infrastructure inspection costs. That tracking mechanism shall include a base level of $64.8 million ($54.1 million + $10.7 million = $64.8 million). Actual expenditures shall be tracked around that base level with the creation of a regulatory liability in any year where AmerenUE spends less than the base amount and a regulatory asset in any year where AmerenUE spends more than the base amount. The assets and liabilities shall be netted against each other and shall be considered in AmerenUE's next rate case. The tracking mechanism shall contain a ten percent cap so expenditures exceeding the base level by more than 10 percent shall not be deferred under the tracking

[119] Commission Rule 4 CSR 240-23.030(10).

mechanism. If AmerenUE's vegetation management and infrastructure inspection costs exceed the ten percent cap, it may request additional accounting authority from the Commission in a separate proceeding. The tracking mechanism shall operate until new rates are established in AmerenUE's next rate case.

3. January 2007 Ice Storm AAO

Introduction:

AmerenUE experienced a severe ice storm in its service territory on January 13, 2007. Staff and AmerenUE agree AmerenUE incurred $24.56 million in storm restoration costs following that storm.[120] In an earlier case, Case No. EU-2008-0141, the Commission approved a stipulation and agreement that gave AmerenUE an accounting authority order (AAO) authorizing it to defer those storm restoration costs for consideration in this rate case.[121] The approved stipulation and agreement also determined the storm restoration costs would be amortized over a five-year period. In other words, an amount would be included in rates that would allow AmerenUE to recover one fifth of the total costs in each of five years. The only disagreement was about when that amortization period should begin. Rather than resolve that question, the stipulation and agreement in the AAO case provided the issue would be deferred for consideration in this rate case, which was already pending at the time.

Staff proposes the five-year amortization period begin on February 1, 2007, approximately two weeks after the storm.[122] AmerenUE contends the five-year

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[120] Cassidy Surrebuttal, Ex. 226, Page 11, Lines 7-9.

[121] *In the Matter of the Application of Union Electric Company, d/b/a AmerenUE for an Accounting Authority Order Regarding Accounting for the Extraordinary Costs Relating to Damage from the January 2007 Ice Storm*, Case No. EU-2008-0141, Order Approving Stipulation and Agreement, April 30, 2008.

amortization period should begin on March 1, 2009, the presumed effective date of the new rates that will be established in this case.[123]

Findings of Fact:

Staff's proposed February 1, 2007, starting date for the amortization period effectively ensures AmerenUE will be unable to recover two fifths of the storm restoration costs for which the Commission granted an AAO. When the rates established in this case go into effect, more than two of the five years of amortization would have already occurred. Those amounts amortized over the first two years would be lost to AmerenUE and likely could not be recovered. In the particular circumstances of this case, that result would be unfair to AmerenUE.

The purpose of an AAO is to give the utility an opportunity to recover extraordinary expenses. In granting AmerenUE an AAO, based on the stipulation and agreement of the parties, the Commission determined the ice storm restoration costs are extraordinary costs, and no party disputes that fact. As Staff points out, an AAO is not intended to absolutely ensure a utility recovers all those extraordinary expenses.[124] However, the utility should be given a reasonable opportunity to make that recovery.

Staff's proposed date for beginning the amortization period would not give AmerenUE a reasonable opportunity to recover those expenses because of the timing of this ice storm in relation to AmerenUE's last rate case. The ice storm occurred on January 13, 2007. That was only two weeks after the January 1, 2007, cut-off date for known and

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[122] Cassidy Surrebuttal, Ex. 226, Page 11, Lines 12-13.

[123] Barnes Rebuttal, Ex. 26, Page 8, Lines 3-5.

[124] Cassidy Surrebuttal, Ex. 226, Page 13, Lines 2-4.

measurable changes in AmerenUE's last rate case.[125] Therefore, AmerenUE incurred the expenses after the close of the test year and as a result could not recover those costs in the normal course of that rate case.

Staff suggests perhaps AmerenUE could have sought recovery of these expenses as an isolated adjustment in the last rate case.[126] However, such recovery would have been unlikely because the actual amount of the storm expenses was not known and measurable until the final invoices from contractors and other utilities were received in June 2007, after the rates from the prior rate case had gone into effect, and long after the evidentiary record in that case had closed. As a result, AmerenUE was effectively precluded from seeking recovery of those storm expenses in the last rate case.

That is important because in ordinary situations, when a utility obtains an AAO, it can control the timing of a rate case in which it will seek to recover the expenses deferred under the AAO. Thus, the utility can weigh the expenses that are being amortized under the AAO against its other expenses and revenues and decide whether it needs to come in for a rate case to try to recover the expenses that are being amortized. In some cases, the utility may conclude it does not need to increase its revenues and will decide not to file a rate case, allowing the costs deferred under the AAO to be amortized out of existence.

In this case, the extraordinary ice storm restoration expenses were incurred while AmerenUE was already in the later stages of a rate case, but too late to be recovered in that rate case. AmerenUE concluded it needed additional revenue as it failed to earn its

[125] Barnes Rebuttal, Ex. 26, Page 8, Lines 10-12.

[126] Transcript, Page 1858, Lines 7-10.

allowed return on equity throughout 2007,[127] but as a practical matter, could not have filed a rate case much before April 2008 when it filed this case.[128] That means AmerenUE could not effectively use the option of filing a rate case to recover the costs sooner, as is frequently done in an AAO situation.

Staff contends AmerenUE would not necessarily be precluded from recovering the full amount of the expenses deferred under the AAO no matter when the five-year amortization begins. In theory, that is true, because once the annually amortized amount of expenses is included in rates, that amount of expenses will remain in rates until the Commission revises those rates in a future rate case. If the five-year amortization begins in 2007, as Staff proposes, the amortization would be complete in 2012. However, if AmerenUE chose not to file another rate case until 2014 the annually amortized amount of expenses would continue in rates for two extra years and AmerenUE would fully recover its storm restoration expenses. Indeed, if AmerenUE did not bring a rate case until 2015 or later, it could actually over-recover those expenses.

However, given the rising cost environment facing AmerenUE, it is unreasonable to believe the company will wait until 2014, or after, to file its next rate case. Indeed, the testimony presented at the hearing indicated AmerenUE will not wait nearly that long to file its next rate case.[129] Furthermore, since the Commission is authorizing AmerenUE to establish a fuel adjustment clause in this case, AmerenUE will be required to file a new rate

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[127] Barnes Rebuttal, Ex. 26, Page 9, Chart at Line 1.

[128] Transcript, Page 1847-1848, Lines 3-25, 1.

[129] Transcript, Page 2210, Lines 9-12, and Ex. 433HC, Page 17, AmerenUE's exact plan for filing future rate cases is highly confidential.

case no later than 2012, so that new rates will go into effect no later than March 1, 2013.[130] Under these circumstances, there is no risk that AmerenUE will over-recover its storm restoration expenses, and beginning the five-year amortization on the date proposed by Staff would guarantee AmerenUE would be unable to recover the full amount of expenses.

Conclusions of Law:

A fuel adjustment clause approved under Section 386.266, RSMo (Supp. 2008), the statute that give the Commission authority to approve a fuel adjustment clause for an electric utility, must contain a provision requiring the utility to "file a general rate case with the effective date of new rates to be no later than four years after the effective date of the commission order implementing the adjustment mechanism."

Decision:

Under the unique circumstances of this case, the five-year amortization period for the storm restoration costs relating to the January 2007 ice storm shall begin on March 1, 2009. This decision is dictated by these particular facts and should not be interpreted as a general rule that would require the beginning of an amortization period in a future case to coincide with the effective date of rates in a future rate case.

4. Deferred Income Taxes

Introduction:

Deferred income taxes arise from temporary differences between book and tax treatment of an item of income or expense. Under well-established regulatory principles, deferred taxes are treated as a reduction to rate base so ratepayers do not pay a return on

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[130] Section 386.266, RSMo (Supp. 2008).

funds provided to the company at no cost.[131] In that way, ratepayers are given the benefit of what is, in effect, an interest free loan from the government to the utility.[132] In other words, the benefit the company receives from being able to keep money by delaying payment to the government is passed along to ratepayers.

There is no disagreement about those principles. The issue concerns several uncertain tax positions AmerenUE has taken before the IRS. Staff wants to treat all of the money associated with those uncertain positions as deferred income taxes, and thus as a reduction to AmerenUE's rate base.[133] AmerenUE argues only the portion of the money it ultimately expects to pay to the IRS should be excluded from the deferred income tax category.[134]

Findings of Fact:

AmerenUE has taken three tax positions with the IRS about which it is uncertain. In other words, it may ultimately have to pay additional tax if the IRS rules against AmerenUE's position. At this time those taxes have not been paid.[135] The IRS audit of AmerenUE's tax positions is still in progress and AmerenUE expects to learn the results of that audit in the summer of 2009.[136]

Generally Accepted Accounting Principles (GAAP) provide rules for recording the effect of tax deferrals. Under a GAAP standard known as FIN 48, AmerenUE is required to record as deferred tax only the portion of the tax liability upon which the company expects

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[131] Staff Report – Cost of Service, Ex. 200, Page 11.

[132] Nelson Rebuttal, Ex. 21, Page 4, Lines 10-16.

[133] Staff Report – Cost of Service, Ex. 200, Page 11.

[134] Nelson Rebuttal, Ex. 21, Page 4, Lines 17-21.

[135] Transcript, Pages 1076-1077, Lines 25, 1.

[136] Transcript, Page 1079, Lines 10-11.

to prevail. The portion of that liability that the company ultimately expects to pay to the government in taxes, including interest, is treated as a "FIN 48 liability"[137]

FIN 48 requires AmerenUE to review its FIN 48 liabilities quarterly and to adjust those liabilities to take into account changes in laws and regulations and the impact those changes may have on the company's prospects of prevailing before the IRS. The company's adjustments are reviewed quarterly by external auditors.[138] AmerenUE would exclude its FIN 48 liabilities from Staff's calculations of deferred taxes for ratemaking purposes. Staff would treat the entire amount of potential tax liability as if AmerenUE will win on all positions and never have to pay the tax.[139]

If the ultimate outcome before the IRS matches the FIN 48 analysis, in other words, AmerenUE loses the uncertain tax positions, there would be no deferral of tax and no means by which AmerenUE would recover the amount that reduced rates, but was not actually realized by the company.[140]

Both ratepayers and shareholders benefit when AmerenUE takes an uncertain tax position with the IRS, because saving money on taxes benefits the company's bottom line and reduces the amount of expense the ratepayers must pay. At the hearing, Staff's witness agreed AmerenUE should pursue such positions.[141] The best way to encourage AmerenUE to continue to take uncertain tax positions is to treat the company fairly in the regulatory process.

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[137] Nelson Rebuttal, Ex. 21, Page 5, Lines 9-19.

[138] Nelson Rebuttal, Ex. 21, Page 5, Lines 21-23.

[139] Staff Report - Cost of Service, Ex. 200, Page 12.

[140] Nelson Rebuttal, Ex. 21, Page 6, Lines 6-9.

[141] Transcript, Pages 1086-1087, Lines 23-25, 1-2.

AmerenUE should not be required to recognize as deferred taxes the amount of its uncertain tax positions it ultimately expects to pay with interest to the IRS. The best means of determining that amount is by recognizing the allocation of those costs AmerenUE already makes under FIN 48. Therefore, the Commission will exclude from the deferred taxes account the amount of AmerenUE's FIN 48 liability.

Conclusions of Law:

There are no additional conclusions of law for this issue.

Decision:

The Commission finds in favor of AmerenUE's position. AmerenUE's FIN 48 liability shall be excluded from consideration in the deferred taxes account.

5. Entergy Arkansas Equalization Costs in SO2 or other Tracker

Introduction:

This issue concerns potential refunds AmerenUE may receive as the result of ongoing litigation before the Federal Energy Regulatory Commission (FERC). The disagreement was between Staff and AmerenUE. At the hearing, Staff and AmerenUE read the following stipulation into the record as a settlement of their disagreement:

> The company shall maintain such books and records as are necessary to allow the Staff to identify the amount of refunds, if any, the company may receive in the future arising from the dispute involving the 1999 purchased power service agreement with Entergy Arkansas described in the surrebuttal testimony of Staff witness John P. Cassidy. The company shall also maintain the books and records necessary to identify any costs associated with obtaining any such refunds such as legal expenses associated with efforts to obtain refunds.[142]

Decision:

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[142] Transcript, Pages 1866-1867, Lines 24-25, 1-10.

The stipulation agreed to by the parties is a reasonable resolution of their disagreement. The Commission accepts that stipulation as a resolution of this issue.

6. Off-System Sales

This issue was resolved by the Stipulation and Agreement as to Off-System Sales Related Issues, which the Commission approved in an order issued on December 30, 2008.

7. The Proposed Fuel Adjustment Clause

General Findings of Fact Regarding Fuel Adjustment Clauses:

The rates AmerenUE will be allowed to charge its customers are based on a determination of the company's revenue requirement. A revenue requirement is based on the costs and income the company experienced during a historical test year. For this case, the test year was established as the 12-month period ending on March 31, 2008, with certain pro forma adjustments through September 30, 2008, trued-up as of September 30, 2008. That means the Commission will use the expenses and revenues measured during the test year to predict the expenses the company will be allowed to recover in future rates. Expenses that may be incurred in the future generally are not included in rate calculations.

Under traditional ratemaking procedures, at the end of the rate case the Commission establishes the rates an electric utility can charge. Once rates are established, the utility cannot change those rates without filing a new rate case and restarting the review process. However, in 2005, the Missouri legislature passed a law authorizing the Commission to establish a mechanism to allow an electric utility to make periodic rate adjustments outside of general rate proceedings to reflect increases and decreases in its prudently incurred fuel and purchased-power costs.[143] The sort of mechanism envisioned by the statute is generally known as a fuel adjustment clause. AmerenUE has requested a fuel adjustment clause in this case.

Requests from Missouri electric utilities for implementation of a fuel adjustment clause are a relatively recent development because of the recent statutory change. However, fuel adjustment clauses are frequently allowed by utility commissions in other states. A chart submitted by AmerenUE's witness indicates 87 out of 94 utilities in non-restructured states, excluding Missouri, already have a fuel adjustment clause in place. Another 3 currently have a request for a fuel adjustment clause pending. Of 27 utilities with more than 50 percent coal capacity in neighboring and other non-restructured states, 26 already have a fuel adjustment clause in place.[144] Clearly, this statute and the accompanying rules have merely transported Missouri back into the mainstream of utility regulation. That mainstream of regulation recognizes a utility must be able to recover its prudently incurred fuel costs and that it is impossible for a utility to earn its allowed return on equity in a rising cost environment without a fuel adjustment clause.

While the new statute, Section 386.266, allows the Commission to approve a fuel adjustment clause, in effect, overturning a 1979 Missouri Supreme Court decision finding fuel adjustment clauses to be contrary to Missouri law for residential customers,[145] the statute does not require the Commission to approve a fuel adjustment clause. Instead, it specifically gives the Commission authority to reject a proposed fuel adjustment clause

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[143] Section 386.266, RSMo (Supp. 2008).

[144] Lyons Rebuttal, Ex. 42, Schedule MJL-RE8.

[145] *State ex rel. Utility Consumers Council of Mo., Inc. v. Pub. Serv. Comm'n*, 585 S.W.2d 41 (Mo. banc 1979).

after giving an opportunity for a full hearing in a general rate case.[146] The statute, while not providing specific guidance on when a fuel adjustment clause should be approved, does provide some guidance on when such a clause is appropriate. Specifically, it indicates any such fuel adjustment clause must be reasonably designed to provide the utility with a sufficient opportunity to earn a fair return on equity.[147]

There are circumstances when the use of a fuel adjustment clause may be appropriate to preserve the financial health of the utility, and no one, including ratepayers, benefits when a utility becomes financially unhealthy. In an era where fuel costs are highly volatile or rapidly rising, a fuel adjustment clause may be appropriate if the company is to earn its authorized rate of return. The problem then is how to determine when a fuel adjustment clause is appropriate.

General Conclusions of Law Regarding Fuel Adjustment Clauses:

Section 386.266.1, RSMo (Supp. 2008), the statute that allows the Commission to establish a fuel adjustment clause provides as follows:

> Subject to the requirements of this section, any electrical corporation may make an application to the commission to approve rate schedules authorizing an interim energy charge or periodic rate adjustments outside of general rate proceedings to reflect increases and decreases in its prudently incurred fuel and purchased-power costs, including transportation. The commission may, in accordance with existing law, include in such rate schedules features designed to provide the electrical corporation with incentives to improve the efficiency and cost-effectiveness of its fuel and purchased-power procurement activities.

Subsection 4 of that statute sets out some of the provisions that must be included in a fuel adjustment clause as follows:

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[146] Section 386.266.4, RSMo (Supp. 2008).

[147] Section 386.266.4(1), RSMo (Supp. 2008)

> The commission shall have the power to approve, modify, or reject adjustment mechanisms submitted under subsections 1 to 3 of this section only after providing the opportunity for a full hearing in a general rate proceeding, including a general rate proceeding initiated by complaint. The commission may approve such rate schedule after considering all relevant factors which may affect the cost or overall rates and charges of the corporation, provided that it finds that the adjustment mechanism set forth in the schedules:
>
> *(1) Is reasonably designed to provide the utility with a sufficient opportunity to earn a fair return on equity;*
>
> (2) Includes provisions for an annual true-up which shall accurately and appropriately remedy any over- or under-collections, including interest at the utility's short-term borrowing rate, through subsequent rate adjustments or refunds;
>
> (3) In the case of an adjustment mechanism submitted under subsections 1 and 2 of this section, includes provisions requiring that the utility file a general rate case with the effective date of new rates to be no later than four years after the effective date of the commission order implementing the adjustment mechanism. ...
>
> (4) In the case of an adjustment mechanism submitted under subsections 1 or 2 of this section, includes provisions for prudence reviews of the costs subject to the adjustment mechanism no less frequently than at eighteen-month intervals, and shall require refund of any imprudently incurred costs plus interest at the utility's short-term borrowing rate. (emphasis added)

Subsection 4(1) is emphasized because that is the key requirement of the statute. Any fuel adjustment clause the Commission allows AmerenUE to implement must be reasonably designed to allow the company a sufficient opportunity to earn a fair return on equity.

Subsection 7 of the fuel adjustment clause statute provides the Commission with further guidance, stating the Commission may:

> take into account any change in business risk to the corporation resulting from implementation of the adjustment mechanism in setting the corporation's allowed return in any rate proceeding, in addition to any other changes in business risk experienced by the corporation.

Finally, subsection 9 of that statute requires the Commission to promulgate rules to "govern the structure, content and operation of such rate adjustments, and the procedure for the submission, frequency, examination, hearing and approval of such rate adjustments." In compliance with the requirements of the statute, the Commission promulgated Commission Rule 4 CSR 240-3.161, which establishes in detail the procedures for submission, approval, and implementation of a fuel adjustment clause.

Is a Fuel Adjustment Clause Appropriate?

Findings of Fact:

The Commission addressed the question of when a fuel adjustment clause is appropriate in AmerenUE's last rate case and in recent rate cases for two other Missouri electric utilities. In all cases, the Commission accepted three criteria for determining whether an electric utility should be allowed to implement a fuel adjustment clause. The Commission concluded a cost or revenue change should be tracked and recovered through a fuel adjustment clause if that cost or revenue change is:

1. Substantial enough to have a material impact upon revenue requirements and the financial performance of the business between rate cases;
2. beyond the control of management, where utility management has little influence over experienced revenue or cost levels; and
3. volatile in amount, causing significant swings in income and cash flows if not tracked.[148]

After applying those criteria in AmerenUE's last rate case, the Commission found that fuel costs for AmerenUE, which derived most of its power through its own coal or nuclear-fired generating plants, were not sufficiently volatile to justify the use of a fuel adjustment clause.[149] In addition, the Commission was influenced by the strength of Staff's witness, Mike Proctor's, testimony suggesting AmerenUE's rising fuel costs would be at least partially off-set by rising profits from off-system sales Aquila, Inc., in contrast to

[148] *In the Matter of Union Electric Company d/b/a AmerenUE's Tariffs Increasing Rates for Electric Service*, Report and Order, Case No. ER-2007-0002, May 22, 2007, Pages 20-21.

[149] *In the Matter of Union Electric Company d/b/a AmerenUE's Tariffs Increasing Rates for Electric Service*, Report and Order, Case No. ER-2007-0002, May 22, 2007, Page 26.

AmerenUE, derived much of its power through natural gas-fired generating plants and purchased power. In those circumstances, the Commission concluded Aquila would be allowed to implement a fuel adjustment clause.[150] For similar reasons, the Commission allowed The Empire District Electric Company to implement a fuel adjustment clause.[151]

Applying that three-part test to AmerenUE, it is clear AmerenUE's fuel and purchased power cost is substantial. The approved Stipulation and Agreement as to Off-System Sales Issues established AmerenUE's total fuel and purchased power costs at $735 million for the test year, which was netted against off-system sales of $451.7 million, resulting in annual net fuel costs of $283.3 million. The cost of fuel and purchased power is AmerenUE's largest expense, comprising 25 percent of the company's operations and maintenance expense.[152] Clearly, these amounts are substantial enough to have a material impact on AmerenUE's revenue requirements and financial performance between rate cases. The first prong of the three-part test is satisfied.

The second prong of the test is whether the fuel and purchased power costs tracked in the fuel adjustment clause are largely beyond the control of AmerenUE's management. The largest portion of AmerenUE's cost to purchase fuel goes toward the purchase of Powder River Basin coal to fire its coal-fired generation plants.[153] AmerenUE buys a lot of Power River Basin coal and Staff and other parties suggest that perhaps the amount of

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[150] *In the Matter of the Tariffs of Aquila, Inc., d/b/a Aquila Networks – MPS and Aquila Networks – L&P Increasing Electric Rates,* Report and Order, Case No. ER-2007-0004, May 17, 2007, Page 37.

[151] *In the Matter of The Empire District Electric Company's Tariffs to Increase Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company*, Report and Order, Case No. ER-2008-0093 July 30, 2008, Page 40.

[152] Staff Report – Cost of Service, Ex. 200, Page 60.

[153] Mantle Surrebuttal, Ex. 224, Page 2, Table LM1.

coal AmerenUE buys would enhance its ability to negotiate coal and transportation costs.[154] However, no one presented a study to actually measure any influence AmerenUE might have over those costs.[155] On the contrary, most of the costs that comprise AmerenUE's fuel costs, the costs that would be tracked in a fuel adjustment clause, are dictated by national and international markets, including competing purchases by China and India, far beyond the control of AmerenUE. Hence, no one suggests AmerenUE can control the market price it pays for coal, diesel fuel to transport that coal, natural gas, nuclear fuel, or the effect Federal carbon legislation may have on coal prices. Neither can it control the other side of its net fuel cost, the price at which it is able to sell electricity into the off-system sales market. The second prong of the three-part test is also satisfied.

The third prong of the previously established test is whether AmerenUE's net fuel cost is volatile in amount, causing significant swings in income and cash flows if not tracked. In AmerenUE's last rate case, the Commission refused to authorize a fuel adjustment clause for AmerenUE because it found the company did not satisfy this prong of the test.[156] In that decision, the Commission was heavily influenced by the fact that AmerenUE's largest fuel cost is for the purchase of coal, and those coal purchases are substantially hedged for upcoming years.

AmerenUE's coal purchase costs are still substantially hedged,[157] but the Commission's previous focus solely on coal purchase costs was misplaced. AmerenUE's net fuel cost, the amount tracked in a fuel adjustment clause, is not dependent simply on

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[154] Mantle Surrebuttal, Ex. 224, Page 5, Lines 9-11.

[155] Transcript, Page 2633, Lines 5-16.

[156] *In the Matter of Union Electric Company d/b/a AmerenUE's Tariffs Increasing Rates for Electric Service*, Report and Order, Case No. ER-2007-0002, May 22, 2007, Page 26.

[157] Neff Direct, Ex. 47, Page 16, Lines 1-9.

the purchase price of coal. Other factors, such as the market price for the sale of off-system power, which AmerenUE largely cannot hedge,[158] are very volatile. AmerenUE's witness, Shawn Schukar explained:

> The variability inherent in generation availability, native load, and market prices can cause the amount and value of off-system sales to vary significantly from one period to another, both on a short-term and long-term basis.[159]

Furthermore, through the testimony of its witness, Ajay Arora, AmerenUE was able to demonstrate that the net fuel costs AmerenUE has actually experienced over the past several years are very uncertain.[160] Considering all the costs and revenues that go into the calculation of AmerenUE's net fuel cost, it is apparent AmerenUE has satisfied the third prong of the three-part test.

In its report and order in the previous rate case, the Commission relied on the three-part test to conclude AmerenUE did not need a fuel adjustment clause at that time. As it has evaluated requests for approval of a fuel adjustment clause from other utilities in other rate cases, the Commission has found that the three-part test does not fully define the question of whether a fuel adjustment clause is needed. Thus, although the Commission has found that AmerenUE now satisfies the requirements of the three-part test, there are other, more persuasive reasons to approve AmerenUE's request for a fuel adjustment clause.

Section 386.266.4(1) RSMo (Supp. 2008) requires that any fuel adjustment charge approved by the Commission must be "reasonably designed to provide the utility with a

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[158] Lyons Rebuttal, Ex. 42, Page 19, Lines 1-3.

[159] Schukar Direct, Ex. 27, Page 14, Lines 16-18.

[160] Arora Surrebuttal, Ex. 24, Page 9, Table AKA-SR1. The numbers in the table are highly confidential.

sufficient opportunity to earn a fair return on equity". While that statutory requirement specifically applies to the design of a fuel adjustment clause rather than the need to implement such a clause, it also states a good standard by which the Commission can measure the need for such a clause. In a sense, the need to provide a utility with a sufficient opportunity to earn a fair return on equity is just a summation of the end goal of the previously described three-part test. The question then becomes, does AmerenUE have a reasonable opportunity to earn a fair return on equity without a fuel adjustment clause?

An examination of recent history indicates the answer is no. AmerenUE is faced with a rising cost environment and consequently is hit hard by regulatory lag. Regulatory lag is simply the time between when the company incurs an increased cost and the time it can recover that increased cost from its customers through a rate increase. As costs rise, AmerenUE inevitably experiences a delay in being able to recover those costs. In other words, the company must run faster toward a goal that keeps moving away.

For example, AmerenUE's cost of delivered coal increased by 12 percent from the amount used to set rates in the last rate case to the amount that will be used to set rates in this case.[161] Delivered coal costs for the next several years, much of which has already been locked in under long-term contracts, will experience similar cost increases in future years.[162] By the time the rates approved in this case go into effect, AmerenUE will have under-recovered $114 million in coal costs since January 1, 2007.[163]

Since fuel costs are the largest expense item for AmerenUE, rising fuel costs have a

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[161] Neff Direct, Ex. 47, Page 4, Lines 1-5.

[162] Neff Direct, Ex. 47, Page 4, Lines 7-13. The precise numbers are highly confidential.

[163] Lyons Rebuttal, Ex. 42, Page 2, Lines 18-20. The number in the testimony is declared to be highly confidential, but it is repeated as public information in AmerenUE's brief at page 32.

large effect on the company's bottom line. As a result, in recent years, AmerenUE has been unable to earn its allowed rate of return. For the period following the implementation of new rates following AmerenUE's last rate case in May 2007, through August 2008, AmerenUE was able to earn an actual return on equity of only 9.31 percent, far below its authorized return of 10.2 percent.[164]

In its Report and Order in AmerenUE's last rate case, the Commission said, "a future rate case, not a fuel adjustment clause, is the proper means by which AmerenUE should recover its rising fuel costs."[165] However, simply filing more frequent rate cases cannot solve the regulatory lag problem for AmerenUE. In Missouri, rate cases generally last 11 months from the time the company files tariffs to increase rates until the Commission issues a decision about that rate increase request. So, for example, this rate case, filed in April 2008, is able to incorporate the substantial January 1, 2008 coal cost increase in AmerenUE's cost of service for consideration in this order. Those coal cost increases will be included in the rates that go into effect at the conclusion of this case on March 1, 2009. However, that means AmerenUE will not recover approximately 14 months of those increased costs. If, following the conclusion of this case, AmerenUE wants to recover its January 1, 2009 coal cost increase, it could perhaps file for its next rate increase in July 2009. Those rates would likely not go into effect until June 2010. By that time, AmerenUE would have lost 17 or 18 months of the 2009 cost increase, as well as 5 or 6 months of the 2010 increase, assuming the 2010 increase could be brought within the test year for that

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[164] Voss Rebuttal, Ex. 2, Page 10, Chart at line 3.

[165] *In the Matter of Union Electric Company d/b/a AmerenUE's Tariffs Increasing Rates for Electric Service*, Report and Order, Case No. ER-2007-0002, May 22, 2007, Page 26.

rate case.[166]

When costs are steadily rising, regulatory lag clearly has a significant impact on AmerenUE's opportunity to earn a fair return on its investment. In its Report and Order in AmerenUE's last rate case, the Commission said "rising, but known fuel costs are the worst reason to implement a fuel adjustment clause...."[167] That statement did not take into account the fact that regulatory lag in a rising cost environment will deprive AmerenUE of an opportunity to earn a fair return on its investment. As a result, the statement is, simply, wrong.

Regulatory lag's pernicious effect on AmerenUE's ability to earn a fair return not surprisingly has an effect on the company's ability to attract investors. For all the reasons previously indicated, fuel adjustment clauses have become extremely common for regulated utilities in this country.[168] As a result, investors expect to see those fuel adjustment clauses in operation. The lack of a fuel adjustment clause puts AmerenUE a step behind the utilities against which it must compete for investment capital.

The credit rating agencies that evaluate AmerenUE have taken note of the company's lack of a fuel adjustment clause. In downgrading AmerenUE's investment grade in May 2008, Moody's Investor Services said:

> The downgrade also reflects the challenging regulatory environment for electric utilities operating in the state of Missouri, as Union Electric is one of the relatively few utilities in the country operating without fuel, purchased power, and environmental cost recovery mechanisms. This lack of automatic cost recovery provisions creates uncertainty regarding the timely recovery of

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[166] Lyons Direct, Ex. 41, Page 11, Lines 4-14.

[167] *In the Matter of Union Electric Company d/b/a AmerenUE's Tariffs Increasing Rates for Electric Service*, Report and Order, Case No. ER-2007-0002, May 22, 2007, Page 23.

[168] Lyons Rebuttal, Ex. 42, Schedule MJL-RE8.

the higher costs and investments being incurred and leads to significant regulatory lag.[169]

In issuing a credit opinion on Union Electric Corporation in August 2008, Moody's reaffirmed that opinion, stating:

> A combination of higher operating costs, limited rate relief, and the lack of cost recovery mechanism in place has resulted in a steady decline in Union Electric's financial metrics and ratings over the last several years.
>
> What Could Change the Rating - Up
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> An increase in the supportiveness of the regulatory environment for electric utilities in Missouri; the implementation of fuel, purchased power, and/or environmental cost mechanisms...
>
> What Could Change the Rating – Down
>
> An adverse outcome of its pending rate case, including the inability to implement a fuel adjustment clause...[170]

Gary M Rygh, a Senior Vice President at Barclays Capital Inc., the investment banking division of Barclays Bank PLC,[171] testifying on behalf of AmerenUE, convincingly described the problem as follows:

> [T]he majority of utilities with which AmerenUE has to compete for capital benefit from the inclusion of an FAC in their ratemaking process. As I addressed earlier, that competition for capital now and in for the foreseeable future will be difficult and intense, and will be even more difficult for AmerenUE if it must compete for capital without the benefit of an FAC.
>
> Indeed, investors, credit rating agencies and others will likely penalize AmerenUE for the risk associated with the inability to better manage the burden associated with procuring fuel for customers unless an FAC is approved for AmerenUE. In a good environment these penalties would be visible, in the current environment and the environment we expect for the foreseeable future, they could be severe. This will likely cause an increase in the cost of capital which will create a longer term and greater cost for customers. The lack of inclusion of a reasonable FAC will continue to keep

[169] Rygh Rebuttal, Ex. 46, Page 25, Lines 9-21.

[170] Gordon Surrebuttal, Ex. 45, Schedule KG-SE2.

[171] Rygh Rebuttal, Ex. 46, Page 1, Lines 7-13.

AmerenUE in the minority of its peers who have these procedures in place and will also be going to market to raise capital.[172]

It would be easy to join with Public Counsel in criticizing the credit rating agencies as "greedy and focused on short-term profits".[173] However, while Public Counsel's witness, Ryan Kind, may not "take a whole lot of stock in what they say as a group,"[174] a whole lot more investors care about what Moody's and the other rating agencies say about AmerenUE than care about Ryan Kind's opinion.

Right or wrong, the opinions of credit rating agencies do matter. And they matter to AmerenUE's ratepayers as well as its investors. A further investment rating downgrade of AmerenUE would increase the company's cost to borrow the capital it needs to meet the electricity needs of its customers. Those increased borrowing costs will ultimately be passed along to ratepayers in a future rate case.

Conclusions of Law:

There are no additional conclusions of law for this issue.

Decision:

The Commission finds that AmerenUE meets the previously described three-part test for approval of a fuel adjustment mechanism. Further, the Commission finds that the company needs a fuel adjustment clause to have a sufficient opportunity to earn a fair return on equity. Finally, the Commission finds that AmerenUE needs a fuel adjustment clause to be able to compete for capital with other utilities that already have a fuel

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[172] Rygh Rebuttal, Ex. 46, Page 24, Lines 1-17.

[173] Public Counsel's Post Hearing Brief, Page 15.

[174] Transcript, Page 2740, Lines 3-5.

adjustment clause. Based on those findings, the Commission authorizes AmerenUE to implement a fuel adjustment clause.

Appropriate Incentive Mechanism

Introduction:

The Commission has authorized AmerenUE to implement a fuel adjustment clause. The Commission now must define an appropriate incentive mechanism to include in AmerenUE's fuel adjustment clause. The statute that authorizes the Commission to establish a fuel adjustment clause for AmerenUE already includes features designed to give the company an incentive to maximize its income from off-system sales and minimize its costs. Specifically, the statute requires a utility operating under a fuel adjustment clause to file a new rate case every four years, and requires the Commission to review the prudence of the company's purchasing decisions every 18 months. But regulatory reviews are only a partial substitute for the direct incentives that can result from a utility's quest for profit. Therefore, the statute allows the Commission to include features "designed to provide the electrical corporation with incentives to improve the efficiency and cost-effectiveness of its fuel and purchased-power procurement activities."[175]

AmerenUE proposed the Commission use the same incentive mechanism it used when it established fuel adjustment clauses for Aquila and Empire in those companies' recent rate cases.[176] The fuel adjustment clause would include a 95 percent pass-through provision. That means only 95 percent of any over or under recovery balance, measured against a base level, would be passed to customers under the fuel adjustment clause. The other 5 percent would be absorbed by AmerenUE's shareholders.

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[175] Section 386.266.1, RSMo (Supp. 2008).

[176] Lyons Direct, Ex. 41, Page 3, Lines 6-14.

Maurice Brubaker, witness for MIEC, proposed an 80 percent pass-through provision. Under his proposal, the other 20 percent of any fuel cost increase would be absorbed by AmerenUE's shareholders. Of course, shareholders would also retain 20 percent of any fuel cost decreases.[177] To protect shareholders and ratepayers from truly dramatic cost variations, Brubaker's proposal would also place a 50 basis point cap on the amount of cost changes that would be absorbed by AmerenUE's shareholders.[178]

Testifying on behalf of the State, Martin Cohen also recommended an 80 percent pass through provision. Alternatively, Cohen proposed an asymmetrical provision that would give AmerenUE's shareholders an 85 percent pass through of any cost increases above the base, while giving ratepayers a 95 percent pass through of any cost decreases below the base.[179]

Public Counsel, through its witness, Ryan Kind, proposed a 50 percent pass through mechanism.[180] AARP and the Consumers Council of Missouri did not offer any testimony on a sharing mechanism, but supported Public Counsel's proposed 50 percent pass through mechanism.[181] Noranda also did not offer testimony on a sharing mechanism, but suggested a pass through sharing mechanism of between 75 and 90 percent.[182] Staff took no position on an appropriate sharing mechanism.[183]

The goal of all these pass-through plans is to ensure AmerenUE retains sufficient

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[177] Brubaker Direct, Ex. 607, Page 9, Lines 2-6.

[178] Brubaker Direct, Ex. 607, Page 9, Lines 12-23.

[179] Cohen Direct, Ex. 500, Pages 23-24, Lines 20-21, 1-5.

[180] Kind Rebuttal, Ex. 404, Page 6, Lines 21-23.

[181] Transcript, Page 2139, Lines 21-25.

[182] Post-Hearing Brief of Noranda Aluminum, Inc., Page 33.

[183] Transcript, Page 2616, Lines 1-6.

financial incentive to make a strong effort to reduce its fuel and purchased power costs. The statute that allows the Commission to approve a fuel adjustment clause contains some protections to ensure the electric utility acts prudently to control its costs. Notably, it requires the Commission to undertake periodic prudence reviews of the company's incurred costs.[184] However, an after-the-fact prudence review is not a substitute for an appropriate financial incentive, nor is an incentive provision intended to be a penalty against the company. Rather, a financial incentive recognizes that fuel and purchased power activities are very complex and there are actions AmerenUE can take that will affect the cost-effectiveness of those activities.

Findings of Fact:

The Commission finds that the 50 percent pass through proposed by Public Counsel is inappropriate because it would largely negate the effect of the fuel adjustment clause. For example, consider the $114 million in increased coal costs that AmerenUE was unable to recover from January 1, 2007 through the March 1, 2009 presumed effective date of rates established in this case.[185] Under Public Counsel's proposal, AmerenUE would be able to pass through to ratepayers only half of those increased costs, and shareholders would be required to absorb the other $57 million in increased costs. No matter how efficiently it operated, there is no evidence to suggest AmerenUE could find cost savings sufficient to balance a cost increase of that magnitude. Therefore, a 50 percent pass through operates not as an incentive, but rather as a means to blunt the desired effect of the approved fuel adjustment clause.

The 80 percent pass through proposals offered by Brubaker and Cohen are more

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[184] Section 386.266.4(4), RSMo (Supp. 2008).

[185] Lyons Rebuttal, Ex. 42, Page 2, Lines 18-20.

reasonable attempts to devise an incentive mechanism. However, those proposals would still impose more costs on AmerenUE than is necessary to provide an appropriate incentive. If AmerenUE's coal costs increased by $137 million in 2009 and 2010 as anticipated, Brubaker's mechanism would still force AmerenUE's shareholders to absorb approximately $25 million in coal costs alone in 2010.[186]

A 95 percent pass through provides AmerenUE sufficient incentive to operate at optimal efficiency because the company already has several incentives in place that encourage it to minimize net fuel costs. First, AmerenUE's largest fuel cost is for the purchase of Powder River Basin coal to fire its power plants.[187] The coal AmerenUE uses is purchased by an affiliated company, AmerenEnergy Fuels and Service Company, which also purchases coal for the unregulated Ameren merchant generating companies operating in Illinois. As a result, AmerenUE pays the same price for coal as the unregulated affiliates.[188] Presumably, Ameren has a strong incentive to minimize costs for its unregulated operations, so AmerenUE would benefit from those same incentives.

Second, AmerenUE's key employees responsible for managing the company's net fuel costs all have personal financial performance incentives related to things like generation levels, generation availability, and cost of generation.[189] Thus, individual employees have a financial incentive to minimize the company's fuel costs.[190]

Third, adjustments under the fuel adjustment clause are based on historical rather projected costs. Hence, AmerenUE will not entirely escape the incentive effects of the

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[186] Lyons Rebuttal, Ex. 42, Page 24, Lines 13-16, as corrected at Transcript, Page 2141.

[187] Mantle Surrebuttal, Ex. 224, Page 2, Table LM1.

[188] Lyons Rebuttal, Ex. 42, Page 21, Lines 3-9.

[189] Transcript, Pages 2179-2180, Lines 23-25, 1-5.

[190] Lyons Rebuttal, Ex. 42, Page 23, Lines 9-17.

regulatory lag between the incurrence of its fuel costs and the recovery of those increased fuel costs from ratepayers under the fuel adjustment clause. Therefore, the company has an incentive to minimize net fuel costs to mitigate that remaining regulatory lag.[191]

Fourth, as required by the Commission's rules, AmerenUE's fuel adjustment clause includes a detailed heat rate/efficiency testing plan that will allow the Commission to guard against imprudent operation and maintenance of the company's generating units, thus controlling net fuel costs.

Fifth, AmerenUE will need to come back to the Commission in its next rate case to have its fuel adjustment clause renewed. As the Commission has previously indicated, "a fuel adjustment clause is a privilege, not a right, which can be taken away if the company does not act prudently."[192] If AmerenUE does not efficiently control its net fuel costs, the Commission could reconsider the fuel adjustment clause.

There is one additional consideration that supports the implementation of a 95 percent pass through provision in AmerenUE's fuel adjustment clause. That is the likely impact the pass through provision will have on AmerenUE credit worthiness in the eyes of Wall Street. The Commission has recently allowed two other Missouri electric utilities, Aquila and Empire, to implement a fuel adjustment clause including a 95 percent pass through provision. To now impose a less favorable pass through provision on AmerenUE would signal investors that AmerenUE was less well regarded by this regulatory agency.[193] When asked specifically about the 80 percent pass through proposal offered by MIEC,

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[191] Lyons Rebuttal, Ex. 42, Page 22, Lines 3-15.

[192] *In the Matter of The Empire District Electric Company's Tariffs to Increase Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company*, Report and Order, Case No. ER-2008-0093 July 30, 2008, Pages 45-46.

[193] Transcript, Pages 2370-2371, Lines 23-25, 1-8. Also, Transcript, Pages 2384-2385, Lines 14-25, 1-7.

AmerenUE's witness, Wall Street investment banker, Gary Rygh, said he would not be comfortable with that proposal because "the markets are looking for bad news ... that would be a fairly tough thing for them to swallow."[194]

The key from the perspective of investors and the rating agencies is that AmerenUE's fuel adjustment clause must be in the mainstream of regulation. Most fuel adjustment clauses in use around the county provide for a 100 percent pass through of costs.[195] To allow substantially less than a 100 percent pass through would push AmerenUE's fuel adjustment clause out of the mainstream and hurt the company's efforts to compete for needed capital.

Some parties argue rating agencies and investors simply look to see whether a fuel adjustment clause is in place and do not concern themselves with the operational details of the clause. In support of this idea they offer the testimony of AmerenUE's rate of return witness, Dr. Roger Morin, who, when asked whether rating agencies essentially view fuel adjustment clauses as either present or not present, replied in the affirmative and indicated such agencies typically do not get into the details of the clause.[196]

However, Dr. Morin's response must be read in the context of earlier questioning regarding rating agencies concern or lack of concern about the technical details of fuel adjustment clauses such as timing and duration of accumulation and recovery periods.[197] As a result, Dr. Morin's comment should not be interpreted as suggesting something as significant as a pass through percentage would not be considered by the rating agencies.

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[194] Transcript, Page 2374, Lines 18-21.

[195] Transcript, Page 2369, Lines 22-23.

[196] Transcript, Pages 382-383, Lines 20-25, 1-2.

[197] Transcript, Pages 362-365.

Indeed, Dr. Morin also testified that the terms of a fuel adjustment clause are important to the credit rating agencies, saying, "I think they would be concerned with a marked deviation from the conventional practice of one to one (pass through of all fuel costs). They would look at the terms of the adjustment clause."[198] MIEC's rate of return witness, Michael Gorman, also testified that in his opinion, "rating agencies are capable of understanding a fuel adjustment clause and understanding the – the effect of that clause in allowing a utility to produce the cash flows necessary to support financial obligations."[199]

Conclusions of Law:

The Commission rule that requires AmerenUE to submit a heat rate/efficiency testing plan as part of its proposed fuel adjustment clause is 4 CSR 240-3.161(2)(P).

Decision:

AmerenUE's fuel adjustment charge shall include an incentive clause providing that 95 percent of any deviation in fuel and purchased power costs from the base level shall be passed to customers and 5 percent shall be retained by AmerenUE. This incentive clause will give AmerenUE a sufficient opportunity to earn a fair return on equity as required by Section 386.266 and the Hope and Bluefield decisions. At the same time, it will protect AmerenUE's customers by giving the company an incentive to be prudent in its decisions by not allowing all costs to simply be passed through to customers.

Rate Design of the Fuel Adjustment Clause:

The details of the tariff that will actually implement AmerenUE's fuel adjustment clause are established through the Stipulation and Agreement as to All FAC Tariff Rate Design Issues, which the Commission approved in an order issued on December 30, 2008.

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[198] Transcript, Page 459, Lines 14-21.

[199] Transcript, Page 545, lines 15-19.

8. Callaway 2 COLA Costs

Introduction:

During the test year, AmerenUE spent $45,987,000 to prepare and file a Construction and Operating License Application (COLA) with the Nuclear Regulatory Commission, seeking approval to construct a second nuclear reactor at the company's Callaway Nuclear Plant.[200] AmerenUE proposes to adjust its accounts to move that approximately $46 million into its plant in service account.

That means the COLA cost would be moved into the company's rate base so that AmerenUE would earn a return on that investment.[201] That $46 million would not be subject to depreciation until the Callaway 2 plant is actually in operation, so AmerenUE would not immediately receive a return of its investment.[202] As a result, if AmerenUE's proposed adjustment is accepted, the inclusion of the $46 million in the company's rate base would have the effect of increasing AmerenUE's cost of service by approximately $5 million per year, the exact amount depending upon the rate of return the Commission authorizes in this case. Several parties oppose AmerenUE's proposal to move the $46 million into rate base as a violation of section 393.135, RSMo, frequently known as the anti-CWIP initiative.

Findings of Fact:

AmerenUE is currently accounting for the Callaway 2 COLA costs as Construction Work in Progress, generally known by the acronym CWIP, just as it would any other capital

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[200] Weiss Supplemental Direct, Ex. 11, Page 8, Lines 6-7.

[201] Transcript, Page 1300, Lines 6-10.

[202] Transcript, Page 1300, Lines 11-24.

project that is not yet complete.[203] A utility does not earn a return on investments held as CWIP until the project for which the investment is made is actually placed in service.[204] However, AmerenUE is allowed to calculate AFUDC (allowance for funds used during construction) on the project until it is complete.[205] AFUDC represents the financing cost associated with construction projects, and when the project is complete, the company will earn a return on the cost of the project, including AFUDC.[206]

For purposes of this rate case, AmerenUE's senior management, presumably AmerenUE's President and Chief Executive Officer, Thomas R. Voss, decided that it would be appropriate to include the Callaway 2 COLA costs in rate base and instructed the company's accountants to make a pro forma adjustment to accomplish that change.[207]

The costs associated with the Callaway 2 COLA are properly accounted for as CWIP, as a necessary construction related cost to operate the Callaway 2 reactor.[208] This is the same accounting treatment the Commission afforded AmerenUE's cost to obtain the operating permit to build the Callaway 1 plant in the 1970s and 1980s.[209]

Missouri's statutes include a provision that explicitly prohibits the inclusion of cost of construction work in progress in rates before the project is fully operational and used for service.[210] AmerenUE attempts to avoid the statute's prohibition on the inclusion of CWIP in rates by arguing that the Callaway 2 COLA costs are not CWIP because the NRC's

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[203] Rackers Surrebuttal, Ex. 202, Page 4, Lines 20-22.

[204] Transcript, Page 1297, Lines 9-24.

[205] Transcript, Page 1298, Lines 3-7.

[206] Rackers Surrebuttal, Ex. 202, Page 3, Lines 17-18.

[207] Transcript, Page 1298, Lines 12-24.

[208] Rackers Surrebuttal, Ex. 202, Pages 4-5, Lines 21-23, 1-2.

[209] Rackers Surrebuttal, Ex. 202, Page 5, Lines 5-10.

[210] Section 393.135, RSMo 2000.

permit to build Callaway 2 might have some independent value apart from the permission to construct the nuclear reactor. In that regard, Thomas Voss, AmerenUE's president and chief executive officer, compared the Callaway 2 COLA to real estate that would be purchased in advance and held for later development.[211]

The supposed independent value of the COLA is based on the eligibility for certain federal tax credits afforded by the filing of the COLA in 2008. The federal Energy Policy Act (EPAct) creates potential tax savings that could save AmerenUE and its ratepayers a total of $500 million over eight years if the Callaway 2 unit is ultimately built. Since EPAct required a COLA be filed and docketed with the NRC on or before December 31, 2008, to be eligible to receive those tax credits, AmerenUE's COLA might have an independent value if AmerenUE later decided to sell the right to build Callaway 2 as a merchant plant.[212]

However, any independent value of the COLA is highly speculative since, so far as AmerenUE's witness was aware, no COLA has ever been sold.[213] In any event, even if the COLA was treated as an asset to be held for future use, that does not allow that asset to be put into rate base, until its is actually in use. That is particularly true where, as here, AmerenUE has no definite plan to either build Callaway 2 or attempt to sell the COLA to a merchant plant operator.[214]

Even if the COLA has some independent value, it is no different from a turbine that AmerenUE might purchase in anticipation of ultimately installing it as part of Callaway 2 or for some other project, or even for eventual resale to some other utility. That turbine would

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211 Transcript, Page 128, Lines 20-23.

212 Transcript, Page 129, Lines 1-5.

213 Transcript, Page 1320, Lines 19-21.

214 Transcript, Page 1309, Lines 5-23.

not be included in rate base until it was actually used to generate electricity, despite its undeniable independent value.[215] If that turbine could not be included in rate base, AmerenUE did not make a convincing argument that the COLA should be included in rate base at this point in time.

Conclusions of Law:

In 1976, Missouri's voters passed an initiative that was codified as Section 393.135, RSMo 2000. That section provides as follows:

> Any charge made or demanded by an electrical corporation for service, or in connection therewith, which is based on the costs of construction in progress upon any existing or new facility of the electrical corporation, or any other cost associated with owning, operating, maintaining, or financing any property before it is fully operational and used for service, is unjust and unreasonable, and is prohibited.

That statute clearly and explicitly forbids the inclusion of CWIP in an electric utility's rates until the construction work is complete and the project is fully operational and used in service.

Decision:

AmerenUE contends the inclusion of the Callaway 2 COLA costs in rate base is simply a means by which ratepayers should be required to bear their fair share of the cost and risk associated with the COLA. Whatever the merits of that proposition, AmerenUE's argument is unconvincing because when Missouri's voters passed the initiative that became Section 393.135, RSMo, they determined a utility would have to wait until a plant was completed and in service before it could recover the cost of its investment. The costs associated with AmerenUE's preparation and filing of the Callaway 2 COLA are properly treated as CWIP and as such they may not be included in AmerenUE's rate base until the

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[215] Transcript, Page 253, Lines 1-7.

Callaway 2 plant is fully operational and used for service.

9. MISO Day 2 Charges

Introduction:

AmerenUE participates in the Midwest ISO, which is a regional transmission organization that jointly operates the transmission systems of its member utilities. Midwest ISO also operates a day-ahead and real-time energy market, referred to as MISO Day 2. In operating that market, Midwest ISO sometimes has to dispatch a utility's generation assets in a manner required to meet the reliability needs of the system while not actually selling any power. In those circumstances, Midwest ISO compensates the affected utilities by making Revenue Sufficiency Guarantee (RSG) payments to the utilities for the use of the assets, and collecting RSG charges from the other member utilities to cover those payments.[216]

Midwest ISO began operating its Day 2 market on April 1, 2005. Subsequently, the Federal Energy Regulatory Commission (FERC) ruled Midwest ISO had not properly followed its tariff when it charged its members for RSG, and ordered the Midwest ISO to resettle those RSG transactions. As a result of that resettlement, in 2007, Midwest ISO billed, and AmerenUE paid, $12,430,094 for additional RSG charges relating to the period of 2005 and 2006.[217]

AmerenUE proposes to amortize these resettlement RSG charges over two years and recover them in rates at approximately $6.1 million per year.[218] Staff opposes the recovery of these charges because the expenses relate to charges incurred in the two

[216] Staff Report – Cost of Service, Ex. 200, Page 23.

[217] Weiss Rebuttal, Ex. 12, Page 6, Lines 8-15.

[218] Weiss Rebuttal, Ex. 12, Page 6, Lines 18-20.

years prior to the test year and because the charges are not recurring and thus will not cause expenses to be higher in future years.[219]

Findings of Fact:

There is very little dispute about the fact regarding this issue. The $12.4 million resettlement imposed on AmerenUE by Midwest ISO covered the period of April 1, 2005, through December 2006.[220] AmerenUE actually paid that resettlement amount to Midwest ISO in April 2007,[221] which was within the test year for this case.[222] Furthermore, although Midwest ISO frequently imposes smaller resettlements, there is no indication AmerenUE will be required to make a resettlement payment of this magnitude in the future.[223]

It is also clear that the Commission has approved AmerenUE's participation in the Midwest ISO, and no one has questioned the prudence of that participation.[224] AmerenUE was required to make the resettlement RSG payment by the terms of the Midwest ISO tariff.[225] The resettlement was necessary because Midwest ISO did not properly follow its tariff in 2005 and 2006, not because AmerenUE did anything wrong.[226]

If Midwest ISO had properly followed its tariff and charged AmerenUE the correct amount in 2005 and 2006, an additional $6.2 million would have been included in AmerenUE's annual revenue requirement in its last rate case and would have been

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[219] Hagemeyer Surrebuttal, Ex. 222, Page 7, Lines 1-10.

[220] Transcript, Page 778, Lines 18-19.

[221] Transcript, Page 779, Lines 4-5.

[222] Transcript, Page 801, Lines 16-18.

[223] Transcript, Page 790, Lines 2-12.

[224] Transcript, Page 809, Lines 7-18.

[225] Transcript, Page 801, Lines 19-22.

[226] Transcript, Pages 801-802, Lines 23-25, 1-6.

recovered from ratepayers during the last two years.[227] If Staff's position is adopted, AmerenUE would be precluded from recovering the $12.4 million resettlement cost and the company's shareholders would be required to absorb that entire cost.[228] A $12 million expense that cannot be recovered from ratepayers would reduce AmerenUE's actual return on equity by approximately 24 basis points.[229] Staff agrees such an impact on AmerenUE's earnings would be significant.[230]

Staff's reason for excluding the cost is that the resettlement cost is non-recurring.[231] That means if the larger amount is included in rates, there is a possibility AmerenUE will be able to over-recover its costs, to the detriment of ratepayers.[232] However, that over-recovery is only possible if AmerenUE waits more than two year to file its next rate case. As has been noted elsewhere in this order, given the rising cost environment facing AmerenUE, it is unlikely the Company will wait more than two years to file its next rate case.[233]

Conclusions of Law:

Since AmerenUE paid the Midwest ISO resettlement charge during the test year, it does not need to obtain an accounting authority order to bring this expense into the rate case. As a result, the accounting standards used to consider the granting of an accounting authority order do not apply. Because this is a test year expense, the Commission has a

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[227] Transcript, Page 803, Lines 20-25.

[228] Transcript, Page 807, Lines 18-25.

[229] Transcript, Page 796, Lines 9-15.

[230] Transcript, Page 809, Lines 4-6.

[231] Transcript, Pages 816-817, Lines 25, 1-3.

[232] Transcript, Page 792, Lines 5-16.

[233] Transcript, Page 791, Lines 17-23.

great deal of discretion when deciding whether to include this expense when setting AmerenUE's revenue requirements for ratemaking purposes.

Decision:

Under the circumstances of this case, fundamental fairness requires that AmerenUE be allowed an opportunity to recover the $12.4 million RSG resettlement cost, which was incurred in the test year and was necessitated by the failure of the Midwest ISO to follow its tariff. AmerenUE's proposal to amortize that amount over two years is a reasonable means to allow that recovery to take place, and that proposal is approved.

10. Incentive Compensation

Introduction:

AmerenUE chooses to pay a portion of its employee compensation as incentive pay. That is, the employees receive that portion of their compensation only if they, or the company, meet certain goals. The compensation in question is, for the most part, not a bonus program restricted to top executives, but rather is a portion of the market-based pay for ordinary employees. AmerenUE offers a total rewards package to its employees, which includes both base pay and incentive pay programs, to attract talent and remain competitive with other employers.[234]

AmerenUE offers several different incentive pay plans, divided into the general categories of long-term compensation, short-term compensation, and an exceptional performance bonus program.[235] Staff would entirely disallow the cost of the long-term compensation program and the exceptional performance bonus program, but would allow a

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[234] Bauer Rebuttal, Ex. 25, Page 8, Lines 7-9.

[235] Bauer Rebuttal, Ex. 25.

small portion of the short-term compensation program.[236] The Commission will separately consider the three categories of incentive compensation.

Findings of Fact:

Long-Term Compensation:

AmerenUE's long-term compensation plans are offered to members of the Ameren Leadership Team, which includes Officers, Directors, and Managers.[237] AmerenUE's witness indicated, "the purpose of a long-term incentive plan is to ensure that the Company's leaders are focused not only on the short-term success of the organization, but also on the long-term success of the organization."[238] The long-term compensation programs attempt to meet that goal by offering stock options, or other means by which executives are given an equity stake in the business.[239]

Ameren offered a restricted stock plan from 2001 through 2005, and replaced that program with the Performance Share Unit Program in 2006. The restricted stock program gave participants annual grants of stock that vested over a 7-year period based on earnings performance. The Performance Share Unit Program gives participants annual performance share units, which allows them to receive stock if certain performance criteria are met.[240] Eligibility for both long-term incentive programs are based on measures of earnings per share or of total shareholder return.[241]

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[236] Hagemeyer Surrebuttal, Ex. 222.

[237] Bauer Rebuttal, Ex 25, Page 5, Chart at Line 3.

[238] Bauer Rebuttal, Ex. 25, Page 19, Lines 4-6.

[239] Bauer Rebuttal, Ex. 25, Page 19, Lines 6-7.

[240] Bauer Rebuttal, Ex. 25, Page 20, Lines 1-4.

[241] Bauer Rebuttal, Ex. 25, Page 5, Chart at Line 3.

The Commission has frequently disallowed costs relating to incentive programs that are based on measures of the financial return achieved by the utility. It has done so because such measures are based on the level of profits the utility can achieve. At best, a utility's level of profitability has little or no benefit for ratepayers. At worst, an increase in the utility's profitability may be harmful to ratepayers if that profitability is obtained by cutting customer service or system maintenance to cut costs and thereby increase earnings per share. Because eligibility for AmerenUE's long-term compensation plans are based on measures of the financial return achieved by the utility, the cost of those plans should fall on the shareholders who will primarily benefit from the company's increased financial return.

Short-Term Incentive Plans:

AmerenUE offers several short-term incentive plans for various groups of employees. One, the Executive Incentive Plan for Officers, is entirely funded by a measure of earnings per share. AmerenUE is not seeking to recover the cost of that program through rates.[242] The other short-term incentive programs are the Executive Incentive Plan for Managers and Directors (EIP-M), the Ameren Management Incentive Plan (AMIP), the Ameren Marketing, Trading and Commodities Plan (AMTC) and the Ameren Incentive Plan (AIP).[243] Except for the EIP-M for members of the Ameren Leadership Team below the Officer level, which is 25 percent funded by earnings per share, these short-term compensation plans are not measured by the company's earnings per share. Rather, they

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[242] Bauer Rebuttal, Ex. 25, Page 15, Lines 11-22.

[243] Bauer Rebuttal, Ex. 25, Page 5, Chart at Line 1.

are funded based on the employee's achievement of pre-defined Key Performance Indicators (KPIs).[244]

The KPIs are part of a system AmerenUE has developed to communicate specific goals to its employees and to drive the performance of those employees.[245] The KPIs focus on four critical areas: financial management of the business, process improvement, the customer, and employees.[246] Each functional group within AmerenUE develops a scorecard of KPIs that will contribute to the overall performance of AmerenUE.[247] Every individual employee receives a scorecard containing from 4 to 6 KPIs.[248] Individual KPIs are designed to focus the employee's attention on such things as increased reliability, customer satisfaction, safety, or operational performance.[249]

Each KPI includes three levels of performance. The first level of performance is called "threshold," and it represents the "minimum acceptable level of goal achievement for any given KPI."[250] At the hearing, AmerenUE's witness clarified that the "threshold" level of performance represents "a continuous improvement toward a goal", not just the minimum an employee must do to keep their job.[251] Beyond the "threshold" level, an employee's performance can reach the "target" level, which is a stretch goal that employees are striving

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[244] Bauer Rebuttal, Ex. 25, Page 5, Chart at Line 1.

[245] Bauer Rebuttal, Ex. 25, Page 4, Lines 13-14.

[246] Bauer Rebuttal, Ex. 25, Page 10, Lines 4-6.

[247] Bauer Rebuttal, Ex. 25, Page 10, Lines 7-10.

[248] Transcript, page 1422, Lines 11-13.

[249] Bauer Rebuttal, Pages 11-14.

[250] Bauer Rebuttal, Ex. 25, Page 10, Lines 11-12.

[251] Transcript, Page 1416, Lines 12-17.

to achieve.[252] Finally, if an employee does very well, they might reach the "maximum" level, which represents a level of performance that is very difficult to achieve.[253] As an employee, or a team of employees moves up in level of performance their incentive compensation will increase.[254]

Staff does not entirely oppose the KPI concept and the short-term compensation program, but for various reasons would disallow most of the costs related to that program.[255] Specifically, Staff would disallow payments made under certain KPIs because they were based on what Staff called financial metrics or what Staff described as project based metrics. In addition, Staff would disallow incentive payments made for performance that reached the "threshold" level, but did not reach the "target" level[256]

Before examining Staff's reasons for disallowing part of the cost of the short-term compensation program, it is important to look at the qualifications of the witnesses presented by Staff and AmerenUE. AmerenUE's witness was Krista Bauer. Ms. Bauer is employed by Ameren Services Company as Manager, Compensation and Performance.[257] She holds a Masters Degree in Industrial/Organizational Psychology from Southern Illinois University in Edwardsville, and she will complete her MBA from Webster University in October of 2009. She has eleven years of human resources experience and has served as

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[252] Bauer Rebuttal, Ex. 25, Page 10, Line 13.

[253] Bauer Rebuttal, Ex. 25, Page 10, Lines 14-15.

[254] Transcript, Page 1425, Lines 9-15.

[255] Staff would allow less than $527,000 into rates, approximately 2 percent of AmerenUE's total incentive compensation costs. Transcript, Page 1501, Lines 1-10.

[256] Transcript, Page 1510, Lines 2-19.

[257] Bauer Rebuttal, Ex. 25, Page 1, Lines 10-11.

adjunct faculty at St. Louis University between 2000 and 2005, where she taught courses in Industrial Psychology.[258]

Staff's witness was Jeremy Hagemeyer. He has been a Utility Regulatory Auditor within the Auditing Department of the Commission's Staff since 2002. He has a Bachelor of Science degree in Accounting and German from Southwest Missouri State University, and an MBA from Fontbonne University.[259] Although Mr. Hagemeyer was a bright and articulate witness for Staff on several issues in this case, he has no real expertise in evaluating or designing a compensation plan for a major utility.[260]

Yet, Mr. Hagemeyer offered testimony suggesting that payments made under specific KPIs, which are part of the overall compensation plan designed by AmerenUE, should, or should not be recovered through rates. Not surprisingly, his standards for deciding what should be recovered and what should be disallowed were rather vague and do not provide the Commission with any real basis to judge the plan. Furthermore, his proposal to disallow all payments for performance that met only the threshold level of the plan clearly misunderstood the intent of the plan. As Ms. Bauer explained, "threshold" is a description of the level of improvement at which incentive compensation is earned. It does not represent the minimum an employee must do to keep their job.

Staff should not be in the business of trying to design a compensation plan for AmerenUE. Staff is not qualified to do so and its attempts to manage the affairs of AmerenUE are inappropriate. That does not mean that anything goes for the company. Staff certainly must evaluate AmerenUE's incentive compensation plans. However, it must

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[258] Bauer Rebuttal, Ex. 25, Page 2, Lines 8-16.

[259] Staff Report – Cost of Service, Ex. 200, Background, Education and Credentials, Page 18.

[260] Transcript, Pages 1468-1471.

do so at a higher level and not get bogged down in the details. AmerenUE's incentive programs must stand or fall as a program. If the overall program is appropriate, AmerenUE should be able to recover the costs of that program through rates. If the overall program is unacceptable, then the entire program will be excluded from rates. The Commission will not attempt to manage the details of those programs.

Looking at the short-term compensation programs as a whole, the Commission finds them to be appropriate for recovery through rates. Incentive compensation programs are very common in business in general and in the utility industry in particular. Among AmerenUE's peer utility companies, 36 out of 37 offer short-term incentive plans for their executives.[261] Thus, AmerenUE needs to offer similar plans to compete for employees with other utilities.

For example, if AmerenUE's research determines that the market rate for a certain position is $60,000 per year, it will evaluate the appropriate base-level of compensation and determine an appropriate amount that should be offered through incentive compensation.[262] It is clear that if AmerenUE simply abandoned its incentive plan and offered market rates as base pay, it would have no difficulty in recovering all those costs through rates.[263] However, AmerenUE has chosen to implement an incentive compensation plan so that it has the ability to reward its employees for achieving the performance goals set by the company. So long as the overall program does not contain incentives that could be harmful to ratepayers, such as the purely financial incentives that

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[261] Bauer Rebuttal, Ex. 25, Page 6, Lines 11-14.

[262] Bauer Rebuttal, Ex. 25, Page 8, Lines 9-15.

[263] Transcript, Page 1546, Lines 11-15.

caused the Commission to disallow recovery of AmerenUE's long-term compensation plan, AmerenUE should be able to recover the costs of incentive compensation through rates.

The Commission finds that the overall KPI system described in the testimony is likely to bring improvements in employee performance that will benefit AmerenUE's ratepayers as well as the company's shareholder. The Commission will allow AmerenUE to recover the cost of those short-term incentive compensation programs through rates.

The Exceptional Performance Bonus Plan:

The final program within AmerenUE's incentive compensation package is known as the Exceptional Performance Bonus Plan. That program applies to 868 management employees below the level of the Ameren Leadership team.[264] The program allows a supervisor to recommend an employee receive a bonus for exhibiting superior performance above and beyond what is expected of them. The supervisor's recommendation is reviewed by senior leadership for review and approval. Awards under the plan generally range from $500 to $3,000.[265] Many of the rewards are given for exceptional performance that directly benefits AmerenUE's customers, such as exceptional performance at restoring power after an ice storm.[266] Staff opposes AmerenUE's recovery of the cost of this program because the program lacks specific criteria by which awards are to be given.[267]

The lack of specific criteria for the program is actually the point of the program. It exists so that unusual and unanticipated exceptional effort can be rewarded. The program could certainly encourage outstanding customer service and exceptional performance that

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[264] Bauer Rebuttal, Ex. 25, Page 17, Lines 17-23.

[265] Bauer Rebuttal, Ex. 25, Pages 17-18, Lines 23, 1-3.

[266] Bauer Rebuttal, Ex. 25, Page 18, Lines 3-18.

[267] Hagemeyer Surrebuttal, Ex. 222, Page 3, Lines 21-22.

would benefit ratepayers and the company as a whole. However, if not run properly, the program could degenerate into a means by which extra money is funneled to management favorites, without any benefit to the company or to ratepayers. The Commission will allow the program to be included in rates, but will direct AmerenUE to maintain proper records of payments made under the program so that Staff can review it in AmerenUE's next rate case.

Conclusions of Law:

There are no additional conclusions of law for this issue.

Decision:

The Commission finds that AmerenUE shall recover in rates the cost of its short-term incentive compensation programs and the cost of its Exceptional Performance Bonus Plan. Taken as a whole, those programs are likely to benefit AmerenUE's ratepayers as well as its shareholders. However, AmerenUE shall not recover in rates the cost of its long-term compensation plan, which the Commission finds will primarily benefit shareholders and not ratepayers.

11. Depreciation

Introduction:

Depreciation is the means by which a utility is able to recover the cost of its investment in its rate base by recognizing the reduction in value of that property over the estimated useful life of the property. AmerenUE's current depreciation rates were established by the Commission in AmerenUE's last rate case, Case Number ER-2007-0002. Public Counsel contends the Commission should adjust downward the established depreciation rates for five specific accounts for the Callaway Nuclear Production Plant.[268] Staff and AmerenUE agree the Commission should not "cherry pick" a few isolated accounts to adjust outside the context of a complete depreciation study, which was not conducted for this case.

Findings of Fact:

A complete depreciation study requires an actuarial analysis of the complete mortality records of all plant account assets owned by the company.[269] Such a depreciation study was performed in AmerenUE's last rate case, ER-2007-0002, and the depreciation rates that resulted from that case have only been in effect since June 1, 2007.[270]

Not surprisingly, complete depreciation studies are expensive and time consuming. Such a study may involve site visits, interviews, data and actuarial analysis, and the production of reports and testimony.[271] That is one of the reasons, the Commission's rules require such depreciation studies to be done only periodically, and not necessarily for every rate case.[272] AmerenUE submitted a complete depreciation study in July 2006, as part of its last rate case, covering the period through December 31, 2005. As a result, AmerenUE's next complete depreciation study would be due in July 2011, unless it files a

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[268] Dunkel Direct, Ex. 400, Schedule WWD-1. The affected accounts are 321 Structures and Improvements, 322 Reactor Plant Equipment, 323 Turbogenerator Units, 324 Accessory Electrical Equipment, and 325 Miscellaneous Power Plant Equipment.

[269] Gilbert Rebuttal, Ex. 209, Page 3, Lines 13-14.

[270] Gilbert Rebuttal, Ex. 209, Page 3, Lines 14-16.

[271] Transcript, Pages 864-865, Lines 18-25, 1.

[272] Transcript, Page 865, Lines 14-18.

new rate case after July 2009, in which case a new depreciation study would have to be filed with the rate case.[273] AmerenUE did not submit a depreciation study in this case.

Public Counsel also did not submit a complete depreciation study in this case. However, through the testimony of its witness, William Dunkel, Public Counsel asks the Commission to order changes to five particular depreciation accounts. Dunkel contends there is a mismatch in these accounts because the approved depreciation rates are calculated using a theoretical reserve instead of actual book reserve.[274]

Dunkel explains that since the Callaway plant was built, depreciation rates have been based on an assumption that the nuclear plant would have a life of 40 years, which was the length of its license from the NRC. However, in the last rate case, the Commission ordered the depreciation rates regarding the Callaway plant be calculated based on a 60-year life span, assuming that AmerenUE would seek and receive a 20-year license extension from the NRC. The actual book reserve, which is based on past depreciation that assumed a 40 year life, is now higher than theoretical reserve, which is based on an assumed 60 year life.[275] Dunkel argues the theoretical reserve and the book reserve should be brought back into balance by adjusting the depreciation rates for the five

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[273] Weidmayer Rebuttal, Ex. 13, Page 5, Lines 8-14. .

[274] Dunkel Direct, Ex. 400, Page 5, Lines 9-11.

[275] Dunkel Direct, Ex. 400, Page 14, Lines 1-16. AmerenUE's witness describes "theoretical reserve" and "book reserve" as follows:

> The theoretical reserve, also known as the calculated accrued depreciation, is as its name implies a calculated amount or reserve and is a function of the age of the electric plant in service and the depreciation parameters selected. The theoretical reserve is commonly used in industry practice as a benchmark to assess the adequacy of a company's book reserve. The theoretical reserve is a calculated amount made at a particular point in time. The Company's accumulated depreciation or "book reserve" is the sum of actual monthly charges that have been recorded by the Company throughout its history to accumulated depreciation for items such as depreciation accruals, salvage, cost of retiring, retirements, etc.

Wiedmayer Rebuttal, Ex. 13, Page 13, Lines 5-12.

specified accounts and reducing AmerenUE's depreciation expense by approximately $7.1 million per year.[276]

Staff and AmerenUE contend no adjustment should be made at this time without the benefit of a full depreciation study. The Commission finds that Staff and AmerenUE are correct in their concern about making an isolated adjustment to a few depreciation accounts outside the context of a full depreciation study. Such an isolated adjustment is closely analogous to the larger concept of single-issue ratemaking. Just as it would be inappropriate to adjust a utility's rates based on a change to a single item without considering changes in all other items that may off-set that single item, it would be inappropriate to adjust a few depreciation rates without looking at all depreciation rates in a complete study. In a complete study, depreciation rates for some accounts may increase, while others decrease. The balance of the increases and decreases is what is important in establishing depreciation rates for the company.

The Commission did look at a complete depreciation study in the last rate case. Furthermore, the parties to that case were aware of the difference between theoretical reserve and book reserve. A Staff witness brought that imbalance to the Commission's attention, but at that time, Staff advised the Commission to simply monitor the imbalance for possible correction in a future depreciation study. No party, including Public Counsel, proposed any adjustment regarding that imbalance in that case.[277]

Public Counsel's witness claims an adjustment should be made in this case because of a "major change" since the last rate case. The "major change" he describes is

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[276] Dunkel Direct, Ex. 400, Page 17, Lines 7-11.

[277] Dunkel Direct, Ex. 400, Page 6, Lines 1-33, quoting *In the Matter of Union Electric Company d/b/a AmerenUE's Tariffs Increasing Rates for Electric Service*, Report and Order, Case No. ER-2007-0002, May 22, 2007, Page 94.

AmerenUE's announcement that it will, indeed, be filing an application to extend the Callaway plant's NRC license by another 20 years.[278] However, AmerenUE's filing of the application to extend the license of the Callaway plant is not a "major change" from the last rate case. It is not a change at all. The question of whether Callaway's service life should be extended for 20 years for depreciation purposes was certainly an issue in the last rate case, and the Commission emphatically ordered that the plant's service life should be extended.[279] Therefore, the 60-year life-span assumption for the Callaway plant was already in place when rates were set in the last case. AmerenUE's decision to actually apply for a license extension changes nothing.

Public Counsel's witness also claims that an immediate change to the depreciation rate for these five accounts is necessary because the imbalance between the actual and theoretical reserve has "grown drastically" since the last case.[280] However, Dunkel actually testified that the actual Callaway book reserve in 2005, measured at Commission approved depreciation rates, was $219 million above the theoretical reserve. By December 31, 2007, he testified that difference had grown to $250 million.[281] While the difference has grown, it is hardly the "drastic growth" that might justify an isolated change to the depreciation rates for just five accounts.

Public Counsel's witness attempts to justify his proposed isolated adjustment by claiming the balancing of possibly increasing and decreasing rates that would take place in

[278] Dunkel Direct, Ex. 400, Page 3, Lines 7-20.

[279] *In the Matter of Union Electric Company d/b/a AmerenUE's Tariffs Increasing Rates for Electric Service*, Report and Order, Case No. ER-2007-0002, May 22, 2007, Pages 87-88.

[280] Dunkel Direct, Ex. 400, Page 8, Lines 17-19.

[281] Dunkel Direct, Ex. 400, Page 8, Lines 19-24, as corrected at Transcript, Page 824.

a complete depreciation study is not necessary because if his adjustment were applied to all accounts, not just the five he proposes to adjust, the result would be a much larger reduction.[282] However, his calculation are based on 2005 data, which likely would not be accurate for 2008.[283] Furthermore, his proposed adjustment would still be based on just a single factor, albeit spread over a wider range of accounts. It would not eliminate the single-issue ratemaking objection to his proposal to adjust the depreciation rates for a few accounts outside of a complete depreciation study.

When the Commission last looked at this issue in the 2007 rate case, it accepted Staff's suggestion to continue to monitor the imbalance between theoretical reserve and actual book accumulated depreciation. The Commission will continue to monitor that imbalance and if Public Counsel wants to raise this issue again in AmerenUE's next rate case in the context of a complete depreciation study, it is free to do so.

In his surrebuttal testimony, Dunkel requested that if the Commission decided not to make his proposed adjustments in this case, it should order AmerenUE to include certain information in its next depreciation study to aid in the review of the imbalance.[284] That request is reasonable and was not opposed by any party. The Commission will order AmerenUE to include the requested information in its next depreciation study.

Conclusions of Law:

Commission Rule 4 CSR 240-3.160 requires any electric utility that submits a general rate increase to submit a complete depreciation study, unless the utility has

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[282] Dunkel Surrebuttal, Ex. 401, Page 6, Lines 10-11.

[283] Transcript, Page 894, Lines 6-9.

[284] Dunkel Surrebuttal, Ex. 401, Pages 10-11, Lines 16-20, 1-4.

previously submitted such a study to the Commission's Staff within the three years before filing the rate case.

Commission Rule 4 CSR 240-3.175 requires an electric utility to submit a complete depreciation study at least once every five years even if it has not filed a rate case within that time.

Decision:

The Commission will not make any changes to AmerenUE's depreciation rates without consideration of a complete depreciation study. When it prepares its next depreciation study, AmerenUE shall provide for each account (1) the book reserve amount, (2) the theoretical reserve amount, (3) the remaining life years, and (4) the whole life depreciation rate with the reserve variance amortized over the average remaining life.

12. Demand Side Management

Introduction:

In AmerenUE's last rate case, the Commission approved a stipulation and agreement that established a regulatory asset that allows AmerenUE to treat demand side management expenditures as a depreciable asset, thus diminishing any advantage AmerenUE might perceive in investing in new generation rather than in demand-side resources.[285] Staff asked the Commission to clarify its previous order by directing that net expenditures were to be included in the regulatory asset account, so that income resulting from demand-side expenditures would be netted against those expenditures.[286] In his rebuttal testimony, Public Counsel's witness, Ryan Kind proposed language to accomplish

[285] Staff Report – Cost of Service, Ex. 200, Page 9.

[286] Staff Report – Cost of Service, Ex. 200, Page 9.

that netting.[287] AmerenUE did not object to the concept of netting, but objected to Kind's language as overly broad.[288]

Findings of Fact:

At the hearing, Kind acknowledged his original language could be difficult to administer. As a result, he offered the following substitute language:

> In addition to booking the incremental costs of implementing DSM programs in its regulatory asset account, UE shall book the reimbursement of incremental costs, in dollars, that are equal to capacity related revenues from any source that the Company receives that are associated with its implementation of DSM programs and not otherwise credited.[289]

At the time of the hearing, Voytas expressed general satisfaction with the change offered by Kind, but indicated he would have to examine the language in more detail before he could accept it.[290] In its brief, AmerenUE offered the following language as a substitute for that offered by Kind:

> DSM should be booked as net expenditures when DSM has a transactionable, identifiable and measurable increase in revenue to the Company. Transactionable refers to tradable products with an identifiable counter-party which provides a value. Identifiable refers to the linkage whereby specific revenue streams can be tied to specific programs. Measurable means that there is a protocol established as the basis for cash settlement.

It appears this issue is moot since the Commission allows AmerenUE to implement a fuel adjustment clause. The netting that would be the result of the language proposed by both AmerenUE and Public Counsel would occur through the fuel adjustment clause.[291] However, to the extent this issue is not moot, the Commission finds that the language

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[287] Kind Rebuttal, Ex. 404, Page 14, Lines 21-25.

[288] Voytas Surrebuttal, Ex. 18, Page 4, Lines 8-14.

[289] Transcript, Page 929, Lines 3-9.

[290] Transcript, Page 948, Lines 15-19.

[291] Transcript, Page 942, Lines 8-25.

proposed by AmerenUE is preferable because it is more narrowly tailored to meet the need identified by the parties.

Conclusions of Law:

There are no additional conclusions of law for this issue.

Decision:

The Commission finds that if this issue is not moot, the language proposed by AmerenUE shall be adopted.

13. Low-Income Weatherization Program

Introduction:

In the Commission's Report and Order resolving AmerenUE's last rate case, ER-2007-0002, the Commission ordered AmerenUE to fund a low-income weatherization program. That order directed $600,000 of that funding be included in AmerenUE's cost of service to be collected from ratepayers. The Commission directed the other $600,000 be paid by AmerenUE using shareholder funds.[292] In response to the 2007 order, AmerenUE entered into a contract with the Missouri Department of Natural Resources, the State Environmental Improvement and Energy Resources Authority (EIERA), and the Public Service Commission, whereby it agreed to pay $1,200,000 to the low-income weatherization fund administered by EIERA on July 5 of each year.[293] AmerenUE made the entire required payment in 2007, but on June 26, 2008, it paid only $900,000 to the fund.

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[292] *In the Matter of Union Electric Company d/b/a AmerenUE's Tariffs Increasing Rates for Electric Service*, Report and Order, Case No. ER-2007-0002, May 22, 2007, Pages 112-113.

[293] A copy of that contract is attached to Wolfe Direct, Ex. 550, as Attachment LW-2.

The Department of Natural Resources asks the Commission to order AmerenUE to pay the $300,000 it withheld in July, and asks the Commission to order AmerenUE to continue funding the program in the future.

Findings of Fact:

At the hearing, the parties agreed there was no dispute about the facts and agreed this issue could be resolved on stipulated facts and as a matter of law. To that end, they agreed to stipulate to the following three facts:

> 1. In the Commission's Report and Order issued in ER-2007-0002, the Commission ordered that: "the Commission directs that the low income weatherization program continue with funding provided $600,000 by ratepayers and $600,000 by AmerenUE shareholders."
> 2. A contract was entered into among the parties and a true and correct copy of that contract is attached to the direct testimony of DNR witness Wolfe, marked as Exhibit LW-2.
> 3. AmerenUE paid $900,000 on or around June 26, 2008, toward that obligation.[294]

The parties also agreed the prefiled testimony of all witnesses relating to this issue could be admitted into evidence without cross-examination.[295]

AmerenUE withheld $300,000 from the July 2008 payment required by the contract because it believed new rates would be going into effect on March 1, 2009 at the conclusion of this case and it was unsure whether this Commission would require it to continue to make the payment under the new rates. Therefore, it withheld payment for the last three months of the fiscal year.[296]

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[294] Transcript, Page 1001, Lines 9-23.

[295] Transcript, Page 1002, Lines 5-9.

[296] Wolfe Direct, Ex. 550, Page 12-18.

As explained in its conclusions of law, the Commission has no authority to require AmerenUE's shareholders to make what is in essence a charitable contribution to the low-income weatherization fund. Therefore, it cannot require AmerenUE's shareholders to continue to contribute $600,000 to the fund. However, there is a continuing need for the low-income weatherization fund. The Commission finds that low-income residential customers face great hardships as they face high energy expenses on a small household income. Weatherization provides long-term benefits to customers by helping reduce energy demand, thereby reducing energy bills.[297] Therefore, the Commission will order AmerenUE to continue to pay $1.2 million per year into the fund, with all funds being recovered through rates. Since the program is continuing at full funding, AmerenUE shall immediately pay into the fund the $300,000 it withheld in June 2008.

There is one other matter that needs to be addressed. The Department of Natural Resources is concerned about disruptions in payment to the EIERA fund every time AmerenUE files a new rate case and thus brings the continued funding of the program into question. AmerenUE concedes the EIERA needs to have a stable source of funding, but is unwilling to commit to making payments that it may not recover in a future rate case.[298] AmerenUE may have an obligation to make those payments under its contract with EIERA, the Department of Natural Resources, and this Commission. However, as indicated in the conclusions of law for this issue, the Commission has no authority to enforce that contract. The Commission, will, however, encourage AmerenUE to continue its stable funding of the program. While this Commission cannot bind a future Commission to make a particular

[297] Wolfe Direct, Ex. 550, Page 6, Lines 4-9.

[298] Mark Rebuttal, Ex. 20, Pages 7-8, Lines 18-23, 1-7.

decision in a future rate case, the Commission believes that AmerenUE will be treated fairly in any future rate case.

Conclusions of Law:

The Commission has broad authority under the law to regulate public utilities. It does not, however, have unlimited power. The case cited by AmerenUE, *City of Joplin v. Wheeler*,[299] although an old case, actually predating the creation of this Commission, establishes the principle that a regulatory body "can no more compel a public service corporation to do or abstain from doing anything not pertaining to the public service itself than it can compel a private individual; for, outside of its public functions, the corporation is a private corporation."[300] By ordering AmerenUE to fund part of the low-income weatherization program the Commission would be requiring the shareholders to make a charitable contribution. Such a contribution has nothing to do with AmerenUE's obligation to provide service to the public and is beyond the Commission's authority.

AmerenUE has entered into a contract that requires the company to pay $1.2 million each July to EIERA. AmerenUE did not make the full required payment in July 2008. In refusing to make that payment, AmerenUE may have violated that contract, but the Commission has no authority to make such a determination. "The PSC is an administrative body created by statute and has only such powers as are expressly conferred by statute and reasonably incidental thereto."[301] The Commission is not a court, and the legislature

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[299] 173 Mo. App. 590, 158 S.W. 924 (Mo. App. 1913).

[300] *City of Joplin*, at 928.

[301] *State ex rel. AG Processing v. Thompson*, 100 S.W. 3d 915, 919 (Mo. App. W.D. 2003)

has not given it authority to enforce a contract.[302] Therefore, if any party want to enforce that contract, it will need to proceed to circuit court.

Decision:

The Commission finds that AmerenUE shall continue to pay $1.2 million per year into the low-income weatherization fund administered by EIERA. AmerenUE's payments to the fund shall be included in the company's revenue requirement to be recovered through rates.

14. Pure Power Program

Introduction:

In AmerenUE's last rate case, the Commission approved AmerenUE's proposal to begin offering a voluntary green energy program.[303] The voluntary program AmerenUE now offers is called Pure Power. Staff opposed the proposed green energy program in the last rate case and now asks the Commission to require AmerenUE to discontinue the program.

Findings of Fact.

The Pure Power program is a voluntary program whereby participating AmerenUE customers agree to pay an additional amount on their monthly bill to purchase a Renewable Energy Credit, known as a REC. The RECs are purchased from a third party, 3 Degrees, which purchases the RECs from the green power producer.[304]

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[302] *Kansas City Power & Light v. Midland Realty*, 338 Mo 1141, 93 S.W.2d 954 (Mo. 1936).

[303] *In the Matter of Union Electric Company d/b/a AmerenUE's Tariffs Increasing Rates for Electric Service*, Report and Order, Case No. ER-2007-0002, May 22, 2007, Page 115.

[304] Barbieri Rebuttal, Ex. 9, Page 3, Lines 8-14.

AmerenUE has entered into a five-year contract with 3 Degrees that fixes the price AmerenUE customers pay for a REC at fifteen dollars.[305] One dollar of that fifteen is kept by AmerenUE as an administrative fee, with the remaining fourteen going to 3 Degrees. 3 Degrees uses that money to buy the REC and keeps any money left over to pay its own expenses, and as profit.

3 Degrees is obligated under the contract to market and administer the Pure Power program and to educate AmerenUE's customers about the program.[306] One half of the RECs 3 Degrees purchases for AmerenUE's customers must come from green power generators located in Missouri or Illinois, with the rest coming from generators located within the MISO region.[307] The Pure Power program is Green-e certified and 3 Degrees pays for an annual Green-e audit through the Center for Resource Solutions.[308]

The Pure Power program has been operating since October 2007.[309] Approximately 4000 AmerenUE customers have chosen to participate in the program during that first year.[310]

Staff is concerned the sale of RECs is not an effective means of producing green power to supplant fossil fuel power. RECs are for the purchase of power generated in the past, and Staff is concerned the sale of RECs will do nothing to encourage the future generation of green power.[311] This is the same concern Staff expressed in the last rate

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[305] Barbieri Rebuttal, Ex. 9, Page 4, Lines 9-10.

[306] Barbieri Rebuttal, Ex. 9, Page 4, Lines 11-13.

[307] Barbieri Rebuttal, Ex. 9, Page 4, Lines 15-20.

[308] Barbieri Rebuttal, Ex. 9, Page 4, Lines 21-23.

[309] Transcript, Page 662, Lines 12-17.

[310] Transcript, Page 713, Lines 7-10.

[311] Staff Report – Class Cost of Service & Rate Design, Ex. 206, Page 19-20.

case. However, other governmental organizations do not share Staff's concern. The National Renewable Energy Lab and the Federal Department of Energy state programs such as Pure Power have assisted in bringing more than 1,000 MWs of new renewable projects online.[312]

A REC is not produced until actual renewable energy is produced. Even though those electrons have already been produced and used, the sale and purchase of a REC stimulates demand for additional renewable energy by sending a market signal to green power producers to develop additional sources of renewable energy.[313] Staff's witness may not believe RECs are effective, but he concedes that millions of RECs are sold each year.[314] He also concedes the Missouri Department of Natural Resources, and the Environmental Protection Agency support the concept of RECs.[315] In fact, he concedes RECs are widely accepted throughout the nation as contributing to the expansion of green generation, although he describes that acceptance as "an unsubstantiated belief, widely accepted."[316]

Staff is also concerned that customers are confused about what they are actually receiving when the purchase a REC. Staff seems to believe customers think they are buying actual electrons generated by a green generation source, when they buy a REC. The concept of a REC and the purchase of the environmental attributes associated with

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[312] Barbieri Rebuttal, Ex. 9, Page 7, Lines 9-11.

[313] Transcript, Page 724, Lines 14-21.

[314] Transcript, Page 629, Lines 16-22.

[315] Transcript, Page 637, Liens 13-18.

[316] Transcript, Pages 641-642, Lines 22-25, 1-4.

green production versus fossil fuel production is difficult to understand.[317] AmerenUE concedes it is difficult to explain to customers that they are purchasing a REC and not electricity. Some of the initial marketing materials sent out by 3 Degrees did not do enough to avoid that confusion, but AmerenUE and 3 Degrees have continued to improve those marketing materials, including major revisions to the Pure Power website. In the end, the desire to improve the marketing materials does not justify terminating the program after only one year of existence.

Aside from its concerns about the effectiveness and the marketing of the Pure Power program, Staff is also concerned the contract between AmerenUE and 3 Degrees does not pass enough money through to actual green energy producers. As previously indicated fourteen of the fifteen dollars AmerenUE collects from participating customers is passed to 3 Degrees for the purchase of RECs. Not surprisingly, not all the money that goes to 3 Degrees is used to purchase RECs. 3 Degrees keeps some to pay for marketing and administration and profit.[318] Staff believes the contract is overly generous to 3 Degrees. However, 3 Degrees assumed the risk that the market price for RECs may rise in the next five years, thus reducing its profit margin. A rise in the market price for RECs is possible as demand for RECs rises because of the imposition of renewable portfolio standards such as the recently enacted Proposition C in Missouri.[319]

Finally, Staff is concerned non-participating AmerenUE customers may be subsidizing AmerenUE's administrative costs associated with the Pure Power program

[317] Transcript, Page 628, Lines 6-14.

[318] The highly confidential numbers are found at Ensrud Surrebuttal, Ex. 220, Page 11, Line 18.

[319] Transcript, Page 748, Lines 11-19.

because AmerenUE is not doing enough to separately track those costs.[320] AmerenUE agrees that non-participating customers should not be subsidizing the program and indicates all administrative costs, as well as revenues generated by the program, are accounted for below the line.[321] Staff is concerned, for example, that the cost of billing customers who participate in the Pure Power program is not segregated from the cost of billing all other customers.[322] However, the maximum potential cost identified by Staff is not substantial and does not justify any immediate accounting change.[323]

The Commission finds that the Pure Power program is a voluntary program that seems to be popular with some of AmerenUE's customers. No customer is forced to participate in the program and if they are unhappy with the program, they can leave at any time. The program is nationally respected and has been awarded the 2008 New Green Power Program of the year award by the U.S. Department of Energy, in conjunction with the U.S. Environmental Protection Agency and the Center for Resource Solutions.[324] Most importantly, the program has only been in operation for one year. It is too soon to properly assess the program and it is certainly too soon to kill the program.

Conclusions of Law:

There are no additional conclusions of law for this issue.

Decision:

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[320] Staff Report – Class Cost of Service & Rate Design, Ex. 206, Pages 21-22.

[321] Barbieri Rebuttal, Ex. 9, Page 9, Lines 5-22.

[322] Transcript, Page 696, Lines 4-10.

[323] Staff Report – Class Cost of Service & Rate Design, Ex. 206, Page 22. The precise number is highly confidential.

[324] Barbieri Rebuttal, Ex. 9, Page 11, Lines 1-5, and Transcript, Page 703-704, Lines 20-25, 1.

The Commission authorizes AmerenUE to continue to offer the voluntary Pure Power program to its customers.

15. Union Issues

Introduction:

The various unions that represent AmerenUE's employees appeared at the hearing to generally support the company's request for a rate increase. However, they asked the Commission to order AmerenUE to spend more money on employee training and to take specific steps to increase its internal workforce so it will use fewer outside contractors. AmerenUE contends it is currently providing safe and adequate service and argues the Commission has no authority to manage the day-to-day affairs of the company.

Findings of Fact:

David Desmond is the business manager of International Brotherhood of Electrical Workers Local 2, AFL-CIO.[325] He testified that too much of AmerenUE's daily workload is performed by less trained subcontractors rather than by AmerenUE's internal workforce.[326] He asked the Commission to require AmerenUE to invest in its employee infrastructure and require subcontractors to meet the standards of training and certification similar to those required of AmerenUE's internal workforce.[327]

Donald Giljum is the Business Manager for the International Union of Operating Engineers Local Union No. 148.[328] He testified AmerenUE has curtailed its training

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[325] Desmond Direct, Ex. 901, Page 1, Lines 2-3.

[326] Desmond Direct, Ex. 901, Page 2, Lines 14-22.

[327] Desmond Direct, Ex. 901, Page 3, Lines 13-19.

[328] Giljum Direct, Ex. 903, Page 1.

activities and allowed internal staffing level to decline to the point it must rely on outside contractors to perform some of the work at its power plants.[329]

Michael Walter is the Business Manager of International Brotherhood of Electrical Workers Local 1439, AFL-CIO.[330] He testified AmerenUE has not spent enough on training new workers and as a result has over-relied on outside contractors to perform normal and sustained work.[331] He asks the Commission to require AmerenUE to spend its rate increase to improve training and increase the portion of the workload performed by its internal workforce.[332]

Michael Datillo is the Business Manager and Financial Secretary of International Brotherhood of Electrical Workers Local 1455, AFL-CIO.[333] Datillo also complained AmerenUE relied too heavily on outside contractors. In particular, he objected to the outsourcing of call center work to a company operating out of North Carolina.[334]

AmerenUE denied its use of outside contractors has diminished the efficiency or safety of the company's operations. AmerenUE demonstrated that measures of power plant reliability have significantly improved over the last 10 years. Since 1998, the equivalent availability[335] of AmerenUE's coal plants has improved from 79.91 percent in

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[329] Giljum Direct, Ex. 903, Page 2.

[330] Walter Direct, Ex. 902, Page 1, Lines 2-3.

[331] Walter Direct, Ex. 902, Pages 2-4.

[332] Walter Direct, Ex. 902, Page 6, Lines 8-23.

[333] Datillo Direct, Ex. 900, Page 1, Lines 2-4.

[334] Datillo Direct, Ex. 900, Page 2, Lines 18-20.

[335] Equivalent availability is the total actual megawatt hours a unit is available after all outages and derates have been subtracted, divided by the total maximum megawatt hours a full unit capacity. Birk Rebuttal, Ex. 15, Pages 6-7, Lines 22-23, 1.

1998, to 90.73 percent in 2008. In the same period of time, the net capacity factor[336] for those plants has improved from 61.92 percent to 79.26 percent.[337] Furthermore, the OSHA incident rate for generation employees has declined over the last ten years from 9.0 in 1998 to 1.9 in 2008,[338] which is near the top quartile rate for generating plants around the country.[339]

AmerenUE acknowledges it is facing an industry-wide shortage of trained linemen, and must, therefore, rely on outside contractor. However, AmerenUE is trying to find more workers that are qualified and is offering a $15,000 bonus for persons who qualify as a journeyman lineman.[340] In addition to a general shortage of linemen, the average age of AmerenUE's work force is getting older. For example, in one union bargaining unit the average age is 49 and one half, with an average retirement age of 55 or 56.[341] As more employees approach retirement, there is a need for increased training to bring new workers in to replace those who are retiring.

In response to those concerns, Commissioner Davis asked the AmerenUE witnesses how the company would spend an extra $3 million on training if provided with additional funds as a result of this case.[342] In response to Commissioner Davis' question,

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[336] Net capacity factor is a ratio of how much power was actually produced by the plants, divided by the capacity of the plants. Birk Rebuttal, Ex. 15, Page 7, Lines 2-3.

[337] Birk Rebuttal, Ex 15, Page 7, Chart at Line 4.

[338] Birk Rebuttal, Ex. 15, Page 8, Chart at Line 1.

[339] Transcript, Page 1810, Lines 22-25.

[340] Zdellar Rebuttal, Ex. 16, Page 11, Lines 12-13.

[341] Transcript, Page 1766, Lines 17-25.

[342] Transcript, Page 1820-1821, Lines 23-25, 1-19.

AmerenUE subsequently filed an exhibit detailing how it would spend extra money on training.[343]

The Commission finds that the evidence presented by the union witnesses does not demonstrate that AmerenUE has failed to supply safe and adequate service to the public. Furthermore, for reasons fully explained in its Conclusions of Law, the Commission does not have the authority to dictate the manner in which AmerenUE conducts its business. Therefore, the Commission will not attempt to dictate to the company regarding its use of outside contractors.

However, the union witnesses and AmerenUE agree there is a need for improved training to replace skilled workers nearing retirement age. Therefore, the Commission will add $1,410,000 to AmerenUE's cost of service to fund increased training staff. The Commission will also allow AmerenUE an additional $1,800,000 for additional training equipment and materials, and external costs, to be amortized over five years and recovered in rates. That would increase AmerenUE's cost of service by an additional $360,000 per year, for a total increase of $1,770,000.

Conclusions of Law:

The Commission has the authority to regulate AmerenUE, including the authority to ensure the utility provides safe and adequate service. However, the Commission does not have authority to manage the company. In the words of the Missouri Court of Appeals,

> The powers of regulation delegated to the Commission are comprehensive and extend to every conceivable source of corporate malfeasance. Those powers do not, however, clothe the Commission with the general power of management incident to ownership. The utility retains the lawful right to manage its own affairs and conduct its business as it may choose, as long as

[343] Ex. 78.

> it performs its legal duty, complies with lawful regulation, and does no harm to public welfare.[344]

Therefore, the Commission does not have the authority to dictate to the company whether it must use its internal workforce rather than outside contractors to perform the work of the company.

Decision:

The evidence presented by the union witnesses does not demonstrate that AmerenUE has failed to provide safe and adequate service and the Commission will not dictate to the company whether it must use its internal workforce or outside contractors to perform the company's work. However, the Commission will add $1,410,000 to AmerenUE's cost of service to fund increased training staff. The Commission will also allow AmerenUE an additional $1,800,000 for additional training equipment and materials, and external costs, to be amortized over five years and recovered in rates. That increases AmerenUE's cost of service in this case by $1,770,000 per year.

16. Hot Weather Safety Program

Introduction:

AARP asks the Commission to order AmerenUE to instigate a limited experimental pilot program designed to encourage low-income seniors to turn on their air conditioners during hot weather by offering them a bill credit during the summer. AmerenUE opposes the pilot program as poorly thought out and unlikely to be effective.

Findings of Fact:

AARP cites studies showing that some seniors refuse to turn on their air conditioners even in very hot weather, in part because of concerns about the high cost of operating an

[344] *State ex rel. Harline v. Public Serv. Com'n*, 343 S.W.2d 177, 182 (Mo. App. 1960)

air conditioner.[345] As a result, those seniors are at a greater risk of dying from heat related illness.[346] AARP's proposed pilot program attempts to address that problem by offering low-income seniors a small bill credit on their bills to encourage them to use their air conditioning when it is hot.

AARP initially proposed to make the hot weather credit available to all low-income seniors in the AmerenUE's service territory at a cost of nearly $1.5 million.[347] However, by the time of the hearing, AARP had reduced its proposal to an experimental pilot program that would provide bill credits of $5 per day for 9.5 extreme heat days during the summer months, for 2,400 participating households. The cost of providing the bill credits would be $114,000, which AmerenUE would be allowed to recover in rates.[348]

The Commission is concerned about the health of the elderly citizens of AmerenUE's service territory, but AARP's proposed pilot program is not well thought out and there is no indication that a bill credit of $5.00 per day will actually prompt an at-risk elderly person to turn on their air conditioning. This sort of program has never been tried anywhere else and AARP admits it does not really know how it will work.[349] A heat alert warning from the Missouri Department of Health, attached to AARP's testimony, indicates for some at-risk elderly persons, "even encouragement from relatives and friends could not convince them to use their air conditioner."[350] In those circumstances, it is hard to see how a slightly

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[345] Howat Direct, Ex. 850, Pages 6-7, Lines 17-23, 1-5.

[346] Howat Direct, Ex. 850, Page 8, Lines 1-20.

[347] Howat Direct, Ex. 850, Page 12, Lines 7-8.

[348] Transcript, Page 1130, Lines 7-12.

[349] Transcript, Pages 1165-1166, Lines 20-25, 1-2.

[350] Howat Direct, Ex. 850, Attachment AARP-JH-3.

reduced utility bill at the end of the month would convince an at-risk person to turn on their air conditioning.

Of course, in terms of this multi-million dollar rate case, the $114,000 it would cost to implement AARP's pilot program is not significant. However, implementation of an ill-conceived pilot program could distract AmerenUE and other interested parties from more effective actions to help the elderly poor. In fact, that was the conclusion of the collaborative group to which AARP presented its proposal last spring.[351] Instead, that collaborative group decided to move forward with other plans to educate the elderly about the dangers of extreme heat.[352]

The Commission finds that AARP's proposed hot weather safety pilot program, while well intentioned, would not be an effective use of AmerenUE's resources and the financial resources of AmerenUE's ratepayers.

Conclusions of Law:

There are no additional conclusions of law on this issue.

Decision:

AARP's proposed hot weather safety pilot program is rejected.

17. Certain Power On and Dollar More Advertising Expense

Introduction:

Staff seeks to disallow approximately $1.36 million in advertising expenses incurred by AmerenUE in promoting its Power On program and its Dollar More program.[353]

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[351] Transcript, Page 1228, Lines 8-14.

[352] Transcript, Page 1231, Lines 5-9.

[353] Transcript, Page 1008, Lines 10-12.

AmerenUE replied that the advertisements challenged by Staff were appropriate for inclusion in rates and their cost should be recovered from ratepayers.

Findings of Fact:

Staff bases its proposal to disallow the cost of certain advertisements on a decision made by the Commission in a 1986 KCPL rate case. In that decision, the Commission defined five categories of advertisements.

1. General: Informational advertising that is useful in the provision of adequate service;
2. Safety: Advertising that conveys the ways to safely use electricity and to avoid accidents;
3. Promotional: Advertising used to encourage or promote the use of electricity;
4. Institutional: Advertising used to improve the company's public image; and
5. Political: Advertising associated with political issues.

In that case, the Commission found the cost of General and Safety advertising could be recovered from ratepayers, while the cost of Institutional and Political advertising should not be recovered. The Commission in that case found promotional advertising could be recovered if it was shown to be cost justified.[354] The Commission finds that categorization of advertising to be useful and will use the same categories in considering this issue.

Staff's witness, Erin Carle, examined hundreds of individual print, radio, television and billboard advertisements, the cost of which AmerenUE seeks to recover in rates. Staff disallowed recovery for many of those advertisements as institutional advertising designed

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[354] *In the Matter of Kansas City Power & Light Company's Tariffs Increasing Rates for Electric Service,* 28 Mo. P.S.C. (N.S.) 228, 270 (1986).

to promote the image of the utility.[355] AmerenUE contend the challenged ads are properly categorized as General, meaning they are informational advertising that is useful in the provisioning of adequate service.

AmerenUE's Power On program is a billion dollar initiative AmerenUE has undertaken to improve the reliability of its electric network. Under Power On, AmerenUE will spend approximately $500 million in mandated environmental expenditures, $300 million in undergrounding work, and $150 million to more aggressively trim trees.[356] Staff conceded that some advertising for Power On should be categorized as General advertising because it conveyed useful information to the public about the specifics of the program. However, Staff claimed the cost of other Power On ads should be excluded because the advertisements did not convey enough useful information to the public.[357]

Erin Carle examined each of AmerenUE's Power On advertisements and offered an opinion on whether each advertisement conveyed enough useful information to the public. The problem with that approach is Erin Carle is an accountant, and is working on her MBA.[358] Although she claims to be an advertising expert for ratemaking purposes,[359] she has no training in the field of advertising, aside from looking at old cases at the Commission.[360]

Not surprisingly, given her lack of expertise and the vague standard by which she was attempting to judge the individual advertisements, Carle's testimony fell apart on cross-

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[355] Carle Surrebuttal, Ex. 219, Page 7, Lines 16-19.

[356] Mark Rebuttal, Ex. 20, Page 6, Lines 7-10.

[357] Transcript, Page 1040, Lines 17-20.

[358] Transcript, Page 1030, Lines 12-20.

[359] Transcript, Page 1038, Lines 19-25.

[360] Transcript, Page 1039, Lines 6-16.

examination and it became clear that her categorization of particular Power On advertisements as either General and thus recoverable, or Institutional, and thus excludable, was essentially arbitrary.

The fault was not with Ms. Carle, but rather with Staff's attempt to individually categorize each and every advertisement produced by AmerenUE. As Mr. Mark testified for AmerenUE, it makes more sense to look at an advertising campaign as a whole.[361] Thus, a simple billboard advertisement that by its nature cannot convey a great deal of information to a motorist rushing by at 70 miles per hour, may motivate and direct that customer to seek out more detailed information from another source.

In the future, Staff would do well to examine advertisements on a campaign basis rather than becoming ensnared in the effort to evaluate individual ads within a larger campaign. If on balance a campaign is acceptable then the cost of individual advertisements within that campaign should be recoverable in rates. If the campaign as a whole is unacceptable under the Commission's standards, then the cost of all advertisements within that larger campaign should be disallowed.

The same finding must be made in relation to the challenged Dollar More advertisement, which was a print advertisement that appeared in the game day program for the St. Louis Rams and urged Rams fans to go to the company website to learn more about the Dollar More program.[362] The overall campaign to promote the Dollar More program is acceptable, so the individual advertisements within that larger campaign shall not be disallowed.

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[361] Transcript, Page 1024, Lines 7-11.

[362] The ads in question are attached to Mark Rebuttal, Ex. 20, Schedules RJM-RE2-9 and RE2-10.

For purposes of this case, Staff's proposal to disallow the cost of certain Power On and Dollar More advertisements is rejected.

Conclusions of Law:

There are no additional conclusions of law for this issue.

Decision:

Staff's proposal to disallow the cost of certain Power On and Dollar More advertisements is rejected.

18. Rate Design

Introduction:

After the Commission determines the amount of rate increase that is necessary, it must decide how that rate increase will be spread among AmerenUE's customer classes. The basic principle guiding that decision is that the customer class causing a cost should pay that cost. During the course of the hearing, Public Counsel, MIEC, MEG, the Commercial Group, and Noranda filed a nonunanimous stipulation and agreement that reached an agreement on how the rate increase should be allocated to the customer classes. AmerenUE did not sign the stipulation and agreement but did not oppose the compromise agreement. Staff, however, does oppose that agreement. Therefore, the Commission cannot approve the stipulation and agreement. Nevertheless, the compromise described in the stipulation and agreement remains the position of the signatory parties and the Commission can consider that position as it decides this issue.

Findings of Fact:

AmerenUE has five customer classes.[363] The Residential class is comprised of residential households. The Small General Service and Large General Service classes are comprised of commercial operations of various sizes. The first three classes receive electric service at a low secondary voltage level. The Small Primary Service and the Large Primary Service are larger industrial operations that receive their electric service at a high voltage level. The final class is Large Transmission Service. There is only one member of that class, Noranda. Noranda operates an aluminum smelter in Southeast Missouri and receives massive amounts of electricity at a transmission voltage level.[364]

To evaluate how best to allocate costs among these customer classes, four parties prepared and presented class cost of service studies. The studies presented by AmerenUE and MIEC used versions of the Average and Excess Demand Allocation method. An Average and Excess Demand Allocation method recognizes that peak demand, the amount of energy that must be produced and delivered during the periods of highest demand, and average class energy consumption, determine how the generation and distribution systems must be structured. The Average and Excess Demand Allocation method gives weight to both of those considerations by evaluating both average class demands and the excess non-coincident peak demands of each class.[365]

Staff and Public Counsel also presented class cost of service studies, but they used a different allocation method known as a Peak and Average Demand Allocation method. Staff's allocation method is based on each class' contribution to the 12 monthly non-

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[363] The Lighting class, which includes street lights, is a sixth class but because of its unique load pattern, it is not treated as a separate class for the class cost of service studies. Staff Report - Class Cost of Service & Rate Design, Ex. 206, Page 9.

[364] Cooper, Direct, Ex. 39, Page 4, Lines 7-11.

[365] Cooper Direct, Ex. 39, Page 13, Lines 7-21.

coincident class peak demands and applies a monthly weighting factor for capacity utilization prior to calculating the class contribution to demand.[366] Public Counsel also presented a second study using a time of use method.

The following chart compares the results of each of the class cost of service studies, indicating the percent change in class revenues required to equalize class rates of return. A negative number means the class is paying more than its indicated share of costs. A positive number means that class is paying less than its indicated share.

Study	Residential	Small General Service	Large General Service	Primary Service	Large Transmission Service
Staff	3.160%	-3.063%	-5.092%	2.901%	4.882%
AmerenUE	6.820%	-6.626%	-7.561%	3.536%	-2.641%
OPC (TOU)	-1.850%	-9.900%	-2.130%	14.470%	23.010%
OPC (A&P)	0.060%	-7.080%	-2.550%	10.480%	11.630%
MIEC	12.300%	-5.800%	-11.000%	-3.800%	-16.200%

The completion of a class cost of service study does not end the rate the design process. The Commission is not required to precisely set rates to match the indicated class cost of service. Instead, the Commission has a great deal of discretion to set just and reasonable rates, and can take into account other factors, such as public acceptance, rate stability and revenue stability in setting rates[367]

AmerenUE and Staff proposed that because their class cost of service studies did not show any large variations from appropriate class contributions, any rate increase should be allotted equally to each customer class. In other words, each class would receive the system average percentage increase. Several other parties advocated various adjustments to benefit the customer classes they represent.

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[366] Staff Report – Class Cost of Service & Rate Design, Ex. 206, Page 11.

[367] Cooper Direct, Ex. 39, Attachment A-2.

The objected-to stipulation and agreement represents a compromise among the various customer classes. It would divide any rate increase into three tiers, as follows:

Tier 1: For any increase up to $80 million, all classes will receive the system average percentage increase.

Tier 2: The Tier 2 spread operates on any approved increase equal to or above $80 million and up to $150 million. Within Tier 2, there are several interrelated adjustments.

> Step 1. The increment directed to the Large Transmission Service class will be one-half of the system average percentage increase.
>
> Step 2. The amount of the increase not directed to the Large Transmission Service class will be spread among the remaining customer classes in proportion to the true-up level of rate revenues of these classes.
>
> Step 3. The residential increase will be adjusted to be equal to the system average percentage increase plus 0.3 percent. For example, a 7 percent system average increase would result in a residential increase of 7.3 percent.
>
> Step 4. The additional revenue generated by the Step 3 adjustment to residential class revenues will be spread among the Small General Services, Large General Services and Small Primary Service rate classes in proportion to the true-up revenues form those rate classes.

Tier 3. Tier 3 applies to the increase amount, if any, in excess of $150 million. Under that Tier, all classes will receive the system average percentage increase.

In other words, the first $80 million of rate increase will be spread equally over all classes as Staff and AmerenUE suggested. It is only for the increment between $80 million and $150 million that any adjustments would be made among the classes.

At the hearing, after the compromise was filed, witness after witness took the stand to testify that the compromise is supported by the studies and would be a reasonable exercise of the Commission's authority to set reasonable rates. Maurice Brubaker, the witness for MIEC, a collection of large industrial customers, testified that the compromise is consistent with the class cost of services studies. He pointed out that the deviations from system average were minor, with no disruptive increases for any customer class.[368] Donald Johnstone testified in support of the compromise on behalf of Noranda, the only member of the Large Transmission Service class.[369] Richard Baudino, testifying on behalf of the Commercial Group, a group of large retailers, described the compromise as reasonable and resulting in "just and reasonable rates the Commission can rely on."[370] Finally, Barbara Meisenheimer and Ryan Kind testified on behalf of Public Counsel. Both Meisenheimer[371] and Kind[372] supported the compromise position.

The only witness who opposed the compromise position was James Watkins representing Staff. He indicated Staff opposed the compromise because it would result in a reduction for the Large Transmission Service, which Staff's study shows is already paying

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[368] Transcript, Page 1916, Lines 1-16.

[369] Transcript, Page 1952-1953, Lines 24-25, 1-7.

[370] Transcript, Page 1965, Lines 4-8.

[371] Transcript, Page 1974, Lines 18-25.

[372] Transcript, Pages 1976-1977, Lines 14-25, 1-13.

less than its indicated share of costs.[373] Staff acknowledged its study also showed that the Small General Service, Large General Service, and Small Primary Services classes should receive a smaller than system average increase, as they would under the compromise position, but not under the across the board increase demanded by Staff.[374] Staff also conceded that only $2.9 million is being redistributed between classes compared to the equal percentage distribution demanded by Staff.[375] That $2.9 million would represent only 0.14 percent of AmerenUE current total revenues.[376] Nevertheless, Staff dogmatically insisted it would oppose the compromise position even if only $1 was redistributed for the benefit of the Large Transmission Service class.[377]

Staff claims its position is justified because its cost of service study shows the Large Transmission Service class should be given a larger than system average increase rather than a decrease. The cost of service studies presented by AmerenUE and MIEC both indicate the Large Transmission Service class should receive a lower than average increase, but Staff believes only its cost of service study, and perhaps that of Public Counsel, is valid.[378]

However, the method Staff uses in its study, the Capacity Utilization method, is a method of Staff's own invention, having been designed by Dr. Michael Proctor in 1982.[379] Staff has used this method since that time, but the method has never been accepted by this

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[373] Transcript, Page 1991, Lines 22-25.

[374] Transcript, Page 1995, Lines 10-15.

[375] Transcript, Page 2017, Lines 11-14.

[376] Transcript, Page 2018, Lines 1-4.

[377] Transcript, Page 2015, Lines 6-10.

[378] Transcript, Page 2025, Lines 10-17.

[379] Staff Report – Class Cost of Service & Rate Design, Ex. 206, Page 12.

or any other Commission in the country.[380] Indeed, the Peak and Average Demand allocation method used by Staff is inherently flawed as it double counts the average demand of customer classes, resulting in customers with higher load factor, in other words industrials, being allocated an inequitable share of production plant investment.[381]

The Commission finds that the compromise position advocated by parties representing all of the customer classes is supported by the class cost of service studies submitted by AmerenUE and MIEC. The class cost of service study offered by Staff is inherently flawed and unreliable, but even that study does not preclude the slight redistribution between classes that will result from the compromise position. The Commission find that the compromise position will result in just and reasonable rates, and the Commission will adopt that position.

Conclusions of Law:

There are no additional conclusions of law for this issue.

Decision:

The Commission adopts the compromise position advocated by Public Counsel, MIEC, MEG, the Commercial Group, and Noranda. That position is described as follows:

Tier 1: For any increase up to $80 million, all classes will receive the system average percentage increase.

Tier 2: The Tier 2 spread operates on any approved increase equal to or above $80 million and up to $150 million. Within Tier 2, there are several interrelated adjustments.

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[380] Transcript, Page 2066, Lines 15-18.

[381] Cooper Rebuttal, Ex. 40, Pages, 4-5, Lines 17-23, 1-4.

Step 1. The increment directed to the Large Transmission Service class will be one-half of the system average percentage increase.

Step 2. The amount of the increase not directed to the Large Transmission Service class will be spread among the remaining customer classes in proportion to the true-up level of rate revenues of these classes.

Step 3. The residential increase will be adjusted to be equal to the system average percentage increase plus 0.3 percent. For example, a 7 percent system average increase would result in a residential increase of 7.3 percent.

Step 4. The additional revenue generated by the Step 3 adjustment to residential class revenues will be spread among the Small General Services, Large General Services and Small Primary Service rate classes in proportion to the true-up revenues form those rate classes.

Tier 3. Tier 3 applies to the increase amount, if any, in excess of $150 million. Under that Tier, all classes will receive the system average percentage increase.

19. FERC 7-Factor Test

Introduction:

This final issue is not contested by any party. Nonetheless, AmerenUE asks the Commission to make a factual determination to satisfy the requirements of its agreement with the Midwest Independent Transmission System Operator, Inc. (Midwest ISO), and Midwest ISO's FERC electric tariff.

Findings of Fact:

The Agreement of Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc., a Delaware Non-Stock Corporation requires its member utilities to request a determination by their state regulatory commission that the utility has classified its energy delivery facilities in accordance with the 7-Factor Test prescribed by the Federal Energy Regulatory Commission (FERC).[382] AmerenUE is a party to that agreement by virtue of its membership in the Midwest ISO.

The FERC 7-Factor Test is a test used to determine whether an energy delivery facility should be classified as either local distribution or transmission.[383] As a participant in the Midwest ISO, AmerenUE has transferred operational control of its electrical transmission facilities to the Midwest ISO. AmerenUE retains control over its local distribution facilities. Thus, the purpose of the determination required by the Midwest ISO agreement is to ensure that the participating utility has properly classified the facilities it has transferred to the control of the Midwest ISO.

AmerenUE's witness, Edward Pfeiffer, testified that AmerenUE has applied the 7-Factor Test in classifying its energy delivery facilities between distribution and

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[382] Pfeiffer Direct, Ex. 53, Page 2, Lines 15-14.

[383] The 7 factors in FERC's test are as follows:

1. Local distribution facilities are normally in close proximity to retail customers.
2. Local distribution facilities are primarily radial in character.
3. Power flows into local distribution systems; it rarely, if ever, flows out.
4. When power enters a local distribution system, it is not reconsigned or transported on to some other market.
5. Power entering a local distribution system is consumed in a comparatively restricted geographical area.
6. Meters are based at the transmission/local distribution interface to measure flows into the local distribution system.
7. Local distribution systems will be of reduced voltage.

Pfeiffer Direct, Ex. 53, Page 3, Lines 1-11.

transmission.[384] He also attached a list of the energy delivery facilities AmerenUE classified as transmission and transferred to Midwest ISO for operations.[385]

Staff's witness, Daniel Beck, testified that the list of transmission facilities identified by AmerenUE "appears to be reasonable". However, Beck indicated he had not reviewed the list and application of the FERC 7-Factor test on a line-by-line basis.[386] Beck also explained that Midwest ISO's FERC electric tariff, which incorporates the requirements of the Midwest ISO agreement referenced by AmerenUE, requires the company to request a determination from the Commission. It does not require that the Commission approve that request. Thus, AmerenUE met the requirement of the Midwest ISO's tariff when it requested the determination, and the Commission does not actually need to approve the requested determination.[387]

Beck testified that if the Commission chooses to make the determination requested by AmerenUE, it should note that its determination does not have any ratemaking impact, and does not modify the terms of AmerenUE's participation in the Midwest ISO.

Conclusions of Law:

Midwest ISO's FERC Electric Tariff provides as follows:

> Prior to the end of the fourth (4th) year of the Transition Period, each Owner shall file a request with the appropriate regulatory authority or authorities (unless a proceeding has already been initiated or completed) for a determination of which of its facilities are transmission facilities or which are distribution in accordance with the seven (7) factor test set forth in FERC Order No. 888, 61 Fed. Reg. 21,540, 21,620 (1996) or any applicable successor test. Each Owner shall use its best effort to cause these determinations to be made before the end of the Transition Period. Owners

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[384] Pfeiffer Direct, Ex. 53, Page 3, Lines 22-23.

[385] Pfeiffer Direct, Ex. 53, Schedule ECP-E1.

[386] Beck Rebuttal, Ex. 217, Page 3, Lines 12-14.

[387] Beck Rebuttal, Ex. 217, Page 2, Lines 25-28.

that are not subject to regulation by a regulatory authority shall apply to the Midwest ISO for such a determination.[388]

Decision:

Based on the uncontested testimony of Edward Pfeiffer, the Commission determines that AmerenUE has classified its energy delivery facilities in accordance with the 7-Factor Test prescribed by the FERC. This determination does not have any ratemaking impact, and does not modify the terms of AmerenUE's participation in the Midwest ISO.

IT IS ORDERED THAT:

1. The tariff sheets filed by Union Electric Company, d/b/a AmerenUE on April 4, 2008, and assigned tariff number YE-2008-0605, are rejected.

2. Union Electric Company, d/b/a AmerenUE is authorized to file a tariff sufficient to recover revenues as determined by the Commission in this order.

[388] Midwest ISO FERC Electric Tariff, First Revised Rate Schedule No. 1, Substitute First Revised Sheet No. 125. Beck Rebuttal, Ex. 217, Appendix C.

3. This report and order shall become effective on February 6, 2009.

BY THE COMMISSION

(S E A L)

Colleen M. Dale
Secretary

Murray and Jarrett CC, concur;
Davis, C, concurs, with separate concurring opinion to follow;
Clayton, Chm, dissents;
and Gunn, dissents, with separate dissenting opinion to follow;
and certify compliance with the provisions
of Section 536.080, RSMo.

Dated at Jefferson City, Missouri,
on this 27th day of January, 2009.

1076-E-480 AH

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
1333 "H" STREET, N.W., SUITE 200, WEST TOWER
WASHINGTON, D.C. 20005

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DISTRICT OF COLUMBIA
PUBLIC SERVICE COMMISSION

OPINION AND ORDER

March 2, 2010

FORMAL CASE NO. 1076, IN THE MATTER OF THE APPLICATION OF THE POTOMAC ELECTRIC POWER COMPANY FOR AUTHORITY TO INCREASE EXISTING RETAIL RATES AND CHARGES FOR ELECTRIC DISTRIBUTION SERVICE, Order No. 15710

Before the Commission:

Betty Ann Kane, Chairman
Richard E. Morgan, Commissioner
Lori Murphy Lee, Commissioner

Appearances:

Deborah M. Royster, Kirk J. Emge, Marc K. Battle, William M. Gausman, Anthony J. Kamerick, Arthur W. Adleberg, James W. Boone, Richard M. Lorenzo, Theodore F. Duver for Potomac Electric Power Company; Elizabeth A. Noel, Brian O. Edmonds, Sandra Mattavous-Frye, Karen R. Sistrunk, Barbara Burton, Laurence C. Daniels, Brenda K. Pennington, Jennifer L. Weberski, Maggie A. Sallah, Barry Cohen, Kevin J. Conoscenti, John Michael Adragna, James H. Boyd, Robert C. McDiarmid, Sharon Coleman, Jeffrey A. Schwarz, J.S. Gilbert, Stephen C. Pearson, Scott Strauss, Adrienne E. Clair, Dennie Lane, John E. McCaffrey, Douglas E. Micheel for Office of People's Counsel; Frann G. Francis, W. Shaun Pharr, Nicola Y. Whiteman for the Apartment and Office Building Association of Metropolitan Washington; Brian R. Caldwell for the District of Columbia Government; Leonard E. Lucas, III for the General Services Administration; Marc Biondi for the Washington Metropolitan Area Transit Authority; Nancy A. White, Robert I. White for the District of Columbia Water and Sewer Authority; Cathy Thurston-Seignious, Beverly Burke, Bernice K. McIntyre for Washington Gas Light Company.

KAWC EXHIBIT
2

TABLE OF CONTENTS

I. BACKGROUND

1. On May 22, 2009, less than 16 months after an increase in its base rates, Potomac Electric Power Company ("Pepco" or "the Company") filed an Application with the Public Service Commission of the District of Columbia ("Commission") requesting a $51.7 million increase in its retail service rates for distributing electricity in the District of Columbia.[1] The Company initially requested authority to earn an 8.88 percent rate of return, including a return on common equity of 11.50 percent. Subsequently, Pepco modified its request, seeking a $44.514 million increase based on a rate base of $1,020,095,000, an 8.53 percent overall rate of return and a 10.75 percent return on equity.[2] Pepco contends that its proposal for higher distribution rates is justified by higher costs (*i.e.,* the higher cost of capital, operations and maintenance expenses, and capital expenditures to maintain poles, wires, and critical equipment) as well as the need for Pepco to invest in new "smart grid" technology.

2. Pepco seeks approval of a surcharge to recover what it alleges are volatile pension-related, other post employment benefits ("OPEB"), and uncollectibles expenses based on a three-year rolling average (rather than actual test year costs); cost recovery for investment in advanced metering infrastructure ("AMI"); a new depreciation study filed December 31, 2008; and other cost of service items.

3. The Company states that current earned returns vary widely by customer class. It proposes to move gradually ("one-quarter of the way") toward equalizing class rates of return, by raising distribution rates (which are only one part of each customer's bill) more for residential than for commercial customers. Overall, Pepco proffers that an average residential customer's bill would increase by 6.1 percent or $6.43 on the total bill under its proposals.[3] Further, Pepco proposes a significant 211 percent increase in Street Light energy distribution rates. Other Pepco rate design proposals include replacement of its current Standby Rider with a new "GT-3A-S" tariff that would apply to customers with behind-the-meter generation that runs in parallel with the Company's delivery system; and a new Volatility Mitigation Surcharge (Rider "VM") to reflect changes in certain volatile expenses.

4. The Commission held a pre-hearing conference on July 2, 2009. By Order No. 15322 the Commission designated the issues for consideration and set the procedural schedule

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1 *Formal Case No. 1076, In the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*, filed May 22, 2009 ("*Formal Case No. 1076*") ("Pepco's Application"). Pepco's Direct Testimony is hereinafter referred to as "Pepco ___"; its Supplemental Direct Testimony as "Pepco (2_)"; its Rebuttal Testimony as "Pepco (3__)"; its post-hearing initial brief as "Pepco Br."; and its post-hearing reply brief as "Pepco R. Br."

2 *See* Tr. 1242.

3 Pepco (A) at 4 (Kamerick).

for this proceeding.[4] We granted petitions to intervene by, among others, the Apartment and Office Building Association of Metropolitan Washington ("AOBA"), the District of Columbia Government ("DCG" or "District Government"); the District of Columbia Water and Sewer Authority ("WASA"); Washington Metropolitan Area Transit Authority ("WMATA"); and the General Services Administration ("GSA").[5] The Office of the People's Counsel of the District of Columbia ("OPC") is a "party as of right."[6]

5. Pepco submitted supplemental direct testimony on July 27, 2009. Order No. 15540 directed the filing of additional testimony concerning Pepco's request for special regulatory asset treatment of its increased 2009 pension costs.[7] OPC, AOBA, the District Government, WASA, WMATA, and GSA all submitted written testimony on September 17, 2009.

6. Rebuttal testimony was filed by all the parties on October 22, 2009. The Commission held evidentiary hearings on November 9, 10, 12, and 13, 2009. The Commission convened community hearings on October 24, November 19, and November 20, 2009. Over 125 community witnesses submitted comments or testified at the Commission's community hearings in this Pepco rate case. All the parties filed post-hearing initial briefs on December 9, 2009, and reply briefs on December 22 or 23, 2009.[8]

II. <u>TEST PERIOD</u> (Issue No. 1)[9]

7. Pepco's application reflects a test year of actual results for the twelve months ending December 31, 2008, adjusted for known and measureable changes, of the conditions which are expected to prevail during the rate-effective period.[10] OPC does not challenge Pepco's

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4 Order No. 15322 (July 10, 2009). The Commission's orders in this proceeding (*Formal Case No. 1076*) are hereinafter referred to as "Order No.___ at (page or ¶ number) (Date)." Orders in other Commission proceedings are cited in the following format: "*Formal Case No.* ___, Order No. ___ (Date), ___ DCPSC ___ (Year)." Court decisions will be cited as "*[<u>Case Name</u>]*, ___A.2d ___, __ (D.C. (Year))." Transcripts of the Commission's evidentiary hearings are cited as "Tr. ___".

5 Order No. 15310 (June 24, 2009).

6 *See* D.C. Code § 34-804 (2009 Supp.) (OPC is a party, as of right, in any Commission investigation, valuation, reevaluation, concerning any public utility operating in District of Columbia). OPC's Direct Testimony is designated as "OPC ___"; its Rebuttal Testimony as "OPC (2__)"; its post-hearing initial brief as "OPC Br."; and its post-hearing reply brief as "OPC R. Br." The direct testimony of an intervenor is identified by party in the form (for example) "WMATA __"; with rebuttal testimony denoted as (for example) "AOBA (2__)"; post-hearing initial briefs as (for example) "GSA Br."; and post-hearing reply briefs designated as (for example) "WASA R. Br."

7 Order No. 15540 (September 2, 2009).

8 The Commission grants the separate unopposed motions of AOBA and the District Government to file their reply briefs, out-of-time on December 23, 2009.

9 Designated Issue No. 1 asks, "Is Pepco's proposed test year ending December 31, 2008, reasonable?"

10 Pepco (A) at 10 (Kamerick); Pepco (C) at 3 (Hook); and Pepco (2C) at 2 (Hook Rebuttal).

use of a test year ending December 31, 2008.[11] No other party filed testimony on Pepco's proposed test year.

DECISION

8. The purpose of adopting a test year is to ensure that rate levels and the revenues they produce have a realistic relationship to the revenue requirements of the Company and to determine costs and investments as accurately as possible to allow the company a reasonable opportunity to recover its costs.[12] Pepco and OPC agree that the December 31, 2008, test year is a reasonable test year. The Commission concurs that Pepco's proposed test year ending December 31, 2008, is reasonable and an appropriate test year on which to review Pepco's Application.

III. RATE BASE (Issue No. 2)[13]

A. Unopposed Adjustments (Ratemaking Adjustments Nos. 2, 3, 5, 12, 19, 20, 21, 22, 24, and 29)

9. Rate base represents the investment the Company makes in plant and equipment in order to provide service to its customers.[14] The undisputed portion of the rate base including agreed adjustments, totals $3.013 million and include Ratemaking Adjustment No. 2 ("RMA No. 2"), CWIP in Rate Base, RMA No. 3, Annualization of Northeast Substation, RMA No. 5, Exclusion of Supplemental Executive Retirement Plans, RMA No. 12, Reflection of FC 1076 Costs, RMA No. 19, Annualization of Software Amortization, RMA No. 20, Annualization of Deductible Mixed Service Cost Tax Method, RMA No. 21, Exclusion of Capitalized Portion of Disallowed Formal Case No. 939 Costs, RMA No. 22, Reflection of Disallowance of Incentive Plan Costs, RMA No. 24, Inclusion of Deferred Customer Education Costs, and RMA No. 29, Reflection of New Method-Repair Categorizations.

DECISION

10. Inasmuch as no party challenges these adjustments and as the Commission has reviewed them and independently found them reasonable, we approve the adjustments.

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11 OPC (A) at 10 (Ramas).

12 *See, e.g., Washington Gas Light Co.*, 1 DCPSC 142 (1975).

13 Designated Issue No. 2 asks, "Has Pepco properly computed its proposed rate base?"

14 *Public Utilities Reports Guide, References*, 9-28 (2008).

B. Pepco's Proposed 13-Month Average Rate Base (Issue No. 2A)[15]

11. Pepco states that its proposed 13-month average rate base is reasonable, properly computed, and conforms to past Commission ratemaking determinations.[16] The rate base proposed by Pepco is $1,020,095,000.[17] OPC, nor any other party, challenges the use of a 13-month average rate base. OPC does, however, recommend various adjustments (totaling $212,109,000) to Pepco's proposed rate base which, if accepted, would result in a rate base of $841.923 million.

DECISION

12. While OPC proposes certain adjustments to Pepco's test year rate base, neither OPC nor any other party objects to Pepco's use of the 13-month average rate base. Moreover, Pepco's use of a 13-month average rate base is consistent with Commission precedent.[18] Therefore the Commission finds, subject to certain adjustments proposed by the parties and discussed below, Pepco's 13-month average rate base is reasonable and appropriate.

C. Construction Work in Progress ("CWIP") (Issue No. 2b)[19]

1. Benning Road Relocation Project

13. **Pepco.** Pepco states that RMA No. 4, the Benning Road Relocation Project ("Benning Road"), reflects a large, unique, one-time project that costs more than $20 million and is part of the District's "Great Street Initiative." It required Pepco to relocate and reconstruct duct banks and manholes, and install electric and fiber optic cable along Benning Road.[20] The project is unique in that, under normal circumstances, reconstruction of ductwork and facilities would not have been necessary in a street modification and repaving project. Pepco indicates that the electric plant installation was energized and in service in February 2009,[21] and the

15 Designated Issue No. 2a asks, "Is Pepco's proposed 13-month average rate base reasonable?"

16 Pepco (C) at 5 (Hook); Pepco (2C) at 2 (Hook Supp).

17 In its initial application, Pepco's proposed average rate base was $1.054 million. Pepco (C)-1 at 1 of 33 (Hook). Pepco Br. 5.

18 *See, e.g., Potomac Electric Power Co., Formal Case No. 748*, Order No. 7457 at 410, 412-417 (December 30, 1981); *Potomac Electric Power Co., Formal Case No. 939*, Order No. 10646 at 54; *Formal Case No. 1053*, Order No. 14712, ¶ 62.

19 Issue No. 2b asks, "Is the construction work in progress that Pepco included in the rate base reasonable?"

20 Pepco (D) at 11-12 (Gausman).

21 Pepco (C) at 8-9 (Hook); Pepco (D) at 12 (Gausman).

adjustment reflects a known and certain change which will take place within six months of the end of the test year, and prior to the end of the rate-effective period.[22] Pepco contends that Benning Road is identical to the Northeast Substation cut-in project approved in Formal Case No. 1053.[23] Pepco proposes to increase rate base by $19.794 million.[24]

14. **OPC.** OPC recommends that the Commission exclude the Benning Road "Retirement Work In Progress" ("RWIP") rate base portion which would reduce rate base by $886,640 and the revenue requirement by $113,000; and reflect the removal of the assets that have been or will be retired as a result of the relocation project.[25] Regarding the first adjustment, OPC argues Pepco failed to clearly demonstrate that the dollars associated with retiring the replaced assets should be included in "Electric Plant in Service" ("EPIS").[26] Regarding the second adjustment, OPC contends that the costs of both the new and old assets being replaced are included in rate base. OPC contends that the Company's filing does not reflect the removal of the replaced assets from rate base.[27]

15. OPC recommends that EPIS and accumulated depreciation be reduced by $1,051,000 to reflect the retirements booked by Pepco and that depreciation expense be reduced by $28,000.[28] OPC contends that it does not have the accumulated depreciation balance for the test year associated with the retired assets, but assumed that the assets were close to fully depreciated. OPC also states that it needs additional information from the Company to determine the full extent of a reduction. Absent the removal from rate base of the assets being retired and removal of the associated depreciation expense, OPC asserts that Pepco's CWIP adjustment associated with Benning Road EPIS and the resulting depreciation expense should be denied.[29] OPC concludes that to include the RWIP depreciation expenditures would result in double recovery.[30]

16. **Pepco Rebuttal.** Pepco agrees with OPC that the retired assets should be removed from rate base.[31] However, Pepco contends that because EPIS and accumulated

22 Pepco (C) at 8-9 (Hook).

23 *Id.* at 8.

24 Pepco (C)-1 at 7 (Hook).

25 OPC (A) at 24-25 (Ramas); OPC Br. 41.

26 *Id.* at 26.

27 *Id.* at 27.

28 OPC R. Br. 72.

29 OPC (A) at 29 (Ramas).

30 OPC Br. 40-41.

31 Pepco (4C) at 9 (Hook Rebuttal).

depreciation will be reduced by the same amount, there is no rate base impact.[32] Therefore, Pepco submits it is proper to increase EPIS by $18.9 million and the reserve by $886,640 because the impact on rate base would be the same.[33] Pepco maintains that the costs are properly included in rate base.

DECISION

17. In response to cross examination by OPC, Pepco later verified in an exhibit filed with the Commission that the RWIP removal costs ($886,640) had been recorded in the test year and should have been removed from rate base.[34] The impact of the correction is reflected in the Company's final proposed revised revenue requirement.[35] OPC's proposed adjustment to remove duplicative removal costs is therefore moot. OPC also contends that the costs of the new assets and the old assets being replaced are included in Pepco's proposed rate base. However, the plant-in-service assets ($1.05 million) have been removed from service and do not impact rate base. Therefore, the additional adjustment proposed by OPC is unnecessary. Finally, OPC's proposed depreciation adjustment ($28,000), which reduces depreciation expense, has been reflected in Pepco's revised revenue requirement.[36] With these changes, the Commission accepts Pepco's adjustment, as amended.

2. 69 kV Overhead Lines

18. **Pepco.** Pepco seeks to recover in rate base the D.C.-allocated portion of the Company's investment in the two temporary 69 kV emergency overhead lines used to provide service to the District of Columbia. Pepco indicates that a segment of the line over the National Park Service's Oxon Cove Park has been removed from service and retired on the Company's books with the remaining portion of the lines de-energized. Pepco represents that the lines were taken out of service in July 2009.[37]

19. **OPC.** OPC contends that Pepco built the two overhead 69 kV lines to provide additional reliability to WASA's Blue Plains Wastewater Plant and that a significant segment of

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32 *Id.* at 10.

33 *Id.*

34 Tr. 1356-1357; *see* Pepco Ex. 50 (filed November 11, 2009).

35 Tr. 907. *See Formal Case No. 1076*, "Revised Revenue Requirement Schedules of OPC's witness Ramas," filed November 20, 2009.

36 Tr. 1242, Pepco Attachment 9 of 34.

37 There is conflicting testimony as to the exact length of the line and the segment removed from service. One Pepco witness testifies that approximately 4,600 feet of the 13,000 feet line was removed, while another states that 4,000 feet of the 16,000 feet line was removed. Pepco (4C) at 2-3 (Hook); OPC Cross Examination Ex. 100; Tr. 1329, 1422.

the lines were "physically removed" and "retired" on the Company's books.[38] Based on these retirements, OPC argues that Pepco's EPIS should be reduced by $2.54 million (D.C.-allocated costs), with a corresponding reduction in depreciation expense of $51,337,[39] and a resulting reduction to the revenue requirement in the amount of $376,000.[40] OPC asserts that the Company has not demonstrated that the lines are abandoned, or that the investment should be included in rate base.[41] To the extent the Commission is inclined to allow rate recovery for the lines, OPC maintains that WASA should be directly assigned the costs.[42] OPC also claims that the dollar value of the portion removed from service should be approximately $1 million, as Pepco witness Gausman testifies, and not $61,529 as proffered by Pepco witness Hook.[43]

20. **Pepco Rebuttal.** Pepco explains that the 69 kV overhead lines were used to provide emergency back-up support for the load supplied by the Potomac River station to the District of Columbia and Blue Plains in case Mirant's Potomac River generating station shut down.[44] The Company acknowledges that a segment of the line which ran over the National Park Service's Oxon Run Park has been removed from service, but maintains that the remainder is available to serve as back-up capacity. Pepco argues that the plans for the lines were approved by the Commission, the costs were prudently incurred, and, therefore, that cost recovery is appropriate.[45]

21. Pepco indicates that, in order to replace dependence on the Mirant Potomac River generating station, two new 230 kV lines were being installed, and, pending installation, the Company needed the two 69 kV overhead lines to ensure public safety, protect the economic viability of the District and avoid a potential environmental failure.[46] Pepco transferred the load from the Potomac River station, which freed up capacity on the existing 230 kV lines to serve other customers within the District of Columbia.[47] Pepco asserts that it proceeded with the work

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38 OPC Br. 24.

39 OPC (A)-15.

40 OPC Br. 33; OPC (A)-3, Summary at 1 of 4.

41 OPC Br. 29

42 *Id.* at. 24, n 58.

43 *Id.* at 33.

44 Pepco (4C) at 2 (Hook Rebuttal).

45 *Id.*, Pepco (3D) at 16 (Gausman Rebuttal)

46 *Id.* at 14-15.

47 Tr. 905-906, 1425. At the time of *Formal Case No. 1044*, Potomac River served approximately 14,927 customers with approximately 11,000 being residential customers. *See Formal Case No. 1044, In the Matter of the Emergency Application of Pepco for a Certificate of Public Convenience and Necessity to Construct Two 69 KV Overhead Transmission Lines and Notice of the Proposed Construction of Two Underground 230 KV Transmission Lines*, Order No. 13895 ("*Formal Case No. 1044*") (March 6, 2006).

based upon Order No. 13895 in Formal Case No. 1044, because neither the Commission nor any other party saw a quick, reasonable alternative to the problem. The issue of cost recovery and allocation was not addressed in Formal Case No. 1044.[48] Pepco acknowledges that the lines are not energized and are not "used and useful" and that the Oxon Run Park section was "physically removed" and retired on the Company records.[49] Pepco contends that the majority of the lines remains available to serve as back-up and can be reconnected, restoring service in five to seven days.[50] Pepco seeks full recovery for the lines, but, in the alternative, proposes that only the retired plant be excluded from rate base.[51]

DECISION

22. We agree with Pepco that its expenditure on the emergency overhead lines was prudent. Without the installation of the 69 kV and 230 kV lines, a major loss of power could have negatively impacted electric service to the District of Columbia and its utility customers.[52] The lines were installed to ensure service reliability in light of the emergency that resulted from the potential closure of Mirant's Potomac River Plant.[53]

23. Pepco, PJM Interconnection, Inc. ("PJM"),[54] and OPC all agreed that the completion of the two 69 kV overhead lines and the two underground 230 kV lines were necessary to ensure service reliability to the areas served by the Potomac River Plant, and they all supported construction of the lines.[55] While acknowledging that Pepco's actions were

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48 Pepco (3D) at 168. (Gausman Rebuttal).

49 Tr. 1328, 1331-1334 (Hooks); Pepco (3D) at 17 (Gausman Rebuttal).

50 Pepco (3D) at 19 (Gausman Rebuttal).

51 Pepco (4C) at 2-3 (Hook). Pepco witnesses have stated two different values for the costs of the retired plant. Pepco witness Hook estimates the total value for retirement purposes to be $61,529, while Pepco witness Gausman estimates the value to be approximately $1million. Tr. 1344.

52 In addition to Blue Plains, affected customers included, among others, all electric customers in Georgetown, Foggy Bottom, major portions of downtown Washington, numerous hospitals, schools, universities, the FBI, the U.S. Justice Department, the U.S. State Department, the Federal Emergency Management Agency, and the U.S. Departments of Interior and Energy. If power was lost, Blue Plains would have had to release raw untreated sewage directly into the Potomac River, which would have a significant adverse impact on the Potomac's ecosystem as well as human health. *See Formal Case No. 1044,* Order No. 13895, ¶ 23. Pepco (3D) at 19 (Gausman); Pepco (4C) at 2 (Hook); Tr. 905-906.

53 *See Formal Case No. 1044*, Order No. 13895.

54 PJM is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia.

55 *Id.*

prudent, OPC opposes cost recovery, arguing that the lines are no longer "used and useful" and that their costs were incurred outside the test year.

24. The Commission finds that cost recovery is warranted here. In fact, the Commission, by Order No. 13895, approved Pepco's application to install the lines.[56] Without the lines, public health and safety, and national security might have been placed at risk. The emergency overhead lines significantly improved Pepco's ability to provide safe and reliable service to District ratepayers. The out-of-period expenditure reflects costs that were justified and adequately supported by Pepco, and is therefore reasonable.

25. Out of test year adjustments have been routinely considered by this Commission on an item-by-item basis.[57] Neither the "out-of-test-year" objection nor the "no-longer-in-service" objection gives appropriate consideration to the emergency situation that was facing the District. Strict adherence to a particular set of general policies should not be pursued to the point where it has a "chilling effect" on the cooperation necessary when emergencies arise. "[T]he Commission may depart from the 'used and useful' standard if it takes into account the extent to which the risk that this particular plant [69 kV overhead lines] would become obsolete was borne by investors in the part and the extent to which they were compensated for it."[58] In this instance, the Commission finds that a balanced decision will serve the best interests of the District of Columbia, Pepco investors, and Pepco ratepayers.[59]

26. Approximately 25 percent of the 69 kV lines have been removed from service; therefore, we will deny Pepco cost recovery for 25 percent of the jurisdictional amount ($2.54 million) that was included in EPIS.[60] Pepco should remove $635,000 from rate base to reflect the full value of the "physically removed" and "retired" segment of the lines. The Commission will allow Pepco to include the remaining amount of the 69 kV lines in rates. To safeguard the safety and reliability of Pepco's distribution system that serves the District of Columbia, the lines will serve as emergency back-up. The Commission is persuaded by Pepco's testimony that it might be "better to leave [the 69 kV overhead lines] up and ready to use again if it were needed, than to tear them down"[61] and that the lines, if needed, could be quickly reconnected.[62] A major

[56] *Id.*, ¶ 25-29.

[57] Earlier case law provides ample precedent for allowing out-of-test-year adjustments, when known and definite deviations from the test year could be calculated with some precision. *See, e.g., OPC v. Pub. Serv. Comm'n,* 610 A.2d 240, 247 (D.C. 1992); *see also, OPC v. Pub. Serv. Comm'n,* No. 08-AA-947 at n. 5 (February 18, 2010).

[58] *See, e.g., Washington Gas Light Co. v. Baker,* 188 F.2d 11, 20 (D.C. Cir. 1951).

[59] "Neither regime [the prudent investment rule or the used and useful rule], mechanically applied with full rigor, will likely achieve justice among the competing interests." *Jersey Central Power & Light v. FERC,* 810 F.2d 1168, 1191 (D.C. Cir. 1987).

[60] Tr. 1329.

[61] Tr. 1337.

outage in the downtown area, where residents, business, essential governmental agencies and hospitals are located, could have catastrophic consequences. It is essential that Pepco be able to bring service back on line in an expedited manner. Pepco shall reclassify the lines in an appropriate account (e.g. "emergency capital spares") consistent with this Order. Pepco shall not remove the remaining portions of the 69 kV overhead lines without first obtaining the explicit prior approval of the Commission.

D. Cash Working Capital (Issue No. 2c)[63]

27. **Pepco.** Pepco proposes to include a $12.194 million cash working capital ("CWC") allowance in rate base based on a net lag of 20.46 days.[64] Pepco represents that the revenue and expense lags used to determine the net lag were taken from the 2005 lead-lag study filed and approved in Formal Case No. 1053. Pepco indicates that CWC was determined by applying Pepco's net lag days to the average daily expense incurred in the test period, to which it made two adjustments. The first adjustment removes $80,873 of District of Columbia-allocated withholding taxes and the second, includes $183,038 for District of Columbia-allocated imprest funds.[65]

28. **OPC.** OPC initially challenged but subsequently concurred with Pepco's CWC calculation.[66]

DECISION

29. The Commission's independent review, finds that Pepco has properly reflected CWC in rate base. The Commission, therefore, accepts Pepco's CWC adjustment.

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62 Pepco (3D) at 19 (Gausman Rebuttal).

63 Issue No. 2c asks, "Is Pepco's proposed cash working capital allowance reasonable?" CWC is the amount of cash required by a utility to operate during the interim between when service is rendered and payment received. It is determined by multiplying the net lag days (difference between the company's revenue and expense lags) by the average daily expense incurred during a test year.

64 Pepco (C) at 19-20 (Hook); Pepco (2C) at 2 (Hook Supp). The revenue and expense lags were determined based on the twelve months ended December 31, 2008.

65 Pepco (C) at 20 (Hook).

66 OPC Br. 43.

E. OPC's Proposed Offset to Rate Base for Ratepayer Funded Reserves

Self-funded Reserve Accruals

30. **OPC.** OPC recommends that the test year average balance of the self-funded reserve accruals for general and auto liability, and the incurred but not reported reserve ("IBNR") for health claims, be reflected as an offset to rate base in recognition that the funds are cost-free capital provided by ratepayers. OPC is concerned with the steady increase in, and size of, the reserve balances. These reserve accruals are included in the cost of service as an expense item.[67] OPC contends that these funds have been collected in advance from ratepayers, have not been paid out in claims and represent ready-available, ratepayer-supplied funds. The funds serve to offset the Company's working capital needs. OPC contends that because of the direct impact of the expense accruals on the reserve balance, it is appropriate to deduct the reserve balance from rate base for each of these non-cash expenses.[68] OPC recommends that the rate base be reduced by $1.34 million for self-funded reserve accruals.[69]

31. OPC also recommends that, in the next base rate case, Pepco be required to provide testimony: (1) describing each of its self-funded reserves; (2) identifying the target reserve balances; (3) explaining how the target reserve balances were determined; and (4) detailing how the expense amounts associated with the reserves were determined.[70]

32. **Pepco Rebuttal.** Pepco testifies that it uses actuaries "in determining the liability balances for workers compensation, long term disability, surviving spouse welfare plan and IBNR."[71] The Company also explains that it uses actuaries to provide a basis for determining probability and estimating accruals for automobile and general liabilities.[72] Following *SFAS* 71 rules, the Company adjusts the self-funded expense accruals and records a regulatory asset for its workers compensation, long term disability, and surviving spouse welfare plan. Pepco represents that historically the Company has included an allowable cost for ratemaking on a pay-as-you-go basis. The difference between the actuarial accrual, as determined by the actuaries, and actual payment is recorded as a regulatory asset.[73]

67 OPC (A) at 18 (Ramas).

68 *Id.* at 19.

69 Tr. 865, OPC Br. 22. Originally OPC had proposed a reduction of $14.45 million.

70 OPC (A) at 21 (Ramas).

71 Pepco (3E) at 5 (White).

72 *Id.* at 5-6.

73 *Id.*

33. Pepco maintains that it follows the guidelines outlined in SFAS 112 and SFAS 5.[74] The expense is based on probable and estimated liabilities and does not have a component for building and maintaining a reserve.[75] Pepco explains that the amount expensed pursuant to General Accepted Accounting Principles ("GAAP") is based upon estimates of future payments. The Company's rates have historically reflected pay-outs for the items included in self-funded accruals, and the difference between accruals and pay-as-you-go is included in the regulatory asset.[76] Pepco states that the amount included in Pepco's expense for cost of service purposes for worker's compensation, long-term disability, and surviving spouse welfare plan does not include a component associated with building up and maintaining the reserve balance. Further, Pepco contends that neither the liabilities nor the regulatory asset associated with it are included in rate base.[77]

DECISION

34. The Commission has reviewed OPC's proposed adjustment, Pepco's response thereto, and the historical treatment of these self-funded reserve accruals. We are not persuaded that the self-funded reserve accruals should be adjusted and, therefore, OPC's proposed adjustment is denied. The Commission is satisfied that Pepco is following GAAP to estimate the expense for the various welfare plans and is recording the reserves properly.

IV. TEST YEAR SALES AND REVENUES (ISSUE No. 3)[78]

A. Weather Normalization of Sales and Revenues[79]

35. **Pepco.** Pepco proposes to reduce test year revenues by $2.065 million (RMA No. 1).[80] Pepco calculates weather-corrected sales and revenues using a 30-year average (1978-2007) in accordance with Order No. 10646.[81] Pepco indicates that to obtain weather corrected sales

[74] Pepco (3E) at 3-5 (White Rebuttal). SFAS 112 requires companies to accrue a liability for employee future absences when attributable to employee services already rendered. SFAS 5 requires an estimated loss be accrued by a charge to income if it is probable that an asset has been impaired or a liability incurred and the loss can be reasonable estimated.

[75] *Id.* at 5, Pepco R. Br. 8.

[76] Pepco (4C) at 8 (Hook Rebuttal).

[77] *Id.* at 8-9.

[78] Designated Issue No. 3 asks, "Are Pepco's test year-sales and revenues appropriate?"

[79] Designated Issue No. 3a asks, "Has Pepco properly weather-normalized its sales and revenue?"

[80] Pepco (F) at 20-21 (Browning), Pepco (2F) at 3 (Browning Supp). Pepco had proposed a $2.196 million adjustment. However, in the November 20, 2009, filing, the update to the Company's revenue requirement model indicates an adjustment of $2.065 million.

[81] *See Formal Case No. 939*, Order No. 10646 (June 30, 1995).

and revenues, it ran regression analyses on daily degree day weather and daily sales to relate energy usage to heating degree days (HDD) and cooling degree days ("CDD").[82] For the summer months, Pepco used a 65 degree base (65°F) and for winter months, both a 35 and a 65 degree (35° and 65°) base. The heating season covers October through March; while the cooling season includes May through October.[83] Pepco states that the weather coefficients developed for each class estimated the weather sensitivity of each class and were applied to the degree day differences from the 30-year average to develop the amount of kWh weather adjustment for the twelve months ending December 2008.[84]

36. **OPC.** OPC proposes to decrease test year revenues by $576,956.[85] OPC contends that Pepco should have used the most recent National Oceanographic and Atmospheric Administration ("NOAA") 30-year normal heating and cooling degree days (1971-2000). Further, OPC contends that Pepco improperly uses two balance points (65°F and 35°F) without providing justification, and uses a time period that is too short to capture changes in temperature and usage patterns.[86]

37. OPC claims that its weather normalization adjustment is more appropriate because, among other things, it: (1) uses Pepco's daily temperature and retail sales data for the period 2005-2008 (which better captures the relationship between consumption and temperature); (2) uses the industry accepted single 65°F balance point,[87] and (3) reflects 1971-2000 30-year normal heating and cooling degree days. OPC argues the use of less than one year of data fails to accurately capture the relationship between electric consumption and temperature. OPC recommends that Pepco's sales revenues be adjusted by approximately $1.62 million.[88]

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82 Pepco (F) at 20 (Browning).

83 *See Formal Case No. 1053, In the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service,* ("*Formal Case No. 1053*") Order No. 14712, ¶ 143. The Commission found Pepco's heating and cooling seasons reasonably designated.

84 Pepco (F) at 20. (Browning); *see also* Pepco (F)-4, -5 and -6 (Updated).

85 OPC (A) at 33 (Ramas).

86 OPC (D) at 5-6, 13 (Mariam); OPC Br. 44. Balance point temperature refers to a point at which no additional heating or cooling is required when outdoor temperatures are higher or less than the balance point, respectively.

87 OPC Br. 49. OPC also states it prefers to include additional appropriately chosen balance point temperatures in order to capture the non-linear relationship between energy consumption and temperature. OPC (D) at 8, n.4. (Mariam).

88 OPC (D) at 18 (Mariam).

38. **Pepco Rebuttal.** Pepco states that NOAA publishes new 30-year normal weather data only once a decade and that NOAA, citing climate change (warming trend), is developing alternatives to the 30-year normal temperatures.[89] Pepco argues that it uses the 35 degree threshold as a variable because the engineering characteristics of electric heat pumps, a major heating technology, imply an inflection point in the relationship between temperature and electricity use. Moreover, regression statistics support its use in many of the rate cases studied.[90] Pepco argues that OPC's approach, among other things, blends data from several years and mixes the heating and cooling seasons, which can muddy the estimation of the relationship between weather and usage.[91]

DECISION

39. The Commission, in past rate proceedings, determined that it would review the issue of weather normalization on a case-by-case basis.[92] Regarding the data to be used to calculate normalization, the Commission determined that "[t]he appropriate data set for a method that uses daily sales and weather shall encompass the most recent twelve-month period."[93] The Commission also determined that "the use of a 30-year period to determine average or normal weather was appropriate."[94] Here, as in prior proceedings, the Commission is interested in the continual refinement and improvement of the analyses that goes into determining normal weather.

40. OPC challenges Pepco's selection of a 30-year period (1978-2007) to determine normal weather. OPC proposes that end of the decade data published by the NOAA, following standards established by the World Meteorological Organization ("WMO"), be used to determine the thirty-year period. However, using the 30-year period (1971-2000) suggested by OPC would lead to weather normals that drop 10 years of data at a time as a result of moving from one decade to the next. For example, during 2011, the WMO normal will change from 1971-2000 to 1981-2010, effectively dropping ten years of data (1971-1980) at one time. By contrast, if the Company were to file a rate case in 2011, its methodology would move the period from 1978-2007 to 1980-2009, thus dropping only two years of data (1978-1979). This is consistent with the Commission's desire for more recent and stable data.

89 Pepco (3F) at 5-6 (Browning Rebuttal).

90 *Id.* at 6-7.

91 *Id.* at 7-8.

92 *Formal Case No. 939*, Order No. 10646 at 73 (June 30, 1995), citing *Formal Case No. 929*, Order No. 10387 at 76.

93 *Id.* at 73.

94 *Id.* at 75.

41. The Commission also finds that Pepco's use of two balance points (65 and 35 degrees) is consistent with what we have permitted in the past.[95] OPC's own witness has recommended multiple balance points in other proceedings.[96] The Commission finds that Pepco has established that the 35 degree threshold as a variable is reasonable because of the engineering characteristics of electric heat pumps. Moreover, regression statistics support its use.[97]

42. Last, the Commission's stated preference is for daily sales and weather that encompass the most recent twelve-month period.[98] OPC has not shown that the use of a 12-month period is too short to capture changes in temperature and usage pattern. OPC has not convincingly shown why the Commission should depart from this established precedent. The methodology used by the Company is reasonable and consistent with our past orders. Therefore, we accept the revenue adjustment as proposed by Pepco. This weather normalization adjustment will reduce test year revenues by $2.065 million.

V. RATE OF RETURN/COST OF CAPITAL (Issue No. 4)[99]

43. As in all base rate proceedings, the Commission must determine a reasonable rate of return including capital costs and the appropriate capital structure for Pepco. We need not discuss in great detail the legal standards and guidelines governing our responsibility to determine a fair and reasonable rate of return and the purpose of that determination. Our continuing basic reliance on *Washington Gas Light Co. v. Public Service Commission,* 450 A.2d 1187 at 1209-1215 (D.C. 1982) (review of Formal Case No. 686) is amply described in many of our discussions of rate of return in rate cases. In this decision also we will adhere to the standards derived from the Supreme Court's decisions in *Bluefield* and *Hope,*[100] as set forth in *Washington Gas Light Co. supra.*

44. With these standards forming the backdrop for our consideration of Issue No. 4, we turn to its various components and the evidence presented on the record of this proceeding by the parties.

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95 *Id.* at 72.

96 Tr. 1021.

97 Pepco (3F) at 6-7 (Browning Rebuttal).

98 Order No. 10387 at 73.

99 Designated Issue No. 4 asks, "Are Pepco's requested cost of capital and capital structure reasonable?"

100 *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923); *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 590 (1944).

a. Overall Cost of Capital

45. The overall costs of capital recommended by the parties to this proceeding are as follows:

Pepco.

Capitalization	Ratio	Cost Rates	Return
Long-Term Debt	53.82%	6.63%	3.57%
Common Equity	46.18	10.75%	4.96
	100.00%		8.53%

OPC.

Capitalization	Ratio	Cost Rates	Return
Short-Term Debt	4.30%	1.35%	0.06%
Long-Term Debt	51.51	6.63	3.41
Common Equity	44.20	9.00	3.98
	100.00%		7.45%

AOBA.

Capitalization	Ratio	Cost Rates	Return
Long-Term Debt	56.00%	6.11%	3.42%
Common Equity	44.00	9.40	4.14
	100.00%		7.56 %

b. Cost of Common Equity (Issue No. 4a)[101]

46. **Pepco.** Pepco recommends a return on equity ("ROE") of 10.75 percent, including a Bill Stabilization Adjustment ("BSA"), discussed below.[102] Initially Pepco recommended an ROE of 11.25 percent, with the BSA adjustment. However, during the hearings, Pepco revised its recommended ROE to reflect the improvement in financial conditions and the abatement of the financial crisis.[103] Pepco's revised ROE is based on a cost of equity range of 10.75 to 11.25 percent, without a BSA adjustment and without any adjustment to reflect

101 Designated Issue No. 4a asks, "What cost of common equity should Pepco be allowed to earn?"

102 Tr. 239-243.

103 Tr. 239. Although Dr. Morin updated his DCF, CAPM, and Risk Premium calculations during the hearing to reflect changes in market conditions, he did not update the analyses he provided as support for his returns on equity.

Pepco's proposed surcharge related to pension, other post-employment benefit ("OPEB"), and uncollectible expenses (the Company's surcharge/deferral mechanism), discussed below.

47. Pepco Witness Kamerick testifies that the Company's proposed ROE is the minimum necessary for the Company to attract capital on reasonable terms in the current capital markets.[104] Witness Morin originally testified that capital markets were in a state of turmoil, extremely volatile and unpredictable,[105] but appeared to be improving.[106] During the hearings, he revised his recommended ROE downward, stating that the "financial crisis has abated, and there had been some significant improvements in the capital markets and stability."[107]

48. To determine the cost of common equity, witness Morin employs three market-based methods: the Capital Asset Pricing Model ("CAPM"), Risk Premium, and Discounted Cash Flow ("DCF") methods. He contends that reliance on a single methodology or preset formula would be inappropriate when dealing with investor expectations because of possible measurement errors and vagaries in individual companies' market data. Dr. Morin uses two proxy groups in his analyses: investment-grade dividend-paying combination electric and gas utilities from AUS Utility Reports (Pepco's Combination Utility Group),[108] and electric utilities in the S&P Electric Utility Index.[109]

CAPM

49. According to witness Morin, the CAPM approach to estimating the cost of common equity is a form of risk premium analysis that is based on the principle that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk. The CAPM provides a formal risk-return relationship anchored on the basic idea that only market risk matters. Market risk is measured by a firm's "beta."[110] The return expected by investors is equal to the risk-free

104 Pepco (A) at 13 (Kamerick).

105 Pepco (B) at 5 (Morin).

106 Tr. 239.

107 Tr. 239-242.

108 These companies allegedly possess large amounts of energy distribution assets, are investment grade, pay dividends, have a market capitalization of more than $500 million, and derive more than 50% of their revenues from regulated utility operations. *See* Pepco (B)-7.

109 Pepco (B) at 57-58 (Morin).

110 *Id.* at 25. Beta is a measure of the volatility, or systematic risk, of a stock or a portfolio in comparison to the market as a whole. A beta of 1 indicates that the stock's price will move with the market. A beta of less than 1 means that the stock will be less volatile than the market. A beta of greater than 1 indicates that the stock's price will be more volatile than the market. Many utilities stocks have a beta of less than 1.

rate (witness Morin uses the current interest rate on 30-year Treasury bond) plus the risk premium. In his analysis, Dr. Morin relies on average betas for his proxy groups and forward-looking and historical studies of long-term risk premiums.[111] Witness Morin also uses an empirical version of CAPM ("ECAPM") because, he contends, CAPM-based estimates of the cost of capital underestimate the return required from low-beta securities and overstate the return required from high-beta securities.[112]

Risk Premium

50. In his historical risk premium analysis, witness Morin estimates the cost of common equity by comparing returns earned by the Standard & Poor's Utility Index and the yield on A-rated utility bonds. Morin states that an historical risk premium was estimated based on an annual time series analysis applied to the utility industry as a whole over a 1930-2007 period. The risk premium is calculated by computing the actual realized return on equity for the S&P Utility Index for each year, using the actual stock prices and dividends of the index, and then subtracting the utility bond return for that year. Dr. Morin then added the average risk premium for the 1930-2007 period to the current risk-free interest rate.[113] Dr. Morin believes that, in the current financial markets, it is more appropriate to use utility bond yields as opposed to government bond yields, as he has previously, because the trends in utility cost of capital are directly reflected in the cost of debt and not by a risk premium estimate tied to government bonds.[114]

Discounted Cash Flow

51. Dr. Morin's DCF analysis is based on the proposition that the value of any security to an investor is the expected discounted value of the future stream of dividends or other benefits.[115] According to Dr. Morin, the standard DCF model assumes a constant average growth trend for both dividends and earnings, a stable dividend payout policy, a discount rate in excess of the expected growth rate, and a constant price-earnings multiple, which implies that growth in price is synonymous with growth in earnings and dividends. It also assumes that dividends are paid at the end of the year, when in fact, dividends are paid on a quarterly basis.[116]

52. As proxies for the expected dividend growth component of the DCF model, witness Morin uses the consensus growth estimates developed by Zacks Investment Research,

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111 *Id.* at 31.

112 *Id.* at 36-40.

113 *Id.* at 44.

114 *Id.* at 43-46.

115 *Id.* at 48.

116 *Id.* at 50.

Inc. ("Zacks") and Value Line. Morin rejects the uses of historical growth rates to estimate expected future growth because several electric utility companies have experienced negative growth rates, and, he believes, historical growth rates have little relevance as proxies for future long-term growth. Witness Morin also rejects OPC's use of the sustainable growth/retention growth method of estimating future growth because, he testifies, this approach assumes that the ROE is constant over time and no new common stock is issued (and, if so, at book value), the method requires an estimated ROE, and this method is not as significantly correlated to measures of value (such as stock prices and price-earnings ratios) as analysts' forecasts.[117]

53. Dr. Morin rejects the use of dividend growth estimates in DCF analysis, because some utilities will continue to lower their dividend payout ratios and so their dividend growth rates are not likely to provide a meaningful guide to investors' growth expectations. Investors, he contends, are more focused on earnings, and earnings growth provides a more meaningful guide to investors' long-term growth expectations. Growth in earnings will support future dividends and share prices. Moreover, dividend growth forecasts are not readily available.[118] In his DCF studies, Dr. Morin increases the current dividend used in calculating the dividend yield component of the DCF model by the expected growth rate, to adjust for the quarterly payment of dividends.[119]

54. Dr. Morin argues that investors must be compensated for flotation costs on an ongoing basis, to the extent that such costs have not been expensed in the past, in order for investors to have the opportunity to earn the ROE set by the Commission. He includes a floatation cost adjustment in his estimates of the cost of common equity.[120]

55. Dr. Morin's revised cost of equity results, including floatation costs are:[121]

Study	ROE
CAPM	9.4%
Empirical CAPM	9.8
Historical Risk Premium	10.9
DCF Combo. Elec. & Gas Utilities –Value Line Growth	11.6
DCF Combo. Elec. & Gas Utilities – Zacks Growth	10.4
DCF S&P Electric Utilities - Value Line Growth	11.2
DCF S&P Electric Utilities – Zacks Growth	11.4

117 *Id.* at 51-54.

118 *Id.* at 55-56.

119 *Id.* at 49-50.

120 *Id.* at 62-67.

121 Pepco witness Morin updated his analysis in light of the changes in market conditions. Tr. 239-243.

56. Based on his revised data, Dr. Morin's range for Pepco's ROE, including floatation costs, is from 10.75 percent to 11.00 percent.[122] As discussed below, with the BSA, Dr. Morin contends Pepco's risk will be reduced and the cost of common equity lowered by some 25 basis points. With a BSA adjustment, his recommended ROE is 10.75 percent.[123] He recommends no surcharge/deferral adjustment.

57. **OPC.** OPC proposes a cost of equity of 9.0 percent for Pepco, with a BSA adjustment and no adjustment to reflect Pepco's surcharge/deferral mechanism. This is a revision of Dr. Woolridge's recommended cost of equity incorporated in the testimony of OPC witness Ramas, which reflects OPC's changed position on the appropriate BSA adjustment.[124] OPC witness Woolridge states that the worst of the credit crisis appears to be over.[125]

58. OPC, like Pepco, utilizes the DCF and CAPM approaches in estimating the cost of common equity.[126] However, OPC witness Woolridge relies primarily on the DCF approach. He employs two proxy groups – his own group of electric companies ("OPC's Electric Group") and Dr. Morin's S&P Electric Group.[127] Dr. Woolridge argues that, based on various financial metrics, Pepco's electric group is slightly riskier than OPC's.[128]

DCF

59. OPC criticizes Dr. Morin's DCF analysis on three bases: dividend yield adjustment, use of the forecasted EPS growth rates from Zacks and Value Line (to estimate the growth rate to be used in the DCF model), and his floatation cost adjustment. Woolridge argues that witness Morin's quarterly timing adjustment to the dividend yield component of the DCF model overstates the equity cost rate. Dr. Morin's approach presumes that investors require additional compensation because their dividends are paid out quarterly instead of in one lump sum. For the dividend yield component of the DCF model, OPC adjusts the dividend yield by one-half (½) the expected growth rate to reflect the growth over the coming year.[129]

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122 Tr. 241.

123 Pepco states that, should the Commission decide to deviate from the capital structure, with each reduction in common equity ratio of 1%, the return on equity would increase by approximately 10 basis points.

124 Tr. 865-866.

125 OPC (B) at 12 (Woolridge).

126 OPC (B) at 25 (Woolridge). OPC primarily relies on the DCF model and gives little weight to the results obtained using the CAPM. Pepco utilized the ECAPM and Risk Premium approaches as well.

127 *Id.* at 14-15. *See* OPC (B)-4.

128 *Id.*

129 OPC (B) at 31 (Woolridge).

60. Dr. Woolridge states that the primary difficulty with the DCF model is estimating expected dividend growth rates. For the dividend growth rate component of the DCF model, OPC contends investors use a combination of historical and projected growth rates for earnings per share ("EPS"), dividends per share ("DPS"), and internal (retention rate) or book value per share growth ("BVPS") to assess long-term potential.[130] To obtain the appropriate growth rate, OPC indicates that it reviewed Value Line's historical and projected growth rate estimates for EPS, DPS, and BVPS. It also utilizes the average EPS growth rate forecasts of Wall Street analysts as provided by Yahoo First Call, Zacks, and Reuters. Nevertheless, OPC contends that Wall Street analysts' EPS growth forecasts are overly optimistic and upwardly biased. Thus, OPC contends that using these growth rates exclusively as a means of estimating a DCF growth rate will overstate the equity cost rate.[131] Based on his analysis, Dr. Woolridge contends that the DCF-based cost of common equity is 9.8 percent for OPC's Electric Group and 10.6 percent for Pepco's S&P Electric Group.

CAPM

61. OPC alleges that there are two flaws in Pepco witness Morin's CAPM analysis: the equity risk premium and his use of the ECAPM approach. In regard to the equity risk premium relied on by Pepco, Dr. Woolridge contends that the Ibbotson's historical returns, relied on by Pepco, are poor measures of the expected market risk premium. According to OPC, leading financial practitioners conclude that the financial crisis has not significantly changed the long-term estimates of the equity risk premium, which is in the 3.5 to 4.0 percent range.[132] Past market conditions do not give a realistic or accurate reading of the expectations of the future.[133] According to OPC, historical bond returns are biased downward because of the past losses suffered by bondholders. Also, because Pepco's study covers more than one period and makes the assumption that dividends are reinvested, the use of geometric means, instead of the arithmetic means used by Dr. Morin, better captures investment performance. OPC contends that the upward bias of the arithmetic means overstates the return experienced by investors.[134]

62. According to Dr. Woolridge, Dr. Morin's use of the ECAPM is inappropriate because Dr. Morin uses Value Line betas in his CAPM, and those betas are adjusted to reflect the fact that, historically, betas tend to regress toward 1.0 over time. Using adjusted betas increases the return for stocks with betas less than 1.0, and decreases the returns for stocks with a beta greater than 1.0. Suggesting that the ECAPM accomplishes the same thing, Dr. Woolridge testifies that Dr. Morin's ECAPM approach makes "two adjustments to the expected return."[135]

130 *Id.*

131 *Id.* at 33, 77 -78.

132 *Id.* at 49. Tr. 223- 224.

133 *Id.* at 58.

134 *Id.* at 59.

135 *Id.* at 66.

63. OPC states that its CAPM analysis relies on three procedures (historic returns, surveys, and expected return models) to arrive at its equity risk premium. OPC maintains that its equity risk premium is consistent with the risk premium found in recent academic studies by leading financial scholars, and employed by leading investment banks and management consulting firms. OPC uses the yield on 30-year U.S Treasury bonds as the risk-free rate of interest in the CAPM. It relies on average betas, as provided by Value Line, for OPC's Electric Proxy Group and Pepco's S&P Electric Group.[136] In estimating the equity risk premium, OPC is not convinced that using historical stock and bond returns to measure the market's future expected return is appropriate. First, historical returns are not the same as forward looking expected returns. Secondly, market risk premiums can change over time. Lastly, market conditions can change such that historical returns are a poor indication of future expected returns.[137] According to Dr. Woolridge, the equity cost rates indicated by the CAPM are 7.5 percent for OPC's Electric Group and 7.8 percent for Pepco's S&P Electric Group.[138]

Risk Premium

64. OPC maintains that Pepco's risk premium analysis includes an "inflated based interest rate" and an excessive risk premium which is based on the historical relationship between stock and bond returns.[139] OPC concludes that the appropriate equity cost rate for Pepco is in the range of 7.5 percent to 10.6 percent, with a midpoint of 9.1 percent. OPC believes this wide range reflects the uncertainty and volatility in the capital markets and that, in recognition of this volatility and uncertainty, an equity cost rate at the upper end of that range is appropriate. Further, OPC believes that it is appropriate to give primary weight to OPC's Electric Group results. Therefore, OPC recommends an equity cost range of 9.50 percent to 10.0 percent, with a midpoint of 9.75 percent. Within this range, Dr. Woolridge proposes an ROE of 9.50 percent, which reflects a 25 basis point reduction for Pepco's poor service and system reliability.[140] When the BSA adjustment is included, OPC's recommended ROE is 9.25 percent. This ROE does not include OPC's recommended surcharge/deferral adjustment. During the hearings, OPC witness Ramas adopted the 50 basis point BSA adjustment determined by the Commission in Formal Case No. 1053, Phase II, producing an OPC-recommended ROE of 9.00 percent.[141]

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136 *Id.* at 40, OPC (B)-11 at 3.

137 *Id.* at 41.

138 *Id.* at 51.

139 *Id.* at 69.

140 *Id.* at 52.

141 Tr. 865-866.

65. **AOBA.** AOBA argues that the ROE Pepco requests substantially overstates current market requirements and contends that investors have experienced significant declines in returns since the last rate case. Additionally, AOBA asserts that Pepco does not appropriately account for the influence of non-utility risks and returns on holding company financial results. According to AOBA, Dr. Morin's results reflect a significant upward ROE bias as a result of his use of comparables and industry groups without risk profiles comparable to that of Pepco's. The data used by Dr. Morin are for the parent holding companies, many of which have substantial investments in generation assets and/or are significantly diversified and, therefore, face much greater risk than Pepco.[142] According to AOBA, of the 27 companies included in Pepco's Electric Group, 15 are assessed by Edison Electric Institute as having either 20 percent to 50 percent unregulated activities or greater than 50 percent unregulated activities. AOBA avers that Pepco's Electric Group of electric companies includes some of the largest generation portfolios in the U.S. and Pepco's "combined gas and electric companies" group is likewise heavily influenced by substantial generation ownership and diversified operations.[143]

66. Witness Oliver states that the bias found in Pepco's DCF analyses also is found in its CAPM and risk premium analyses. As in his DCF analysis, Morin's risk premium does not differentiate between electric distribution utilities and electric utilities holding substantial generation portfolios or utility holding companies that have significant non-regulated activities. It makes no attempt to account for biases that are introduced as a result of reliance on electric utility stock price data that incorporate information for generation activities and non-regulated activities. Last, he fails to account for, or make any adjustment to reflect, the influence of changes in the composition of the industry over time, including industry consolidation and diversification experienced over the last two decades.[144] According to AOBA, the standard deviations associated with Pepco's annual risk premium estimates are roughly three to four times the magnitude of witness Morin's computed average for those risk premiums. The comparatively large standard deviations render Pepco's computed equity risk premiums, at best, very poor and unreliable indicators of future equity risk premiums.[145]

67. Further, AOBA contends Morin's CAPM and ECAPM are biased because the proxy group he employs to estimate a beta for Pepco includes PHI as well as a number of large utility holding companies.[146]

68. Witness Oliver recommends an ROE of not greater than 9.9 percent, including floatation costs. He considers his own DCF analyses; witness Morin's CAPM, ECAPM, and historical risk premium analyses, which he gives little weight; and the ROEs allowed in other

[142] AOBA (A) at 16-19 (Oliver).

[143] *Id.* at 19-22.

[144] *Id.* at 23-24.

[145] *Id.* at 25.

[146] *Id.* at 27-28.

electric utility rate proceedings in 2008 and the first half of 2009. Witness Oliver uses two proxy groups in his DCF analysis, one a group having substantial electric distribution operations and the other a group of gas distribution utilities. In his DCF studies, witness Oliver relies on projected earnings growth rates from Thompson Financial Network and Zacks Investment Research to estimate expected future growth.[147] Witness Oliver averages the composite of his DCF results for gas and electric utilities with his computed average of recent commission ROE determinations for electric utilities.[148] This results in an ROE of 9.9 percent, before any BSA or surcharge/deferral adjustments. With a BSA adjustment, AOBA recommends an ROE of 9.4 percent.[149]

69. **WMATA.** Dr. Foster contends that the Commission should "keep Pepco's ROE at the current authorized level (10 percent before the BSA adjustment) if there is no BSA or Rider VM (surcharge/deferral mechanism)."[150] Dr. Foster states that he reviewed 126 cases that involved electric utilities and natural gas companies for the period 2007-2009. The average allowed return over the three year period was 10.34 percent. Dr. Foster maintains that Pepco is less risky than most of the utilities in the group he analyzed because, unlike Pepco, the electric companies in the group have extensive generation and, therefore, face more risk due to competition.[151] Further, Dr. Foster believes PEPCO faces less risk than other utilities because: (1) natural gas utilities face greater business risk than electric distribution companies; (2) PEPCO's customer profile is less risky than that of other utilities, and its service territory is more affluent; and (3) the Washington Metropolitan Area has a stronger economy than the U.S. as a whole.[152]

147 *Id.* at 28-29. AOBA (A)-1.

148 During the hearing, Pepco witness Morin attempted to update AOBA witness Oliver's ROE testimony. Having reviewed the exhibits, it is apparent that Pepco is seeking to introduce new testimony that will enhance its case without the data's undergoing appropriate scrutiny. Although Pepco contends that the testimony and evidence address witness Oliver's direct testimony, the testimony is nevertheless new. The cost of capital, and in particular the return on equity, is an important component in rate proceedings, requiring careful and fair consideration and weighing of the evidence. Fairness requires that the parties be given an opportunity to examine the new data and to challenge it, if they so desire. The parties were not afforded that opportunity. Procedural due process outweighs any probative value the testimony might possess. The scope of rebuttal is within the discretion of the Commission. The Commission hereby grants AOBA's motion to exclude Pepco Cross Examination Exhibit Nos. 11, 12, and 13 and to correct the transcript to show that these exhibits were never formally admitted into evidence.

149 *Id.* at 29 -30.

150 WMATA (A) at 4 (Foster).

151 *Id.* at 6-9.

152 *Id.* at 5-6.

DECISION

70. In its decisions, the Commission has relied primarily on the DCF method to determine a utility's cost of common equity because the Commission consistently has found that the DCF method produces more reasonable results than those of other calculation methods. Nevertheless, the Commission's preference for the DCF method does not preclude consideration of other methods for calculating the cost of equity. The Commission has taken into account the results of the various approaches (DCF, CAPM, and Risk Premium) in estimating the ROE in this proceeding. The Commission, however, will focus on the DCF model (relying primarily on forecasted growth rates) to determine the appropriate ROE.

71. In the application of the DCF model, the Commission implicitly has given considerable weight to forecasted earnings growth rates (estimates of earnings growth over the next approximately five years) in the recent past, as opposed to historical growth rates in earnings, dividends, and book value and retention growth rates. Although the expected dividend growth rate is one of the components of the DCF model, earnings growth rates often are used as a proxy. Arguably, based on the uncertainty and volatility in this economy, the forecasted earnings growth rates may overstate the long-term expected dividend growth rate to be used in the DCF model at this time, since, if earnings are unusually low when the estimates are made, this would produce unusually high estimates of expected growth in the roughly 5-year period covered by projected rates. However, some of this effect is captured in Pepco's updated ROE estimate.

72. Pepco recommends a ROE of 10.75 percent including a flotation adjustment, which, according to Pepco witness Morin, represents approximately 30 basis points. The Commission traditionally excludes floatation costs from its ROE calculation, since floatation costs are treated as an expense item. Pepco's proposed 10.75 percent ROE also reflects its BSA adjustment. This recommendation is based on a range of reasonable returns of 10.75 to 11.00 percent, before any BSA or surcharge/deferral adjustments. In other words, to incorporate its BSA adjustment, Pepco adopted the lower end of its range of reasonable returns. Further, historically, in its application of the DCF model, the Commission has projected the dividend yield component of the DCF model forward by one-half the expected growth rate, rather than the growth rate which is Pepco's approach. Pepco alleges that using one-half the growth rate understates the dividend yield by 10 basis points.[153] Finally, in Formal Case No. 1053, the Commission concluded that Pepco's ROE results for its electric proxy group overstated Pepco's required return on its distribution operations due to the inclusion of companies that have risk profiles different from that of Pepco, i.e., the inclusion of companies with greater risk due to generation and unregulated operations. The Commission continues to believe that this is a consideration in estimating Pepco's ROE.[154]

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153 Pepco (3B) at 13 (Morin).

154 Order No. 14712, ¶ 33.

73. OPC recommends a ROE of 9.50 percent, before BSA or surcharge/deferral adjustment, but including a 25 basis point reduction adjustment for poor performance. In that the Commission has deferred the issue of the reliability of service to another docket, it would be inappropriate to adjust the Company's ROE for reasons of poor performance when reliability is not an issue for determination in this proceeding.[155] Without this adjustment, OPC's ROE figure is 9.75 percent. Additionally, OPC's recommendation understates the return required by investors because of its partial reliance on historical growth rates to estimate expected future growth. OPC's Exhibit B-10 (at page 3) shows that the historic returns relied on by OPC include numerous negative growth rates which most likely do not reflect investor's expectations going forward. With its revised BSA adjustment of 50 basis points, OPC recommends an ROE of 9.00 percent.

74. AOBA's recommended ROE, without a BSA adjustment, is 9.9 percent. This ROE is based in part on returns allowed in other jurisdictions in 2008 and the first half of 2009, 10.37 percent. As for WMATA, it simply states that the risks of providing transmission and distribution service have not increased since the Commission's decision in F.C. No. 1053, and the starting point for the ROE allowed in this proceeding should be the 10.0 percent ROE (without a BSA adjustment) allowed in that proceeding. With its recommended BSA adjustment of 50 basis points, AOBA's proposed ROE is 9.5 percent.

75. The Commission finds that the parties' recommendations establish parameters that, when narrowed by the considerations above, support our informed determination that a reasonable range for Pepco's allowed ROE is 10.0 percent to 10.25 percent. Based on this range, the Commission finds that an ROE of 10.125 percent, before BSA or surcharge/deferral adjustment, is appropriate at this time. This allowed return on common equity reflects the interests of the community and the Company in the receipt and provision of safe and dependable electric distribution service at reasonable rates. Moreover, it will allow Pepco to raise capital on reasonable terms.

76. As discussed below, the Commission adopts a BSA adjustment of 50 basis points in this proceeding and does not adopt the Company's proposed surcharge/deferral mechanism. When the 50 basis point BSA adjustment is included, Pepco's allowed return on common equity capital is 9.625 percent.

c. Cost of Debt (Issue No. 4b)[156]

77. **Pepco.** Pepco calculates its cost of long-term debt to be 6.63 percent.[157] This cost rate was obtained by examining Company-specific contractual interest payments. Dr. Morin

155 *Formal Case No. 1076*, Order No. 15322, ¶ 8 (July 10, 2009).

156 Issue No. 4b asks, "Has PEPCO properly determined its cost of debt?"

157 Pepco (B)-18 (Morin).

contends that Pepco's calculation methods are consistent with the methods approved in previous rate proceedings.[158]

78. **OPC.** OPC adopts Pepco's long-term debt cost rate of 6.63 percent. OPC, in addition, calculates a short-term debt rate by adding the average yield on 1-month, 3-month, and 12-month LIBOR rates in 2009 of 1.0 percent plus an additional 35 basis points,[159] for a cost rate of 1.35 percent.[160]

79. **AOBA.** AOBA witness Oliver challenges Pepco's cost of debt on two grounds. First, he states, Pepco's calculation includes a computational error which overstates the cost of debt. He contends that Dr. Morin incorrectly subtracted the Unamortized Loss on Debt Reacquisition from the Company's Long-Term Debt balance when he should have added it. If Dr. Morin had added, the cost of debt would be 6.30 percent, not 6.63 percent, he states. Second, according to AOBA, the Company's issuance of $250 million of first mortgage bonds in December 2008 was imprudent because the cost rate is 140 basis points greater than that of any of Pepco's other bonds. Further, the need for the issuance did not emanate from the financing requirements of the Company's distribution operations, and the issuance should have been deferred. The need for the funding was related to the Mid-Atlantic Power Pathway ("MAPP") project. AOBA recommends that Pepco's cost of long-term debt be set at 6.11 percent.[161]

80. **Pepco Rebuttal.** Regarding the treatment of the Company's Unamortized Loss on Debt Reacquisition costs, Pepco witness Kamerick argues that Pepco witness Morin did add this amount to the Company's Long-Term Debt balance; it was AOBA who subtracted. He states that the Net Outstanding Long-Term Debt balance of $1.54 billion is a liability, a credit balance, while the Unamortized Loss on Debt Reacquisition of $38.89 million is a debit on the balance sheet. Adding the two items together results in a net credit balance of $1.50 billion.[162]

81. Regarding the Company's first mortgage bonds issued in December 2008, Pepco contends that market conditions warranted the issuance of long-term debt at that time; short-term credit was tight; banks and other liquidity-constrained companies were being downgraded; commercial paper market was severely constrained; and Pepco could not issue commercial paper. Pepco also contends that the duration and the severity of the liquidity crisis were unknown, and the Company did not know if it could secure financing in 2009. Because the outlook for the capital markets was highly uncertain, Pepco made the decision to pre-fund its anticipated 2009 funding needs when the markets allowed, in December 2008. Contrary to

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158 Pepco (2B) at 2 (Morin Supp).

159 OPC alleges that Pepco was borrowing from its credit facility at 35 basis points above the applicable interest rate. OPC Br. 54.

160 OPC (B) at 17 (Woolridge).

161 AOBA (A) at 37-41 (Oliver).

162 Pepco (3A) at 12 (Kamerick).

AOBA's contention, Pepco submits that funding for the MAPP project was $56 million, or only 8 percent of Pepco's construction budget for 2009 of $727.0 million.[163]

DECISION

82. The Commission traditionally has adopted a cost of debt that is reasonable and accurately reflects the Company's costs. Pepco has presented evidence that its current cost of long-term debt of 6.63 percent is both. OPC adopts this rate. While, AOBA argues that Pepco's cost rate should be lower, we disagree. The Commission finds that Pepco has correctly calculated its long-term debt cost. We are convinced that Unamortized Loss on Debt Reacquisition was treated correctly in Pepco's calculation of the cost of debt. AOBA's second argument is equally without merit. There is nothing in the record that suggests that the issuance of the December 2008 bonds was primarily related to the MAPP project.[164] We also agree that the Company had no basis in December 2008 to assume that credit market conditions would improve in the near term. There is nothing in the record showing that the Company's action was imprudent and AOBA has not provided any evidence to the contrary. Therefore, based on the foregoing, the Commission accepts Pepco's cost of long-term debt of 6.63 percent. As discussed below, the capital structure allowed for Pepco does not include short-term debt.

d. Capital Structure (Issue No. 4c)[165]

83. **Pepco.** PEPCO uses an actual test year capital structure as of December 31, 2008. Pepco asserts that a balanced debt-equity ratio is essential to securing good credit ratings and accessing the capital markets on reasonable terms.[166] Pepco argues that in these difficult times it is essential that it have investment grade ratings. According to Pepco, an investment-grade status decreases borrowing costs, improves access to capital of longer terms, and enables Pepco to absorb any negative volatility in its financial performance.[167] The Commission, Pepco asserts, should strive to maintain and improve the Company's financial ratings so that it will continue to have access to the capital markets on reasonable terms, which is in the best interest of ratepayers and Pepco's ability to provide cost-effective, safe and reliable service.[168]

84. Dr. Morin states that, if the Commission deviates substantially from this proposed capital structure, the cost of common equity and the cost of debt should be adjusted as well. If

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163 *Id.* at 13-15.

164 PHI's financial reports show that the bulk of the Holding Company's 2009 financing needs are associated with distribution and the MAPP project is only 8% of 2009 construction costs. *Id.* at 15.

165 Issue No. 4c asks, "Is the capital structure that PEPCO uses to develop its overall cost of capital reasonable and appropriate?"

166 Pepco (A) at 22 (Kamerick).

167 Pepco (B) at 75 (Morin).

168 Pepco (A) at 23-25 (Kamerick); Pepco (B) at 77 (Morin).

the debt ratio is increased, the risk and required returns of the Company also are increased. Dr. Morin compares Pepco's capital structure with the capital structure of electric utilities, and that of combination electric and gas companies. He contends that the Company's requested common equity ratio of 46.18 percent, while lower than the common equity ratios adopted by regulators for electric utilities in 2008 (48.4 percent) and the common equity ratios of combined electric and gas utilities (48.3 percent), is reasonable for ratemaking purposes.[169]

85. **OPC.** OPC includes short-term debt in its proposed capital structure, arguing that Pepco, normally, and electric utilities, typically, employ short-term debt in their capital structures.[170] OPC witness Woolridge adds that his proposed capitalization is in line with the average capital structure of OPC's Electric Group.[171] Dr. Woolridge states that Pepco's average capital structure ratio for the most recent four quarters includes 6.80 percent short-term debt, 47.37 percent long-term debt, and 45.83 percent common equity. Dr. Woolridge contends that the average capital structure of OPC's Electric Group for the most recent four quarters includes 5.60 percent short-term debt, 49.9 percent long-term debt, 0.50 percent preferred stock and 44.00 percent common equity.[172] Based on this information, OPC proposes capitalization ratios it believes are consistent with the average capital structure of its Electric Group – 51.51 percent long-term debt, 4.30 percent short-term debt, and 44.20 percent common equity.[173]

86. **AOBA.** Mr. Oliver does not accept Pepco's argument that its proposed capital structure is based on Company-specific data. He offers two reasons. First, as a subsidiary of PHI, Pepco's utility capital structure is insulated from market forces and subject to potential manipulation by the holding company. Second, Pepco's capital structure is not static over time. The Company's proposed capital structure represents a "snap-shot" view of the Company's capital structure.[174] Mr. Oliver also takes issue with Dr. Morin's assertion that the method Pepco used to compute the proposed capital structure is consistent with Commission precedent, claiming that nothing in F.C. No. 1053 established precedent. Nor, he states, does Dr. Morin offer any evidence of precedent for the pro forma adjustments reflected in the Company's capital structure calculations.[175]

87. AOBA also challenges Dr. Morin's representation that his common equity percentages compare favorably with those of other electric utilities. Witness Oliver submits that

169 Pepco (B) at 72-73 (Morin).

170 OPC (B) at 16 (Woolridge).

171 OPC (B) at 16-17 (Woolridge).

172 OPC (B) at 16 (Woolridge); OPC (B)-5.

173 *Id.* at 16-17.

174 AOBA (A) at 43. (Oliver).

175 *Id.* at 44.

this is because the common equity ratios in Dr. Morin's analyses show a wide range of common equity ratios, and simply averaging those percentages without examining the reasons for the differences is not instructive. Further, the combination electric and gas companies relied on by Dr. Morin are actually holding companies, many of which have substantial generation ownership and diversified operations which may influence their common equity ratios. Mr. Oliver contends that updated data for Dr. Morin's combination companies show that the common equity ratio has fallen from the 48.3 percent figure reported by Pepco to 46.6 percent. Finally, he "observes" that, if a common equity percentage is computed for companies in Dr. Morin's group of comparable size to Pepco Holdings (he does not identify these companies), the average common equity ratio is 43.9 percent. On this basis, AOBA recommends a capital structure for use in this proceeding consisting of 44 percent common equity and 56 percent long-term debt.[176]

88. **Pepco Rebuttal.** According to Pepco, AOBA disregards Pepco's capital structure and, instead, uses a hypothetical one. Pepco contends that Witness Oliver ignores the fact that Pepco issues its own debt and that the rating agencies rely on Pepco's financial information in rating that debt. Pepco notes that witness Oliver also ignores the fact that the Commission, in Formal Case No. 1053, adopted Pepco's capital structure. Witness Kamerick testifies that Pepco's capital structure is in line with the average common equity ratio for electric companies as reported in the July 2, 2009, Regulatory Research Associates' Regulatory Focus Report and with the revised average common equity ratio for Dr. Morin's entire group of combination electric and gas comparables provided by Oliver.[177]

89. Regarding OPC's recommended capital structure, Pepco states that short-term debt as it is used by Pepco provides temporary funding for the Company's construction requirements, which are permanently financed with either long-term debt or common equity. OPC's comparables include companies with debt that is financing the securitization of stranded costs and should be excluded from OPC's calculations because it is not used to finance utility operations. Pepco contends that, if securitization debt is excluded, OPC's data are updated for the four quarters ended June 30, 2009, and other classification adjustments made, OPC's comparables would support a higher common equity ratio. Further, Pepco indicates that it has repaid all of its short-term debt as 2009 progressed.[178]

DECISION

99. The issue before the Commission is the reasonableness of Pepco's capital structure. However, no party has presented any persuasive testimony that shows that Pepco's capital structure is unreasonable. They merely have presented alternative capital structures. As long as we find Pepco's proposed capital structure to be reasonable, it does not matter that there are alternatives that may be reasonable also.

176 *Id.* at 44-46.

177 Pepco (3A) at 16 -17 (Kamerick Rebuttal).

178 *Id.* at 17- 20.

100. OPC recommends a capital structure that includes short-term debt because it states that Pepco normally employs short-term debt in its capital structure. OPC further states that its proposed capitalization is in line with the average capital structure of its Electric Group. We are satisfied that Pepco uses short-term debt as a temporary funding source for the Company's construction requirements, which are permanently financed with long-term debt and common equity. The outstanding short-term debt Pepco had on its books in 2008 was completely repaid in 2009.

101. AOBA suggests an alternative capital structure based on its interpretation of the data Pepco uses as support for its proposed capital structure. Nevertheless, Pepco's capital structure compares reasonably to those of other electric utilities. Finally, AOBA alleges that Pepco's capital structure is subject to manipulation by PHI. However, AOBA has not presented any evidence to support that contention.

102. The Commission finds Pepco's proposed capital structure to be reasonable and adopts it to calculate the Company's overall rate of return. In this proceeding, Dr. Morin presented Pepco's capital structure. In future rate cases, the testimony on Pepco's capital structure should be offered by the individual who prepared, or is responsible for the preparation of, the capital structure calculations.

e. Surcharge and Deferral Mechanism (Issue 4d)[179]

DECISION

103. Because the Commission rejects Pepco's proposed surcharge and deferral mechanism,[180] this issue is moot.

f. BSA Adjustment (Issue No. 4e)[181]

104. **Pepco.** Dr. Morin testifies that, with a Bill Stabilization Adjustment, the Company's risk is reduced and the cost of common equity "declines by some 25 basis points." Dr. Morin explains that his 25 basis point adjustment is based on: (1) utility bond yield differentials between A-rated and Baa-rated bonds, (2) observed beta differentials, (3) differential common equity ratio requirements for S&P Business Risk Score, and (4) the

179 Issue No. 4d asks, "If PEPCO is permitted to implement the surcharge and deferral mechanism that it has proposed, should there be a reduction in PEPCO's authorized return on equity (ROE) to account for the Company's reduced business risk? If so, by how much should the authorized ROE be reduced?"

180 *See* Issue No. 8.

181 Issue No. 4e asks, "Should PEPCO's authorized ROE be adjusted downward to reflect reduced risk resulting from the Company's proposed implementation of a Bill Stabilization Adjustment and, if so, by how many basis points?"

application of informed judgment.[182] These are the same bases he relied on in Formal Case No. 1053. When Dr. Morin revised his proposed ROE, rather than include a 25 basis point adjustment, he simply adopted the lower end of his range of reasonable estimates, 10.75 percent to 11.00 percent to reflect the reduced risk associated with the Company's proposed BSA.[183]

105. **OPC.** Dr. Woolridge recommends a 25 basis point ROE adjustment to reflect the reduction in risk associated with a BSA. He testifies that he has not conducted any studies and is not aware of any studies that ascertain the reduction of risk associated with decoupling rate design mechanisms.[184] However, Woolridge indicates that he is aware of a number of commissions that have adopted such mechanisms, recognized the related risk reduction, and adjusted the authorized return on equity. These decisions, he states, indicate that an adjustment of up to 50 basis points may be appropriate.[185] Dr. Woolridge's BSA recommendation is revised by witness Ramas to reflect the Commission's 50 basis point BSA ROE adjustment in Formal Case 1053.[186]

106. **AOBA.** AOBA witness Oliver contends that there should be a downward adjustment to Pepco's ROE of 55 - 75 basis points if the BSA is adopted. The first basis of Mr. Oliver's adjustment is the same as in F.C. No. 1053 -- Pepco's willingness to give up its repression adjustment in F.C. No. 1053 if the BSA were adopted and his estimate of the dollar value of the Company's proposed repression adjustment, along with the dollar value of Pepco's proposed ROE adjustment if the BSA were approved (25 basis points). On this basis alone Witness Oliver believes the ROE adjustment should be at least 55 basis points. In this proceeding, Mr. Oliver adds that parties rarely offer trade-offs that are not structured to be favorable to the offering party. Therefore, "it would follow that, if Pepco were willing to forgo a revenue adjustment assessed to have at least 55 basis points of value, the value to the Company of the BSA must be noticeably in excess of 55 basis points." On this basis witness Oliver recommends a total adjustment of 55–75 basis points.[187]

107. **WMATA.** Dr. Foster testifies that the ROE adjustment to reflect the BSA (although he does not recommend a BSA) should be 50 basis points.[188]

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182 PEPCO (B) at 69 -71 (Morin)

183 Tr. 241-242.

184 OPC (B) at 53 (Woolridge).

185 *Id.*

186 Tr. 865-866.

187 AOBA (A) at 30-32 (Oliver).

188 WMATA (A) at 12-13 (Foster).

108. **Pepco Rebuttal.** Dr. Morin avers that there is no foundation or support for Mr. Oliver's 50 basis point adjustment to the ROE to reflect the reduced risk associated with the BSA. Morin claims that most, if not all, electric utilities are under some form of adjustment clause/cost recovery/rider mechanisms. Dr. Morin indicates this is largely embedded in financial data, such as bond ratings and business risk scores. Further, Dr. Morin states that a 50 basis points adjustment makes no sense because, if the same adjustment is made to the Company's long-term bond yield of about 5.75 percent, the resulting bond yield would be 5.25 percent, which is less than the bond yield on utility bonds rated AA (double A). Morin submits that this is an "absurd situation" given that utility bonds are rated Baa on average.[189]

109. Dr. Morin claims that the 50 basis point adjustment is not consistent with other recent regulatory decisions. He contends that his Exhibit (3B)-2 shows that the difference in allowed returns for utilities with, versus those without, revenue decoupling mechanisms is 10 basis points. He states that the average authorized ROE in 2009 through the time of his rebuttal testimony was 10.5 percent for utilities with BSA-like mechanisms.[190]

DECISION

110. Dr. Morin testifies that with a Bill Stabilization Adjustment the Company's risk is reduced and the cost of common equity "declines by some 25 basis points." He claims that a 50 basis point adjustment is not consistent with other recent regulatory decisions. We do not believe the comparison to other jurisdictions is compelling. Although the other jurisdictions may have had similar issues, it has not been shown that mechanisms in those jurisdictions are comparable to Pepco's BSA or that the overall focus and concerns in those proceedings were similar to those of this Commission. Each jurisdiction applies its own informed judgment based on the information before it to determine the respective ROE adjustments. Based on our review of the record and our informed judgment, we find that the 50 basis point BSA ROE adjustment determination made in Formal Case No. 1053, Phase II, should be adopted in this proceeding as well.[191]

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189 Pepco (3B) at 79-81 (Morin).

190 Pepco (3B) at 82 (Morin).

191 *See Formal Case No. 1053, Phase II*, Order No. 15556. Beginning November 1, 2009, and thereafter, the BSA is calculated based on Pepco's monthly billed revenues, modified to account for major outages. A 50 basis point reduction in Pepco's return on equity (ROE) was ordered, as part of the approval of the BSA, to provide a balance of benefits to consumers in exchange for the benefit to the Company and shareholders of reaping lowered business risk. The Commission ordered the BSA to apply to all customer classes except streetlights ("SL"), telecommunications network service ("TN"), and Temporary Service ("T").

G. Overall Cost of Capital

111. Based on our findings, above, we determine that the following reflects a fair and reasonable overall cost of capital for Pepco.

Capitalization	Ratio	Cost Rates	Return
Long-Term Debt	53.82%	6.63%	3.57%
Common Equity	46.18	9.625	4.44
	100.00 %		8.01 %

This return falls within the zone of reasonableness. It will allow the company to maintain its financial integrity, attract capital on reasonable terms, and earn a return commensurate with those other investments of similar risk.

VI. OPERATING EXPENSES (Issue No. 5)[192]

A. Unopposed Adjustments (Ratemaking Adjustments Nos. 2, 3, 5, 6, 7, 8, 10, 12, 18, 19, 21, 22, 23, and 24)

112. Operating income is derived by subtracting the costs Pepco incurs in providing service to customers (including taxes) from the revenue it receives for electric distribution service.[193] Various adjustments to the test year revenues and expense are proposed by the parties and are either accepted, rejected, or otherwise modified by the Commission in order to determine operating income. In this case, the Company's uncontested operating income was $762,000 for the test year period which include RMA No. 2, Inclusion of Projects Completed and In Service; RMA No. 3, Annualization of NE Substation Cut In; RMA No. 5, Exclusion of Supplemental Executive Retirement Plans; RMA No. 6, Exclusion of Industry Contributions and Membership Fees; RMA No. 7, Exclusion of Advertising and Selling Expense; RMA No. 8, Inclusion of Interest Expense on Customer Deposits, RMA No. 10; Reflection of Non-Deferred Regulatory Costs at 3-Year Average Amount, RMA No. 12; Formal Case No. 1076 Outside Counsel/Consulting Deferred Costs, RMA No 18; Reflection of Change in PSC and OPC Budget Assessment; RMA No. 19, Annualization of Software Amortization; RMA No. 21, Reflection of F.C. No. 939 Disallowance; RMA No. 22, Reflection of Disallowance of Incentive Plan Costs;

192 Designated Issue No. 5 asks, "Is each of Pepco's proposed adjustments to test-year operating expenses just and reasonable?"

193 *See OPC v. Pub. Serv. Comm'n,* 399 A2d. 43 (D.C. 1979).

RMA No. 23, Removal of Adjustments to Deferred Compensation Balances; and RMA No. 24, Inclusion of Deferred Customer Education Costs.

DECISION

113. The parties agree that there is no dispute and either support the above adjustments or do not oppose them. Inasmuch as no party challenges the above adjustments and the Commission has reviewed them and independently found them reasonable, we approve the adjustments. The parties dispute other operating income and expenses adjustments that we discuss and decide below.

B. Pepco's Proposed Adjustments

1. Credit Facility Costs

114. **Pepco.** Pepco proposes to adjust rate base and operating income to reflect the inclusion of Pepco's share of the cost associated with PHI's $1.5 billion credit facility (RMA No. 9). Pepco explains that the credit facility, which terminates in 2012, facilitates the issuance of commercial paper (short-term debt) on an as-needed basis, assuring investors and rating agencies that Pepco has a committed line of credit with banks in the event of a liquidity problem.[194] The credit facility provides Pepco with a backstop borrowing mechanism to handle day-to-day cash requirements.[195]

115. Pepco's credit facility includes two costs: start-up costs, which are amortized over the facility's useful life; and an annual maintenance fee. Pepco proposes to include the D.C.-allocated portion of the average unamortized start-up costs balance ($143,000) in rate base and the amortization of the start-up costs ($37,000) in O&M expense, similar, it contends, to the treatment of interest paid on customer deposits. Pepco indicates that the annual maintenance fee is $211,000; $88,000 on a D.C. allocated basis and that it is responsible to pay this fee whether Pepco uses the facility or not. The Company proposes to add the D.C. allocated portion of this fee to O&M expense as well.[196] Together, the D.C. allocated credit facility costs total $125,000.

116. **OPC.** OPC does not challenge recovery of annual maintenance fees. It does, however, challenge the recovery of start-up costs. OPC proposes to reduce rate base by $143,000 to remove the unamortized balance of start-up costs and expenses by $37,000 to remove the associated amortization amount.[197] OPC argues that the amortization of start-up

194 Pepco (C) at 10-12 (Hook).

195 *Id.*

196 *Id.* 11-12.

197 OPC (A) at 50 (Ramas).

costs is not a cost that is typically included in above-the-line costs and should be recorded in FERC Account 428 – Amortization of Debt Discount and Expense, in which the Company confirms that it records such amortization. OPC contends that the cost of financing is a debt cost, and Pepco has excluded short-term debt from its capital structure[198]

117. OPC asserts that the majority of the start-up fees was incurred prior to the test year and should have been included in Pepco's last rate case.[199] The costs include charges from the entity providing the credit facilities and administrative costs such as outside counsel fees.[200] OPC contends that while these costs may be deferred and subsequently amortized as debt costs for book purposes, these costs typically are not included in above-the-line costs, and deferral is not treated as a regulatory asset.[201] Pepco, OPC further contends, should not be allowed to now to go back and request a return on these costs through their inclusion in rate base. OPC avers moreover that Pepco should not be allowed to record the associated amortization of these costs as operating expense because these costs are not analogous to either interest earned on customer deposits or bank commitment fees.[202]

118. **AOBA.** AOBA also believes that the costs associated with the credit facility should be eliminated. AOBA argues that Pepco's proposal denies District ratepayers any recognition of short-term debt costs that are significantly below long-term debt costs while requiring ratepayers to pay for setting up and maintaining the credit facility.[203] AOBA states that Pepco's proposal would allow the Company to substitute lower short-term borrowing costs for long-term debt assumed in its capital structure and capture the difference as earnings for its shareholder, PHI.[204] AOBA argues that the Company's request should be denied in the absence of explicit recognition of short-term debt in the Company's capital structure. AOBA recommends that O&M expense be reduced by $125,000.[205]

119. **Pepco Rebuttal.** In rebuttal, Pepco argues that the credit facility plays a critical role in Pepco's liquidity and its ability to access the credit market in difficult economic times.[206]

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198 *Id.* at 47; OPC Br. 84.

199 OPC (A) at 48.

200 *Id.*

201 *Id.* at 49.

202 OPC Br. 85-86.

203 AOBA Br. 23.

204 *Id.*

205 AOBA (A)-6 (Oliver).

206 Pepco (4C) at 21-22 (Hook Rebuttal).

Pepco contends that amortization of the start-up costs over the life of the facility is similar to how one would amortize the underwriting costs of bonds, over the remaining life of the facility. Pepco maintains that what is relevant is not when the costs were incurred but whether the credit facility is providing a benefit to customers.[207] Pepco acknowledges the oversight in not requesting cost recovery in Formal Case No. 1053, but argues that that should not bar recovery at this time. Pepco further contends that the Commission has allowed retroactive commencement of amortization periods.[208] Pepco also asserts that the inclusion of the costs in FERC Account 428 is not a bar to cost recovery through rate base amortization.[209]

DECISION

120. We are not persuaded by OPC's and AOBA's arguments that ratepayers are being deprived of recognition of short-term debt costs in their capital structure, as a basis for rejecting Pepco's credit facility adjustment. The Commission determines that Pepco's actual capital structure, which does not include short-term debt, is reasonable and compares reasonably to that of other electric utilities.[210] Short-term debt as it is used by Pepco provides temporary funding for the Company's construction requirements, which are permanently financed with either long-term debt or common equity.[211] The credit facility supports liquidity, or the Company's short-term financing needs.

121. The Commission is mindful of the doctrine of retroactive ratemaking.[212] While we recognize the general principle precluding Pepco from charging higher rates in the future to recoup past costs, that concept does not bar the Commission from properly recognizing the amortization of costs associated with the credit facility.[213] Costs that are amortized by definition are not retroactive. Moreover, the Commission is not authorizing recovery of prior period costs; these are ongoing costs associated with the credit facility.

122. As Pepco enters into new, and amends existing credit facility agreements, start-up costs are incurred and the prior agreement costs are then rolled into the new or modified agreement, just like a revolving credit agreement. We recognize that these costs normally would

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207 Pepco Br. 42.

208 *Id.*, citing *Formal Case No. 929*, Order No. 10448 (June 7, 1994) (allowing retroactive commencement of amortization of costs back to 1992).

209 Pepco Br. 43.

210 *See infra* ¶¶ 101-102.

211 Pepco (3A) (Kamerick) at 17-20.

212 *See People's Counsel of District of Columbia v. Pub. Serv. Comm'n*, 472 A.2d 860, 866 (D.C.1984).

213 *Id.*

be reflected in the calculation of the cost of short-term debt. We also recognize that Pepco did not request permission to defer credit facility costs in any prior proceeding. However, Pepco's oversight notwithstanding, the credit facility is beneficial to ratepayers. It has allowed the Company to access the capital and credit markets to meet its daily working requirements on less expensive terms. Balancing the interest of ratepayers and the Company, and recognizing the importance of Pepco's ability to raise capital on reasonable terms, the Commission approves the Company's adjustment and will permit the Company to recover start-up costs and annual maintenance fees.

2. Deferral of Formal Case No. 1053 Costs

123. **Pepco.** Pepco increases O&M expense by $31,000 and the unamortized balance to be included in rate base by $643,107, and reduces accumulated deferred income taxes ("ADIT") by $267,000 to reflect the amortization of outside counsel and consulting costs incurred in Formal Case No. 1053 over a three-year period.[214]

124. **OPC.** OPC does not challenge Pepco's proposed O&M expense adjustment, but takes issue with Pepco's calculation of the unamortized balance included in rate base. OPC states that Pepco calculated the 12-month average by using $747,839 (actual costs incurred) as the starting point and then taking the monthly unamortized balances through December 2008 to arrive at the Company's proposed $643,107 adjustment. OPC contends that the appropriate amount is $155,800 (which represents the total unamortized balance of deferred costs as of the mid-point of the rate effective period), which is consistent with the methodology Pepco uses to calculate the unamortized balance of Formal Case No. 1076 rate case costs (RMA No. 12). OPC originally recommended reducing Pepco's rate base by $487,307.[215] ADIT would be reduced by $116,337, instead of the $267,000 proposed by Pepco (increasing rate base by $150,448).[216] In its revised revenue requirement filing, OPC's $116,337 ADIT figure was changed to $64,153, and its $150,448 increase in rate base was changed to $202,632.[217]

DECISION

125. OPC argues that the methodology Pepco uses to calculate the average unamortized balance of Formal Case No. 1053 costs is inconsistent with the methodology used to calculate the average unamortized balance of Formal Case No. 1076 costs.[218] According to

214 Pepco (C) at 12 (Hook); Pepco (C)-1 at 11; *Formal Case No. 1053*, Order No. 14712, ¶¶ 198-199.

215 OPC (A) at 16-17 (Ramas); OPC (A)-3, Sch. 2 (Ramas).

216 *Id.* at 18.

217 OPC Revised Revenue Requirement Schedules, (Exhibit (A) -3, Schedule 2 (revised) (November 20, 2009).

218 OPC Br. 34-36.

OPC, Pepco proposes to set the unamortized balance of Formal Case No. 1076 costs at the average balance as of the mid-point of the rate-effective period (June 30, 2010), while it calculates the unamortized balance of Formal Case No. 1053 costs using the average balance for the twelve months ending December 2008. This results in an inflated balance of Formal Case No. 1053 costs being included in rate base.[219] OPC contends the method used to calculate the unamortized balances of both cases should be the same.[220] This would reduce unamortized balance of Formal Case No. 1053 costs. Pepco challenges OPC's recommendation to decrease the amount of unamortized Formal Case No. 1053 costs reflected in rate base. Pepco argues that in Formal Case No. 1053, the Commission approved a three-year amortization of the 13-month average of total costs incurred.[221] Pepco contends that OPC is proposing to roll forward a full two years after the end of the test period to pick up the average unamortized cost balance at December 31, 2010.[222]

126. No party opposes Pepco's proposed O&M expense. We find the Company's adjustment reasonable and, therefore, the Commission accepts the adjustment. However, as it relates to the unamortized deferred Formal Case No. 1053 costs, the Commission agrees with OPC that the reflection of these costs in rate base should be concurrent with the first year of the rate-effective period of this proceeding. The costs are known and measurable. The Company's argument that using the 2010 average would effectively be "rolling forward a full two years after the end of the test period"[223] incorrectly characterizes the related costs. The average unamortized cost balance for the 13-months ending December 31, 2010, includes costs beginning within a year after the end of the test year. Therefore, the Company's reliance on Formal Case No. 869 is misplaced. In Formal Case No. 869, the Commission refused to consider the final increment of the Ohio Edison capacity because it would not begin until 18 months from the close of the test period. The expense was too remote from the test year.[224] In the instant case, the cost calculation begins within a year from the close of the test period. Remoteness from the test year is not at issue as it relates to this adjustment. Formal Case No. 1076 costs (RMA No. 12) are calculated based on the expected first year of the rate-effective period. The Commission finds that because Formal Case No. 1076 costs are based on the first year of the rate-effective period, and because the average Formal Case No. 1053 unamortized cost balance is known and measurable for that first year of the rate-effective period, those costs should be used in the Formal Case No. 1053 calculations as well.

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219 OPC R. Br. 11.

220 *Id.*

221 Pepco Br. 6.

222 Pepco(4C) at 5 (Hook Rebuttal).

223 Pepco (4C) at 5:3-4 (Hook Rebuttal).

224 *In re Potomac Electric Power Co., Formal Case No. 869*, Order No. 9216, 10 DCPSC 23, 110 (1989).

3. Uncollectible Expense

127. **Pepco.** Pepco proposes to increase O&M expense by $300,000 (RMA No. 16) from $3.142 to $3.442 million to reflect the budgeted 2009 level of uncollectible expense.[225]

128. **OPC.** According to OPC, Pepco has not supported its projected 2009 uncollectible expense for the District of Columbia or for its distribution-related costs, nor has the Company shown that its methodology is reasonable. OPC states Pepco derived its 2009 Maryland, District of Columbia and total uncollectible expense by utilizing the total net write-offs and the total reserve adjustments for 2007 and 2008 for the District of Columbia and Maryland, and compared them to total District of Columbia and Maryland billed revenues.[226] OPC challenges this adjustment in that it includes revenues beyond distribution revenues and the District is disproportionately impacted by the higher bad debt ratio estimate for Maryland. OPC also contends that the level of uncollectible expense appears to be significantly impacted by adjustments to bad debt reserve made by Pepco in 2007 and 2008, instead of being based on net write-offs of uncollectibles.[227] Further, the Company's projection methodology factors in total budgeted revenues for the District of Columbia and Maryland and is not specific to distribution service.[228]

129. OPC recommends that the percentage of the historic average of net write-offs to revenues, which the Company has not calculated, be applied to the adjusted test year revenues to determine a normalized uncollectible cost to include in rates.[229] OPC contends that the amount included in the test year includes not only the net write-offs of account balances but also adjustments to the bad debt or uncollectible reserve. Additionally, the test year amount includes the impact of amounts expensed to increase the bad debt reserve that are not specific to distribution-related accounts receivable balances being written off.[230] OPC estimates the three-year average (2006-2008) of D.C. distribution-specific uncollectible expense to be $1.28 million, $2.16 million less than requested by the Company.[231]

130. **AOBA.** AOBA contends that Pepco's proposal is not reflective of the expense it should anticipate for the rate-effective period.[232] AOBA argues that a three-year (2007-2009)

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225 Pepco (C) at 14 (Hook); Pepco (C)-1 at 19; Pepco (4C) at 13 (Hook Rebuttal).

226 OPC (A) at 36 (Ramas).

227 *Id.* at 37.

228 *Id.*

229 *Id.* at 39.

230 *Id.* at 38.

231 OPC Br. 75; Tr. 866-867. Initially, OPC recommended that test-year uncollectibles be set at $1.01 million. OPC (A) at 41 and 42 (Ramas).

232 *Id.*

historical average of actual write-offs would be more appropriate.[233] The three-year average is $2.98 million, $458,000 less than the Company's proposed $3.44 million.[234]

131. **Pepco Rebuttal.** Pepco counters that the Commission's policy has consistently been to set rates based on the conditions that are likely to exist during the rate-effective period, and, for that reason, it allows post-test-year adjustments and projections.[235] Pepco argues that its forecasts are accurate. Pepco indicates that its budgeted uncollected expense was $3.44 million; its actual expense for the twelve months ended September 30, 2009, was $3.50 million, and its year-to-date (September 30, 2009) recorded amount on an annualized basis was $3.53 million.[236] Pepco claims that OPC's suggested $1.28 million uncollectible expense is slightly more than one-half the write-offs likely to occur in 2009, without taking in account the need for allowance for reserve balances.[237] Pepco argues that the use of the average of 2006-2008 data introduces significant regulatory lag, since uncollectible amounts are not written off until six months after the fact.[238]

DECISION

132. Pepco proposes an adjustment to test-year operating expenses to reflect the 2009 budgeted amount of uncollectible expense.[239] Both OPC and AOBA object to using the budgeted amount of uncollectibles. OPC proposes a three-year historical average of actual write-offs net of collection, with no recognition of a reserve balance,[240] while AOBA proposes a three-year average because it believes that the budgeted amount is not reflective of the expense Pepco will incur during the rate-effective period.[241] All the parties acknowledge, either implicitly or tacitly, that the economic crisis has had an impact on uncollectibles.[242] The data presented by Pepco in this proceeding, however, does not show a discernable trend in the actual uncollectible

233 AOBA (A) at 53-54 (Oliver).

234 *Id.* at 54,

235 Pepco Br. 39, citing *Formal Case No. 1053*, Order No. 14712, ¶¶ 7, 208-209 (citations omitted).

236 Pepco (4C) at 14 (Hook Rebuttal).

237 *Id.* at 16.

238 *Id.* at 15.

239 Pepco (C) at 19 (Hook); Pepco (4C) at 13 (Hook Rebuttal).

240 OPC (C) at 38-39 (Ramas).

241 AOBA (A) at 53-54 (Oliver).

242 OPC Br. 2; AOBA (A) at 53-54 (Oliver); Pepco Br. 38.

rate. In determining the allowance for uncollectibles, the Commission is concerned with Pepco's actual bad debt experience, not the potential for bad debts, which may or may not be realized. Despite Pepco's contention that its post year budgeted uncollected expense is accurate, Pepco has not unequivocally shown that the budgeted amount is reflective of the rate-effective period. Pepco maintains that reliance on a three-year average is indefensible in light of current economic conditions.[243] However, the economy has shown signs of improvement. In fact, Pepco's testimony was revised to reflect the improvement in financial conditions and the subsiding of the economic crisis.[244] Pepco's 2009 uncollectible expense appears to be an anomaly and not reflective of rates to be expected in the rate-effective period. Therefore, we reject Pepco's adjustment to use the 2009 budgeted uncollectible expense.

133. We have often used a three-year average to provide normalization for expenses that fluctuate from year to year. Expense fluctuations may be the result of such things as revenue fluctuations or the general state of the economy. Nevertheless, we believe the use of a three-year average may dampen the unusual volatility experienced in 2009 and result in under-recovery. Therefore, we determine that the average of 2008 and 2009 uncollectible expense best reflects the rate-effective period, for this proceeding only.

4. Storm Restoration Costs

134. **Pepco.** Pepco proposes to normalize O&M expense associated with storm restoration efforts (RMA No. 17) to its three-year average level consistent with Formal Case No. 1053. This would result in an increase of the three-year average storm damage costs of $517,000 and O&M expense of $190,922.[245]

135. **OPC.** OPC contends that costs (such as base salary, wage costs and employee benefits) which comprise more than half of this adjustment would have been incurred regardless of the storm and should not be included in the normalized adjustment. OPC asserts that storm damage costs should be limited to incremental, non-labor costs that were specifically caused by the storm and that an employee labor cost adjustment is reflected in other adjustments, specifically, wages and employee benefit costs.[246] OPC submits that Pepco's wages and salaries adjustment presumably includes overtime-related costs which include overtime for storm-related costs.[247] OPC argues that Pepco has not demonstrated that the level of overtime costs incorporated in its wage annualization adjustment is not reflective of normal, recurring overtime levels. According to OPC, Pepco's test year storm damage restoration costs of $190,922 should

243 Pepco Br. 40, n. 178.

244 Tr. 239.

245 Pepco (C) at 14 (Hook); Pepco (C)-1 at 20; *See Formal Case No. 1053*, Order No. 14712, ¶¶ 195, 199.

246 OPC (A) at 43-44 (Ramas).

247 *Id.* at 45.

be reduced by $74,775 (the labor component to the adjustment), reducing storm damage restoration costs by $265,697.[248]

136. **Pepco Rebuttal.** The Company responds that storm restoration efforts result in higher than normal labor costs, which are by definition incremental and that there is no duplication of the adjustment to labor costs.[249] To exclude labor costs from the three-year normalized amount would defeat the purpose of normalization.[250] Pepco contends that OPC's argument ignores the fact that the storm damage normalization adjustment in this case is not driven by 2008 labor costs, which are the subject of other adjustments, but by 2006 costs which are not.[251] Further, Pepco claims that storm costs are not typical of on-going O&M activities, which it argues is the premise of OPC's conclusion that labor is addressed in other adjustments. Pepco asserts that during storms all Company employees become available to work storm-related activities which increase the storm workforce by 50-60 percent. Pepco argues that these costs are "all subject to unusual increases during significant storm events due to extended overtime at time and a half and double pay, shift differentials, holiday pay, changes of shift payments, etc."[252]

DECISION

137. We agree with Pepco that storm restoration efforts do result in higher than normal labor costs, which are by definition incremental. The Company has satisfactorily explained its storm damage restoration adjustment. Labor costs increase during storm events due to overtime, pay and shift differentials, and the use of all available personnel (labor and management) to respond to storms.[253] Based on our review of the record, there is no evidence of duplicative overtime labor costs. Therefore, the Commission approves Pepco's adjustment to normalize O&M expense associated with storm restoration efforts to its three-year average level consistent with Formal Case No. 1053. However, in the next rate case, the Company should more clearly demonstrate that storm expense is "incremental" and that its internal labor costs (and in particular base/non-overtime wages) have not been incurred elsewhere such that they are additive or incremental costs. Moreover, the Company is directed to clearly separate out storm-related labor costs from its wage and salary adjustment in its next rate case.

248 *Id.* at 45; OPC (A)-3, Sch. 14.

249 Pepco (4C) at 19-22 (Hook Rebuttal).

250 *Id.*

251 Pepco Br. 37.

252 Pepco (3D) at 21 (Gausman Rebuttal).

253 Pepco (3D) at 21 (Guasman Rebuttal).

5. Interest Synchronization

138. **Pepco.** Pepco proposes to increase D.C. Income Tax ("DCIT") and Federal Income Tax ("FIT") expense (RMA No. 27) by $312,000 and $985,000, respectively, to reflect the synchronization of interest expense for income tax purposes with that inherent in the Company's return on rate base.[254] Pepco represents that this treatment is in accordance with the Commission's decision in Formal Case No. 1053 and prior cases. Pepco explains the Company's interest synchronization adjustment is based on the weighted cost of debt of 3.57 percent comprised solely of long-term debt.[255]

139. **OPC.** OPC recommends an adjustment to synchronize interest expense used to calculate income based on the embedded cost of debt and capital structure recommended by OPC. OPC recommends a weighted cost of debt that includes both short-term and long-term debt of 3.47 percent. OPC also uses its adjusted rate base of $841,923 in its calculation. OPC indicates that the resulting adjustment to net operating income is $3.49 million.[256]

DECISION

140. Pepco and OPC used the same method of calculating interest synchronization and its approach is in accordance with Commission precedent. The difference in its recommended adjustment reflects the differences in its proposed rate base and weighted cost of debt. Accordingly, we approve the Company and OPC's method of adjustment and its approach, but the interest synchronization adjustment must reflect the Commission's decision in this proceeding related to the weighted cost of debt and the adjusted rate base.

C. OPC's Proposed Adjustments

1. Directors' & Officers' Liability Insurance

141. **OPC.** OPC recommends that Directors' and Officers' Liability insurance ("D&O insurance") expense be shared 50/50 between shareholders and ratepayers, reducing insurance costs by $163,379.[257] OPC argues that the purpose of D&O insurance is to protect shareholders from decisions of the Board of Directors. Ratepayers have no role in choosing the Board of Directors or the Company officers. OPC asserts in the event that Pepco's officers and directors are successfully sued by its shareholders, it is shareholders and not ratepayers who will be compensated for the losses incurred due to mismanagement or impropriety.[258]

254 Pepco (C) at 17 (Hook); Pepco (C)-1 at 30 (original filing). This adjustment was amended and reflected in Pepco's November 20, 2009, filing (Responses to Transcript Data Requests) (November 20, 2009).

255 *Id.*

256 OPC Revised Revenue Requirement Schedules, OPC (A)-3, Sch. 18 (Ramas).

257 OPC (A)-3, Sch. 17 (Ramas).

258 OPC (A) at 50-51 (Ramas).

142. **Pepco Rebuttal.** D&O insurance, Pepco submits, enables the Company to: (1) attract and retain competent directors and officers; and (2) protects the Company's balance sheet from losses due to lawsuits that could divert needed capital from investments made to provide reliable service to customers.[259] Increasing scrutiny and the risk exposures related to corporate governance decreases the ability to maintain a high-quality board and senior management team. Pepco notes that the vast majority of all publicly-held companies purchase D&O insurance. Pepco indicates that OPC neglects to consider the necessity for publicly-held companies to have D&O insurance and contends that it ultimately benefits customers. Pepco notes that the Commission has approved full recovery of D&O insurance premiums in all its prior rate cases. Pepco asserts D&O insurance is a reasonable and necessary cost of doing business for any publicly-traded corporation[260] and that OPC's adjustment should be rejected.

DECISION

143. The Commission finds that Pepco has met its burden of persuasion for the inclusion of D&O insurance costs in rates. D&O insurance is a necessary and reasonable expense to attracting and retaining qualified officers and directors and a reasonable cost of business. Therefore, we reject OPC's proposed adjustment.

D. Pension and OPEB Expenses (Issue No. 5a)[261]

1. Pension Expense

144. **Pepco.** The Company, in RMA No. 15, seeks to increase rate base by $20.09 million and O&M expense by $6.3 million, consistent with the treatment approved in Formal Case No. 1053, for 2009 pension and OPEB costs as estimated by the Company's independent actuary, Watson Wyatt Worldwide.[262] To keep costs under control, Pepco indicates that PHI entities made a $300 million cash infusion to the Company-wide plan, of which Pepco made a $170 million contribution.[263]

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259 Pepco (4C) at 23-25 (Hook Rebuttal).

260 Pepco Br. 43.

261 Designated Issue No. 5a asks, "Is the level of Pension and OPEB expenses in the revenue requirement just and reasonable?"

262 Pepco (C) at 14 (Hook); Pepco (C)-1 at 18 of 33; Pepco (2C) at 3-4. (Hook Supp.). *See* Order No. 14712, ¶¶ 112, 113. In the November 20, 2009, filing, the overall increase to rate base was revised to $20.09 million and the O&M expense was revised to $6.3 million.

263 Pepco (2A) at 5 (Kamerick Supp).

145. **OPC.** OPC agrees that the Company's proposed level of OPEB expense is reasonable.[264] However, OPC contends that Pepco's proposed pension expense is not reflective of the costs that will be incurred in the rate-effective period. OPC noted that Pepco proposes an increase from the test year level of $8.558 million to $25.196 million, a 194 percent increase,[265] which includes Pepco's pension costs and PHI Service Company costs allocated to Pepco.

146. OPC argues that the primary driver behind the increase in pension costs is the actuarial loss (26.6 percent) experienced by the pension plan during 2008.[266] The actuarial assumptions for 2008 had assumed a long-term rate of return on plan assets of 8.25percent. According to OPC, two components of the pension expense calculation were impacted by the loss: the component for the expected return on plan assets; and the net loss (gain) amortization.[267]

147. OPC argues that pension costs for the rate-effective period will be lower than the 2009 costs Pepco projects.[268] OPC indicates that from 2006 through 2008, Pepco made zero cash contributions to its pension plan assets. In 2009, Pepco made a significant contribution ($170 million) to the pension plan assets. OPC submits that larger expected return on plan assets as a result of this contribution serves to reduce pension costs. Further, the funding of the pension plan assets served to reduce future pension costs for many years while earnings on plan assets offset the expense.[269] Also, pension expense is projected by Pepco to significantly decline from 2009 to 2011 on a total PHI basis.[270] OPC concedes that pension costs for the rate-effective period will likely be higher than the historic test year amounts, but maintains the costs are likely to be lower than the current year level as a result of the cash infusion into the plan.[271] While the 2009 cost is known and measurable, it is neither known nor likely to be reflective of the costs in the rate-effective period. OPC recommends that costs be based on an average of actual 2008 and 2009 pension and OPEB expenses. Therefore, OPC recommends that pension expense be reduced by $1.94 million.[272]

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264 OPC (A) at 51 (Ramas).

265 OPC (A) at 51-54 (Ramas). Initially, on direct, Pepco proposed a pension expense of $22.138 million.

266 *Id.* at 53-54.

267 *Id.*

268 OPC (A) at 52-54 (Ramas).

269 In 2009, Pepco contributed $170 million to the pension plan, with the expected contribution on a total PHI basis of $300 million. OPC states the impact of these cash contributions on pension expense actuarial calculations will be more fully realized in 2010. *Id* at 55.

270 OPC (A) at 55-56 (Ramas).

271 OPC Br. 92.

272 OPC (A) at 57 (Ramas).

148. **AOBA.** AOBA challenges both the pension and OPEB expenses alleging that 2009 expense levels are higher than the costs the Company anticipates in the rate-effective period.[273] AOBA contends that even if the estimates for 2009 are reasonably accurate, there is no basis to assume that they will remain at the 2009 level for 2010 and beyond. AOBA states that, just as the stock market decline in 2008 led to the surge in the Company's estimated 2009 pension expense, the rebound of the market over the past several months can be expected to yield a decline in estimated 2010 pension costs. AOBA contends that it would be more appropriate to use a three-year historical average of pension and OPEB costs.[274] Based on its recommendation, AOBA's adjustment reduces pension and OPEB expense by $3.49 million[275]

149. **Pepco Rebuttal.** Pepco modified its request and proposes an increase in its pension expense to $25.196 million to reflect a subsequent valuation by Watson Wyatt Worldwide.[276] Pepco contends OPC "has not demonstrated that using the simple average of 2008 and 2009 pension expense as a predictor is any more reasonable than would be any other random assumption about the 2010 level of expense."[277] Pepco argues that OPC's proposed treatment would violate the ratemaking principles which OPC elsewhere defends that adjustments should not reflect predicted changes more than 12 months beyond the test year.[278] Pepco contends that AOBA's recommendation (use of a three-year average) should likewise be rejected because AOBA has not offered any evidence that a three-year average will be representative of pension and OPEB costs in the rate-effective period.[279]

2. Prepaid Pension Asset

150. **OPC.** OPC also asserts that it would not be appropriate to reflect the impact of the 2009 actuarial valuation on the prepaid pension asset in rate base. OPC submits that net-of-tax, the prepaid pension asset should be reduced by $814,000 on a Pepco distribution-related basis and $299,796 on a District of Columbia basis.[280] OPC also contends the calculation of net-of-tax prepaid OPEB liability was in error and should be corrected. OPC submits that the adjustment necessary to reflect the corrected net-of-tax OPEB liability is an additional $633,000

273 AOBA (A) at 51 (Oliver).

274 *Id.* at 41.

275 AOBA (A)-4 (Oliver).

276 Pepco (4C) at 30 (Hook Rebuttal).

277 Pepco (4C) at 27 (Hook Rebuttal).

278 Pepco Br. at 32; Pepco (4C) at 26-27 (Hook Rebuttal).

279 Pepco (4C) at 27-28.

280 OPC (A) at 58 (Ramas).

offset to rate base on a Pepco distribution-related basis and $233,134 on a District of Columbia basis.[281]

151. OPC argues that Pepco has not established that irreparable injury to its financial metrics is inevitable unless it receives an immediate order for regulatory asset treatment of its increased pension costs.[282] OPC states that, to date, it has not seen where Pepco's 2009 pension expense has negatively affected Pepco's credit rating or financial metrics.[283]

152. **Pepco Rebuttal.** The Company asserts that OPC has provided no basis to use an average of actual 2008 and 2009 pension asset data. Additionally, it avers that OPC uses the average expense for 2010 while using the average rate base for 2009, which results in a mismatch of the asset with expense. In fact, Pepco contends that the average net-of-tax balance of the prepaid asset will be significantly higher in 2010 than 2009. Finally, Pepco argues that, if the expense level is updated to reflect 2010, then so too should the corresponding rate base component.[284]

DECISION

153. While Pepco argues that its pension costs should be based on the final 2009 Watson Wyatt Worldwide actuarial report, AOBA correctly points out that, even if the estimates for 2009 are reasonably accurate, there is no basis to assume that they will remain at the 2009 level for 2010 and beyond. Pepco states that there has been significant improvement and stability in the capital markets, and, as noted previously, the Company acknowledges that the stock market has shown recent signs of improvement.[285] As stock prices improve, pension costs will decline as shown in the actuarial report. The record shows that pension expense is projected by Pepco to significantly decline from 2009 to 2011.[286] The actuarial report estimates that pension costs will decline from a high of $95.25 million in 2009 to $69.1 million in 2011.[287] Moreover, the 2009 projections do not reflect the PHI entities' $3 million contribution to the pension plan assets. We agree with OPC that pension costs for the rate-effective period will likely be higher than the historic test year amounts, and that costs are likely to be lower than the current year level as a result of the cash infusion into the plan.

281 *Id.* at 59.

282 OPC (C) at 45 (Bright).

283 *Id.* at 46-47.

284 *Id.* at 29.

285 Tr. 239.

286 OPC (A) at 55-56 (Ramas).

287 OPC (A)-22 (Ramas) (Watson Wyatt Worldwide project pension costs).

154. Based on the record, it is clear that the extreme volatility experienced by Pepco will not likely continue in the future and that an averaging that recognizes 2009 as an anomaly is appropriate. A two-year average (2008-2009) will appropriately recognize the higher expense incurred by Pepco, also will recognize that 2009 was an unusually bad year and provide the Company's pension assets with an opportunity to rebound. Therefore, for this case and this case only, Pepco's pension costs will be estimated for the rate-effective period based on a two-year (2008-2009) average of actual pension costs. The prepaid pension asset will, for this proceeding only, likewise be calculated based on a two year average (2008-2009). The Commission's decision on these two adjustments shall not be viewed as precedent going forward. Finally, the Commission also accepts the Company's proposed level of OPEB expense as reasonable.

E. Pepco Employees and Employee Related Costs (Issues No. 5b)[288]

1. Wage and Salaries

155. **Pepco.** Pepco proposes to increase O&M expense by $422,000 (RMA No. 13) to reflect annualized employee salary and wage increases which occurred during the test year (March 1, 2008, for exempt employees, and June 1, 2008, for union/bargaining unit employees).[289] This adjustment also includes a 2.0 percent wage increase effective June 1, 2009. There was no non-union wage merit increases in 2009, so there is no adjustment to non-union wages beyond the annualization of the March 1, 2008, increase. Pepco represents that the level of employees and employee-related costs reflected in the test year represents the Company's best estimate of what it thinks it will experience in the rate-effective period. The amount of the adjustment to wages takes into account changes in employee levels, consistent with the Commission-approved treatment in Formal Case No. 1053.[290]

156. **OPC.** OPC contends that the Commission should: (1) disallow the Company's projected 1.5 percent union wage increase effective June 1, 2009; (2) correct the average number of test year employees used in determining the test year wage increase annualization; and (3) use the July 31, 2009, employee counts for determining the test period wage annualization adjustment.[291]

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288 Designated Issue No. 5b asks, "Do Pepco's representations regarding number of employees and employee-related expenses accurately portray the number of employees and employee-related expenses that the Company will experience during the rate-effective period?"

289 Pepco (C) at 12-13 (Hook); Pepco's initial request was $384,000, which was subsequently revised in its November 20, 2009, update. *See* Pepco's November 20, 2009, response to Transcript Data Requests, page 18.

290 *Id.*

291 OPC Br. 92.

157. In support of its first contention, OPC states that the union contract expired on May 31, 2009 and Pepco, nine months after the end of the test year, still has not provided a new union contract or disclosed the percentage wage increase for 2009 allowed for in the new contract.[292] Therefore, OPC submits that the 2009 wage increase is not known and certain, and too remote from the test year.

158. As for OPC's second contention above, OPC asserts that Pepco should use a 13-month average number of employees (exempt and union) to calculate the impact of annualization of the 2008 wage increases and the projected 2009 bargaining unit increase.[293] OPC claims that the number of employees used by Pepco differs from both the 12-month and 13-month average. Pepco applies a reduction factor to apply to the annualized wage increases in the prior rate case (F.C. No. 1053). The Company derived its reduction based on the number of employees at the end of the test year as compared to the average number of employees during the test year. The 13-month average test year numbers for exempt and bargaining unit employees are 306 and 1,056, respectively.[294]

159. Finally, because the number of employees continues to decline, OPC applies a reduction factor it says is consistent with Formal Case No. 1053, utilizing a post-test year employee count based on most recent known and measurable data. OPC therefore uses the actual number of exempt and bargaining unit employees, which, as of July 31, 2009, was 299 and 1,031 respectively.[295]

160. Based on the above, OPC proposes an adjustment that reduces Pepco's wage annualization adjustment by $131,000.[296]

161. **Pepco Rebuttal.** Pepco responds that the union contract was ratified on September 3, 2009, with a 2.0 percent wage increase (0.5 percent more than estimated) just over eight months after the end of the test year.[297] This makes the increase known and measurable. Pepco submits that OPC acknowledges that the remoteness argument does not apply to known and measurable changes occurring within one year of the end of the test year.[298] Pepco contends in addition that OPC's remoteness argument is contradictory to its recommendation that the

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292 OPC (A) at 60-62 (Ramas).

293 *Id.* at 63.

294 *Id.* at 64.

295 *Id.* at 64-65.

296 *Id.* at 65.

297 Tr. 351-352; Pepco (4C) at 30-31 (Hook Rebuttal).

298 Tr. 894-896.

Commission calculate the wage and salary adjustment using a July 2009 headcount as opposed to an end of the year headcount.[299]

2. Employee Health and Welfare Costs

162. **Pepco.** As for employee health and welfare costs, the Company proposes to increase O&M expense (RMA No. 14) by $315,000 to reflect changes in employee health and welfare costs in the rate-effective period.[300] The Company urges the Commission to accept its forecasts of trends in costs in that they are supported by expert judgment.[301] The proposed increase consists of: (1) an eight percent escalation of test year medical costs ($877,000); (2) a five percent escalation of test year dental costs ($54,000); and (3) a five percent escalation of test year vision costs ($13,000).[302] Pepco also includes employee club costs of $132,000, of which $95,000 is associated with an annual dinner for Pepco employees.[303]

163. **OPC.** OPC argues that RMA No. 14 should be rejected in its entirety. It claims that the escalation factors are unsupported, ignore changes in the employee benefits plans that would offset costs increases and are inconsistent with the actual trends in benefit costs experienced by the Company over the past several years.[304] More significantly, OPC contends that Pepco does not identify how the changes and/or revisions to its medical, dental, and vision plans going into effect in 2009 will impact overall costs. OPC states that Pepco's benefit trends generally are based on a regional survey of six companies in Virginia, Maryland, and the District of Columbia. However, the escalation factors used by Pepco did not appear in the survey. In addition, the survey does not appear to factor in changes in Pepco's medical, dental and vision plans structures or changes in cost sharing between employers and employees.[305]

164. OPC further asserts that, on average per-employee, medical and prescription costs have declined between 2007 and 2008. Overall medical costs decreased by 0.4 percent in 2007 and increased by 1.0 percent in 2008. Clearly, OPC asserts, Pepco has not justified the 8 percent

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299 Pepco (4C) at 32-33 (Hook Rebuttal).

300 Pepco (C) at 13-14 (Hook). Changes associated with medical, dental and vision plans reflect anticipated percentage increases developed by the Human Resources Department based on surveys conducted by Lake Consulting, a consulting actuary.

301 Pepco Br. 35, citing *Potomac Electric Power Co., Formal Case No. 785*, Order No. 7716 at 38-39 (1982) ("we are inclined to accept the indications of 1982 trends and the judgmental predictions of the experts as to the continuation of those trends with respect to the cost of money").

302 Pepco (C)-1 at 17.

303 *See* Pepco's Response to OPC follow-up data request OPC 19-26(c) (Exhibit OPC (A)-30), and OPC's revised revenue requirement schedules, Schedule 12, filed November 20, 2009.

304 OPC (A) at 66-67.

305 *Id.* at 67-68.

medical escalation rate that it proposes for 2009. Therefore, OPC recommends that Pepco's proposed $315,000 increase in employee benefit costs should be denied.[306]

165. As to Pepco's $132,000 employee club costs, OPC recommends that the Commission deny the entire amount including funding for the annual dinner function and other employee club events in light of the current economic environment. This cost should be funded entirely by shareholders. Therefore, OPC concludes that test year expense should be reduced by $44,036.[307]

166. **Pepco Rebuttal.** Pepco argues that the benefit survey is reliable to use as a basis for future projections and states that, based on annualized data reflecting eight months of actual 2009 experience, the projections are 99 percent accurate.[308] Pepco also notes that OPC witness Ramas agreed on cross examination, that the forecast was accurate and acknowledged that she had no information to refute the accuracy of the numbers.[309] Regarding employee club costs, Pepco argues that, in addition to the small dollar amount, the expenditure reflects the Company's aim of attracting and retaining workers.[310]

DECISION

167. It has been the Commission's policy to include collectively bargained union wage increases that are known and measurable in rates in order to more accurately reflect cost in the rate-effective period.[311] In keeping with its practice, the Commission will authorize Pepco's 1.5 percent union wage adjustment that the Company originally expected would be effective June 1, 2009, five months after the end of the test period. However, the Commission finds that it cannot approve the entire 2.0 percent increase that is represented to be included in the ratified contract. Although Pepco claims that the contract has been ratified, much is not known regarding the contract. Pepco has yet to present the contract to the parties and to this Commission to review and evaluate the scope and effect of the negotiated concessions made by the Company and its rate impact, if any. Additionally, the Commission accepts Pepco's headcount as modified by OPC, to reflect the reduction in the number of employees.[312]

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306 *Id.* at 69.

307 *Id.* at 70. This represents the D.C. portion of the expenses.

308 Pepco (4C) at 32-33 (Hook Rebuttal).

309 Tr. 901-902.

310 Pepco (4C) at 35 (Hook Rebuttal).

311 *See Formal Case No. 929,* Order No. 10387.

312 OPC (A) at 60-64. Tr. 1242.

168. As for employee health and welfare costs, the Commission accepts Pepco's proposed adjustment which reflects changes in employee health and welfare costs in the rate-effective period.[313] The Company had urged the Commission to accept forecasts of trends in costs which are supported by expert judgment.[314] The actual 2009 employee health and welfare benefit costs support the accuracy of the Company's forecast. The costs are known and measureable. However, the Commission rejects that portion of Pepco's adjustment that relate to employee club costs. Although the dollar amount is small and Pepco's effort to increase employee morale is commendable, this is a cost that shareholders, and not ratepayers, should bear.

F. Pepco's Proposed Three-Year Rolling Average of Pension Costs, OPEB, and Uncollectible Expenses (Issues Nos. 8 and 8a)[315]

169. **Pepco.** To smooth out the impact of unusually high 2009 pension costs, Pepco proposes a surcharge to collect a three-year rolling average, rather than each year's actual costs, of its volatile pension costs, uncollectible expenses, and other post-employment benefit ("OPEB") expenses.[316] The surcharge would be reset annually, and any difference between the surcharge amount and the actual expense for each year would be deferred as a regulatory asset/liability and treated as a recoverable cost of service in the Company's next rate case.[317] According to Pepco, the impact of its "Volatility Mitigation Surcharge" ("VM tariff") would be a $3.4 million reduction in Pepco's revenue requirement in the present case.[318]

170. Alternatively, Pepco proposes to use ordinary base rates (rather than an annually updated surcharge) to collect its pension/OPEB/uncollectible expenses, set at a three-year average level.[319] Under this alternate proposal, "any differential between the three-year average level reflected in base rates and the current-year expense is deferred as a regulatory asset upon which capital costs accrue at the authorized rate of return."[320] Pepco contends that this

313 Pepco (C) at 13-14 (Hook).

314 Pepco Br. 35, citing *Potomac Electric Power Co., Formal Case No. 785*, Order No. 7716 at 38-39 (1982) ("...we are inclined to accept the indications of 1982 trends and the judgmental predictions of the experts as to the continuation of those trends with respect to the cost of money").

315 Designated Issue No. 8 asks, "Is Pepco's proposal to recover a rolling three-year average of pension costs, other post-employment benefits, and uncollectible expenses through a surcharge, and to defer for future recovery or refund the difference between the average and actual incurred amounts, reasonable?" Designated Issue No. 8a asks, "Is Pepco's alternative deferral proposal reasonable?"

316 *See* Pepco (A) at 30 (Kamerick); Pepco (G) at 14 (Bumgarner).

317 Pepco (C) at 22-24 (Hook); Pepco (A) at 30 (Kamerick). *See also* OPC (C) at 29-30 (Bright).

318 Pepco (C) at 23-24 (Hook); Pepco (A) at 30-31 (Kamerick); Pepco (G)-6 (Bumgarner).

319 Pepco (2A) at 5 (Kamerick Supp. Direct).

320 *See* Pepco (C) at 24- 25 (Hook); Pepco (G) at 15 (Bumgarner); OPC (C) at 39-40 (Bright).

alternative is workable because, "although it hurts the Company's cash flow, it provides for cost recovery."[321]

171. **OPC.** In opposing Pepco's initial proposal, OPC points out that the Commission rejected a similar Pepco proposal in Formal Case No. 1053, on the grounds that pension/OPEB costs do not require any different treatment than Pepco's other operating expenses.[322] OPC argues that the alleged volatility of the pension and OPEB expenses in this case is not materially different from the variability that the Commission found insufficient to justify a departure from test year ratemaking in Formal Case No. 1053.[323] Nor do Pepco's "uncollectibles" show sufficient "volatility" to justify a surcharge.[324] OPC argues that the spike in Pepco's 2009 pension costs reflects the recent economic downturn, that it is not representative of the future, and that it does not show that pension expenses are typically so volatile that they should be recovered through an extraordinary surcharge mechanism.[325] OPC asserts that a surcharge would undercut Pepco's incentive to control its pension, OPEB, and uncollectible expenses. The Company's proposed VM tariff contains only perfunctory procedures that OPC contends do not present a meaningful opportunity for review by OPC and other intervenors.[326] OPC notes that the Maryland Public Service Commission recently rejected a similar surcharge request from Delmarva Power and Light. In sum, OPC argues that Pepco has not justified a surcharge for recovering its pension costs, OPEB, and uncollectible expenses. OPC concludes that these are ordinary operating expenses that should be considered in traditional ratemaking procedures. OPC submits that there is no support for Pepco's claim that a surcharge is necessary to avoid a downgrade in the Company's credit rating.[327]

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321 Pepco (2A) at 6 (Kamerick).

322 OPC (C) at 29-32 (Bright), citing *Formal Case No. 1053*, Order No. 14712, ¶365.

323 *See* OPC Br. 138-140; OPC R. Br. 57-58; OPC (C) at 34. "Although the amount of D.C. pension expenses shown on OPC's Exhibit varied from a negative $600,000 in 2001 to $3.8 million in 1994, and the D.C. OPEB expense varied from $2.2 million in 1994 to $4.6 million in 2007, this Commission concluded [in *Formal Case No. 1053*] that such fluctuations in expense did not justify a departure from test-year ratemaking." *Id.*

324 *Id.* at 35.

325 *Id.* at 34, 36. OPC also states the $3.4 million revenue reduction associated with Pepco's proposal occurs only because a three-year average is less than the immediate 2009 "spike" in Pepco's pension costs. "By using the average expenses to lower the amounts included in the initial surcharge, Pepco is giving up only a very short term reduction in cash flow in exchange for a guaranteed recovery of these expenses on a dollar for dollar basis." OPC (C) at 37 (Bright).

326 *Id.* at 38-39 (OPC also states the surcharge VM tariff rider "does not provide for the recovery of the [possible $10 million] regulatory asset/liability between general rate proceedings," though "Pepco witness Bumgarner indicated that a provision would be added if the Commission approves the mechanism").

327 OPC Br. 137; OPC R. Br. 56-58; OPC (C) at 39.

172. OPC opposes Pepco's alternative proposal on similar grounds. It claims that Pepco's alternative proposal entails a higher revenue requirement than the VM tariff surcharge, because "it includes an accrued return on the regulatory asset and the surcharge does not." OPC contends that the Commission should simply set Pepco's pension, OPEB and uncollectible expenses at reasonable, representative levels.[328]

173. OPC argues that Pepco's recent multi-million-dollar contributions to its pension fund (approved by the Commission over OPC's objections)[329] do not support the Company's request for extraordinary relief on its 2009 unrecovered pension expense. Those contributions were made to satisfy mandatory pension funding requirements, and OPC claims that Pepco's proposal to include them in rate base will more than recover these amounts from ratepayers.[330]

174. **AOBA.** Echoing many of the same contentions as OPC, AOBA objects to Pepco's new proposed surcharge. AOBA argues that a surcharge would recover increasingly large pension and OPEB costs outside of normal ratemaking procedures; it would make these costs more difficult to verify; it would undercut Pepco's incentives to manage its pension, OPEB, and uncollectible expenses; and it would shift risk on these costs to ratepayers who are not in a position to manage them.[331] Further, AOBA contends that the surcharge allows only a shortened period (60 days) for parties to review the prudence of costs flowed through the surcharge, and no opportunity for review or comment by parties other than Commission staff.[332]

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328 OPC (C) at 40 (Bright). OPC urges that, if the Commission imposes a surcharge, it should apply only to pension costs which have "shown somewhat greater variability year-to-year" than OPEB and uncollectible expenses. "Second, the Commission should specify that any surcharge mechanism is not intended to be permanent and that Pepco will have the burden of showing * * * why any deferral mechanism should remain in place. Third, the Commission should make clear that Pepco is not entitled to earn a return on any regulatory asset that should accrue for under-recovered amounts." Finally, OPC suggests that an annual open hearing should be held on any surcharge, with the burden of proof on Pepco to justify the reasonableness of any expenses included in the surcharge. *Id.* at 40-41.

329 *See Formal Case No. 1053*, Order No. 14712, ¶¶ 102-113.; Order No. 14832, ¶¶ 6-16.

330 OPC Br. 143; OPC (C) at 47-48 (Bright).

331 AOBA (A) at 72, 71-82 (Oliver). AOBA contends that the surcharge rider VM proposed by Pepco is also technically flawed. *First*, Pepco's rolling 3 year average would always be based in part on estimated costs (not actual costs as Pepco suggests). *Second,* Pepco proposes to treat pension/OPEB/uncollectible expenses as a "regulatory asset/liability," improperly suggesting that, even before these expenses are examined, they are presumptively recoverable in future rates. Finally, the surcharge contains no effective date or schedule for annual filings. *See id.* at 73-75.

332 To reasonably assess the prudence of Pepco's pension and OPEB costs, AOBA argues, one would have to examine whether Pepco has limited its use of "defined benefit" pension plans or replaced those programs with "defined contribution" pension plans whose costs can be more easily controlled. Pepco's pension and OPEB costs would have to be compared with those for other electric distribution utilities, and reasonable limitations and controls would have to regulate how pension and OPEB costs are charged by PHI to Pepco. AOBA (A) at 80-82.

175. AOBA also disagrees with Pepco's alternative suggestion to create a regulatory asset for future recovery of the amount by which Pepco's actual pension, OPEB, and uncollectible expenses exceed the level allowed in base rates. AOBA contends that this proposal would diminish Pepco's incentives to control costs, and shift risks to ratepayers that traditionally have been borne by the Company. Pepco's regulatory asset approach provides no assurance that only "prudently incurred" pension costs would be allowed.[333]

176. With the significant upturn in the stock market during the second half of 2009 and the improvement in the economy, AOBA argues that Pepco's early forecasts overstate its actual requirements for future pension, OPEB, and uncollectible funding.[334]

177. **WMATA.** WMATA points out that, over the period 2007 through 2009, pension costs are responsible for most of the volatility and increase in Pepco's pension, OPEB and uncollectible expenses. WMATA graphically presented the evidence on Pepco's year-by-year pension, OPEB and uncollectible expenses (in thousands of dollars) as follows:[335]

	Pension	OPEB	Uncollectibles	Total
2007	$7,280	$11,075	$2,367	$20,722
2008	$8,558	$10,800	$3,142	$22,500
2009 est.	$22,138	$10,915	$3,442	$36,495

If Pepco were granted a surcharge, WMATA argues, this would reduce its risks, thereby reducing its cost of capital and warranting an adjustment of Pepco's ROE.[336]

178. The surcharge mechanism in Rider VM is preferable, WMATA argues, to Pepco's "regulatory asset" proposal because the VM surcharge adjusts up and down with the swings associated with the expenses. WMATA argues that the surcharge in Rider VM should include only pension expenses, which account for a significant portion (10 percent) of Pepco's operating expenses, and which are outside Pepco's control and volatile because they are related to the financial markets. WMATA argues that, by contrast, Pepco's OPEB and uncollectible expenses are not volatile or unpredictable, and they should remain as part of Pepco's base rates.[337]

179. **Pepco Rebuttal.** The Company defends its three-year amortization proposal for pension/OPEB/uncollectible expenses as a "typical regulatory approach," often used to prevent

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333 *Id.* at 76-82.

334 AOBA R. Br. 20-23.

335 *See* WMATA (A) at 14 (Foster).

336 WMATA Br. 6, 8, 9; WMATA (A) at 14-15.

337 WMATA Br. 8-9; WMATA (A) at 15-16.

rates being set based on an unusual expense event.[338] To support its proposition, Pepco cites Formal Case No. 922 where the Commission accorded Washington Gas Light Company "an opportunity to file for an annual increase for OPEB related costs" on the ground that "without this mechanism, Washington Gas may not be able to record a regulatory asset, which will significantly damage the Company's earnings." For similar reasons, Pepco seeks to recover volatile pension, OPEB, and uncollectible expenses in this case.[339] Pepco avers that there is "volatility from year to year" in these costs because of changes (beyond Pepco's control) in the discount rate and the financial markets that impact the amount of PHI's pension liability.[340]

180. Pepco argues that OPC is simply speculating in using a simple average of the Company's 2008 and 2009 pension expenses to estimate the level of pension expense that should be reflected in the rate effective period beginning in January 2010.[341]

181. The Company also objects to setting pension and OPEB expenses at the three-year average level, as AOBA recommends, without creating an associated regulatory asset covering the difference between that average level and the actual expense incurred.[342] While some of the expenses recovered under Rider VM would be estimated costs, Pepco contends that they would be continually subject to true-up so the Company would not over-recover actual expenses. Equally without merit is AOBA's claim that Rider VM implies Commission pre-approval of the prudence of the costs. Pepco asserts, to the contrary, that the Rider does not foreclose prudence review; in fact, it requires Pepco to furnish the Commission staff with sufficient workpapers for the review and audit of the surcharge. Pepco contends also that there is no merit in AOBA's objection that many pension/OPEB costs covered by the proposed surcharge are billed to Pepco by PHI. Pepco argues that these pension/OPEB costs are no less real or necessary for Pepco because they relate to PHI Service Company employees.[343]

182. Moreover, Pepco argues, the originally estimated pension costs could now be replaced by actual cost figures.[344] Pepco submits, assuming the expense levels are updated to reflect the final 2009 actuarial report, OPC has correctly stated the necessary revisions to OPEB liability, namely a $7.6 million reduction to D.C. distribution-related rate base, or a reduction of

338 Pepco (3A) at 22 (Kamerick).

339 Pepco R. Br. 41-42, citing *Washington Gas Light Co., Formal Case No. 922*, Order No. 10307 (1993).

340 Pepco (3A) at 23- 25.

341 Pepco (4C) at 25-27 (Hook).

342 *Id.* at 27-28.

343 Pepco R. Br. 42-43.

344 *See* Pepco (4C) at 28-29. Pepco objects to OPC's proposed adjustment to prepaid pension costs unless the Commission should decide that actual 2009 expenses should be used. Moreover, Pepco cautions that the timing of the expense and rate base components should be the same, so that "if the expense level is updated to reflect calendar year 2010," as OPC proposes, "then so too should be the corresponding rate base component." *Id.*

$233,000 from the Company's original filing. The Company also submits Pepco Exhibit (4C)-8 to show the adjustments that would be made if both 2009 actual pension costs and 2009 actual OPEB expenses were used in calculating Pepco's rates. The exhibit also reflects the correction to the computation of the OPEB liability.[345]

DECISION

183. The Commission rejects the Company's surcharge proposal and directs Pepco to continue recovering these expenses through rates. We are persuaded by the evidence presented by OPC and WMATA that no striking "volatility" is shown in Pepco's OPEB and uncollectible costs, and it is less than that found insufficient to justify a surcharge in Formal Case No. 1053. There was a spike in Pepco's 2009 pension costs, but this appears to be an anomaly.

184. Traditional ratemaking treatment, instead of a surcharge, is supported by the fact that Pepco failed to show that the recent volatility in its pension costs is likely or expected to be a recurring issue. As pointed out by the parties, the stock market has improved. A surcharge would guarantee a dollar-for-dollar recovery of these specific costs and would diminish the Company's incentive to control those costs. The Company failed to show that a pension/OPEB/uncollectibles surcharge is necessary to avoid serious harm to Pepco's financial well-being. Accordingly, we find no justification on this record for ordering specialized rate treatment by excluding these classic, ongoing utility expenses from the standard, contextual ratemaking analysis.

G. Pepco's Proposed Regulatory Asset Treatment of Its 2009 Pension Costs

185. **Pepco.** The Company alternatively seeks regulatory asset treatment of the excess of its 2009 pension expenses over what is currently being recovered in Pepco's rates. (OPEB and uncollectibles were not included in this request.) Pepco states that the rates set in this case will not become effective until 2010. However, the spike in its 2009 pension expenses will have to be recorded on the Company's books in 2009. Unless its requested accounting treatment is approved in 2009, Pepco argues, it will not have any opportunity to earn its authorized rate of return and its stock prices and bond ratings will be adversely affected.[346]

186. Pepco avers that its pension expenses have increased dramatically from $2.791 million a year (the amount reflected in Pepco's current rates) to $8.153 million a year (Pepco's calendar year 2009 O&M pension expenses as estimated on March 1, 2009) to $9.280 million a year (the Company's calendar year 2009 O&M pension expenses as estimated more recently).[347] Though expense items often show some variation, Pepco argues that its 2009 pension costs should be given special accounting treatment because of the sheer size of this unexpected

345 *Id.* at 29-30.

346 Pepco Br. 74-79; Pepco R. Br. 43; *Affidavit of Pepco Witness Anthony J. Kamerick* at 2-4.

347 *Id.* at 2, ¶ 4.

expense, which was caused by the impact of the current economic crisis on the value of its pension fund assets.[348] To support its position, Pepco cites *South Carolina Electric and Gas Company*, S.Car. Docket No. 2009-36-E, Order No. 2009-81, where the South Carolina Commission authorized the establishment of a regulatory asset to track the $26.7 million decline in value of a utility's pension fund assets due to current economic conditions.

187. In supplemental direct testimony, Pepco witness Hook testified that the regulatory asset covering 2009 pension costs would be approximately $6.5 million. Pepco would amortize this sum over a three-year period which would increase Pepco's revenue requirement by approximately $2.5 million.[349]

188. **OPC.** OPC argues that stock market fluctuations in the value of Pepco's pension assets do not justify special regulatory treatment for Pepco's pension costs. OPC contends that, ordinarily, the risks of stock market fluctuations are borne by the utility. OPC notes that, to date, the 2009 pension expense issue has not negatively affected Pepco's credit rating or financial metrics or caused "irreparable harm."[350]

189. OPC points out that the Commission recently rejected a similar Pepco request in Formal Case No. 1053.[351] There Pepco requested a surcharge to permit recovery of its pension and OPEB expenses, arguing that financial conditions including stock market fluctuations cause its pension-related expenses to deviate significantly from its test period expenses. OPC argues that the Commission properly rejected this claim.[352]

190. OPC's supplemental direct testimony notes that, in Order No. 15540, the Commission rejected Pepco's request for an immediate order for regulatory asset treatment of its 2009 pension costs.[353] Further, OPC notes that none of the jurisdictions to which Pepco has applied (Maryland, New Jersey and Delaware) has authorized Pepco to treat its 2009 pension expenses as a regulatory asset.

191. OPC argues that Pepco has not shown that its 2009 pension costs have dramatically affected its financial status, threatened its credit rating, or justified regulatory asset treatment for its pension costs.[354] OPC concludes that Pepco's request for a pension related

348 *Id.* at 2-4.

349 Pepco (3C) at 1-2 (Hook).

350 OPC (C) at 45, 46 (Bright).

351 *Id.* at 44. *Formal Case No. 1053*, Order No. 14712, ¶ 365.

352 OPC (C) at 46-47.

353 OPC (2C) at 4 (Bright).

354 *Id.* at 6-10 (Bright).

regulatory asset of \$6.5 million amounts to impermissible "single issue ratemaking and retroactive ratemaking."[355]

192. **Pepco Rebuttal.** The Company retorts that, contrary to OPC's submissions, Pepco's proposed tracking mechanism for pension costs is used by many utility companies and is consistent with the widespread use of ROE incentives, riders, trackers, and other cost recovery mechanisms.[356] Pepco contends that other jurisdictions are now actively considering Pepco's request for regulatory asset treatment of its 2009 pension costs.[357]

193. The Company states that its pension costs spiked dramatically in 2009, yielding a \$6.5 million shortfall. Pepco claims that were it denied authorization to collect that \$6.5 million shortfall, it would equate to a loss of "approximately 60 basis points in rate of return, which translates to over 130 basis points return on equity." While OPC discounts the impact of this on Pepco's financial ratings, Pepco asserts that Fitch's rating service recently noted (September 2, 2009) that Pepco's "stable" credit rating assumes that regulatory Commissions "will provide reasonable and timely recovery of costs incurred by PHI's utility subsidiaries, including pension costs."[358] Moody's Investor Service also stated in August 2009 that a utility's ability to timely recover costs is critical. The Company argues that "the inability to recover as a regulatory asset the 2009 pension expense not recovered through rates effective in 2009 is detrimental to the Company in areas that encompass 90 percent of what Moody's takes into account when deriving our credit rating."[359]

DECISION

194. The Commission rejects Pepco's alternative proposal seeking the creation of a "regulatory asset" for recovery of its pension costs. Our decision here is in accord with our recent ruling in Formal Case No. 1053, where we rejected a comparable tracking proposal.[360] It also accords with the recent decision of the Maryland Public Service Commission, which rejected a similar request by Delmarva Power & Light for a surcharge, or amortization, of large pension and OPEB costs incurred because of the recent economic downturn.[361] None of the

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355 OPC (2C) at 11; OPC (C) at 47-48.

356 Pepco (3B) at 85-87 (Morin). The pension costs at issue are from a current period, Pepco notes, so OPC is mistaken in claiming that establishment of a regulatory asset would constitute retroactive ratemaking. Pepco R. Br. 44.

357 Pepco (4A) at 2 (Kamerick).

358 Pepco (4A) at 2-5.

359 *Id.* at 3-8.

360 Order No. 14712, ¶ 365.

361 *See In re Delmarva Power & Light Company*, Maryland PSC Case No. 9192, Order No. 83085 at 12-16 (December 30, 2009).

other jurisdictions to which Pepco has applied (Maryland, New Jersey and Delaware) has authorized Pepco to treat its 2009 pension expenses as a regulatory asset.

195. Ordinarily, the risks of stock market fluctuations are borne by the utility.[362] Traditional ratemaking analysis is well-suited to address fluctuations in pension costs. Pepco did not demonstrate that its financial situation is as precarious, or that its pension fund losses were as extreme, as was the case for the South Carolina utility that received "regulatory asset" relief in the *South Carolina Electric and Gas Company* case.[363] Regulatory asset treatment might diminish Pepco's incentives to control its pension costs. We also have considered the community comments objecting to high pension cost recovery by Pepco.[364] The Commission finds that, on this record, Pepco failed to carry its burden of proof to justify a departure from traditional ratemaking procedures for recurring pension costs.

H. Transactions between Pepco and Other PHI Affiliates (Issues Nos. 7 and 7a) [365]

196. **Pepco.** The Company submitted a benchmarking study by the Hackett Group to support the reasonableness of its affiliate transactions. The study compares Pepco to 27 other electric utility companies on: (1) the ratio of "Administrative and General" ("A&G") expenses to total sales; and (2) the ratio of total A&G expenses to net utility plant.[366] Hackett concluded that PHI Service Company's costs are in line with its peers and are therefore reasonable.[367]

197. **OPC.** OPC seeks a $189,000 reduction in Pepco's District operating expenses to eliminate an error in which the PHI Service Company over-allocated deferred compensation costs to Pepco. OPC indicates that Pepco has agreed to make this correction.[368] OPC also seeks to eliminate from Pepco's operating expenses $170,691 in one-time, non-recurring District-

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362 *See, e.g.*, Order No. 15540, ¶ 11.

363 Our decision today safeguards Pepco against any "significant damage" to the Company's earnings. Accordingly, this case is very different from *In re Washington Gas Light Co.*, Formal Case No. 922, Order No. 10307 (1993) (cited by Pepco R. Br. 41-42), where special regulatory treatment was found necessary to avoid damage to the utility.

364 *See* ¶ 456 *infra*.

365 Designated Issue No. 7 asks, "Are the PHI Service Company costs charged by Pepco reasonable?" Designated Issue No. 7a asks, "Are the benchmarks filed by Pepco reasonable and do they support the costs charged to Pepco?"

366 Pepco (A)-1 at 1, 2 (Kamerick).

367 Pepco Br. 62-63; Pepco (I) at 4, 5, 9, 10 (Snowball).

368 OPC Br. 128; OPC (C) at 16 (Bright).

allocated costs that PHI Service Company paid to outside consultants for work on its "Utility of the Future" initiatives.[369]

198. Over the longer term, OPC recommends several Commission actions to facilitate further inquiry into the costs (over $160 million in direct and allocated charges) that have been allocated to Pepco by PHI Service Company. *First*, OPC asks the Commission to issue a final Affiliate Transactions Code of Conduct for energy utilities in D.C. in Formal Case 1009. *Second*, OPC requests an audit of the transactions between Pepco and its affiliates as well as an audit of Pepco's adherence to the new Code of Conduct.[370] *Third*, OPC contends that Pepco should be required to submit more information about its "affiliate transactions," both in Compliance Filings and in annual filings of FERC Form No. 60 with this Commission. Otherwise, OPC states that it is waiting for the results of the independent audit that the Commission ordered in Formal Case No. 1053 to assess many of the costs that PHI's Service Company has allocated to Pepco in the District.[371]

199. OPC submits a list of reasons why it considers Pepco's benchmark study defective and why the study should not be used to determine the reasonableness of the PHI costs that were allocated to Pepco.[372] More fundamentally, OPC questions whether any benchmark study which does not exclude unreasonable costs from all the "benchmarked" companies (such as executive incentive plan and supplemental retirement plan costs of the kind that this Commission has excluded from Pepco's recoverable costs) should be used to decide the reasonableness of the "affiliate charges" borne by Pepco.[373]

200. OPC argues that comparing the ratio of A&G expenses to sales is not meaningful. Moreover, OPC states that Pepco reports a ratio of A&G to sales that is higher than that of PHI's other utility affiliates. Similarly, OPC points out that another PHI-affiliated electric utility has a lower ratio of total A&G expenses to net utility plant than Pepco. OPC contends the implication is that Pepco may be allocated disproportionate A&G costs within the PHI group.[374]

369 OPC (C) at 16-17; *see also* OPC Br.128.

370 OPC Br. 126-127; OPC (C) at 12, 11-14.

371 *See* OPC Br. 127-128; OPC (C) at 4-5, 12-13, citing *Formal Case No. 1053*, Order No. 14712, ¶ 170.

372 OPC (C) at 17-27 (Bright). The study is based on a small sample of peer group companies; the data for the peer group companies was based primarily on years prior to 2007; the A&G costs included in the study represent only about 60% of the costs charged to Pepco by the PHI; revenue is used as the primary driver for the Finance and Executive & Corporate Services functions which represent 62% of the A&G costs studies; the median companies included in the Finance and Executive & Corporate Services function peer group had substantially less revenue than PHI, which causes a distortion of these benchmark ratios in favor of PHI; study lacks the qualitative analysis (executive interviews, stakeholder surveys, and recommendations) that would have yielded a deeper analysis.

373 OPC Br. 135; OPC (C) at 26.

374 *Id.* at 27-29. OPC argues that, in any event, Pepco witness Kamerick failed to show how his sample of 27 electric companies is comparable to Pepco, or how Pepco's A&G expenses are reasonable.

201. **AOBA.** AOBA argues that the Commission should deny Pepco any increase in Service Company charges over the levels currently included in Pepco's D.C. distribution rates. AOBA argues that Pepco has not shown the reasonableness of any of the "affiliate costs" allocated to it. Instead, AOBA contends that Pepco witness Snowball's benchmark study addresses only vaguely-defined holding company costs (not the costs allocated by holding companies to utilities). Unlike a normal third-party service contract, the Service Agreement between Pepco and PHI places no limitations on the dollar amounts or number of hours that the Service Company can bill to Pepco. AOBA contends that there are no criteria for assessing the adequacy, timeliness or quality of the Service Company's performance. The Company's benchmarking study does not compare the cost of services provided by PHI against what the cost would be if the services were provided by Pepco or an independent third party. Nor does the study address whether the PHI Service Company costs charged to Pepco are in line with similar charges made to other utilities.[375]

202. **Pepco Rebuttal.** The Company defends its benchmarking study as one that contains "appropriate peers" for comparison with PHI, because of its correlation with PHI on the "core demographics of revenue, countries and employees." Pepco argues that OPC's criticism about the lack of a service company within the organizational structure of the peer group companies is of no moment, because "Hackett eliminates these organization difference by evaluating the full cost of the process to the company – regardless of where the activity occurs."[376]

203. Pepco claims the study appropriately focuses on A&G costs because it provides the Commission with an opportunity "to get deep down into productivity-type measures to figure out if the services that [the] Service Company was providing were comparable to other similar services being provided and paid for by other companies."[377] In focusing on A&G costs, the study excludes costs that are not subject to allocation to Pepco,[378] and it shows the reasonableness of the total Service Company A&G costs assigned to Pepco. Pepco indicates that older labor costs in the study were appropriately adjusted for inflation.[379] Pepco also claims that "the methods by which these Service Company costs are directly charged or allocated to Pepco

375 AOBA Br. 32-34; AOBA (A) at 66-70 (Oliver).

376 Pepco Br. 63; Pepco (3I) at 3-7 (Snowball).

377 *Id.* at 66-67.

378 The study covers A&G costs that are charged or allocated to both regulated and non-regulated entities within PHI, including Pepco. Pepco Br. 65; Pepco (3I) at 8. "Groups within the Service Company, which provide services directly to:(1) one or a discreet number of regulated utilities; or (2) non-regulated affiliates, were not included within the scope of the benchmark study." *Id.* at 8-9. "In other words, if the costs were not subject to allocation to Pepco, they were excluded. The excluded groups were associated with engineering, call center and non-regulated activities of energy business affiliates." Pepco Br. 65-66; Pepco (3I) at 8-9.

379 Pepco Br. 64-65.

are covered by the PHI Cost Allocation Manual, which has been approved by the Commission."[380]

204. The Company states that its study is one in which the "Finance and Executive & Corporate Services (ECS) comparisons are normalized using revenue." OPC criticizes the smaller size of the comparison peer companies, but Pepco argues that its "normalization" procedure accounts for this difference in size and that ECS activity is driven more by revenue than by other factors such as number of employees, cost of goods sold and number of legal entities.[381]

205. In response to AOBA's contentions, Pepco claims that its study properly assesses the costs of a particular service based on "Hackett's definition of a particular A&G process, not how each individual company may internally define such a process." Pepco acknowledges that its benchmarking study did not compare services provided in-house with those that PHI outsourced. The study did, however, factor in outsourced costs as part of a total aggregated cost against which to compare peer group data.[382]

206. With respect to "Utility of the Future Costs" which OPC challenges as one-time consultant expenses, Pepco explains that these costs relate to a variety of ongoing projects and activities. While they were categorized under a general "Utility of the Future" umbrella, these costs are for initiatives that would have been undertaken anyway as part of Pepco's ongoing utility operations.[383]

DECISION

207. The Commission finds that the Company's presentation is generally similar to the one that Pepco made in Formal Case No. 1053, where the Commission approved Pepco's recovery of the PHI/affiliate costs allocated to it.[384] Pepco has justified its recovery of PHI/affiliate costs under the standards in our earlier case. The Commission is persuaded by Pepco's testimony to also allow recovery of the disputed $170,691 in "Utility of the Future" operating expenses, since these appear to be on-going recurring expenses for a variety of

380 Pepco (3I) at 6, 14 (Snowball).

381 *See id.* at 9-12.

382 *Id.* at 12-14.

383 Pepco R. Br. 39-40; Pepco (4C) at 36 (Hook); Pepco (3D) at 15-16 (Gausman).

384 In *Formal Case No. 1053*, the Commission had only an estimate that Pepco's D.C. customers were being allocated roughly $37 million of PHI Service Company costs. *Formal Case No. 1053*, Order No. 14712, ¶ 154 160. In this case, Pepco is seeking to recover approximately $41.3 million of PHI Service Company costs from District ratepayers, an increase of approximately $4.3 million, or 11.6%. *See* OPC Exhibit (C)-1, Pepco response to OPC Data Request 3-38.

traditional utility activities and projects, not one-time non-recurring expenses. While the parties object to certain costs, no party has shown that the PHI Service Company has been inefficient or ineffective in the services that it provides to Pepco, or that the PHI/affiliate costs allocated to Pepco are unreasonable. The only exception, which OPC and Pepco have agreed to, is that $189,000 should be deleted from Pepco's D.C. operating expenses to eliminate an over-allocation of deferred compensation costs from the PHI Service Company to Pepco.

208. The Commission still has some outstanding concerns regarding the level of costs that the PHI Service Company is incurring and then allocating to its subsidiaries including Pepco. We agree with OPC about the desirability of: (a) issuing a final Code of Conduct for energy utilities in the District in Formal Case No. 1009; (b) requiring Pepco to submit more information about its affiliate transactions in its Compliance Filings and in annual filings of FERC Form No. 60 with this Commission; and (c) ordering a more investigative audit of the transactions between Pepco and its affiliates. To address our concerns, the Commission has decided to order an independent audit and operational review of the PHI Service Company and Pepco to determine the reasonableness of the costs that are being incurred by the Service Company, and allocated to Pepco, as well as the effectiveness of Pepco's operations. This will be a prospective review. It will look at management, operating practices and procedures, and the services provided to Pepco, to determine its effectiveness and efficiency and whether the costs being incurred and allocated to Pepco are reasonable and appropriate. To save costs and improve our own efficiency, we will consider a regional approach working in coordination with Commissions from other jurisdictions.[385] This will require Commission action in other dockets as well as in this case. Separate orders, to be issued later, will address all these matters in more detail.

I. Past AMI Expenses (Issue No. 9) [386]

209. **Pepco.** The "smart grid" program embraced by Pepco's Blueprint for the Future includes a commitment to implement Advanced Metering Infrastructure ('AMI"). The Company now seeks to amortize, over a three-year period, the December 31, 2008, balance of its AMI start-up costs in the District, while including the unamortized portion in its rate base. Pepco indicates that the start-up AMI costs at issue (some $911,000) were incurred in 2007 and 2008 primarily for outside consultants and reassigned Pepco employees, who were investigating customer needs and planning to make AMI work. Pepco claims that the only AMI costs at issue are "incremental costs," not previously accounted for.[387]

385 We note that two other jurisdiction, New Jersey and Delaware, have already undertaken PHI/affiliate management audits.

386 Designated Issue No. 9 asks, "Is Pepco's proposal to include in proposed rates amounts previously expended for AMI reasonable?"

387 *See* Pepco Br. 80, 82-83; Pepco (A) at 5-8 (Kamerick); Pepco (C) at 16-17 (Hook) (discussing Adjustment 26). The start-up AMI costs "support the future installation and integration of a meter data management system, the AMI requirements development, AMI software applications, and the overall management of the project." Pepco (D) at 13 (Gausman). "We also developed Requests for Proposals and sent them to vendors to obtain pricing

210. In June 2009, the Council passed an emergency statute authorizing recovery of Pepco's AMI costs.[388] The Council subsequently passed the Fiscal Year 2010 Budget Support Second Emergency Act of 2009 ("Budget Act") which effectively approves the implementation of AMI in the District of Columbia.[389] Thereafter, Pepco received a $44.6 million federal grant for its smart grid/AMI activities under the American Recovery and Reinvestment Act of 2009 ("ARRA").[390] However, neither the D.C. statute nor the federal grant covers Pepco's start-up AMI costs incurred in 2007 and 2008.[391]

211. Pepco argues that these start-up AMI costs should be treated as a regulatory asset subject to Commission review for prudence.[392] The Company also argues that "regulatory asset" treatment is appropriate because it had ample evidence from which to conclude that its recovery of AMI start-up costs was "probable." According to Pepco, this evidence included support by the Commission and OPC for the Company's AMI pilot program; the record of prior Commission hearings relating to AMI; communications from the Commission; the Council's enactment of two pieces of legislation supporting AMI; and the Commission's leadership role at NA... ...rting AMI initiatives.[393]

information for a meter data management system, IT systems (software and hardware) and AMI systems consisting of meters, communication equipment and software. * * * we [also] formulated detailed business cases for each of P... ...ior ... *Id.* at 14.

388 *See A... d Metering Infrastructure Implementation and Cost Recovery Authorization Emergency Act of 2009,* (Bill 18-2... Act 18-107) (June 18, 2009) (calling on Pepco "to net any utility cost savings resulting from AMI deployment from the regulatory asset" and specifically reserving the Commission's authority to review Pepco's AMI expenses for prudence).

389 *See Fiscal Year 2010 Budget Support Second Emergency Act of* 2009 (Bill 18-443, Act 18-207) (October 15, 2009).

390 *See* Tr. 51-52 120, 128, 130 (Pepco witness Kamerick). The ARRA statute appears at 123 Stat. 115, 26 U.S.C. §1 (February 17, 2009). There are still open questions about exactly how this ARRA money will be used in Pepco's AMI activities. *See* Tr. 130 (Kamerick). These matters will be addressed by the Commission in *Formal Case No. 1056, In the Matter of the Application of the Potomac Electric Power Company for Authorization to Establish a Demand Side Management Surcharge and an Advance Metering Infrastructure Surcharge and to Establish a DSM Collaborative and an AMI Advisory Group ("Formal Case No. 1056")* filed, April 4, 2007. *See* ¶ 453, *infra.*

391 The statute on AMI costs that was enacted by the Council appears to apply prospectively only, from and after the date of its enactment (June 18, 2009). Technically, then, this D.C. statute does not apply to the 2007 and 2008 AMI start-up costs at issue here in Formal Case No. 1076. Similarly, testimony at the hearings indicated that Pepco's recently-received federal grant money is not available to cover Pepco's $911,000 in AMI start-up costs. *See* Tr.1456-1457 (colloquy between Chairman Kane and Pepco witness Gausman) (U.S. DOE grant money does not cover Pepco's 2007 and 2008 AMI expenses; instead, it covers earlier AMI expenses only during the 90 day period (August, September, and October 2009) before the federal grant was made).

392 Pepco (A) at 6 (Kamerick).

393 Pepco Br. 81; Tr.54,135,137-138,164-165 (Pepco witness Kamerick); OPC Exhibits 2,3.

212. **OPC.** OPC objects to Pepco's three-year AMI amortization proposal, arguing that the Company is improperly using "regulatory asset" treatment as a means to retroactively recover AMI expenses incurred in 2007 and 2008.[394] OPC claims that SFAS No. 71 and the FERC Uniform System of Accounts prohibit creation of a regulatory asset in the absence of a prior regulatory approval.[395] Moreover, OPC argues that "the Company should not be encouraged to take a self-help approach of deciding that such unapproved retroactive costs can be reclassified as regulatory assets on the assumption that it is 'probable' that the Commission will allow retrospective recovery."[396]

213. OPC also argues that Pepco cannot show that, at the time it decided to create a regulatory asset in 2007, it had "available evidence" that its recovery of AMI start-up costs was "probable" under SFAS 71. OPC contends that the unspecific statements of alleged support by the Commission for Pepco's recovery of the AMI expenses, aired for the first time on redirect examination, are far from sufficient to demonstrate that at the time the Company decided in 2007 to defer its AMI expenses as a regulatory asset, it had available evidence to support a determination that the Commission would probably allow future recovery of the expenses.[397] Citing a Maryland PSC order, OPC argues that Pepco did not need to create a regulatory asset for AMI costs in order to obtain federal funding.

214. OPC acknowledges that the Council passed legislation (D.C. Act 18-107) authorizing Pepco to implement AMI "if the Company obtains a sufficient amount of federal funds" under the new ARRA statute. OPC argues that the statute should not have any impact on this case, because the Act does not address Pepco's 2007 and 2008 expenses. Nor does that Act approve of Pepco's unilateral use of a "regulatory asset" as a means to retroactively recover AMI expenses incurred in earlier years.[398]

215. OPC objects to Pepco's 2007 AMI start-up costs as improper retroactive recovery.[399] OPC also argues that because Pepco's 2008 AMI expenses were a one-time, non-recurring "abnormal" contractor costs, they should not be included in Pepco's test year expenses. OPC thus argues that Pepco should write-off the entire $911,000 D.C. portion of its AMI expenses for 2007 and 2008.[400]

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394 OPC Br. 154-168; PC R. Br.59-60; OPC (C) at 50 (Bright).

395 OPC Br. 156-160; OPC (C) at 50-56.

396 OPC (C) at 56 (Bright).

397 OPC Br. 163; and *see* OPC R. Br. 60.

398 OPC Br. 164-166; OPC (C) at 58. *Accord* Tr. 927-928 (OPC witness Bright).

399 OPC Br. 166-168.

400 *Id.* at 168; OPC (C) at 57, 59.

216. **AOBA.** Objecting to Pepco's recovery of AMI start-up costs, AOBA argues that Pepco failed to show that these costs were "incremental." Nowhere in its presentation does Pepco detail the base from which it measures "incremental" costs. AOBA submits that this Commission's policies leave Pepco with considerable discretion as to how to treat expenditures that occur between rate cases. However, Pepco's sweeping theory that it can recover "incremental" costs from a prior period (which allegedly caused Pepco to exceed its authorized revenue) threatens to place all such costs beyond effective Commission scrutiny. Accordingly, AOBA opposes Pepco's "incremental cost" theory.[401]

217. Further, AOBA contends that Pepco has not shown that its AMI start-up costs were necessary or essential to its provision of distribution service. AOBA argues that Pepco has not yet demonstrated the cost-effectiveness of its proposed AMI plan for the District of Columbia.[402]

218. AOBA points out that the Company failed to obtain prior Commission approval for the creation of a "regulatory asset" to cover the AMI start-up costs that it elected to defer for future recovery. AOBA concedes that a "regulatory asset" can be created in some circumstances for Pepco costs whose recovery is "probable." However, AOBA argues that Pepco did not identify any specific "signals from the Commission or other documents" that supported its decision that AMI recovery was "probable" so as to justify the creation of a regulatory asset for 2007 and 2008 AMI-related costs.[403]

219. In any event, AOBA contends that the three-year amortization is arbitrary, and fails to match the recovery of AMI start-up costs with the timing of expected benefits from the AMI system. AOBA concludes that if these AMI start-up costs are permitted in rates, they should be recovered over the full expected 15-year life of the associated AMI equipment.[404]

220. **Pepco Rebuttal.** Contrary to OPC's submission, Pepco counters that its AMI start-up costs were prudently incurred, for the benefit of customers. The start-up AMI work was necessary to enable the Commission to review the cost-effectiveness of the technology. It helped obtain federal funding. Pepco argues that denying cost recovery would create a disincentive for Pepco initiatives that benefit ratepayers. Pepco argues that the overall prudence and cost effectiveness of the AMI project was shown in Formal Case No. 1056, and is supported by the

401 AOBA Br. 27-28; AOBA R. Br. 23-24. *See generally* AOBA (A) at 56- 61, 82 (Oliver).

402 AOBA Br. 27, 28.

403 *Id.* at 27; AOBA R. Br. 23-24.

404 AOBA Br. 28-29; AOBA R. Br. 25.

District Government's recent enactment of legislation supporting the AMI project.[405] Accordingly, Pepco argues that its 2007 and 2008 AMI start-up costs should be recoverable.[406]

221. Pepco witness White proffers that the Company's decision to record certain AMI costs as a regulatory asset is consistent with SFAS No. 71 and FERC and GAAP accounting principles. Both of these standards provide that a regulatory asset may be established if recovery in future rates is "probable."[407] Moreover, Pepco argues that it did not need a prior regulatory order before these costs were recorded as a regulatory asset based on its interpretation of the standards.[408] Pepco proposes to treat its AMI start-up costs as a regulatory asset and to amortize them over a three-year period rather than expensing them in the year they were incurred.[409] These are "incremental, one-time expenses in support of the AMI project," and Pepco argues they are properly treated as deferred expenses.[410]

DECISION

222. We find that the totality of events surrounding Pepco's AMI program implementation in the District of Columbia warrants Pepco's recovery of its AMI start-up costs. Beginning in April 2007, the Company originally proposed the implementation of AMI in the District of Columbia as part of its "Blueprint for the Future" initiative.[411] While this matter was under Commission review, the federal government enacted the American Recovery and Reinvestment Act of 2009 ("ARRA").[412] The ARRA authorizes the U.S. Department of Energy ("DOE") to award grants up to 50 percent of the cost to facilitate the deployment of smart grid technologies, including AMI.[413] In order to ensure that the District of Columbia was positioned

405 Pepco (3D) at 23-26 (Gausman).

406 Pepco R.Br. 45-46; Pepco Br. 79-80, 83.

407 Pepco Br. 80-81; Pepco R .Br. 45; Pepco (3E) at 7-9 (White). Pepco argues that OPC quoted only part of the FERC standard for reporting costs as a regulatory asset, and that the Company's AMI costs fit under one of the FERC criteria that OPC neglected to mention. *Id.* Pepco Br. 81-82.

408 Pepco Br. 80-82; Pepco R. Br. 45; Pepco (3E) at 6-10 (White).

409 Pepco (4C) at 37-38 (Hook), referring to Pepco (3E) at 6-10 (White) and Pepco (3D) (Gausman). According to Pepco, "A three-year amortization period has historically been used in the District of Columbia to spread out the recovery of certain costs; a recent example would be the costs associated with Formal Case No. 1053, which are currently being amortized over a three-year period. Costs associated with severance programs have also been amortized over three years." *Id.* at 39.

410 Pepco (3D) at 23-26 (Gausman).

411 *See Formal Case No. 1056* (April 4, 2007).

412 *See* Pub. Law 111-5 (February 2009).

413 *Id.*

to receive ARRA funding, the Council passed the Budget Act,[414] which effectively approves the implementation of AMI in the District of Columbia, provided the Commission determines that the Company has received a sufficient amount of federal funds (presumably) to make AMI cost effective.[415] In October 2009, DOE granted Pepco $44.6 million under the ARRA statute for AMI implementation, covering both future AMI expenses and some earlier AMI expenses incurred during the 90 day period before the federal grant was made.[416] Subsequently, in December 2009, we determined that Pepco had received sufficient federal funds for AMI implementation in the District of Columbia.[417]

223. These events support Pepco's proposal for recovery. We further conclude that these start-up AMI costs were prudently incurred. However, the Commission finds that Pepco's 2007 and 2008 AMI start-up costs should be capitalized, and amortized over 15 years – the average service life of AMI meters – rather than the three years requested by Pepco.[418] The start-up AMI costs that Pepco incurred in 2007 and 2008 should be recorded in a tracking capital account and amortized over 15 years. Only the $911,000 in 2007 and 2008 start-up AMI costs are at issue in this Pepco rate case, and only the capitalization and amortization of those start-up AMI costs will be reflected in the rates that we set today.

224. We are not approving "regulatory asset" treatment for these AMI start-up costs. The Commission agrees with OPC and AOBA that "regulatory asset" treatment is not appropriate for costs incurred before the issuance of a regulatory order approving AMI implementation. Previously-incurred AMI start-up costs that are not recoverable under the ARRA grant are to be capitalized and amortized over 15 years, not expensed in Pepco's rates, so there is no retroactive ratemaking. We appreciate AOBA's concern about the sweeping nature of

414 *See* D.C. Act 18-207 (October 15, 2009).

415 *Id.*

416 We note that at the hearing Pepco correctly indicated that ARRA funding is available for AMI expenses incurred within the 90 day period before the October 2009 award. However, the Company's 2007 and 2008 AMI expenses do not qualify to be paid by the new funding. *See* DOE FOA- DE-FOA-0000058, p. 37.

417 *See Formal Case No. 1056, In the Matter of the Application of the Potomac Electric Power Company for Authorization to Establish a Demand Side Management Surcharge and an Advance Metering Infrastructure Surcharge and to Establish a DSM Collaborative and an AMI Advisory Group and Formal Case No. 1070, In the Matter of the Investigation into the Potomac Electric Company's Non-AMI Demand Response Program,* Order No. 15629, ¶¶ 14-15 (December 17, 2009).

418 There was some variance in the evidence submitted about the average service life of AMI meters. The Commission is persuaded, however, that 15 years is a fair figure. Testimony from Pepco witness Spanos was that the average service life of the new AMI meters is 15 years. Pepco (3H) at 24 (Spanos) ("manufacturers of the technology and utility meter specialists anticipate an average service life of 15 years. . . . Finally, the estimated parameters used by other electric utilities for the implementation of AMI meters is an average service life between 12-18 years and a net salvage percent between 0 and negative 5 percent."). *Accord* Tr. 442-445, 450-459, 478-479 (Pepco witness Spanos) (though expected service life of a new non-AMI meter is about 39 years, the average service life of a new AMI meter is 15 years, in part because of its computer-based components). *See also* Commission Ex. No. 18.

Pepco's "incremental cost" theory. The start-up AMI costs being placed into a tracking/capital account will be subject to Commission scrutiny. Our decision properly spreads the recovery of these AMI start-up costs over the time when benefits are expected to be received from the AMI system.[419] As a result of the 15-year amortization, Pepco's annual amortization expense is $60,708, as compared to $303,543 under a 3-year amortization. Based on a 15-year amortization, the average unamortized balance to be included in rate base is $880,274, as compared to $758,857 under a 3-year amortization. The average accumulated deferred tax (a reduction to rate base) is $365,171 under the 15-year amortization, as compared to $314,802 under the 3-year amortization.

VII. DEPRECIATION RATES (Issue No. 6)[420]

225. **Pepco.** Pepco proposes new depreciation rates to be applied to the District of Columbia assets for electric distribution and general plant. Pepco uses the straight-line remaining life technique method with the average life procedure.[421] As it relates to the treatment of net salvage, the Company contends that its estimate of future costs results in the most reasonable interpretation of the full service value of Company assets.[422] Based on the difference between the depreciation rates proposed in Pepco's new Depreciation Study (filed December 31, 2008) and the currently approved rates (approved in Formal Case No. 869), Pepco proposes an increase in depreciation expense (RMA No. 25) of $4.7 million. Rate base would be reduced by $2.35 million.[423]

226. Pepco contends that its depreciation study is reasonable; its proposed depreciation rates were computed with the appropriate District of Columbia book reserve; and its accumulated depreciation reserve is computed correctly based on the District of Columbia's jurisdictional amounts.[424] The plant studied matched, as closely as possible, the plant allocated/assigned to the District of Columbia cost of service calculations. The accumulated depreciation reserve amounts were consistent with the plant balances that were studied and historical depreciation rates

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419 Pepco argued that its AMI start-up costs were largely employee costs (for hiring outside consultants, and moving around PHI/Pepco employees), not associated with AMI meters. There is no doubt, however, that these employee costs were associated (though not exclusively with AMI meters) with the start-up of the AMI program as a whole.

420 Designated Issue No. 6 asks, "Is Pepco's depreciation study reasonable?"

421 Pepco (H) at 8, 12 (Spanos).

422 *Id* at 22.

423 Pepco (C) at 17-18 (Hook); Pepco (C)-1 at 28. Accumulated depreciation would be increased by $2.35 million which would result in a decrease of $2.35 million in rate base.

424 Pepco (2F) at 4 (Browning).

approved by the Commission and that served as the basis of the depreciation expense incorporated in rates.[425]

227. **OPC.** OPC counters that Pepco's depreciation study is not reasonable. OPC recommends a net depreciation and amortization expense for plant of $45.4 million, which is $6.4 million less than the Company's current depreciation expense of $51.8 million. Combining the $6.4 million with OPC's recommended $975,000 amortization of regulatory liability for cost of removal results in a net $7.4 million reduction in depreciation and amortization expense.[426]

1. Reserves Used in the Computation of Depreciation Rates (Issue No. 6a)[427]

228. Pepco's Depreciation Study shows the book reserve amounts and how they were used in the calculations.[428] According to Pepco, its Depreciation Study used the simulated accumulated depreciation reserves for the system general plant accounts. For the plant located in Virginia, simulated depreciation reserves were developed for these plant balances that were consistent with the historical approved District of Columbia depreciation rates.[429] Pepco contends that the book reserve used in its study is the most reasonable given that many assets for Pepco are not maintained on a jurisdictional level.[430] The Company further states that [t]he "simulation" of the reserve was simply dividing of the District of Columbia book reserve by the District of Columbia general plant allocation ratio.[431] Subsequently, during the evidentiary hearing, Pepco provided information showing that it had removed $60 million from D.C. depreciation reserve amounts in its newly implemented PowerPlant accounting record system.[432] OPC expressed concern about Pepco's removal of $60 million on the Company's books from the District of Columbia Depreciation Reserve.[433]

425 *Id.* at 4-5.

426 OPC (E) at 41 (Majoros); OPC (E)-12 and (E)-13.

427 Designated Issue No. 6a asks, "Are Pepco's proposed depreciation rates computed with the appropriate District of Columbia book reserve?"

428 *See,* Pepco (H)-1 at III-3–III-6, III-116–III-160 (Spanos).

429 Pepco (F) at 22-25 (Browning).

430 Pepco (2H) at 9 (Spanos Supp.).

431 Pepco (2F) at 5-8 (Browning Supp.).

432 Tr. 1385-1387, 1398.

433 *See* Issue No. 6b, asks, "Is Pepco's accumulated depreciation reserve computed accurately based on District of Columbia's jurisdictional amounts?"

DECISION

229. The Commission has reviewed Pepco's Depreciation Study for General Plant Accounts and finds that Pepco utilizes "system-wide" depreciation reserve amounts, instead of the D.C depreciation reserve amounts.[434] This results in an overstatement of D.C. depreciation rates. In calculating the proposed 4.89 percent amortization rate for Account 397, Communication Equipment, Pepco uses "system-wide" numbers in which the book accumulated depreciation reserve is 65.95 percent of the original cost of Plant-in-Service.[435] However, Pepco's Study shows for the District of Columbia that the book accumulated depreciation reserve is 74.70 percent of the original cost of Plant-in-Service.[436] This indicates that past District of Columbia ratepayers provided recovery for a higher percentage of the investment than is true system-wide. Using District of Columbia-specific depreciation reserve, the D.C. depreciation/amortization rate for this account is 3.63 percent.[437] A similar problem exists for the other "General Plant" depreciation/amortization rates that Pepco proposes. Pepco acknowledges that it did not use D.C. reserve values in the calculation of its proposed D.C. depreciation rate.[438] The Commission finds it troubling that Pepco used system-wide depreciation reserve figures when D.C.-specific figures are available. Pepco is directed to recalculate "General Plant" depreciation/amortization rates using D.C. book reserve and D.C. original cost amounts. Using D.C-specific General Plant depreciation/amortization rates result in a General Plant accrual that is $687,743 less than the amount calculated using system-wide depreciation reserves numbers.[439]

2. Computation of Accumulated Depreciation Reserve (Issue No. 6b)[440]

230. **Pepco.** Pepco's plant accounting system captures, among other things, the depreciation reserve by jurisdiction. The system then calculates the jurisdictional reserve, with the exception of general plant which is functionalized between transmission and distribution

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[434] In *Formal Case No. 1053*, the Commission directed Pepco to place in service a system that would maintain depreciation expense, accumulated depreciation reserve, cost of removal, and salvage information separated by jurisdiction and by FERC account each month. *See* Order No. 14712, ¶¶ 129-131.

[435] $73,558,650 (System-wide Book Reserve) / $111,532,249 (System-wide Original Cost) = 65.9 5%. *See* Pepco (H)-1 at III-5 and III-159 (Pepco Depreciation Study) (Spanos).

[436] $35,689,386 (D.C. Book Reserve) / $47,774,524 (D.C. Original Cost) = 74.70 %. *See* Pepco (H)-1 at III-6 (Pepco Depreciation Study) (Spanos).

[437] Commission Ex. No. 32.

[438] Commission Ex. No.1 6.

[439] Commission Ex. No. 32.

[440] Designated Issue No. 6b asks, "Is Pepco's accumulated depreciation reserve computed accurately based on District of Columbia's jurisdictional amounts?"

because it supports all facets of Pepco's operations.[441] Pepco contends that its accumulated depreciation reserve is computed accurately and based on D.C. jurisdictional amounts.[442]

231. **OPC.** OPC asserts that Pepco has failed to show that its accumulated depreciation reserve has been computed accurately based on District of Columbia jurisdictional amounts. OPC's concern relates to the transfer in 2008 of $60 million from D.C. jurisdictional accumulated depreciation reserve into the corresponding Maryland account and a similar, nearly $1 million transfer in 2009.[443] OPC argues that the accuracy of Pepco's allocation of accumulated depreciation reserves between jurisdictions can be eliminated by the use of the whole life technique because the whole-life technique does not rely on depreciation reserves in calculating rates.[444]

232. According to OPC, the whole life technique is theoretically superior because it does not skew the depreciation rates to be applied to new plant based on the condition of the reserve accumulated through depreciation of existing plant.[445] OPC maintains that the whole-life technique (along with separate handling of the reserve imbalances) ensures that depreciation rates consistently match the projected service life of plant assets, while still allowing for the recovery of the appropriate depreciation expense.[446] OPC recommends that a depreciation study be conducted every three to five years and asserts that frequent depreciation study updates are important regardless of the technique employed.[447]

233. **Pepco Rebuttal.** Pepco counters that the whole-life technique is flawed in that it does not take into account past recovery patterns or the relationship of the theoretical reserve to the actual accumulated depreciation amount. Unlike the remaining-life technique, the whole-life technique has no checks and balances to make sure full recovery is achieved.[448] Pepco states that the jurisdictional amounts used to calculate the Company's accumulated depreciation reserves matched what the Company had developed in the past for cost of service and what was used in cost of service based on the rates approved by the Commission and that Pepco tracked the

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441 Pepco (F) at 15 (Browning).

442 Pepco (2F) at 4 (Browning Supp.).

443 OPC Br. 100.

444 OPC (E) at 37 (Majoros). The whole-life technique calculates depreciation rates based on expected average service life of the utility's assets. The remaining-life technique subtracts any existing depreciation reserve from the original cost of the plant assets, plus current estimate of net salvage, and divides the results by the estimated remaining service life of those assets.

445 OPC Br. 103.

446 OPC (E) at 6 (Majoros).

447 OPC Br. 106; Tr. 434.

448 Pepco Br. 50-51.

amounts at the function level.[449] Pepco argues that without the benefit of the reserve, the Company would not be able to access the reserve to address under-recovery.[450]

DECISION

234. One of the goals of depreciation is to have the investment fully recovered at the time of its expected retirement. The accumulated depreciation reserve is the amount that has been recovered already from customers in past depreciation rates. In order to calculate how much remains to be recovered in the future, one needs to deduct the amount already recovered from customers in past depreciation rates. Adjusting for the amount in the accumulated depreciation reserve occurs in the remaining-life technique, but does not occur in the whole-life technique.

235. OPC has not shown that it would be advantageous to change from the use of remaining-life to whole-life in determining depreciation reserve. OPC contends that with whole-life, the reserve imbalance would be addressed "with separate amortization of the reserve imbalances."[451] However, it still would be necessary to determine the D.C. reserve amount for use in the amortization of the reserve imbalances. In addition, depreciation reserve amounts are used in other important calculations, such as the calculating of the net rate base. Moreover, OPC acknowledges that if the Commission were to adopt whole-life rates, in some instances an asset may not be fully depreciated at the time of its expected retirement.[452] OPC argues the whole-life rate is better for new investment; however, at the time of the installation of a new investment, the whole-life rate for that new investment is the same as the remaining-life rate.[453] The Commission will continue to use remaining-life depreciation rates which are designed to have an investment fully depreciated by the time of its expected retirement.

236. Prior to the implementation of PowerPlant, Pepco did not track jurisdictional depreciation reserve in an accurate manner. Pepco acknowledges that it did not keep jurisdictional records by FERC account and that it employed a blended depreciation rate.[454] Further, the Company acknowledges that the $60 million PowerPlant adjustment was necessary to align or match up the amounts shown using the prior depreciation method with the amounts used in PowerPlant.[455] The Commission is satisfied with Pepco's explanation for this adjustment.

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449 Pepco R. Br. 28.

450 *Id.* at 30.

451 OPC R. Br. 40.

452 OPC (E) at 38 (Majoros).

453 Commission Ex. No. 30.

454 Tr. 1390 -1392.

455 Pepco indicates that it plans to implement another $940,000 adjustment to PowerPlant near the end of 2009. Commission Ex. No. 54.

The $60 million adjustment will be accepted to establish the District of Columbia accumulated depreciation reserve amount to be used as the starting point for the new PowerPlant accounting system. After this $60 million adjustment, no further adjustment to the D.C. reserve is allowed for the purpose of changing the PowerPlant reserve amounts to match the reserve amounts as calculated under the prior cost-of-service method. All entries into PowerPlant must be in conformance with the Uniform System of Accounts ("USOA"). Additionally, for the sake of uniformity, consistency, and clarity, in all future reports, studies, and other filings before the Commission, Pepco is directed to use the D.C. accumulated depreciation reserve amounts and D.C. depreciation expenses as shown in PowerPlant.

3. Regulatory Liability Account

237. **OPC.** OPC recommends that the $33 million[456] in the depreciation reserve that is for net removal cost be transferred to a regulatory liability to prevent the possibility that these excess collections might be diverted to general income by Pepco.[457] OPC states that the $33 million represents excess money collected from ratepayers in anticipation of a future expense. Currently the $33 million liability is recorded in the accumulated depreciation reserve. OPC urges the Commission to recognize Pepco's non-legal asset retirement obligations ("AROs") reserve as a regulatory liability for regulatory and ratemaking purposes. OPC states that Pepco has done so in its annual GAAP reports; however, it has not done so for regulatory and ratemaking purposes.[458] If future costs prove lower than forecasted, the unused money should be returned to ratepayers.[459] OPC states that two recent events underscore the need to protect this money: (1) the impending move from GAAP to International Financial Reporting Standards ("IFRS"); and (2) a filing by Georgia Power asking to amortize its cost of removal regulatory liability back to the company.[460] Based on the above, OPC proposes amortizing the $33 million back to ratepayers over the remaining life of Pepco's plant, which would produce a negative $975,000 annual expense.[461]

238. **Pepco.** Pepco counters that OPC's proposal is "bad ratemaking" and that OPC has failed to substantiate that the amount in reserve for net salvage represents excess

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456 OPC states that the regulatory liabilities from non-legal asset retirement obligations ("AROs") associated the cost of removal of long-lived plant for 2006, 2007, and 2008 equals $298 million. The D.C. jurisdictional portion as of December 31, 2008, was $32.9 million.

457 OPC Br. 121.

458 *Id.* at 26.

459 OPC (E) at 22 (Majoros).

460 *Id.* at 30.

461 *Id.* at 36.

collection.[462] Pepco states that OPC has made no showing that the theoretical reserve amounts for net salvage are zero. Returning these amounts back to customers will cause further under-recovered situations for all accounts.[463] Moreover, Pepco replies that it cannot transfer depreciation reserve money to income without the Commission's approval. Georgia Power neither did, nor could, take such action unilaterally.[464]

DECISION

239. Any method that recovers the future cost of removal over the life of the investment will collect money from ratepayers in advance of paying for the actual removal (this includes both the SFAS-143 method and Pepco's proposed method). That money should be held for future removal costs, and not all of it should be returned to ratepayers. Thus, transferring the reserve to a regulatory liability or returning all of the non-legal removal cost reserve to ratepayers would not be appropriate. Therefore, OPC's proposal is denied. To address OPC's concerns about the possible transfer of any excess collections to income by Pepco, the Commission hereby orders that Pepco not transfer any money from Account 108, Accumulated Provision for Depreciation, to income without prior Commission approval.

4. Pepco's Net Salvage/Net Removal Cost (Issue No. 6c)[465]

240. **Pepco.** Pepco maintains that its net salvage/net removal cost is properly calculated and fair to both Pepco and its customers.[466] Pepco opposes the use of the SFAS-143 present value method[467] to determine net salvage/net removal costs stating that the use of the methodology would result in Pepco under-recovering its costs.[468] Pepco alleges that it would under-recover because the future net salvage percents it employed were conservative and that the traditional present value approach is dependent on annual increases.[469] Pepco admits that its method results in the collection of future inflated removal costs from current customers and uses

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462 Pepco (3F) at 24-26 (Browning Rebuttal).

463 Pepco (3H) at 23 (Spanos Rebuttal).

464 Pepco R. Br. 39.

465 Designated Issue No. 6c asks, "Is Pepco's Net Salvage/Net Removal Cost properly computed?"

466 Pepco (H) at 21-24 (Spanos), Pepco (2H) at 9-10 (Spanos Supp.).

467 The Commission in Order No. 15322 ordered Pepco to file a revised Depreciation Study using the SFAS-143 present value formula used in the Maryland Public Service Commission Case No. 9096. *See Formal Case No. 1076*, Order No. 15322 (July 10, 2009). Pepco, though, calculated its rates following the approach in Maryland Case No. 9092 stating that the Case No. 9096 SFAS-143 formulas initially used in Maryland were flawed.

468 Pepco (2H) at 5 (Spanos Supp.).

469 *Id.* at 2, 5.

net salvage cost at a future price level.[470] Pepco contends, however, that recovery under the SFAS-143 present value method using a 7.96 percent discount factor is "significantly back loaded."[471] In its direct testimony, Pepco utilizes a zero percent discount factor in an alternate SFAS-143 calculation.[472]

241. **OPC.** OPC argues that Pepco charges current ratepayers the full costs of future inflation, costs that Pepco has not incurred. This approach front-loads costs and fails to match costs to the period in which they are incurred. OPC contends that Pepco's approach is inconsistent with "intergenerational equity" concepts and accrual accounting.[473]

242. OPC states that only the present value approach matches inflation to the periods in which it is incurred. According to OPC, Pepco front-loads future inflation costs into current periods resulting in the collection of excess payments from current customers.[474] OPC points out that Commissions in the three nearby jurisdictions do not allow Pepco nor the Pepco affiliates (Pepco in Maryland, Atlantic City Electric in New Jersey, and Delmarva in Delaware) to charge current customers for future inflation.[475]

243. OPC asserts that, consistent with the Commission's directive in Order No. 15322, Pepco should have used the present value of the projected future costs in order to develop the current dollars needed to cover the future cost of removal, i.e., discounted the inflated amounts back to its present value. OPC states that the same result can be reached by removing inflation from the calculation of projected future removal costs.[476] OPC claims that the present value approach reduces Pepco's inflated future cost of removal ratio and, therefore, the resulting net salvage ratio, to a much smaller component of the depreciation rate calculation.[477] OPC states that Pepco should be required to recalculate its depreciation rates consistent with SFAS-143 as ordered in Order No. 15322. OPC maintains that Pepco has failed to recalculate depreciation rates using the jurisdictional District of Columbia book reserve and SFAS-143 present value method for future net salvage as directed by the Commission.[478]

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470 Pepco (3H) at 11 (Spanos Rebuttal).

471 Pepco (2F) at 11 (Browning Supp.).

472 Pepco (2H) at 7-8 (Spanos Supp.).

473 OPC Br. 113.

474 OPC (E) at 19 (Majoros).

475 Tr. 1064 -1066.

476 OPC (E) at 14-15 (Majoros).

477 *Id.* at 16. New Jersey, Pennsylvania, and Delaware have adopted a variant of the present value approach - an average net salvage allowance approach which sets the cost of removal to the dollar level the utility actually experienced on average over a recent period to remove plant from service.

478 OPC E) at 8 (Majoros); *See* Order No. 15322 at 8-9.

244. OPC offers adjustments to the "present value" rates as filed by Pepco. OPC replaced the 7.96 percent discount rate with discount factors solely reflecting inflation; adopted whole-life depreciation, which will eliminate the debate on the propriety of jurisdictional book depreciation reserves in the context of depreciation rate calculations; and made other changes to present value calculations. OPC argues that use of a rate of return as the discount rate implies that the rate has some relationship to earnings. However, OPC asserts, the purpose of the discount rate is to remove the effect of future inflation from Pepco's charges to current customers. OPC contends that using its present value methodology would decrease annual depreciation expense by $6.4 million.[479]

245. **Pepco Rebuttal.** Pepco states that if the SFAS-143 method is used, which it opposes, the maximum discount rate it supports are the same inflation rate Majoros had proposed as the discount rate, as opposed to using the 7.96 percent cost of capital.[480] Use of the inflation rate as the discount rate produces a higher accrual than using the cost of capital. Using the inflation rate as the discount rate produces a SFAS-143 net salvage cost of approximately $7 million, whereas, the 7.96 percent rate produces an annual accrual of $4.2 million.[481] Pepco contends that if a 7.96 percent discount rate were used, future customers will pay up to 7 times more toward the cost of removal than current customers. In inflated adjusted dollars, the present value method results in future customers paying up to 3 times more than current customers using the 7.96 percent discount rate.[482]

246. Pepco challenges OPC's calculation using the present value method, stating that the formula used by OPC bears no resemblance to the SFAS-143 calculations the Commission requested and that Pepco performed.[483] Pepco states that OPC's recommended distribution-net salvage annual accrual of $1.9 million would not even meet the historical $4.5 million distribution D.C. removal cost that occurred in 2008.[484]

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479 *Id.* at 8-9; OPC (E)-3 (Majoros).

480 *Id.* at 22-23.

481 Pepco (3H)-1.

482 Pepco Br. 54.

483 Pepco (3F) at 19 (Browning Rebuttal).

484 *Id.* at 22. Pepco notes that OPC used the whole-life technique which Pepco opposes.

247. The parties presented several different net salvage recovery proposals. The annual expense that would be charged to customers are shown below:

Summary of Net Salvage Proposals

	Total Annual Accrual for Future Net Cost of Removal In D.C. Distribution Accounts (millions)
1. Pepco Primary Recommendation[485]	$14.4
2. SFAS-143 (MD Case No. 9092 Formulas) at 7.96% Discount Rate[486]	$4.2
3. SFAS-143 (MD Case No. 9092 Formulas) at "Inflation only" Discount Rate (2.66% to 5.24% depending on the account)[487]	$7.0
4. OPC (OPC (E)-12,13) OPC calculation of Present Value at "Inflation only" Discount Rate and uses Whole life & Regulatory Liability.[488]	$1.9[489]
5. OPC Calculation of Present Value at 7.96% Discount Rate (OPC (E)-3)[490]	$0.5[491]
6. For Comparison: Actual Cost of Removal expense for D.C. Distribution in 2008[492]	$4.5

485 Pepco (C)-2 (Hook); Exhibit (H)-1 at III-4 and III-6 (Spanos).

486 Pepco (3H)-1 (Spanos Rebuttal).

487 Pepco (3F)-7 at 1 (Browning Rebuttal); OPC (E)-5.

488 OPC (E)-12 and (E)-13 (Majoros).

489 Pepco calculated. *See* Pepco (3F)-6 (Browning Rebuttal).

490 OPC (E)-3 (Majoros).

491 Pepco calculated. *See* Pepco (3F)-4 at 2 (Browning Rebuttal).

DECISION

248. Pepco's existing depreciation rates were established approximately 20 years ago at a time when net salvage was often positive.[493] In the past when net salvage was positive, that meant that the gross salvage received at the time of retirement would adequately pay for the cost of removal. In that instance, the Commission did not need to determine how to collect the future cost of removal in customer rates because the future gross salvage usually covered the future cost of removal. Since its last depreciation study, Pepco's net salvage factors have become negative for almost all of the distribution accounts.[494] One reason for this is that Pepco changed its accounting methodology, which reduces the reported amount of gross salvage. This is the first case in which the Commission is faced with a proposal that would impose significant charges on current customers to pay for the future distribution costs of removal.

249. Now is the time to review the methodology used by Pepco to ensure that the treatment adopted is designed to properly charge current customers for future costs. The Commissions in at least three nearby jurisdictions do not allow Pepco or Pepco affiliates to use the net salvage method that Pepco proposes in this case. In addition, as a result of SFAS-143 and FERC Order No. 631, companies nationwide, including Pepco, are already using the SFAS-143 present value calculations for future cost of removals that are legally required to occur ("legal AROs").

250. OPC's argument that Pepco's method creates intergenerational inequity by charging current customers more in "real" dollars then future customers has merit. Pepco acknowledges as much.[495] Additionally, the record shows Pepco's method charges current customers for future inflation.[496] Because of this, the Commission will adopt a net salvage method that minimizes the collection of future inflation from current customers and corrects these other problems.

251. OPC proposes several adjustments to the SFAS-143 formulas, as shown in Maryland Case No. 9092, including the use of whole-life, the creation and amortization of a regulatory liability, and the use of a discount rate based on inflation. OPC has not identified any jurisdiction that is using OPC's modified "present value" formulas, and the modified formulas produce very small dollar accruals, as shown in the "Summary of Net Salvage Proposals" table above. Pepco points out that OPC's recommended annual accrual of $1.9 million would not

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492 Pepco (3F) at 22 (Browning Rebuttal).

493 OPC Br. 42-43.

494 OPC (E) at 5; OPC (E)-1 (Majoros).

495 *See,* OPC Br. at 113, OPC Cross Examination Exhs. 16 and 34.

496 Pepco (3H) at 11 (Spanos Rebuttal); Tr. 414-415.

equal the historical $4.5 million distribution D.C. removal cost that occurred in 2008.[497] We therefore reject OPC's modified "present value" formulas. The Commission believes that the formulas from Maryland Case No. 9092, using inflation based discount rates, produce an annual accrual for D.C. distribution net salvage of $7.0 million that is both fair and reasonable.[498]

252. The record shows that the SFAS-143 method does collect the necessary amount of net salvage costs over the life of the asset. Pepco's example (Pepco Ex. (2F)-2), where the average remaining life increases midway in the life of an account, never occurs in any actual account.[499] In all actual accounts, the average remaining life decreases over time, i.e., it has a declining pattern. Pepco admits that its method results in the collection of future inflated removal costs from current customers and in the collection of net salvage cost at a future price level. Fairness and equity require that the Commission adopt a methodology that, to the extent possible, balances the interest of current and future ratepayers. The SFAS-143 method accomplishes this. Pepco should not be allowed to charge current customers for future inflation, nor should Pepco be allowed to charge current customers in higher-value current dollars for a future cost of removal amount that is calculated in lower-value future dollars. Therefore, the Commission adopts the SFAS-143 method, using the formulas from Maryland Case No. 9092, with the rate of inflation rate used as the discount factor. These SFAS-143 present value calculations as reflected in Pepco (3F)-7 will result in an annual D.C. distribution accrual for net cost of removal of approximately $7 million.

5. Recording of Gross Salvage Value (Issue No. 6d)[500]

253. During the hearings, the Commission became aware that Pepco made two different internal accounting changes in 2004 and 2005 that have reduced the amount of gross salvage that Pepco records.[501] In 2004, Pepco changed the accounting treatment of "third party" accident reimbursements, which reduced the amount of third party reimbursements that Pepco recorded as gross salvage.[502] In 2005, Pepco changed its accounting of scrap materials.[503] Some

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497 Pepco (3F) at 22 (Browning Rebuttal).

498 Pepco criticized the Maryland Case No. 9092 formulas. Many of Pepco criticisms of Maryland Case No. 9092 were based on a discount rate of 7.96%, which produced an annual accrual for D.C. distribution net salvage value of $4.2 million. Pepco (3H)-1.

499 Pepco's Ex. (2F)-2 (Browning Supp).

500 Designated Issue No. 6d asks, "Is Pepco correctly recording its gross salvage in accordance with FERC's Uniform Systems of Accounts?" In response to Issue No. 6d, OPC answers, "Yes". OPC did not provide any other testimony on this issue. *See* OPC (E) at 5 (Majoros); OPC Br. 122.

501 Tr. 316-317; Commission Ex. 10.

502 Commission Ex. 10.

503 *Id.*

costs previously assigned as salvage are now considered scrap not related to retirement of assets.[504] The Commission is concerned about the impact that these two internal accounting changes made by Pepco may have on future depreciation studies and resulting customer rates.

DECISION

254. Reducing the recorded gross salvage amount makes the net salvage more negative and increases the calculated depreciation rates, everything being equal. Reducing reimbursements recorded as gross salvage decreases gross salvage that Pepco records and could increase the calculation of future depreciation rates. The two accounting changes made by Pepco would have a tendency to increase depreciation rates, which, in turn, may increase customer rates. We find no acceptable rationale for Pepco's changes in the accounting methods. Therefore, we direct Pepco to resume recording capitalized third-party reimbursements as salvage and resume crediting them into Account 108, Accumulated Provision for Depreciation. In addition, Pepco is directed to record scrap salvage as salvage and credit it to Account 108. However, nothing in this Order prohibits Pepco from using a representative sampling to decrease the effort required to comply with this directive.

VIII. IMPACT OF D.C. AND FEDERAL TAXES[505]

A. Consolidated Tax Returns

255. The Commission stated in Pepco's last rate case that it might revisit the "consolidated tax issue", *i.e.*, the issue of what ratemaking treatment is appropriate to reflect the fact that Pepco participates in the PHI group's consolidated income tax returns.[506] As part of a consolidated group of PHI companies, with losses to offset Pepco's taxable income, Pepco's effective tax liability in a consolidated return is generally less than it would be if it files as a stand-alone company. In Formal Case No. 1053, the Commission approved its "long-standing position that a stand-alone approach is the most reasonable method of setting rates." However, the Commission went on to state:

> While a stand-alone method may have the disadvantage of saddling ratepayers with tax costs that are not actually paid to the Government, it has the benefit of insulating ratepayers from the losses attributable to PHI's unregulated affiliates in a volatile market. Courts have held that adopting the stand-alone method is a matter within the discretion of the regulatory body.

504 Pepco (2E) at 2 (White Supp.).

505 Designated Issue No.10 asks, "Does PEPCO's presentation of its revenue requirements properly reflect the impacts of any changes in District of Columbia and Federal tax regulations?"

506 Pepco's federal consolidated group includes over 60 corporations, while the D.C. consolidated group includes just over a dozen. Pepco (J) at 5 (Warren).

> We recognize that other jurisdictions have adopted alternatives to the pure stand-alone approach that we uphold here. The other alternatives range from sharing mechanisms to a prorated consolidated return approach.[507] However, the advantages and disadvantages of those alternative methods have not been sufficiently explored in this proceeding to warrant the adoption of a new policy. If the parties wish to make more detailed arguments supporting an alternative method in the next rate base proceeding, the Commission will revisit its policy of pure stand-alone treatment.[508]

256. **Pepco.** The Company requests an annual allowance of $9,758,000 for District of Columbia income taxes and $33,260,000 for federal income taxes. Pepco updated its annual allowance to $8,835,000 for District of Columbia income taxes and $30,366,000 for federal income taxes.[509] The Company states that these figures were calculated on a stand-alone basis for determining its taxes, as approved by the Commission in Formal Case No. 1053.[510]

257. **OPC.** OPC seeks a rate base reduction of $172.9 million, and recognition of "Intercompany Deferred Income Taxes," to give ratepayers some of the tax savings that Pepco's parent company PHI realizes from filing consolidated federal and D.C. income tax returns covering Pepco.[511] OPC argues that Pepco did not – and will not in the future – actually pay the higher taxes that Pepco collects from its ratepayers.[512] Instead, OPC asserts that Pepco pays taxes only through PHI, whose consolidated tax returns show much lower federal and D.C. tax liabilities because they add together Pepco's taxable income with tax losses from other PHI

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507 In particular, the Commission noted New Jersey's rationale that where a utility's operations produce income that provides the opportunity for tax savings through offsetting annual losses of the other subsidiaries, the "ratepayers who produce the income that provides the tax benefits should share in those benefits." *Formal Case No. 1053*, Order No. 14712 at 88 n. 616.

508 *Formal Case No. 1053*, Order No. 14712, ¶ 240.

509 *See* Tr. 1242.

510 *See* Pepco (C) at 17, 14-15 (Hook); Pepco (2C) at 6 (Hook) on Adjustments 27 and 18.

511 *See* OPC (C) at 60-73 (Bright) (urging a $140.2 million rate base reduction for federal taxes); OPC (C) at 73-85 (urging an additional $32.7 million rate base reduction for D.C. taxes); and OPC (C)-7. OPC first calculates how much money PHI currently transfers from Pepco to other PHI unregulated subsidiaries (as money collected from Pepco ratepayers for Federal and D.C. taxes but never paid to the Federal or D.C. governments). OPC states that balance should be included in Pepco's rate base as a rate base deduction "similar to the rate base deduction for Accumulated Deferred Income Taxes." *Id.* at 73, 77-78.

512 OPC states that Pepco has been paying Federal income taxes on a consolidated basis since 1984 and D.C. income taxes on a consolidated basis since 2001. OPC (C) at 78. "In the 24 years the Company has been paying taxes using a consolidated tax return, there were always Group Members with tax losses." *Id.* at 81.

subsidiaries. OPC claims its "Consolidated Tax Adjustment" ("CTA") properly recognizes this fact and adjusts the utility's cost of service to prevent an over-recovery from ratepayers.[513]

258. OPC points out that PHI has saved millions of dollars in federal and D.C. income taxes over the years by filing consolidated income tax returns covering Pepco, two other regulated subsidiaries, and 60 other non-regulated subsidiaries.[514] OPC argues there is no reason to saddle Pepco ratepayers with the costs of "phantom income taxes" that Pepco never actually pays to the government. First, OPC argues that there is nothing about PHI's self-serving intra-company tax sharing agreement with its subsidiaries that justifies forcing Pepco ratepayers to subsidize PHI's unregulated loss affiliates. Second, OPC argues that its CTA system is fairer because it would allow PHI's unregulated loss affiliates to continue to realize benefits from associating with PHI (such as improved access to capital), without being unfairly subsidized by Pepco ratepayers.[515] OPC argues that its even-handed CTA proposal allows unregulated loss affiliates to get the benefit of cash payments for tax losses, while Pepco ratepayers get a rate base reduction for Pepco funds transferred to the affiliates (originally collected by Pepco as "taxes" but never actually paid to the government by PHI/Pepco).[516] Without this rate base reduction, OPC argues, Pepco's ratepayers are subsidizing PHI's non-regulated affiliates since these non-regulated affiliates are not entitled to cash payments for tax losses on a stand-alone basis.[517]

259. OPC claims that its CTA proposal represents a sharing of benefits in much the same way as the tax benefits of accelerated depreciation are shared between shareholders and ratepayers. OPC indicates that in both cases the deferred income taxes are deducted from rate base as ratepayer supplied capital and in both cases the Company retains use of the money but ratepayers are not charged for the time value (return) of the funds.[518]

260. OPC points out that its CTA rate-base-reduction proposal is different from its earlier proposal (rejected in Formal Case No. 1053) to decrease Pepco's tax expense.[519] OPC's new CTA proposal treats consolidated tax savings in the same manner as other accumulated deferred income taxes, as a reduction of rate base. OPC contends that this sort of sharing of CTA tax benefits between shareholders and ratepayers was approved in *Washington Gas Light Co. v. Pub. Serv. Comm'n*, 450 A.2d 1187, 1233-1235 (D.C. 1982). OPC argues that its new rate

513 *Id.* at 62-63.

514 OPC Br. 169-171; OPC (C) at 69, 76-77.

515 OPC Br. 172-173.

516 OPC Br. 179.

517 OPC Br. 178.

518 OPC Br. 174.

519 OPC Br. 174-176; OPC (C) at 79; Tr. 938- 939, 962-963 (OPC witness Bright).

base reduction proposal also responds to the Commission's concern about insulating ratepayers from the losses attributable to PHI's unregulated affiliates in a volatile market.[520] Essentially, OPC suggests that its proposal would yield only downward adjustments to Pepco's rate base,[521] because OPC's adjustment comes into play, and yields a rate base adjustment, only when Pepco's collection of stand-alone taxes from Pepco ratepayers creates "consolidated income tax savings" that PHI transfers internally from Pepco to other PHI unregulated subsidiaries (as money collected from Pepco ratepayers for "current" taxes, but never paid to the Federal or D.C. governments).[522] Consequently, OPC contends that "Pepco's utility customers would never be required to pay for income taxes greater than the income taxes computed using the stand-alone method."[523]

261. OPC indicates that three major alternatives exist for making a consolidated tax adjustment.[524] *(1) New Jersey Approach.* OPC states that its approach is modeled after the one in New Jersey, where the Commission makes a consolidated tax deduction from rate base. The rationale is similar to the rationale for deducting accumulated deferred income taxes from Pepco's rate base because this is ratepayer-provided money that Pepco has not yet had to pay to the government. OPC argues that this approach appropriately recognizes the time value of money.[525] *(2) Texas Approach.* OPC proffers that Texas follows a slightly different "time value of money" approach that ultimately makes a deduction from utility income taxes (not utility rate base). OPC indicates that Texas earlier followed a "consolidated capital structure" approach (described below), but then switched to its current method. Texas first calculates what the deduction for rate base would be (*i.e.,* the taxes that the utility pays out to its unregulated affiliates) and then calculates a time value of money associated with that, because the unregulated affiliates get to use that money before they actually have any taxable income. Texas

520 OPC agrees that "Pepco's customers are not and should not be exposed to the costs and risks associated with PHI's non-regulated operations since these businesses are engaged in non-regulated activities." OPC (C) at 81 (Bright).

521 Two caveats were added by OPC witness Bright during the Commission hearings. First, OPC states that if PHI's unregulated loss companies eventually have taxable income, as Pepco said they would, then "it turns around" so that Pepco's rate base would be increased. Tr. 994 (OPC witness Bright). OPC also testified that, if Pepco experiences a tax loss, as it did in 2008 that would cause an upward adjustment to Pepco's rate base. Given the experience of PHI and Pepco during the last several years, however, when Pepco generally had positive taxable income and PHI's affiliates generally had large tax losses, OPC indicates that it would take "a whole bunch of years in a row of tax losses" by Pepco before this effect would register as an increase in Pepco's rate base. *See* Tr. 989-999 (colloquy between OPC witness Bright and Commissioner Morgan).

522 OPC (C) at 84-85.

523 *Id.* at 80. OPC avers that its proposal would not confiscate PHI shareholder property. Its proposed rate base reduction for deferred income taxes "is not a permanent reduction of the Company's tax expense for ratemaking purposes. Instead, these consolidated tax savings are treated in the same manner as other accumulated deferred income taxes – as a reduction of rate base." *Id.* at 84.

524 Tr. 961 (OPC witness Bright).

525 Tr. 972, 962, 963, 968 (OPC witness Bright).

then takes the number that OPC proposes to deduct from rate base, multiplies it by an interest factor, and then reduces the income taxes of the utility by the amount of that interest.[526] *(3) Florida/ Pennsylvania/ Virginia/ West Virginia Approach.* OPC notes that other states set utility rates by using a consolidated capital structure. That is, they use the capital structure of the consolidated group of which the utility is a member, relying on using the debt of the consolidated entity for calculating the interest that is used in calculating income taxes, and then reducing the tax expense listed for the regulated utility.[527]

262. OPC witness Bright states that PHI's consolidated group (including Pepco) paid taxes in 2008, but not before.[528] OPC's witness confirms that OPC is seeking a CTA based on at least five years of accumulated deductions from rate base.[529] Theoretically, OPC acknowledges, if PHI's unregulated loss affiliates never have any taxable income, then there could be losses that could get larger than Pepco's rate base. However, OPC points out that Pepco witness Salatto testified that the unregulated loss affiliates would eventually have taxable income, in which case "it turns around" and Pepco's rate base would grow again.[530] OPC points out that Pepco had an income tax loss in 2008 and might have one in 2009 because of bonus depreciation.[531] Citing decades of PHI history, OPC argues that "[t]he income taxes paid to the federal and D.C. governments are never equal to the stand alone amounts of the Group Members with positive taxable income because there are always some entities with taxable losses." [532]

263. OPC witness Bright suggested during the hearings that a 50/50 split of benefits might be appropriate, between the unregulated loss companies (on the one hand) and Pepco and its ratepayers (on the other hand). OPC contends this would give the unregulated loss companies some of the benefit of the tax deductions they generate, which lower taxes for the consolidated group, while also giving some compensation to Pepco and its customers who are providing immediate cash to the PHI consolidated group and its loss companies.[533] OPC agrees that when it talks about the current value of money, it conceptually is looking at the benefit that is going to the unregulated loss companies as if it were a loan from Pepco to those companies that eventually will be repaid. That is why OPC deducts just the interest from Pepco's rate base.[534]

526 Tr. 958- 959, 961 (OPC witness Bright).

527 Tr. 959-960 (OPC witness Bright)..

528 Tr. 967 (OPC witness Bright).

529 Tr. 975-976, 978-982, 993-994 (OPC witness Bright).

530 *See* Tr. 994 (OPC witness Bright).

531 Tr. 952 (OPC witness Bright).

532 OPC Br. 179.

533 Tr. 986-988, 992 (OPC witness Bright).

534 Tr. 994-995 (OPC witness Bright in colloquy with Chairman Kane).

OPC insists that, under its proposal, the unregulated loss companies would still get the cash payments to them from the consolidated group in payment for its tax deductions,[535] but that "ratepayers get the rate-based deduction," and therefore get a return on the money.[536]

264. **Pepco Rebuttal.** Overall, Pepco's rebuttal characterizes OPC's view as "a punitive consolidated tax adjustment that retroactively strips tax benefits away from other PHI companies, *i.e.*, the companies that bore the risks and incurred the costs associated with attaining the tax benefits, and unilaterally assigns the benefits, but not the costs, to Pepco's District of Columbia utility operations, as a cost of service adjustment, to artificially lower customer rates." The Company argues that OPC has not justified overthrowing this Commission's longstanding "stand-alone" policy of keeping a consolidated Company's utility operations separate from its unregulated businesses.[537] Pepco asserts that OPC's CTA proposal reflects a small minority viewpoint that "conflicts with settled D.C. practice, economic logic and, most significantly, regulatory equity."[538] The Company marshals a broad array of legal and policy arguments in opposition to OPC's proposed CTA.

265. *First*, Pepco argues that CTAs are contrary to settled ratemaking practices of the FERC and the vast majority of state commissions. According to Pepco, there are only five States that recognize CTAs of the kind that OPC seeks here. Pepco contends that two states (Pennsylvania and Oregon) require CTAs through legislation, while three other states (New Jersey, West Virginia, and Texas) allow their Commissions discretion to impose CTAs.[539]

266. At least 37 other states have rejected CTAs, according to Pepco, noting that this Commission rejected CTAs as "highly speculative" in Formal Case No. 912 (decided in 1992). In Formal Case No. 929 (decided in 1994) this Commission again rejected CTAs on the ground that they "distort[] the true costs of electric service."[540] While the Maryland Commission is currently considering a CTA proposal, it earlier rejected CTAs in a 1972 *Columbia Gas* rate case, stating "[i]t is not proper rate-making to base revenue requirements upon costs not related to the utility operation under review." Similarly, the Maryland Commission again rejected CTAs in a 1991 Pepco case, stating that "[i]t is a rule of general application that the rates charged for a

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535 Tr. 989-999 (OPC witness Bright).

536 Tr. 990-991 (OPC witness Bright).

537 *See* Pepco Br. 83-98; Pepco R.Br. 46-52; Pepco (3A) at 8-9 (Kamerick).

538 Pepco (J) at 4 (Warren).

539 Pepco Br. 86, 95-98; Pepco (J) at 30-34 (Warren). *Accord* Tr. 1258-1259 (Pepco witness Warren).

540 Pepco Br. 95-97. To be sure, Pepco acknowledges, the Commission approved of CTAs in an old 1982 Washington Gas Light case. However, Pepco argues that old WGL case was "factually unique" because WGL owned the unregulated affiliate company that incurred the tax losses. "Here, Pepco has not invested in, nor has it taken any of the risks associated with the activities of other PHI unregulated affiliates." Pepco R. Br. 50. As the D.C. Court of Appeals noted, the Federal Power Commission decided to return to a stand-alone method, after briefly approving of CTAs. Pepco R. Br. 51.

regulated utility service should reflect only the cost associated with providing utility service; they should not reflect costs associated with other businesses run by the utility."[541] The Commissions in Minnesota and New Mexico similarly rejected CTAs in recent opinions.[542]

267. The Company states that FERC also has consistently used the "stand-alone" method (excluding affiliates) to calculate regulatory tax liability.[543] In sum, Pepco argues that there is "a message in the fact that only a handful of regulatory jurisdictions employ CTAs – and that in only three states have regulators affirmatively chosen to do so. CTAs, while they may be superficially attractive mechanisms to lower rates, simply cannot stand up to anything like a rigorous reasoned analysis. The broad application of principled analysis and regulatory equity is the reason why CTAs remain rare."[544]

268. *Second*, Pepco argues that CTAs unreasonably reduce a utility's revenues. In its post-hearing brief, Pepco claims that Statement of Financial Accounting Standards No. 109 (SFAS 109) compels it to follow a "stand-alone" approach to taxes regardless of whether this Commission decides to impose CTAs for ratemaking purposes. The "imposition of CTAs will reduce revenues but will have no impact on the Company's financial reporting obligations. Pepco contends that if the Commission were to impose a CTA, the Company's revenues would decrease, but its tax expense would remain the same." Over time, Pepco argues, this will simply erode a utility's ability to achieve its authorized equity return.[545]

269. *Third*, Pepco argues that CTAs violate the "cost responsibility" principle, which dictates that the party that incurs a cost is entitled to the associated tax benefit.[546] Pepco avers that tax benefits have value and belong to the entity that incurred the tax loss. OPC's proposed CTA adjustment violates these principles, Pepco submits, because OPC "asks this Commission to assign to customers, tax benefits that are embedded in costs incurred by shareholders." That is, CTAs extract the benefits of non-regulated tax losses from shareholders and assign them to utility customers who did not share in the costs and risks of the underlying investments that

541 Pepco Br. 95-97.

542 Pepco Br. 97-98; Pepco (J) at 31, 33, and Pepco (J)-2, citing *Xcel Energy*, Minn. Docket No. E-022/GR-05-1428 (September 1, 2006) and *Pub. Ser. Comm'n of New Mexico*, N. Mex. Case No. 07-00077- UT (final order April 25, 2008).

543 Pepco Br. 91, 98.

544 Pepco (J) at 34 (Warren).

545 *See* Pepco Br. 86, 93-94; Pepco (J) at 28-29 (Warren). *See also* Pepco Br. 87-89.

546 Pepco Br. 90; Pepco (J) at 19 (Warren). Two common examples that OPC acknowledges, Pepco states, concern the ratemaking treatment accorded to imprudent or unnecessary utility costs that are disallowed for ratemaking purposes (*i.e.*, costs that a Commission decided cannot be recovered from ratepayers). The Company and OPC agree, says Pepco, that utility shareholders (not ratepayers) get the tax benefit of such disallowed costs. *Id.* at 20-24.

generated these tax benefits.[547] They thereby diminish the profitability of the non-regulated activities that produce tax losses. Pepco argues that this may impede socially beneficial activities by non-regulated affiliates (such as alternative energy investments) that Congress wishes to incentivize with tax benefits.[548]

270. *Fourth*, Pepco claims that CTAs lack any coherent rationale. To begin, Pepco states that CTAs are inconsistent with tax principles allowing consolidated tax returns. Tax sharing agreements (like the one between Pepco and its PHI affiliates) that "compensate loss affiliates for the use of their losses" represent a common, commercially reasonable practice and they are "the norm."[549] Moreover, Pepco witness Warren states that PHI's allocation of internal losses to its affiliates, including Pepco, is consistent with traditional accounting and SEC principles.[550] The SEC approved PHI's internal tax sharing agreement.[551] Another basic objection, Pepco argues, is that allowing CTAs would breach the traditional regulatory wall between regulated and non-regulated entities. "Where a CTA is imposed, the results of non-jurisdictional operations will have a direct effect on the setting of jurisdictional rates." Finally, "while the consolidated return process was intended to prevent the imposition of a tax cost on the use of multiple corporations under common ownership, the imposition of a CTA creates a regulatory cost in its stead, thereby frustrating the very purpose for which consolidated returns exist."[552]

271. *Fifth*, Pepco contends that OPC's proposal is deeply flaw because OPC crams five years' worth of CTAs into its proposed $172.9 million reduction to rate base. OPC gives no explanation for using five years worth of CTAs, including prior years' CTAs, and Pepco argues that OPC's proposal amounts to retroactive rulemaking.[553]

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547 *See* Pepco Br. 86.

548 *See* Pepco Br. 86, 91-93; Pepco R.Br. 49-50; Pepco (J) at 25-26. Pepco noted that, under tax law at the time of the Commission hearings, tax losses may be carried back two years, and carried forward for 20 years into the future. *Id.* at 8.

549 Pepco (J) at 14, 6; Pepco Br. 87; Pepco R. Br. 48-49. *Accord* Tr. 1269- 1272 (Pepco witness Warren).

550 Pepco (J) at 15-16, 26-28 (Warren). Pepco witness Salatto confirms that "all companies with positive taxable income pay their separate company, stand-alone tax liabilities, and all companies that incur tax losses are paid for the use of those losses when they are absorbed, thereby reducing PHI's consolidated taxable income. No distinction is made between regulated and non-regulated companies. * * * In fact, on its 2001 and 2008 tax returns, Pepco reported stand alone, separate company tax losses and received, or will receive, substantial cash transfers as a result of the absorption of its tax losses by PHI." Pepco (K) at 4-5.

551 Tr. 1310 (Pepco witness Salatto).

552 *Id.* at 9.

553 *Id.* at 11-13.

272. Pepco argues further that OPC's CTA proposal is very different from that of New Jersey's. To begin with, New Jersey's CTA started in 1990 and was effective only prospectively, and not a retroactive basis.[554] OPC and New Jersey both use cumulative CTAs, but under the New Jersey approach, rate-based offsets can be reversed whenever the non-regulated company that produced the loss can use its own loss. Earlier losses would not give rise any longer to a rate-based offset. Pepco contends that this is very different from OPC's proposal, under which the regulated utility would have to suffer a loss before OPC's cumulative CTAs would reverse.[555] Pepco argues that, under OPC's approach, rate base is permanently reduced and goes only one way and will not "reverse" at some point, unless the regulated utility suffers a tax loss.[556]

273. The Company argues that OPC's presentation on the CTA issue is largely the same as the inadequate CTA claims it presented in Pepco's last rate case.[557] According to Pepco, OPC's assumptions seeking to justify a CTA are wrong. OPC's fundamental claim is that ratepayers should not have to pay for "phantom" taxes that are never in fact paid by Pepco. But tax expenses set during a rate case need not be (and seldom is) the same as the actual taxes paid by Pepco.[558] OPC's assumptions about how its CTA would work also are flawed, according to Pepco. Though PHI affiliates' losses frequently offset Pepco's taxable income, Pepco had income tax loss in 2001 and 2008, because of bonus depreciation, pension contributions, and a change in its tax accounting method for treating capitalized overhead costs. The Company contends that it might have another tax loss year in 2009 because of bonus depreciation.[559]

274. *Sixth*, Pepco argues that PHI investors, in making investments relied on the continuing availability of tax deductions that are safeguarded by longstanding Commission precedent upholding the stand-alone method of computing income tax expense.[560] At least for

554 Tr. 1260-1261, 1281-1282 (Pepco witness Warren).

555 Tr. 1261, 1264-1265 (Pepco witness Warren).

556 Tr. 1266-1267 (Pepco witness Warren). *Accord* Tr. 988-989, 975-976, 978-983 (OPC witness Bright) (acknowledging that, under OPC's proposal, if Pepco experiences a tax loss, it would cause an upward adjustment to rate base, but that it would take "a whole bunch" of tax loss years in a row by Pepco to significantly reduce the large CTAs produced under OPC's proposal).

557 *See* Pepco Br. 84-85; Pepco R. Br. 46-47; Tr. 930-946 (OPC witness Bright).

558 Tax-book timing differences, Pepco states, are in all cases temporary and are caused by normalization, interest synchronization and other similar adjustments. *See* Pepco R.Br. 47; Pepco Br. 87-89.

559 *See* Tr. 1253-1254, 1256 (Pepco witness Warren); Tr. 1295-1297, 1303-1305, 1312-1314 (Pepco witness Salatto). *See also* Tr. 952 (OPC witness Bright).

560 Pepco Br. 83-84, 92. "Departure from the Commission's stand-alone method without grandfathering investments made on the basis of existing Commission policy at the time such investments were made is highly punitive and is the equivalent of changing the ground rules in the middle of a contest. Accordingly, any Commission change in policy regarding CTAs should apply only to investments made after the imposition of the policy." Pepco Br. 84; *see id.* 92-93.

those PHI affiliated member companies that engage in leveraged leasing of equipment,[561] those member companies relied on a "stand-alone" assignment of tax benefits to them (for accounting purposes in pricing and structuring their equipment leasing deals years ago). "If the tax benefits are commandeered by inclusion in a CTA calculation, the investment itself is impaired." Consequently, Pepco argues, "any CTA calculation should exclude tax losses attributable to leveraged lease investments."[562]

DECISION

275. Given the record before us, the Commission has decided to adhere to our traditional stand-alone approach regarding federal and district tax expense, which is widely followed by the majority of Commissions throughout the country.[563] OPC's CTA proposal has several flaws which, in our opinion, reinforce our adherence to this long-standing policy.

276. OPC's CTA proposal undercuts common tax practice for affiliate companies, violates the "cost responsibility principle," and threatens to create inequities for other PHI affiliate companies (such as those engaged in equipment leasing) that "earned" the tax benefits and relied on their availability to them, as Pepco notes. Moreover, OPC's proposal is significantly different from the New Jersey approach.[564] OPC's CTA proposal threatens to create an immediate massive $172.9 million reduction to Pepco's rate base in this case. A rate base adjustment of that magnitude might well destabilize Pepco's financial condition. Over time, recognizing "Intercompany Deferred Income Taxes" on Pepco's books as OPC urges might reduce Pepco's rate base to zero.[565] By contrast, under New Jersey's CTA approach, PHI's unregulated loss affiliates will eventually have taxable income so that "it turns around" and Pepco's rate base rises again.[566] OPC's proposal would not "turn around" unless Pepco suffers significant tax losses year after year, a much less likely prospect in our view.[567]

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561 Pepco (J) at 45-48. "[S]everal of the PHI affiliates that produced substantial tax losses did so directly as a result of being engaged in the business of leveraged leasing. * * * * The consideration of the tax losses produced by such transactions in the calculation of a CTA essentially appropriates for customers part of what the lessor has paid for. In other words, these highly engineered transactions are priced to reflect the cash flows generated by the tax losses that are embedded in their structures." *Id.* at 46-47.

562 *Id.* at 47, 48.

563 The Maryland PSC recently reaffirmed the majority view and rejected CTAs. *See In re Delmarva Power & Light*, Md. Case No. 9192, Order No. 83085 at 20-23 (December 30, 2009).

564 *See* Tr. 1261, 1264-1267 (Pepco witness Warren) (explaining differences between OPC's CTA proposal and New Jersey's CTA system). *Accord* Tr. 988-989, 975-976, 978-983 (OPC witness Bright).

565 *See* Tr. 994 (OPC witness Bright).

566 *See* Tr. 1317-1318 (Pepco witness Salatto).

567 *See* Tr. 1261, 1264-1265 (Pepco witness Warren).

277. The Commission did not receive evidence on, and was unable to fully evaluate, the possible impact of the 2008 tax loss position of Pepco and PHI,[568] recent changes in tax law,[569] and whether PHI's unregulated affiliates would be immune from D.C. taxes with or without an intercompany agreement on taxes.[570] As was the case in Formal Case No. 1053, the Company proffers a more sound policy argument in favor of maintaining the stand-alone approach. We were particularly persuaded by the sound tax and accounting arguments made by Pepco witness Warren which were reflected in the Minnesota and New Mexico Commission decisions cited by Pepco.[571] Therefore, the Commission rejects the adoption of OPC's particular CTA proposal.

B. Bonus Depreciation

278. **OPC.** OPC argues that the Company should make an adjustment to show the actual amount of bonus depreciation it received for 2008, instead of the preliminary audit amount it included in rate base.[572]

279. **Pepco.** The Company agrees. Pepco changed its tax accounting method for its 2008 tax return, but it did not receive IRS approval to do so until May 2009, too late to reflect the new method in its original ratemaking filing here. "Due to the difference related to this deduction between Pepco's tax provision and its return, there is an increase of $85.6 million, on

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568 In most years PHI as a whole reports taxable income. Tr.1304 (Pepco witness Salatto). In 2008, however, PHI had a tax loss. *See* Tr. 1302, 1305-1306 (Pepco witness Salatto).

569 Ordinarily, the net operating loss (NOL) carry-back period for businesses is two years, and the NOL carry-forward period is 20 years. In the 111th Congress, the American Recovery and Reinvestment Act of 2009 (P.L. 111-5) provided business taxpayers with $15 million or less in gross receipts an opportunity to extend the carry-back period for up to five years for NOLs incurred in 2008. The Worker, Homeownership, and Business Assistance Act of 2009 (Pub. L. No. 111-92), enacted on November 6, 2009, extended the carry-back period to five years for all business taxpayers except those who have received certain federal assistance relating to the financial crisis. Under this law, a taxpayer can use the extended carry-back period for an NOL incurred in 2008 or 2009, but not both. Further, P.L. 111-92 stipulates that the amount of loss that can be carried back to the fifth year is limited to 50% of the taxpayer's taxable income in the fifth carry-back year. This limitation, however, does not apply to businesses with $5 million or less in gross receipts that make a five-year carry-back election after enactment of the legislation.

570 The query is whether an unregulated PHI affiliate that is immune from D.C. taxes, and which would never contribute D.C. tax deductions to the PHI group, should be entitled to any allocated "state tax" payments from Pepco under PHI's intercompany tax agreement.

571 *See* Pepco (J) at 31-33 (Warren), Pepco (J)-2, citing *Xcel Energy*, Minn. Docket No. E-022/GR-05-1428 (September 1, 2006); *Pub Ser. Comm'n of New Mexico*, N. Mex. Case No. 07-00077-UT (final order April 25, 2008). *Accord: City of Charlottesville, Virginia v. FERC*, 774 F.2d 1205 (D.C. Cir. 1985), cert. denied, 475 U.S. 1108 (1986) (court upholds FERC's stand-alone policy); Hahne & Aliff, Accounting for Public Utilities §§17.05-17.06, §19.03 (2009) (strongly arguing against CTAs).

572 OPC (A) at 22 (Ramas).

a system basis, to the 2008 deferred tax balance. This amount was recorded in the Company's books and records in September 2009."[573] The Company states that the DC allocated portion of its increased bonus depreciation deduction, taking interest synchronization into account, reduces Pepco's revenue requirement by $4.5 million.[574]

DECISION

280. The Commission accepts the adjustment for bonus depreciation (and interest synchronization) that Pepco and OPC agreed upon.

IX. JURISDICTIONAL COST ALLOCATION (Issue No. 11)[575]

281. The Commission approved Pepco's jurisdictional cost allocations in its last rate case. Rejecting OPC's proposed coincident peak method, the Commission reaffirmed the validity of the average and excess noncoincident peak ("AED-NCP") method for allocating Pepco's system-wide costs to the District of Columbia.[576]

282. **Pepco.** The overwhelming majority of Pepco's distribution costs (*e.g.,* for lines, substations, transformers, and meters) were directly assigned to the jurisdiction that uses those plant facilities.[577] The study in Pepco (F)-1 shows how other costs and operating expenses such as Cash Working Capital were calculated by jurisdiction.

283. Though most of its cost figures for transmission and distribution facilities are taken from FERC accounts, Pepco states that several items (*e.g.*, uncollectible accounts, and General Plant) had to be "functionalized" to determine the distribution-related portion of those costs.[578] For example, the major exception to Pepco's direct cost assignment approach concerns the cost of subtransmission facilities – which carry electricity through both the District of Columbia and other jurisdictions. Pepco states that it allocated these costs between jurisdictions, based on the Commission-approved AED-NCP method.[579] Pepco submits that its other jurisdictional cost allocations are not disputed.

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573 Pepco (K) at 7-9 (Salatto).

574 *See* Pepco (4C)-12 (Hook) and Pepco (4C) at 40 (Hook).

575 Designated Issue No.11 asks, "Are Pepco's proposed jurisdictional cost allocations for distribution service reasonable?"

576 *Formal Case No. 1053*, Order No. 14712, ¶¶ 253-256.

577 Pepco (F) at 7, 24 (Browning).

578 Pepco (F) at 5-6.

579 Pepco submits that the Commission has consistently approved the AED-NCP allocation method for many years, citing *Formal Case No. 905*, Order No. 9868, *Formal Case No. 929*, Order No.10387, Formal Case No. 939, Order No. 10646, and most recently in *Formal Case No. 1053*, Order No. 14712. Pepco (F) at 10-11, 24.

284. **OPC.** OPC argues that the AED 4-CP coincident peak demand allocation method is superior to the AED-NCP method for allocating Pepco's subtransmission costs between Maryland and the District of Columbia.[580] OPC agrees with Pepco's approach of directly assigning most of its costs to each jurisdiction.[581] OPC argues, however, that using the AED-NCP method to allocate other costs (particularly subtransmission costs) is not optimal;[582] that it is inconsistent with the AED 4-CP jurisdictional cost allocation method that Pepco uses in Maryland, and that it risks over-collecting distribution costs from D.C. [583]

285. OPC asks the Commission to "direct Pepco to provide a test year jurisdictional and class cost of service study based on application of the AED 4-CP method to subtransmission plant and related costs." As Pepco's AMI system is deployed, and more demand interval data becomes available for each of Pepco's customer classes, OPC predicts that the accuracy of test year jurisdictional and class coincident and non-coincident demands should improve, resulting in more accurate jurisdictional and CCOS studies in the future.[584] OPC asserts, however, that there is no reason for delay in switching to the AED 4-CP method for jurisdictionally allocating Pepco's subtransmission costs.[585]

286. **GSA.** GSA states that Pepco's jurisdictional cost allocations "follow generally accepted techniques approved in prior Commission rate cases."[586]

287. **Pepco Rebuttal.** OPC has identified no new circumstances, Pepco argues, that would warrant a change from the traditional AED-NCP method. According to Pepco, when accurate data are used, OPC's AED 4-CP method would actually increase the assignment of costs to the District of Columbia. The Company agrees that cost allocation methods might be

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580 OPC (F) at 5 (Smith).

581 *Id.* at 8.

582 OPC states that Pepco's subtransmission system is designed to serve the single CP peak on the subtransmission system. OPC argues that there is "a disconnect" between the CP-related way in which costs are incurred on Pepco's subtransmission system (on the one hand) and how costs are allocated under the AED-NCP method (on the other hand), because the AED-NCP method considers energy use and non-coincident peak demand, but not the CP demand of the facilities. OPC (F) at 9-10; OPC Pre-Hearing Br. 20-21. By contrast, the AED 4-CP method of allocating subtransmission costs, used in Maryland, considers a combination of energy use and coincident peak demand. OPC (F) at 11.

583 OPC acknowledges that subtransmission facilities account for only about $155 million (approximately 8%) of Pepco's $1.9 billion total distribution plant. OPC (F) at 11.

584 OPC (F) at 13.

585 OPC Br. 183-187; OPC R. Br. 65-66.

586 GSA (A) at 5 (Goins).

reexamined when the AMI system is in place and better data on customer usage becomes available.[587]

DECISION

288. OPC has not presented any new circumstances or "good reason" to overthrow the well-established AED-NCP method of jurisdictional cost allocation. The Commission recently approved that method as valid and imbued it with a heavy presumption of reasonableness. As stated in our opinion in Formal Case No. 1053:

> The Commission believes the AED-NCP approach appropriately combines an energy allocator with a non-coincident peak allocator because the design of the subtransmission and distribution system is properly based on both energy and demand characteristics. An energy allocation component is appropriate because as energy costs have risen, an electric utility should utilize cost effective met[illegible] to reduce energy losses in its substations, lines, and transformers. A n[illegible] allocator is also appropriate because the maximum [illegible] of the subtransmission and distribution system are non-coincide[illegible] peak demands. The use of a non-coincident peak based methodology [illegible] AED-NCP is reasonable to reflect demand-related system design and [illegible]

Even if Pepco were to focus on the distribution business, in its post-divestiture period, "it would remain appropriate to apply the AED-NCP method."[589] The Commission's rationale specifically covers Pep[illegible] subtransmission costs.

289. The Commission may re-examine the AED-NCP method, and whether it should be replaced with the AED 4-CP method, once AMI is in place and better data on customer usage is available. OPC and Pepco both agree that this should be done.

X. THE COMPANY'S REVENUE REQUIREMENT

290. The Commission finds that Pepco's District of Columbia adjusted rate base for the test period is $1,010,267,000, and that a fair rate of return (including capital costs and capital structure) on that D.C. rate base is 8.01 percent. The Commission further finds that the level of return required when the 8.01 percent rate of return is applied to the adjusted test year rate base of $1,010,267,000 is $80,922,000.

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587 Pepco Br. 99; Pepco (3F) at 11-12 (Browning).

588 *Formal Case No. 1053*, Order No. 14712, ¶ 255.

589 *Id.* at 94.

291. The Commission finds that the adjustment that would increase Pepco's test-year revenue to the level of gross revenue requirements computed in accordance with the findings in this Opinion and Order is $19,833,000, which includes a proper allowance for taxes.

XI. CUSTOMER CLASS DISTRIBUTION OF PEPCO's RATE INCREASE (Issue No. 12)[590]

292. The Company proposes to move gradually ("one-quarter of the way") toward equalizing class rates of return by raising distribution rates (which are only part of each customer's bill) more for residential than for commercial customers. Overall, an average residential customer's bill would increase by 6.1 percent ($6.43 on the total bill) under Pepco's proposal. Pepco justifies its proposed class revenue requirements by pointing to its Class Cost Allocation Study ("CCOSS"), which shows significant disparities in class rates of return ("ROR").[591]

293. OPC urges a nearly across-the-board approach, modeled on the Commission's decision in Pepco's last rate case (Formal Case No. 1053), with the residential class receiving an increase of 1 percent more than non-residential classes. GSA recommends cutting interclass revenue subsidies under Pepco's proposed revenue spread by 10 percent (around $6.2 million) to $56 million to make a stronger movement toward cost-based rates and equal class RORs. WMATA proposes a stronger movement ("one third of the way") toward equalized class RORs. Traditional principles of gradualism, Pepco argues, support its more gradual approach to lessening the disparities in customer class RORs.[592]

A. Class Cost Allocation Study (CCOSS) (Issue No. 12a)[593]

294. **Pepco.** The Company's class allocation study shows that current earned returns vary widely by customer class. At the low end of the range are the standard residential classes, Schedules R and AE, and Rider RAD, with returns in the negative range (-2.6 percent to -4.6 percent) and the streetlighting class (Schedule "SL") with a -4.3 percent. The high end of the

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590 Designated Issue No. 12 asks, "Is Pepco's proposed distribution of its revenue requirements reasonable?"

591 The Company's CCOSS, in Pepco (F)-3 (Browning), shows the demand and customer components of embedded cost for each of Pepco's customer classes. The study compares class RORs to the overall jurisdictional ROR. Pepco (F) at 17 (Browning). To comply with past Commission directives, Pepco also submitted a marginal cost study in Pepco (G)-5, that covers only distribution costs. The Company states that "[b]ecause this is a Distribution-only rate request, the Company has not produced Generation or Transmission Marginal Cost Studies." Pepco (G) at 13-14 (Bumgarner). PEPCO argues that marginal cost studies have been used in the past to design rates that primarily recovered generation-related costs; that there is no longer any good reason to produce a marginal cost study, now that PEPCO has sold its generation plants; and that the Commission should dispense with the obligation to produce such studies in future Pepco rate cases. *Id.* at 14.

592 *See* Pepco (G) at 3-8 (Bumgarner).

593 Designated Issue No. 12a asks, "Is Pepco's proposed Class Cost Allocation Study reasonable?"

range contains the large commercial high voltage class (Schedule GT-3A) at 15.6 percent and the Rapid Transit Schedule RT class at 13.4 percent. Generally, the residential classes provide significantly negative earnings on distribution service while commercial classes provide above average rates of return."[594] To develop the Company's CCOSS, Pepco witness Browning assigned and allocated rate base items and operating expenses to functions and classes based on the principle of cost causation.[595] He utilized different types of "demand allocators" to allocate demand costs in a way that appropriately recognizes that various facilities are sized to meet various loads.[596]

295. **OPC.** OPC claims that the cost of subtransmission facilities should be allocated by the AED 4-CP method. OPC argues that Pepco's CCOSS fails to distinguish between the differing cost of the cheaper "radial and overhead systems" that serve residential customers on the one hand and more costly network and downtown D.C. underground systems that serve commercial customers on the other hand. Nearly 90 percent of Pepco's investment in distribution lines is related to the more costly underground system that commonly serves commercial customers. OPC stops short of saying that Pepco's CCOSS is "fatally flawed." However, OPC argues that the defects in Pepco's CCOSS would support an across-the-board approach to setting customer class revenue targets in this case.[597] OPC also requests that, in the future, the Commission should direct Pepco to use the AMI system to obtain detailed information regarding the load characteristics and types of customers served by radial and underground network facilities respectively, which may allow a more accurate CCOSS.[598]

296. **AOBA.** AOBA accepts Pepco's CCOSS, saying that it reflects Commission-accepted methodology and provides a reasonable assessment of costs and revenues by class of service. AOBA warns, however, that Pepco's CCOSS does not reflect the substantial subsidies that are being provided to Residential Aid Discount ("RAD") customers through the Energy Assistance Trust Fund ("EATF") and the Residential Aid Rider Surcharge ("RAD surcharge"). According to AOBA, the customers in all other classes are required to pay over $5.1 million in EATF and RAD surcharges each year to subsidize the RAD class.[599]

297. AOBA also states that the Company's CCOSS shows wide differences in customer class rates of return. The overall average ROR for the District is 7.04 percent, with commercial customers paying more than twice the system average ROR, while the residential, RAD and SL classes pay a negative ROR. AOBA asserts that test year 2008 D.C. jurisdictional

594 Pepco (G) at 6 (Bumgarner); *see* PEPCO (F)-3.

595 Pepco (2F) at 13 (Browning); Pepco (F) at 16-19 (Browning).

596 *Id.* at 18-19 (Browning).

597 OPC (F) at 5-6, 16-19 (Smith); OPC Pre-Hearing Br. 21-22.

598 OPC (F) at 5-6, 20.

599 AOBA (A) at 84-85, 88 (Oliver).

revenues for Pepco were $68.8 million, with Pepco's large and small commercial customers (*i.e.*, the GT and GS customer classes) contributing $79.1 million, while all other classes combined contributed a negative net income of -$10.3 million. AOBA also claims that Pepco's commercial customers have long paid more than their fair share, and that residential and streetlighting customers clearly contribute disproportionately to Pepco's need for additional revenue. Moreover, AOBA submits, class RORs have grown further apart since Pepco's last distribution base rate case. AOBA concludes that fairness and equity dictate that this trend toward growing the subsidization of residential and streetlighting services must be reversed.[600]

298. **District Government.** The District Government argues that Pepco's CCOSS is inaccurate for the streetlighting ("SL") and traffic signal ("TS") classes. DCG contends that earlier deferred AMI/smart meter costs are improperly attributed to the SL class, which has no use or need for smart meters.[601] DCG also argues that the CCOSS improperly includes a small amount of revenue from 24-hour Burning Streetlights, which DDOT has totally eliminated. DCG submits that streetlighting is an off-peak service and that the streetlighting and traffic signal classes have shown a negative 10.13 percent growth in kWh usage because of DDOT's conservation efforts. Accordingly, DCG argues, the SL and TS classes do not create any added costs or a need for an expanded Pepco system; yet Pepco's CCOSS does not consider peaking or system cost additions.[602]

299. DCG maintains that the Company's CCOSS is also internally inconsistent on SL/TS rates. Though it allocates demand and customer costs to the SL and TS rate schedules, DCG contends that the CCOSS does not include these demand elements in its rate designs for SL and TS. Instead, DCG argues, Pepco uses energy-only rates in pricing the cost of service for these schedules. Overall, the District Government criticizes Pepco's CCOSS as a "mechanistic model" that gives some information about relative class RORs, but is limited because it involves no judgment or consideration of non-cost factors that have long been considered in setting class revenue targets for the SL and TS rates.[603]

300. Turning to the RAD rate, DCG argues that, contrary to AOBA, Pepco's CCOSS accurately tracks RAD costs, using methods that have long been approved.[604] DCG states that RAD class costs do not reflect the RAD and EATF surcharges because the RAD class gets the benefit. The District Government submits that other customer classes, however, received credit

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600 AOBA Br. 41-43; AOBA (A) at 85-89.

601 "The SL and TS rate schedule services do not need smart meters, since their usage is estimated based on type and size of lamp. Further, there can be no direct load control capability or dynamic pricing to produce incentives to change the SL and TS loads during peak periods." DCG (2A) at 6-7.

602 DCG Br. 8-9; DG Govt. (A) at 12-15 (Petniunas).

603 DCG (A) at 12-15, 19-20 (Petniunas).

604 DCG (2A) at 13-15.

in the CCOSS for providing those benefits to the RAD.[605] It concludes that the CCOSS is accurate for the RAD class.

301. **GSA.** GSA accepts Pepco's CCOSS as reasonable.[606] The only criticism that GSA has is that Pepco's CCOSS is based on identifiable loads without regard to a customer's on-site generation or when maintenance might be scheduled or other factors recognizing that distributed generation may add value to the system.[607]

302. GSA asserts that OPC's criticisms of the CCOSS are wide of the mark. GSA claims that whether or not OPC has correctly identified flaws in the CCOSS,[608] it is essentially irrelevant given the massive residential subsidies identified by Pepco's CCOSS. GSA recognizes that target class revenue requirements proposed by Pepco seek to address "an interclass subsidy problem that keeps getting bigger." GSA argues that no one can reasonably claim "rate shock" if a 50 percent increase in distribution charges produces an increase of less than 10 percent in a customer's total electricity bill. Neither GSA's nor Pepco's proposed revenue spread would create rate shock in trying to move residential rates towards cost of service.[609]

303. **WASA.** WASA submits that Pepco's CCOSS utilizes a general cost allocation formula that overstates the costs of serving WASA's Blue Plains facility under the GT-3B rate. Two old subtransmission feeder lines running under the Potomac River and dating from the 1950s and 1970s provide service solely to Blue Plains.[610] When the depreciated costs of these old subtransmission facilities are directly assigned to Blue Plains, as WASA urges, the cost of service for Blue Plains is significantly lowered.[611] WASA's "corrected" CCOSS shows an above-system-average 16.02 percent class rate of return for the GT-3B class, as opposed to

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605 DCG R.Br. 5; DC Govt. (2A) at 14-15.

606 GSA (A) at 5 (Goins).

607 *See* Tr. 1182-1183, 1192 (GSA witness Goins). This CCOSS dispute between GSA and Pepco affects the rates for standby service (S) and the dispute about Pepco's proposed new GT-3A-S rate for GSA's steam plant with its on-site generation capability. *See infra* pp. 137-141.

608 GSA (B) at 7 (Goins). GSA submits that OPC's criticisms of the CCOSS are minor, in that using OPC's recommended AED 4-CP allocation method (instead of Pepco's AED-NCP method) would reduce the District's revenue requirement by less than 1%. The Commission rejected OPC's criticism of the way the CCOSS allocated overhead and underground distribution system costs in *Formal Case No. 1053*. *Id.* at 6-8.

609 GSA Br. 5; GSA R.Br. 2; GSA (B) at 6-10.

610 WASA Br. 7-8; WASA (A) at 10, 6 (Phillips).

611 *Id.* at 8-9 (Phillips). While Pepco's CCOSS uses an allocation formula to allocate approximately $1.5 million in rate base to Blue Plains, WASA's direct cost allocation method assigns only $921,000 in rate base to Blue Plains. *Id.* WASA states that "the total original cost of the Blue Plains Feeders was $1,574,000. This stands in stark contrast to the allocated subtransmission costs of $3.2 million reflected in Pepco's allocation." WASA Br. 8.

Pepco's 6.77 percent class ROR figure. WASA submits that the impact on other classes is slight (less than 1 percent) when the over-assignment of costs to the GT-3B class is corrected.[612]

304. WASA urges that direct cost assignments can and should be made for Blue Plains instead of using Pepco's general cost allocation formula. First, WASA argues that NARUC principles encourage direct cost assignments in preference to allocation formulas whenever possible. Blue Plains is served exclusively by two under-river 69 kV lines, and does not benefit from Pepco's subtransmission system generally.[613] Second, WASA argues that direct cost assignments lead to the best price signals.[614] Testimony at the hearings established that the old feeder lines running under the Potomac River meet all reliability criteria and give Blue Plains a "firm supply," such that Blue Plains could still maintain its supply even if it loses one of these under-river supply lines.[615]

305. WASA and Pepco disagree about whether two temporary overhead 69 kV lines ("Emergency Overhead Feeders"), which are now partially dismantled and not in use, provide "backup" facilities for Blue Plains whose costs could or should be allocated to WASA.[616] WASA witness Edwards testified that, because the Blue Plains facility is already served by two reliable 69 kV subtransmission lines that run under the Potomac River, WASA did not pursue the idea of using the Emergency Overhead Feeder lines as long-term additional backup.[617] WASA argues that the two overhead 69 kV lines in dispute (Emergency Overhead Feeder lines 69021 and 69022) were installed temporarily, as an aid to Pepco's construction in 2006-2007 of two major new underground 230 kV transmission lines running into the Potomac River Substation. After that, the Emergency Overhead subtransmission lines would no longer be in use.[618] WASA

612 WASA Br. 3, 7, 9, 22; WASA (A) at 10-14. "This difference is strictly a result of directly assigning the full cost of the two 69 kV feeders to WASA rather than allocating WASA a share of the total subtransmission plant, which WASA's Blue Plains facility does not and cannot use." *Id.* at 13.

613 WASA R.Br. 1-3.

614 WASA R.Br. 3-4.

615 *See* WASA Br. 2, 5; Tr. 1484 (Pepco witness Lizza), Tr. 1475-1476 (WASA witness Edwards), Tr. 1435-1436, 1467-1468 (Pepco witness Gausman).

616 *See* WASA R.Br. 4-11.

617 *See* WASA Br. 18; Tr. 1475-1476 (WASA witness Edwards); Tr. 1435-1436 (Pepco witness Gausman). WASA's full load at Blue Plains could be served by just one of the two 69 kV lines running under the Potomac River. Moreover, these two old 69 kV subtransmission lines meet all of the applicable reliability criteria that Pepco has for service to Blue Plains. WASA Br. 2, 15, 14; Tr. 1435-1436, 1467-1468 (Pepco witness Gausman). Blue Plains has a firm supply, Pepco witness Lizza acknowledged, and can still maintain supply if it lost one supply line. *See* Tr. 1484.

618 *See* WASA Br. 4; Tr. 1471-1472 (WASA witness Edwards). WASA states that "the Emergency Overhead Feeders were installed as only a temporary measure to facilitate construction of the long term solution to the Mirant situation, *i.e.*, two new 230 kV transmission lines that would connect additional supply sources to the Potomac River Substation. During that time, the Emergency Overhead Feeders allowed Pepco to shift the Blue Plains load off of the Potomac River Substation, freeing up capacity on the two existing 230 kV lines into that station to serve other

argues that these Emergency Overhead Feeder lines are not currently in use; not providing any "backup" service to its Blue Plains facility; and WASA is not pursuing any such overhead "backup" lines for Blue Plains.[619] WASA's emergency plans at Blue Plains do not include restoring power on the Emergency Overhead Feeder 69 kV subtransmission lines, which WASA understood were only temporary.[620]

306. WASA is sympathetic to Pepco recovering the costs of the Emergency Overhead Feeders. However, WASA insists that those feeders supplied many Pepco customers (not just Blue Plains). WASA concludes that, to the extent the Commission permits recovery of the costs of the Emergency Overhead Feeders in this case, those costs must be allocated among all Pepco customers.[621]

307. **WMATA.** WMATA argues that Pepco's CCOSS shows that the residential class is being unfairly subsidized by other customer classes. This sends the wrong price signals, and undercuts the residential class's incentives to conserve.[622]

308. **Pepco Rebuttal.** Pepco states that OPC's complaint about residential class cost assignments makes no difference because even if the cost of underground-related expenses is eliminated from the calculation, the residential class is still earning a negative rate of return.[623] Equally without merit, Pepco contends, are the District Government's objections to the costs assigned to the streetlight class. Though DCG touts the off-peak nature of SL usage, Pepco states that SL costs were calculated in accord with methods that the Commission has approved in earlier cases. The Company states that it took into account the energy conservation reductions in kWh usage by the SL and TS classes. Pepco claims that, even if no subtransmission or primary related costs were assigned to the SL class, the SL class would have a negative ROR (-0.6 percent) showing that the SL class is due a substantial rate increase in order to begin to align revenues with costs.[624]

309. Addressing WASA's claims about the cost of serving Blue Plains, Pepco states that WASA overlooked the costs of the two 69 kV Emergency Overhead circuits that were connected to Blue Plains to maintain reliable service during the construction of the additional

customers. Construction of the new 230 kV transmission lines was completed in 2006 and 2007, respectively, and, as Pepco freely acknowledges, the Emergency Overhead Feeders were taken out of service in July 2009, as required by a critical National Park Service permit that has now expired." WASA Br. 4. *Accord.* WASA Br. 12, 24.

619 WASA Br. 4; Tr. 1472, 1475-1476, 1482 (WASA witness Edwards).

620 WASA Br. 4-5, 14-18, 24-25; Tr. 1470 (WASA witness Edwards).

621 WASA R.Br. 11.

622 WMATA (A) at 16-18 (Foster).

623 Pepco (3F) at 13-14 (Browning).

624 *Id* at 2-3.

230 kV circuits that was authorized in Formal Case No. 1044. The original $6,182,033 cost of these Emergency Overhead circuits—which provide reliability and backup benefits to Blue Plains -- significantly exceeds the costs that Pepco now allocates to Blue Plains. Pepco argues that it would likely increase the assigned costs to Blue Plains, rather than decrease them, if a major share of the costs of these feeders were added to the cost of service of Blue Plains that WASA calculates.[625] The Company insists that it should be allowed to recover the costs of the two overhead 69 kV lines, which were installed as an emergency measure with Commission approval in Formal Case No. 1044.[626] Moreover, Pepco argues, once the new 230 KV underground lines were installed in May/June 2007, the continued operation of the 69 kV lines would be solely for the reliability of the Blue Plains facility.[627] Pepco states that the overhead 69 kV lines have not operated since the removal of a section on National Park Service land in Oxon Cove Park. Instead, Pepco submits, the overhead lines served as a backup, ensuring reliability to Blue Plains, the Naval Research Lab substation, the Metro Traction Power Station at Congress Heights, the District of Columbia Fire and Police training centers, D.C. Village, and the Hadley Memorial Hospital, as well as other facilities.[628] According to Pepco, the overhead 69 kV lines could be reconnected within 5 to 7 days in the event of an emergency.[629]

DECISION

310. We find that the Company has established the basic reasonableness of its CCOSS. Pepco properly assigned and allocated rate base items and operating expenses to functions and classes based on the principle of cost causation.[630] The Company also utilized different types of

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625 *Id.* at 9-11 (Browning). Pepco witness Hook stated that "these 69 kV lines were used to provide back-up support for the District of Columbia load supplied from the Potomac River Substation, as well as for the operation of Blue Plains facility in the event of loss of Mirant's Potomac River generating system. In July of 2009, pursuant to an agreement with the National Park Service, a segment of the lines over Park Service land was removed; the remaining portion is available to serve in a back-up capacity if needed." Pepco (4C) at 2 (Hook).

626 Pepco (3D) at 13-16 (Gausman). Pepco states that the two new 69 kV lines were built in 2005- 2006 on an emergency basis to ensure continuous service to Blue Plains. With little or no warning, Mirant shut down its Potomac River Plant, threatening reliable electric service to a major portion of the District of Columbia, including the Blue Plains treatment facility. *Id.* at 14. Originally, Pepco planned to ensure service to Blue Plains with new underground 230 kV lines. However, licensing difficulties with the National Park Service, the time required for underground construction of the new 230 kV lines, and the need to avoid a "Blue Plains failure," led Pepco to construct two new 69 kV lines overhead with a permitting condition to remove part of the overhead line at Oxon Cove Park within two years. For a period of eleven months, from July 2006 through June 2007, the two 69 kV lines ensured adequate service to Blue Plains until the new underground 230 kV systems were built. *Id.* at 13-20 (Gausman).

627 *Id.* at 16.

628 Pepco (3D) at 19 (Gausman). *Accord* Tr. 1439-1440 (Gausman).

629 *See* Tr. 1435 (Pepco witness Gausman).

630 Pepco (2F) at 13 (Browning); Pepco (F) at 16-19 (Browning).

"demand allocators" to allocate demand costs in a way that appropriately recognizes that various facilities are sized to meet various loads.[631]

311. OPC's objections concerning differences between overhead and underground facilities were considered and rejected in Pepco's last rate case where we found that OPC's concern with the assignment of overhead and underground facilities does not undermine Pepco's allocation of rate base and operating expenses to the residential class.[632] We also rejected in that case OPC's suggested use of the AED 4-CP method (instead of the AED-NCP method) for allocating subtransmission costs.[633] The Commission finds that Pepco now has the ability to identify outages by customer class,[634] so that it should be able to study and resolve the issue raised by OPC about the relative cost of overhead versus underground systems. The Company is directed to examine this issue and to include the study and its results in its CCOSS presentation in the next Pepco rate case.

312. We also noted in Pepco's last rate case that, "while it is true that the Commission previously gave weight to PEPCO's embedded and marginal class cost-of-service studies, the Commission's more recent guidance shows a preference for embedded costs."[635] Obtaining valid Pepco marginal cost studies has been fraught with difficulty. Nevertheless, we deny Pepco's request to dispense with marginal cost studies altogether. There may be some value in our looking at marginal cost studies in the future, as a judgmental factor, even if they cover only marginal distribution costs. The Commission will continue its past practice in which marginal costs may be one non-mathematical, judgmental factor among many that the Commission may consider in its discretion in the future in setting class rates.

313. WASA's suggested direct-cost-allocation "correction" to Pepco's CCOSS on the GT-3B (Blue Plains) rate is denied for several reasons. WASA and Pepco vigorously disputed whether it is proper to set the Blue Plains rate by direct cost allocations instead of an allocation formula.[636] Our general policy, however, is to disfavor single-customer rates that are set solely on the basis of narrowly-based directly-assigned costs, as opposed to costs that are determined by allocation from a wider pool of costs for similarly-situated customers. Such single customer rates, based on a very narrow base of cost information, may be subject to volatile changes if their directly-assigned CCOS changes suddenly because of future events.

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631 *Id.* at 18-19 (Browning).

632 *Formal Case No. 1053*, Order No. 14712, ¶ 282.

633 *Formal Case No. 1053*, Order No. 14832 at 10.

634 *See Formal Case No. 1053, Phase II*, Pepco Deborah Royster's July 7, 2009, letter to Commission (Company has developed necessary programming to calculate outage hours by customer class); *see also* Direct Testimony of Pepco witness Browning, pp. 11-12 (May 12, 2009).

635 *Formal Case No. 1053*, Order No. 14712, ¶ 274.

636 *Compare* WASA Br. 19-23 and WASA R.Br. with Pepco Br. 102 and Pepco R. Br. 52-56.

314. We have also determined that the cost of the physically intact part of the 69 kV Emergency Overhead Feeders[637] should be placed in rate base as "emergency capitalized spare."[638] Our decision today is that Pepco is entitled to full recovery (*i.e.*, recovery of costs plus a rate of return) on that rate base item from Pepco's customer base as a whole. We agree with WASA, and the record overwhelmingly demonstrates, that Pepco's recovery on this item should come from its system as a whole, and not just from WASA. The currently unused, partially dismantled overhead 69 kV lines provide potential "back-up support" not only for WASA's Blue Plains facility, but also for many other customers on the system.[639] OPC's claim that the Emergency Overhead Feeder lines were or are primarily for Blue Plains is inconsistent with the evidence in this record and the Commission's decision in Formal Case 1044.[640] Accordingly, the cost of the 69 kV Emergency Overhead Feeder lines, which are in Pepco's rate base as "emergency capitalized spare," should be recovered equitably from all of Pepco's customers, and not just from WASA.

315. To safeguard the safety and reliability of the electric distribution system in this area, the Commission also directs that Pepco not dismantle what remains of the 69 kV Emergency Overhead Feeders without first obtaining prior explicit Commission permission. We thus agree with the point made by Pepco witness Hook that it might be "better to leave [the 69 kV Emergency Overhead Feeder lines] up and ready to use again if it were needed, than to tear it down."[641]

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637 OPC stated that no service has been provided through these two overhead 69 kV lines since July 2007. *See* Tr. 881-883 (OPC witness Ramas); WASA Br. 11-12. Pepco admits that these lines were removed or "cut" in July 2009. Tr. 1434 (Pepco witness Gausman); Tr. 1489 (Pepco witness Lizza). One portion of these lines – approximately 4,000 feet (out of 13,000 to 16,000 feet) over National Park Service land in Oxon Cove Park – has been physically removed and retired on Pepco's financial records. *See* Tr. 1328-1331, 1342 (Pepco witness Hook); Tr. 1421-1422 (Pepco witness Gausman). Pepco conceded that OPC is right to delete $61,000 from plant in service to account for the fact that these facilities are not in service. Tr. 1328-1330 (Pepco witness Hook). Given that 25% of the $2.5 million Emergency Overhead lines have been retired, the Commission directs that an additional $574,000 be deleted from Pepco's plant in service.

638 *See infra* ¶¶ 22-26.

639 *See* WASA Br. 3-4, 12-13, 23-24; WASA R. Br. 5; Pepco (3D) at 19 (Gausman); Pepco (4C) at 2 (Hook); Tr. 905-906 (Pepco witness Morin) (14,000 other customers, besides Blue Plains, are served by the Potomac River substation).

640 Testimony was presented that Blue Plains is a "firm supply" facility, with reliable supply lines (two 69 kV lines running under the Potomac River), so that Blue Plains can still maintain its supply even if it loses one supply line. *See* Tr. 1484 (Pepco witness Lizza), Tr. 1475-1476 (WASA witness Edwards), Tr. 1435-1436 (Pepco witness Gausman). The two old 69 kV feeder lines running under the Potomac River to serve Blue Plains currently meet all the applicable reliability criteria that Pepco has for service to Blue Plains. Tr. 1435-1436 (Pepco witness Gausman); Tr. 1484 (Pepco witness Lizza). *See Formal Case No. 1044*, Order No. 13895 at 10-11, and Order No. 13958 at 5-6 quoted in WASA's R. Br. 8-9, 10.

641 Tr. 1337 (Hook).

B. Impact on Customer Class Rates

316. **Pepco.** The Company seeks to reduce the amount by which any class rate of return is greater or less than its overall D.C. jurisdictional ROR.[642] According to Pepco, the rate designs approved in Formal Case No. 1053 provide improved price signals,[643] but the rates resulting from that case made little progress in eliminating interclass subsidies between the residential and non-residential classes. Gradualism was an overriding concern of the Commission in that case, given the then recent large increases in Standard Offer Service ("SOS") rates. The small 1 percent differential between the residential and non-residential class increases authorized in that proceeding did not reduce the significant disparities that currently exist in class RORs.[644]

317. Two steps were utilized by Pepco to allocate its overall revenue requirement in a way that reduces disparities in class RORs. Because the residential classes were shown to have very low negative returns, the first step increased their rates of return by one-quarter of the way toward the overall rate of return of 8.88 percent that the Company is seeking in this case. This resulted in the residential class receiving $18.8 million, or about 36 percent of the total $51.7 million increase originally requested by Pepco. The other major under-earner, the SL energy class, was then adjusted one-half of the way from the present negative 4.33 percent return toward a zero return, producing an additional $324,000. The SL service class's return was judgmentally set at 1 percent producing a $33,000 increase from that class. Next, each remaining commercial class was adjusted half of the way toward the overall rate of return. Since this step still resulted in a revenue deficiency, each commercial class's return was adjusted by a constant factor until the overall revenue increase target was reached.[645] According to Pepco, the outcome brings class RORs closer together.

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642 Pepco (G) at 5 (Bumgarner); PEPCO (2G) at 2 (Bumgarner). The Company states that it measures its success at achieving this goal by utilizing a Unitized Rate of Return ("UROR"). "A UROR greater than 1.0 means that the customer class is providing a greater than average return. A UROR less than 1.0 means that the customer class is providing less than the average return." Pepco (G) at 5.

643 In particular, Pepco applauds the Commission's decisions to modify the Residential Standard Schedule "R" Minimum Charge to a Customer Charge, to increase that charge to $2 per month. This moves the non-residential Customer and Demand charges closer to cost and reduces the relative energy component of the "R" rate. Pepco (G) at 4.

644 *Id.* at 3-4.

645 Pepco (G) at 6-7 (Bumgarner); *see* Pepco (2G) at 2.

Customer Class RORs under PEPCO's Proposals[646]

	Current			PEPCO's Proposed	
	Class Revenues	class ROR	UROR	new class ROR	UROR
1. Residential					
Residential R	$48.21m	-3.05%	-0.43	0.27%	0.03
Residential AE	$11.94m	-3.90%	-0.55	-0.28%	-0.03
RAD	$3.94m	-5.35%	-0.76	-4.56%	-0.51
Residential TOU	$1.05m	10.84%	1.54	12.97%	1.46
2. Small Commercial					
GS					
GS-LV	$51.80m	14.25%	2.02	15.05%	1.69
GS-HV	$0.061m	21.51%	3.06	19.48%	2.19
SL Energy	$1.11m	-5.07%	-0.72	-2.17%	-0.24
SL Service	$0.477m	0.37%	0.05	1.00%	0.11
TN	$0.37m	6.59%	0.94	10.38%	1.17
3. Large Commercial					
GT-LV	$168.64m	12.39%	1.76	13.91%	1.57
GT-HV-3A	$0.49m	10.62%	1.51	12.83%	1.44
GT-HV-69KV	$3.15m	6.77%	0.96	10.48%	1.18
GT-HV-other	$73.16m	18.24%	2.59	17.48%	1.97
Metro-RT	$9.06m	15.70%	2.23	15.93%	1.79
Total D.C. jurd.	$373.45m	7.04%	1.00	8.88%	1.00

318. **OPC.** Relying on the approach taken by the Commission in Pepco's last rate case, OPC recommends that each customer class receive the same percentage increase in base distribution charge with the exception that the residential class receive an additional 1 percent increase over the non-residential increase.[647] OPC argues that Pepco's proposed class revenue targets would result in rate shock for the residential class. According to OPC, Pepco's proposed 47 percent increase in residential distribution rates cannot be masked as only a 6.1 percent increase when rolled into the total bill for supply, transmission, distribution and surcharges.

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646 *See* Pepco (G) at 6-7 (Bumgarner); Pepco (G)-1 and (G)-1a (charts) (Bumgarner); Pepco (F)-3 (chart) (Browning). *See also* AOBA (A) at 85-92 (Oliver); WMATA (A) at 17 (Foster); GSA (A)-1 (Goins).

647 OPC (F) at 5-6, 23-24 (Smith); OPC Pre-Hearing Br. 22.

319. OPC argues that the Commission's policies of gradualism and rate-continuity are undermined by Pepco's proposed sharp increase in residential rates. As in Pepco's last rate case, OPC urges the Commission to be mindful of continuing increases in the SOS rates, which have increased approximately 25 percent in the last two years, and the continuing economic challenges facing consumers, as well as the District of Columbia's unemployment rate of over 10 percent (placing D.C. at the ninth highest unemployment rate of all U.S. states).[648]

320. **AOBA.** In general, AOBA agrees with Pepco's proposed method to distribute its overall jurisdictional revenue increase among customer classes.[649] The only exception, according to AOBA, is the RAD class, in which the RAD class rates should not be frozen (as Pepco recommends) but instead should be raised by the lesser of: (1) the percent increase in the Consumer Price Index for urban wage and clerical workers (CPI-W) since the time that the most recent RAD rate caps were initiated (*i.e.,* 22.4 percent); or (2) 50 percent of whatever increase the Commission approves for the Residential ("R") class. If the Commission does not grant Pepco's full requested revenue increase, then AOBA recommends that one-third of any reduction in the Company's overall revenue request be spread among all classes across-the-board. The remaining two-thirds should be distributed among the rate classes that have greater than system average RORs to reduce subsidies between Pepco's customer classes.[650]

321. **District Government.** The District Government argues that there should be no increase in the streetlight and traffic signal rates, or at most, an increase of the average increase for all classes of customers.[651] Objecting to Pepco's proposed class revenue targets for the SL and TS classes, DCG argues that Pepco's proposed increase of 211 percent (or $324,000) for these classes[652] overemphasizes class RORs, creates rate shock, and ignores rate gradualism and non-cost factors.[653]

322. DCG contends that the Company's proposals reflect a mechanistic reliance on embedded costs, overlooking the fact that, since the 1980s, the Commission has always priced the SL and TS rates at only marginal energy costs because of public safety and welfare

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648 *Id.* at 22-24.

649 AOBA (A) at 91 (Oliver).

650 *Id.* at 91-93.

651 DCG Br. 1-2, 6, 11.

652 Even worse, DCG states, is GSA's proposed 319.82% increase for the SL and TS rates. Because SL/TS service has long been considered a public good, it is reasonable to expect other classes of service to subsidize SL/TS service to some extent. DCG Br. 7-8.

653 DCG (A) at 7 (Petniunas). DCG argues that the Commission in allocating costs among customer classes and in designing rates, has long considered a wide variety of non-cost factors, including peak causation/diversity; risk and reliability; growth of load; historical rate patterns; equity; fairness; conservation; revenue stability; social goals; value of service; and public safety and welfare. DCG (2A) at 8-9 (Petniunas).

considerations, and the extreme off-peak nature of SL/TS service. According to DCG, the Company's, AOBA's and GSA's proposals for raising SL and TS rates do not follow principles of gradualism, equity, and rate stability; they disregard important historical considerations like the value of service to the community provided by streetlights and traffic signals; and they overlook the fact that SL/TS rates provide risk-free returns.[654]

323. DCG submits that the SL and TS classes are risk free, providing stable usage patterns, loads and revenues for Pepco.[655] DCG submits that this stability reduces the need for future rate increases. Accordingly, the District Government maintains that the SL/TS classes should receive a lower rate increase and a lower required ROR than other classes.[656]

324. The District Government also contends that the Company's proposed 211 percent increase in SL rates will result in rate shock, arguing that there is no merit in Pepco's "total bill argument," which seeks to mask a sharp increase in SL distribution rates by bundling it together with unregulated SL generation costs. DCG submits that the same principles that moderated the requested SL/TS increase in Pepco's last rate case, gradualism and non-cost factors, should apply again in the present case.[657]

325. DCG states that the only significant development in SL/TS load or usage patterns since Pepco's last rate case is an increasing trend in reduced usage due to conservation. More SL/TS conservation measures are planned for the future.[658] DCG argues that it should be rewarded for its successful conservation efforts.[659] DCG also relies on the provisions of the Clean and Affordable Energy Act of 2008 ("CAEA") to support its proposition that those with the greatest ability and follow-through on conservation should get the lowest rates.[660]

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654 DCG Br. 4-6, 10-11; DCG (2A) at 5, 7, 13.

655 DCG Br. 10; DCG (2A) at 10 (Petniunas).

656 DCG Br. 11-13; DCG (A) at 16-17; DCG (2A) at 6.

657 DCG Br. 3-5; DCG R.Br. 4-5.

658 DCG Br. 7; DCG (A) at 17-18. Trends in SL energy usage are pointed downward with a 10% reduction since 1995 and a 3% reduction in the last two years alone. "Thus, 30% of DDOT's 19 year energy reduction was achieved since the Commission's last rate order." DCG Br. 7. Old inefficient traffic signal lights have been replaced with high efficiency LED lights, the District reports. "This measure has reduced the TS kWh use from 18.1 million kWh in 2001, to 10.5 million kWh in 2008, a 42% decrease in usage." DCG (A) at 18. According to the District Government, DDOT is planning to replace over 800 more streetlights with LEDs this October. It is also planning to replace all streetlights with LEDs in the future. *Id.* DDOT recently eliminated all unmetered 24-hour burning streetlights in the District, and all streetlights now receive the lower Standard Night Burning rate. DCG Br. 7, 13.

659 DCG Br. 7.

660 DCG cites Section 401 of the CAEA. DCG (A) at 18-19.

326. The District Government argues further that SL/TS service is a public good that benefits the community, without excluding any potential user. It promotes social interaction, deters crime, promotes business, and facilitates pedestrian and vehicular traffic. These unique public safety and welfare benefits, combined with the extreme off-peak nature of the service, DCG argues, justify low rates for the SL/TS class.[661]

327. DCG claims that there is improper loading of Pepco's system costs on the SL and TS classes because these classes are billed on a straight kWh basis that triggers the imposition of a set of surcharges, even though Pepco's CCOSS calculates the cost of the SL and TS classes based on demand and customer costs (not energy costs).[662] SL and TS base revenues are only $166,189, but when six surcharges based on kWh energy usage are added, the total of the base rate and distribution surcharges on a kWh basis produces a total bill of $1,085,423, reflecting 85 percent in surcharge revenues.[663]

328. Finally, DCG asserts that outages in streetlighting and traffic signal service also trigger additional operational costs, and risks of liability, which should be reflected in lower rates for the SL and TS rate schedules.[664] Because signal outages create a public safety hazard, the District Government has incurred significant capital expenses (over $3.5 million since 2007) to obtain emergency back-up generators, uninterruptible power supply systems, and retrofitted cabinets. In addition, DCG submits that it has incurred significant personnel costs (about $400,000 in 2008) for responding to traffic signal outages.[665]

329. **GSA.** GSA contends that, while Pepco's proposed revenue spread reduces disparities in customer class rates of return, this allocation still would increase the interclass revenue subsidy for the residential class from $61 million to $62 million. GSA claims that OPC's proposal would balloon the residential subsidy to around $72 million, leaving a negative residential class ROR and only an "extremely modest" movement towards cost of service. GSA recommends cutting interclass revenue subsidies under Pepco's proposed revenue spread by 10

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661 DCG Br. 11; DCG (A) at 6-8. SL/TS's non-cost benefits include: crime prevention, promotion of social interaction, promoting business, and facilitating pedestrian and vehicular traffic. Moreover, any traffic signal outages can provide significant risks for citizens and liability risks to the District Government. DCG states that the Commission's decision in *Formal Case No. 1053* recognized the validity and importance of non-cost factors (such as rate continuity, gradualism, their off peak nature, and the value of services as a public good) in setting class revenue targets for the SL and TS classes. In that case, the Commission limited the percentage increases for the SL and TS classes to the increase for the residential class. DCG (A) at 9-10.

662 DCG (A) at 20.

663 *Id.* at 20-21.

664 DCG Br. 14; DCG (A) at 23. For example, the number of power outages to District traffic signals has increased in recent years from 216 (2006) to 239 (2007) to 284 (2008) to 203 in the first eight months of 2009. DCG (B) at 2 (Dey).

665 *Id.* at 5.

percent (around $6.2 million) to $56 million to make a stronger movement toward cost-based rates and equal class RORs.[666]

330. GSA notes that OPC's proposed revenue spread is identical to the one adopted in Formal Case No. 1053, but the revenue spread did nothing to mitigate the huge interclass revenue subsidies that continue to this day. GSA contends that OPC's approach fails to move toward cost-based rates. GSA states that though OPC relies on Pepco's CCOSS to propose higher Customer Charges in the residential rate design, OPC ignores the massive subsidies shown in the CCOSS that keep residential rates far below cost.[667]

331. GSA contends that residential customers (excluding RTM customers) should receive a 61 percent distribution base rate increase (compared to Pepco's proposed 47 percent increase). GSA's proposal would increase an average residential customer's total bill by 8.2 percent. If Pepco receives less revenue than it is requesting, then GSA recommends reducing the increase for each class while maintaining the relative increases it recommends. For example, if the allowed increase is half of Pepco's requested increase, then the increase for residential customers should be 30.51 percent (half of GSA's recommended 61.02 percent).[668]

332. Opposing Pepco's proposed new GT-3A-S tariff for GSA's steam plant, GSA objects to the high cost that Pepco is proposing for this new rate which may discourage the development of distributed on-site generation.[669] GSA argues that the rate for its steam plant should be no higher than the actual cost of providing service to it.[670] According to GSA, this would involve a 20.93 percent increase for its steam plant as opposed to Pepco's proposed 23.38 percent increase.[671] Eventually, GSA suggests, a 10 to 20 percent discount might be appropriate for customers that (like GSA's steam plant) have distributed generation.[672] These issues are discussed further in the rate design section of this Order.

333. **WASA.** WASA argues that Pepco's CCOSS overstates the costs of serving WASA's Blue Plains facility under schedule GT-3B, and that the true class rate of return for the GT-3B class is 16.02 percent (not 6.77 percent as Pepco's CCOSS claims). Since this is more than Pepco's D.C. jurisdictional average ROR, WASA argues that a decrease is appropriate to

666 GSA Br. 2, 4-5, 15; GSA R.Br. 5; GSA (A) at 8-9, 15,16, 13-14 (Goins); GSA (B) at 3-4 (Goins).

667 GSA Br. 2; GSA (B) at 5-6.

668 GSA (A) at 16-17.

669 *See* Tr. 1192-1199 (colloquy between Commissioner Morgan and GSA witness Goins).

670 *See* GSA (A) at 25-28.

671 *See* Tr. 1177-1181 (GSA witness Goins); GSA (A) at 25-28.

672 *See* Tr. 1194-1195 (GSA witness Goins).

recognize the true cost of serving Blue Plains.[673] WASA objects to Pepco's proposed 37.7 percent increase in GT-3B rates. Instead, WASA argues, a 29.3 percent decrease in WASA's rates is required to eliminate the subsidy presently paid by WASA.[674]

334. **WMATA.** WMATA argues that Pepco's proposed class revenue targets do not go far enough toward lessening residential class subsidies. WMATA is recommending no change to the residential RAD rate class, as WMATA supports the Commission's efforts to protect that segment of the population least able to pay.[675] Otherwise, however, WMATA asks the Commission to move more quickly by going "one-third of the way" (as opposed to Pepco's proposed "one-quarter of the way") toward equal customer class RORs.[676]

335. WMATA states that the gradual movement toward cost-based rates ordered in Formal Case No. 1053 failed to reduce the significant disparities that still exist in class RORs. WMATA now contends that, since the SOS rate increase in 2009 was only 2.7 percent, as compared to more than 12 percent for 2007 when Formal Case No. 1053 was decided, the SOS should no longer constrain the Commission from moving more quickly toward cost-based rates.[677]

336. **Pepco Rebuttal.** The Company argues that its "one quarter of the way" approach is reasonable, as shown by the fact that it lies in the middle of the other parties' positions. It claims that a 6.1 percent increase in residential customers' total electric bill is modest and will not cause "rate shock." Rebutting OPC, Pepco argues that it is the total bundled price of electricity, not just the distribution portion, that affects the decision whether or not to consume an additional kWh. In answer to OPC's claims about increases in SOS rates and the general state of the economy, Pepco notes that a meaningful movement toward cost for the residential class may be more appropriate now than it was in Formal Case No. 1053. Pepco states further that the recent SOS increases have dramatically moderated downward to the 3 percent range from the double digit increases that the Commission was looking at when it decided Formal Case No. 1053 two years ago.[678]

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673 WASA (A) at 15 (Phillips); *see id.* at 14-16.

674 WASA Br. 3, 9; WASA (A) at 15.

675 WMATA Br. 11.

676 WMATA Br. 10-11; WMATA (A) at 17-21 (Foster). WMATA states that Pepco should follow its two-stage approach to determining class RORs. The first step should be to increase the residential class rates one-third of the way toward the overall rate of return allowed by the Commission. This approach will eliminate the negative earnings in the residential classes (except for RAD), thereby requiring that the residential classes cover Pepco's allocated operating costs. In the next rate case, Pepco could take other steps toward cost based rates. *Id.*

677 WMATA Br. 9-10; WMATA (A) at 16- 19 (Foster).

678 Pepco (3G) at 3-5 (Bumgarner).

337. Turning to SL and TS rates, Pepco argues that the District Government failed to show that it incurred increased costs because of power outages to traffic signals.[679] Overall, Pepco argues that its proposed SL/TS distribution rate increases involve only small increases to total SL/TS bills, and are consistent with rate gradualism. Pepco states that even with this increase, the SL class will still produce a negative 2.17 percent return on equity. This degree of subsidy, Pepco argues, should more than satisfy the desire to recognize the "non-cost factors" cited by the District Government.[680] Pepco acknowledges that streetlighting and traffic signals are a public good that contribute to public welfare, safety and the quality of life in the District. However, the Company asserts, there are many other businesses and organizations in the District that are served by Pepco that also contribute to the quality of life, and it points out that those considerations have rarely entered into rate design or revenue distribution decisions of the Commission.[681]

338. Pepco argues that the "unique load characteristics" of GSA's steam plant justify creating a new GT-3A-S rate class; that this customer's load factor is only 16 percent, or about 75 percent lower than the 64 percent load factor for other customers on the GT-3A schedule on which the GSA plant is currently served.[682] Pepco states that GSA's proposed 20.93 percent increase for this facility is not far from Pepco's proposed 23.39 percent increase. Moreover, Pepco notes that the proposed GT-3A-S class provides (and will continue to provide) a lower class ROR than the remainder of the GT-3A class. The Company states that only if the GSA steam plant were relieved of its entire share of the subsidy for the residential class, would it receive a small ($2,546) revenue decrease under a "fully equalized class ROR" regime. The Company indicates that its GT-3A and GT-3A-S rates are calculated in the same manner as all other commercial rates and that they recover the full cost of service plus a fairly determined portion of the remaining subsidy to the residential and other underperforming classes. Therefore, Pepco argues, they are not a market barrier to the development of customer-owned cogeneration plants.[683]

339. As for the two new overhead 69 kV lines that were built in 2005-2006 on an emergency basis to ensure continuous service to D.C. customers, Pepco insists that it is entitled to recover the cost of these ordinary and necessary outlays.[684] The Company suggests that the

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679 Pepco (3D) at 11-13 (Gausman). "The outage percentages are 0.16% and 0.13% for 2008 and 2009 (through September 11, 2009), or less than two tenths of one percent of the actual operating hours of these systems." *Id.* at 12-13.

680 Pepco (3G) at 5-6 (Bumgarner). *Accord* Tr. 1408-1409 (Pepco witness Bumgarner).

681 Tr. 1409-1410 (Pepco witness Bumgarner).

682 Pepco (3G) at 6-8. The operation of GSA's cogeneration plant causes the load factor for this account (*i.e.*, the ratio of the average load to peak load measured at the meter, a measure of plant utilization) to be lower than that of other customers on the GT-3A schedule. *Id.* at 6.

683 Pepco (3G) at 9-10 (Bumgarner).

684 *Id.* at 13- 20.

costs would be properly assignable to WASA's Blue Plains facility because the continued operation of the 69 kV lines would be solely for the backup reliability of the Blue Plains facility.[685]

DECISION

340. The Commission enjoys wide latitude in setting customer class revenue requirements. Traditionally, in setting class revenue requirements, we have considered class cost of service as well as a broad range of other factors in addition to the cost of service for each class.[686] The courts have never imposed a requirement of uniformity among the rates of return from different customer classes.[687] For example, customer class rates of return may vary based on the risk to Pepco because the level of risk is a valid factor to consider in rate design.[688] Differences can be based not only on quantity, but also on the nature, time, and pattern of use, so as to achieve reasonable efficiency and economic operation.[689] Other valid non-cost factors that may be considered in setting both customer class revenue requirements and rate designs, include

685 *Id.* at 16. Pepco claims that WASA asked it to replace a removed overhead portion of the 69 kV lines with an underground system and that discussions on this topic, including the cost responsibility of this underground segment, are continuing. Pepco (3D) at 19-20.

686 *See, e.g., Washington Gas Light Co.*, 450 A.2d at 1199-1209. There is also a new statute that states: "In supervising and regulating utility or energy companies, the Commission shall consider the public safety, the economy of the District, the conservation of natural resources, and the preservation of environmental quality." *See* Clean and Affordable Energy Act of 2008 § 401, D.C. Law 17-250, 55 DCR 9225 (October 22, 2008), amending the Commission's organic act of March 4, 1913, ch.50, § 8 ¶ 96A.

687 *Washington Gas Light Co. v. Pub. Serv. Comm'n*, 450 A.2d 1187, 1207 (D.C. 1982); *Accord Apartment House Council of Metro. Washington, Inc. v. Pub. Serv. Comm'n*, 332 A.2d 53, 57 (D.C.1975) ("equal return from customer classes is not required"). Wholesale FERC principles about equalized class RORs do not apply mechanically to set retail class RORs in Pepco rate cases. The state commissions that set electric rates at the retail level must consider a much more diverse set of customers, different issues, and a different calculus of interests, than exists at the wholesale level. For example, at the retail level the costs of electricity are commonly tax deductible business expenses for retail business customers but not for retail Residential customers. For these reasons, the case law and Commission precedent about retail electric rates in the District of Columbia are different from FERC cases about wholesale rates where fewer non-cost considerations apply and the courts insist on more equalized customer RORs. *See, e.g., Alabama Electric Coop. Inc. v. FERC*, 684 F.2d 20, 27 (D.C. Cir. 1982), cited in *Formal Case No. 1053*, Order No. 14712 at 99, n. 719.

688 *Potomac Electric Power Co., Formal Case No. 1053*, Order No.14712, ¶ 337.

689 *Apartment House Council of Metro. Washington, supra*, 332 A.2d at 57. In some cases, the old discretionary factors for setting class revenue targets must be updated. To be specific, the Commission in the past sometimes allocated a greater-than-average percentage increase to the customer classes (such as WMATA) whose rapidly growing demand for electricity was contributing more than other classes to the need for Pepco to build costly new electric generating plant. *See, e.g. Formal Case No. 748*, Order No. 7457 (December 30, 1981), 2 DCPSC 401, 443-444 (1981). In today's post-divestiture environment, where Pepco is a "wires only" electric distribution company and not an electric generating company, this factor must be restated. A modern corollary might be: what customer class(es), if any, are contributing disproportionately to the need for Pepco to build costly new distribution plant?

"equitable considerations" such as value of service to the customer and ability to pay, historical rate patterns, the need to conserve energy resources, and other market-place realities, as well as principles of gradualism and rate continuity.[690]

341. **The Commission's General Approach.** The options available to the Commission in setting class revenue targets in the present case cover a wide spectrum and include: (1) OPC's nearly-across-the-board approach, with the residential class receiving an increase of 1 percent more than non-residential classes, following the approach taken by the Commission in Formal Case No. 1053; (2) Pepco's proposed "one quarter of the way" approach toward more equal class rates of return; (3) GSA's proposed 10 percent (approximately $6.2 million) reduction in interclass subsidies; and (4) WMATA's "one third of the way" approach toward more equal customer class RORs. All these options involve some departure from a strict across-the-board approach with some additional revenue burden being imposed on the residential class that has a comparatively low class ROR.

342. The Commission agrees with Pepco, AOBA, GSA, and WMATA that we should move to reduce the disparities that now exist in class RORs. This principle has limits. The Court of Appeals, and this Commission, has repeatedly held that equal class RORs are not required and that the Commission has statutory authority to consider many valid cost and non-cost factors in setting class revenue targets and rate designs.[691] Historic rate patterns in the District of Columbia have been that the residential classes pay lower class RORs than the commercial class RORs. The Commission is not compelled to equalize class RORs for residential and commercial retail Pepco customers. We believe, however, that the severe disparities in class RORs that now exist call for corrective action.

343. **Residential Rates.** Today's decision reduces Pepco's requested $44.51 million revenue increase for the District by more than half, to $19.833 million. Out of that D.C. jurisdiction-wide increase, only $7.14 million (or 36.0 percent) will go to increase the residential class revenue target. This decision mirrors Pepco's proposal, which was supported by AOBA, on the more moderate end of the proposals submitted to us, that the residential class should receive 36 percent of the total D.C. jurisdictional increase. Residential rates will increase in the present case by more than an across-the-board amount. However, the disparities in class RORs will be reduced, and all class RORs will move closer to the overall D.C. jurisdictional ROR. No further movement toward equalized class rates of return is warranted in this case. However, we must recognize that the severe economic downturn has hit District of Columbia ratepayers

690 *See, e.g. Washington Gas Light Co.*, 450 A.2d at 1199- 1209; *Formal Case No. 869*, Order No. 9216, 10 D.C.P.S.C. 22, 133-134 (1989).

691 *See, e.g., Washington Gas Light Co. v. Public Serv. Comm'n*, 450 A.2d 1187, 1207 (D.C. 1982); *accord*: *Apartment House Council of Metro. Washington, Inc. v. Public Serv. Comm'n*, 332 A.2d 53, 57 (D.C. 1975) ("equal return from customer classes is not required").

hard.[692] The Commission heard community comments confirming the dire economic situation of many D.C. residential ratepayers, particularly senior citizens and the disabled on fixed incomes.

344. The Commission must balance the competing interests in a way that is reasonable and fair to all stakeholders. Our ruling today is moderate. We have decided to recover the residential rate increase primarily through an increase in the Customer Charge. As discussed further below,[693] we are increasing the Customer Charge for the residential class to $6.65, and simultaneously reducing the volumetric (kWh) rates in residential distribution charges, so that the residential class pays no more than the class revenue target we set today. This will move the rate design of residential distribution rates away from volumetric (kWh) rates, and towards rates that are based more on customer and demand charges, as is appropriate in the new era where Pepco is a "wires only" electric distribution company.

345. In making this decision, we have very specifically considered the need for rate gradualism.[694] While our ruling today will reduce the disparities that now exist in class RORs and narrow the gap between the very low residential class ROR and the higher commercial classes' RORs, we point out that it still leaves the residential class with a negative class ROR. The Commission is acting in a measured way to narrow the gap in customer class RORs and move all Pepco customer classes closer to UROR, as all the parties agree should be done, consistent with the constraints imposed by a recovering economy, both nationally and in the District of Columbia in particular.

346. **Residential Aid Discount (RAD).** The Commission's concern for low-income residential customers is reflected in our long-standing Residential Aid Discount ("RAD") program, which provides rate relief to eligible, low-income residential customers. The Commission has decided to increase the class revenue target for the RAD class by only a modest amount, which will be determined by long-overdue RAD rate design changes discussed below.

347. We are simplifying and clarifying the RAD rate structure while still giving RAD customers a very sizable discount compared to non-RAD residential rates (standard R and AE). To begin, RAD rates should be structured more like standard residential rates in order to send better cost signals and reflect how Pepco's "wires only" distribution charges should be recovered

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692 We note that in referring to the "state of the economy" in various places in this Order, such a reference will mean different things to different groups, depending upon the context in which it is used. For example, it can mean stock market prices when referring to Pepco's cost of capital, or it can mean unemployment, the price of goods and/or median income levels when referring to District ratepayers. Whether the economy can be described as terrible, severe, recovering, etc., also depends upon the context in which it is described.

693 *See infra* at 118-124.

694 The Commission must fairly balance a wide variety of considerations, of which gradualism is one. *See, e.g., Watergate East Inc. v. Pub. Serv. Comm'n*, 665 A.2d 943, 949 (D.C. 1995) (court approves significant rate increase for Watergate, noting that "gradualism is but one of many factors to be considered and weighed in setting rate designs" and that it should not trump other considerations such as the need for reasonable cost recovery).

from all customers. The existing monthly Distribution Charges for RAD customers[695] consist of: (1) a Minimum Charge of $0.19 per month, which includes the first 30 kWh of electric usage; (2) a per kWh charge for electric usage between 31 and 400 kWh per month; and (3) a higher per kWh charge for electric usage in excess of 400 kWh per month.[696] We are replacing the Minimum Charge with a Customer Charge of $2.50 going forward.[697] We are also eliminating the initial RAD 30 kWh rate block, a vestige of outdated tariffs, which was included in the Minimum Charge.[698] That rate block will be replaced with a new initial rate block that will charge for electric usage from 1-400 kWh per month, similar to the initial 400 kWh rate block in Pepco's tariffs for standard Residential and Residential AE service. As is currently the case, a second block containing higher rates per kWh is charged for electric usage in excess of 400 kWh per month.[699] The existing tailblock[700] rates for RAD and RAD-AE are currently higher than the corresponding tailblock rates for the R and AE classes, a rate design anomaly that must be corrected. If the rates for the R and AE classes resulting from this case are lower than the corresponding RAD rate blocks, the RAD block rates should be adjusted downward so that the RAD and RAD-AE block kWh rates will be the same as they are in the R and AE rates.[701]

348. Overall, the RAD class revenues to be recovered from all RAD kWh rates (in RAD's distribution rates) will remain the same as they are now. Thus, for example, to the extent that the RAD tailblock rates are reduced, then the rates from other blocks must increase to make up for the revenue loss from the tailblock.[702] This applies to RAD-AE also. The moderate increase in the RAD class revenue requirement is due solely to the increase we are ordering in the new RAD Customer Charge, which replaces the current RAD 30 kWh Minimum Charge.

349. The impact of these changes to the RAD rate structure will give RAD customers a discounted Customer Charge (as compared to standard R and AE customers) as well as retaining a discounted rate for the first 400 kWh of RAD consumption (or the first 700 kWh of RAD-AE

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695 There are two RAD rate classes: RAD-Standard and RAD-AE (All Electric).

696 There is an additional block of higher rates for the RAD-AE customers for electric usage in excess of 700 kWh per month.

697 The Commission is thus increasing the RAD minimum charge by slightly less than one-half of the increase to the Residential Customer Charge.

698 A rate block is defined as a rate structure under which consumption is divided into units or tiers and a price is set for each tier or unit of service used. Block rates can be either declining or inverted. P.U.R. Glossary for Utility Management (1992).

699 Currently, the second block for RAD-AE customers covers 401-700 kWh per month, and a third block consist of even higher charges per kWh for usage in excess of 700 kWh per month.

700 The last block for each rate class is called the "tailblock".

701 In no event should the RAD and RAD-AE block rates be greater than the corresponding R or AE block rates, respectively.

702 This change in RAD structure may provide a modest conservation incentive to RAD customers.

consumption). These changes will move the RAD rate away from recovery through volumetric (kWh) rates and towards more emphasis on recovery through customer charges. These changes also will help to simplify and clarify RAD rates and reduce the size of the gap between RAD and non-RAD residential rates, which has increased unintentionally during the period when rates were capped.[703]

350. **GT-3B (WASA's Blue Plains Facility).** WASA's suggested rate reduction for Blue Plains was based on its suggested direct-cost-allocation "correction" to Pepco's CCOSS on the GT-3B (Blue Plains) rate. For the reasons we stated earlier, the Commission rejects WASA's direct-cost-allocation correction/reduction to the Blue Plains rate. The recoverable costs of Pepco's overhead 69 kV Emergency Overhead Feeder lines are to be recovered equitably from all Pepco's customers, not just from WASA. WASA's Blue Plains's class revenue target is to be calculated consistent with these principles and consistent with Pepco's proposed methodology for calculating commercial class revenue targets within the constraint of a reduced overall $19.8 million rate increase for the District of Columbia.

351. **Streetlights and Traffic Signals.** Together the SL Energy and SL Service classes now produce some $1.59 million in revenues, or only 4/10 of 1 percent of Pepco's total D.C. jurisdictional revenues of $373.45 million. We stated in Pepco's last rate case that streetlight and traffic signal rates "will now, and in the future, contribute to the cost of service based on embedded cost principles tempered by the Commission's principles of gradualism and rate continuity."[704] We also said that "the comparative low risk of the SL and TS classes" is a valid factor to consider in setting SL and TS rates.[705]

352. We determine that it is appropriate in the present case to move toward more cost-based SL and TS rates. Ordinarily, this would entail a significant increase for the streetlight class since, as Pepco emphasizes, it is presently earning a negative class ROR. We accord significant weight, however, to DCG's argument that the low risk of the SL and TS classes warrants the imposition of a lower SL/TS ROR than would otherwise be the case. Taking gradualism and rate continuity into account, as well as the low risk of the SL/TS classes and all the non-cost and other factors cited by DCG, we will raise SL and TS rates by the same percentage (approximately 17.5 percent) that is being imposed on the low-earning residential class. This increase is significantly lower than Pepco's proposed increase for the streetlight class. The Commission points out that SL/TS rates will still yield very low or negative class RORs. We find that the outcome reached in this case for SL/TS rates adequately reflects

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703 The complexity of the RAD rate, and the need to clarify and simplify it, is illustrated by our opinion in *Formal Case No. 1053*, Order No. 14712, ¶¶ 422-442, discussing RAD summer tailblock anomalies that were created, accidently, by the complex regulatory history of the RAD rate.

704 *Formal Case No. 1053*, Order No. 14712, ¶ 277.

705 *Id.* at 118.

gradualism, as well as all the conservation, low risk, non-cost and other factors cited by the District Government.[706]

353. **Commercial Classes.** The Commission adopts Pepco's proposed method to distribute among the commercial classes the remaining revenue burden, *i.e.*, the overall $19.833 million D.C. jurisdictional rate increase, minus the $7.14 million increase allotted to the Residential class minus the dollar increase allotted to Streetlights and Traffic Signals. The outcome brings class RORs closer together.

XII. RATE DESIGNS (Issue No. 13)[707]

354. **Overview.** The Company is partial to the rate designs approved in Formal Case No. 1053, which increased its fixed cost recovery relative to its recovery for energy usage. Pepco requests that these rate designs be preserved in the present case. It proposes that class revenue targets be recovered by applying an across-the-board increase to each rate component of its residential and commercial rates.[708] Pepco's rate design proposals also include recognition of a new "GT-3A-S" tariff for GSA's steam plant, and a significant increase in Street Light energy distribution rates which currently earns a negative class rate of return. No increase is proposed for the Residential Aid Discount (RAD) rate.

355. We indicated in Formal Case No. 1053 that Pepco is now a "wires only" distribution company; therefore, the rate designs for Pepco's customers should shift away from volumetric recovery to recovery based on fixed customer charges and distribution charges. Consistent with this pronouncement, our Order today increases the customer charge for residential and RAD customers in order for Pepco to more gradually recover actual customer and fixed costs. Otherwise, Pepco's proposed rate designs would not adequately progress toward recovering customer and fixed costs directly (not through energy-delivery charges).[709] Accordingly, the Commission directs the Company to present rate designs in its next rate case

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706 *See, e.g., Watergate East Inc. v. Pub. Serv. Comm'n*, 665 A.2d 943, 949 (D.C. 1995) (court approves significant rate increase for Watergate, noting that "gradualism is but one of many factors to be considered and weighed in setting rate designs" and that it should not trump other considerations such as the need for reasonable cost recovery).

707 Designated Issue No. 13 asks, "Are Pepco's proposed rate designs just and reasonable?"

708 Pepco (G) at 4-5, 8 (Bumgarner); Pepco (2G) at 3 (Bumgarner). All of Pepco's customer class rates differentiate between summer (June through October) and winter (November through May) rates. *See* Pepco (G)-2 (PEPCO rate schedules); Pepco (G)-3 (Bumgarner).

709 OPC recognized that Pepco needs to redesign its rates to de-emphasize volumetric recovery and to recover more of its required revenue through demand and distribution rates. The District Government also noted that it is anomalous to calculate CCOS for the SL and TS tariffs on the basis of demand and customer costs while billing these customers on a straight kWh basis. DCG witness Petniunas stated, however, that he was not advocating a demand rate for the SL and TS rate schedules at this time. DCG (A) at 23.

that (consistent with gradualism) place greater emphasis on customer charges and demand charges and less emphasis on volumetric (kWh) charges.

A. Residential Class Rate Designs (Issue No. 13a)[710]

1. Customer Charge for Residential, AE, and R-Time-of-Use

356. **Pepco.** Pepco supports the structure of its current residential rate designs, which encompass standard Residential (R), Residential All-Electric (AE), and Residential Time-of-Use (R-TM) rates. As approved by the Commission in Formal Case No. 1053, the R rate now collects a greater percentage of revenues from fixed customer charges as opposed to charges for energy use.[711] To collect the class revenue target for the R class, Pepco proposes to increase each component part of the R rate by an across-the-board amount, while freezing the rates for the RAD.[712] Pepco's originally proposed changes for distribution rates for standard residential customers appear below:

710 Designated Issue No. 13a asks, "Are the rate designs by classes reasonable?"

711 Pepco (G) at 4-5 (Bumgarner). The components of Pepco's standard residential rates (R, R-AE) include a fixed customer charge, as well as rate blocks for different levels of energy usage (kWh) (covering the first 400 kWh, and in excess of 400 kWh), and surcharges. *See* Pepco (G)-2 (Pepco rate schedules) at R-3 to R-5, R-41 (for SOS); Pepco (G)-3 (Bumgarner). Time-metered residential rates (R-TM) include a customer charge, as well as rate components covering energy usage (kWh) (on peak, intermediate, off peak) and surcharges.

712 *See* Pepco (2G) at 3 (Bumgarner).

Distribution Rate Changes for Residential Classes[713]

	Current Rates		Proposed Rates	
Residential-	summer	winter	summer	winter
Standard "R"				
Customer Charge	$2.00	$2.00	$2.93	$2.93
First 400 kWh	$0.00945	$0.00945	0.01385	0.01385
Excess of 400 kWh	$0.02796	$0.01942	0.04098	0.02846
Residential-All Electric "AE"				
Customer Charge	$2.00	$2.00	$3.10	$3.10
First 400 kWh	$0.00945	$0.00945	0.01467	0.01467
Excess of 400 kWh	$0.02796	$0.01552	0.04339	0.02408
Residential-Time-of-Use "R-TM"				
Customer Charge	$9.09	$9.09	$11.17	$11.17
kWh Charge	$0.03717	$0.03717	0.04566	0.04566

357. In its post-hearing brief, Pepco changed position indicating that it "does not object" to OPC's proposal to raise the residential customer charge to $6.65 (from Pepco's originally proposed level of $2.93), while adjusting the energy usage charges in the first 400 kWh rate block downward.[714] Pepco states that this might better align residential rates with the largely fixed nature of the costs of providing distribution service.

358. **OPC.** As indicated, OPC recommends increasing the customer charge in the Residential R and Residential AE rates from $2.00 to $6.65 per month, to move them closer to actual cost, and to match Pepco's Maryland residential customer charge. OPC recommends further that additional revenues collected through the customer charge should be used to reduce the first 400 kWh block of each rate, which will lessen the impact on average usage residential customers.[715]

713 *See* Pepco (G)-2 (Bumgarner) at Eighth and Ninth Revised Pages, pp. R-3, R-4, and Sixth and Seventh Revised Pages p. R-5 (showing before and after rate schedule tariffs for R, AE, and R-TM).

714 Pepco Br. 103.

715 OPC (F) at 7, 28-29 (Smith). "If the Commission orders a revenue increase for the residential class that differs from the Company's proposal, the R and AE rate design should still be set at $6.65 and the 400 kWh block adjusted accordingly." *Id.* at 29.

359. Over the long term, OPC suggests that the Commission rely on AMI-generated meter data to quantify demand, and permit a fundamental restructuring of Pepco's rate designs. At present, OPC contends that Pepco's rate designs suffer from the fundamental problem of recovering most of its distribution-related fixed costs through an energy (kWh) charge that varies with usage. OPC argues that the objective of rate design in the future should be to move from Pepco's current outdated rates based primarily on delivered kWh to new rates that "isolate Pepco's opportunity to recover its fixed costs from the impacts of energy efficiency or DSM."[716] OPC states that an AMI system should allow for the design of more accurate retail electricity distribution rates (by jurisdiction and customer class) (based on kW or demand) and more controllable commodity rates (based on kWh or energy) that reward customers for lowering energy usage during peak demand periods.[717]

360. **District Government.** DCG agrees with OPC that there is a basic disconnect between the cost allocation methodology in Pepco's CCOSS (which shows demand and customer related costs) and the Company's SL and TS rate schedules, which are designed as 100 percent kWh charges. Those kWhs are then used for surcharge collections which, in the case of SL/TS rates, account for 85 percent of the total bill. DCG contends that over the next several Pepco rate cases, Pepco's "revenue recovery should be shifted more toward demand costs and less revenue be collected from the energy charges."[718]

DECISION

361. The Commission agrees with OPC and DCG that Pepco's rate designs should move from rates that recover costs primarily through energy-delivery (kWh) charges to rates emphasizing recovery through demand and customer charges. This is imperative in the new era of unbundled electricity service, where Pepco is a "wires only" distribution company. Pepco's costs are now demand and customer costs, not energy costs. As previously indicated, we direct Pepco and the parties to propose rate designs that reflect this reality, with due regard for concerns about transition and gradualism, in Pepco's next rate case.

362. The Commission adopts OPC's and Pepco's proposals to raise the fixed customer charge component of Residential R and Residential AE rates from $2.00 to $6.65 per month. This will bring customer charges closer to actual cost (about $10.00)[719] and correct price signals, and is preferable to a simple across-the-board increase in all component parts of residential class rates to reach the targeted class revenue requirement. Our opinion explains that, while the

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716 *Id.* at 25-28. *See* OPC Pre-Hearing Br. 22-23.

717 OPC (F) at 29-31. "Hourly pricing, critical peak pricing, and critical peak load reduction rebates are just some of the alternative rate mechanisms that can be designed and implemented with a fully functional AMI system. The availability of these new alternative pricing mechanisms will empower retail customers to better control their energy costs." *Id.*

718 DCG (2A) at 22-23 (Petniunas).

719 *See* Commission Ex. No. 22.

residential customer charge is being raised to $6.65, the residential energy-delivery charges will be reduced to keep the residential class revenue increase limited to 36 percent ($7.14 million) of the overall D.C. jurisdictional $19.833 million increase that we approve today.[720]

363. We also adopt Pepco's unopposed proposal to move the Customer Charge for R-TM from $9.09 to $11.17.[721] The total percentage increase in the distribution rate for R-TM will be the same as that of the other residential classes (R and AE).

2. Residential Aid Discount (RAD)

364. Twenty-seven years ago, the Commission approved Pepco's residential aid rider ("RAR") program, to provide rate relief to eligible, low-income residential customers (defined as Low Income Home Energy Assistance Program ("LIHEAP")-eligible, DDOE-certified Pepco customers) by reducing their electric costs by six percent per year. The costs associated with the RAR were distributed to all customer classes equally on an across-the-board basis.[722] The old RAR program is now called the Residential Aid Discount (RAD) program.[723]

365. Two sources of funding now exist for the RAD program; the "legislative subsidy" provided by the Energy Assistance Trust Fund (EATF) and the "regulatory subsidy" provided by all other Pepco customer classes to RAD customers as approved by the Commission.[724] The statute, as amended, establishing the EATF as a non-lapsing fund provides as follows:

> (c) The Energy Assistance Trust Fund shall be used solely to fund:
>
> (1) The existing low-income programs in the amount of $3.3 million annually; and
>
> (2) The Residential Aid Discount subsidy in the amount of $3.0 million annually; provided, that the subsidy shall be in the amount of $5.207 million for Fiscal Year 2009.

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720 *See supra* ¶ 345.

721 *See* Pepco (G)-2 (Bumgarner) at Sixth and Seventh Revised Pages p. R-5 (showing before and after R-TM rate).

722 *See Potomac Electric Power Company, Formal Case No. 785*, Order No. 7716 (December 29, 1982), 3 D.C.P.S.C. 450, 557-565 (1982); *and see Potomac Electric Power Company*, Formal Case No. 869, Order No. 9216 (March 3, 1989), 10 D.C.P.S.C. 22, 162 (1989) (outlining the history of the RAR/RAD program).

723 *See* D.C. Code § 8-1773.01(13) (2009 Supp.).

724 *See, e.g.*, Tr. 650, 665 (Pepco witness Bumgarner).

(d) The Mayor, pursuant to subchapter I of Chapter 5 of Title 2, may issue rules to modify the assessments under subsection (b) of this section and the programs funded by the EATF.[725]

366. Although the Commission is currently considering eligibility rules and other aspects of the RAD program in Formal Case No. 813, several RAD issues were designated for consideration in this Pepco rate case.

a. Level of RAD distribution rates (Issue No. 15a)[726]

367. **Pepco.** The Company proposes no increase in RAD distribution rates. Though the cap on RAD distribution rates expired on August 31, 2009 under the Pepco/Conectiv Merger Settlement Agreement, Pepco argues that any increase in RAD rates would not be appropriate in light of "the current adverse economic climate."[727]

368. **AOBA.** AOBA recommends that RAD rates be raised by the "Consumer Price Index for Urban Wage-Earners and Clerical Workers" ("CPI-W") amount or alternatively one-half of the percentage increase approved for the residential class, whichever is less. AOBA challenges Pepco's proposed freeze on RAD distribution rates, arguing that the RAD class is already over-subsidized. AOBA recommends that, effective January 1, 2011, RAD charges should be increased by the percentage increase in the CPI-W for the 12 months ended September 2010. Additionally, AOBA recommends a similar RAD adjustment be made each year to the RAD surcharge with the revenues flowed through to all other customers.[728]

369. **District Government.** DCG urges a freeze on RAD rates.[729] It criticizes AOBA's request for annual increases in RAD rates, arguing that this ignores the state of the economy, historic rate patterns, and the needs of RAD customers. DCG contends that no evidence supports AOBA's RAD proposal because AOBA failed to undertake any independent study of RAD customer needs, or the support available to RAD customers from non-utility

725 D.C. Code. § 8-1774.11(c), (d) (2009 Supp.) (amended 2010).

726 Designated Issue No. 15a states, "According to the PEPCO/Connectiv Merger Settlement Agreement, the RAD distribution price cap will be lifted on August 31, 2009. Should RAD distribution rates be maintained at the same level or should they be altered as a result of changing revenue requirements from this rate case?"

727 Pepco Br. 108; Pepco (2G) at 8 (Bumgarner); Tr. 574-575, 663 (Pepco witness Bumgarner).

728 AOBA Br. 50-52, 57; AOBA (A) at 103-108 (Oliver); Tr. 815-823 (AOBA witness Oliver). AOBA complains that Pepco's rationale for freezing RAD rates ignores the substantial benefits the RAD class already receives from a negative class ROR, the freeze on RAD rates ordered in Formal Case No. 1053, and the additional subsidies to RAD customers provided by other customer classes through the Energy Assistance Trust Fund and the RADS surcharge. All customer classes have been hurt by "the current adverse economic climate, AOBA argues. AOBA (A) at 103-107,110.

729 DCG Br. 16, 27.

sources, or the impact of its RAD proposals. DCG argues that because unemployment in the District is over 10 percent, median income levels in D.C. fell by over 22 percent in 2009, and low-income families are having difficulties paying their bills; therefore, any proposal to reduce the RAD subsidy "should wait until after the economy turns around."[730]

370. DCG suggests that one consideration supporting a RAD freeze is the requirement of the "Clean and Affordable Energy Act of 2008" ("CAEA") which calls for the Commission to consider the economy and the "the situation of the low-income customers in the District of Columbia and their need for assistance" in setting rates.[731] DCG asserts that the subsidy should be recovered from other classes of customers through the RAD surcharge, or the EATF, or other mechanisms that the Council may create in the future. DCG urges the Commission to wait until Pepco's next rate case to assess the various ways in which the RAD discount can be distributed to other classes of customers, especially in light of potential changes in the eligibility standards for Federal LIHEAP and RAD assistance.[732]

DECISION

371. In this instance, the options available to the Commission include *(1) RAD Simplification*: simplifying the RAD rate structure, including possibly increasing the fixed RAD minimum charge, as suggested at the hearings in colloquies between Pepco witness Bumgarner and Commissioners Kane and Morgan;[733] or *(2) RAD Rate Freeze*: Pepco, the District Government, and WMATA recommend no increase or change in the RAD rate; or *(3) Moderate RAD Rate Increase*: for example, raising RAD rates by a CPI-W amount or one-half of the percentage increase in residential rates, whichever is less (recommended by AOBA).

372. The Commission determines that a modest increase in the RAD class revenue requirement is in order, through the application of the new $2.50 RAD customer charge.[734] Our decision to moderately increase RAD distribution revenues, while simplifying and improving the RAD rate structure, considers the economy of the District of Columbia and the community

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730 DCG Br. 16-19; DCG R.Br. 5-6; DCG (A) at 27; DCG (2A) at 16-17 (Petniunas).

731 *See* DCG (A) at 18-19 (Petniunas). The statutory text of D.C. Code § 34-808.02 (new CAEA § 401) states: "In supervising and regulating utility or energy companies, the Commission shall consider the public safety, the economy of the District, the conservation of natural resources, and the preservation of environmental quality."

732 *Id.* at 25-26. "A future mechanism could be a RAD Adjustment Clause to reflect Pepco's timely collection of the RAD discount due to changes in Federal LIHEAP standards. Whatever the case, Pepco should be allowed to recover the full costs of any revenue discounts attributable to the RAD class by allocating this discount to other classes of customers." *Id.*

733 *See* Tr. 673-687); *Accord* Tr. 1135-1136 (colloquy between Commissioner Morgan and DCG witness Petniunas).

734 *See supra* ¶ 348.

comments we received about the economic difficulties of District residents.[735] In this regard, we also note that SOS charges will be decreasing for the period June 1, 2010, through May 31, 2011.[736]

373. The Company's concern that it "should be allowed to recover the full costs" of any RAD discount (Pepco (G) at 12-13 (Bumgarner)) suggests the need to include an annual "true-up" mechanism for the RAD program. This is an issue that Pepco may raise with the Council for its consideration, along with other key issues regarding the RAD program.

b. RAD surcharge (Issue No. 15b)[737]

374. **Pepco.** Pepco's original filing requested an increase in the RAD surcharge to recover slightly over $1 million in unreimbursed RAD discounts that were received by RAD customers during the billing months of December 2007 through September 2008.[738] However, the recently-enacted "Residential Aid Discount Subsidy Stabilization Emergency Amendment Act of 2009 ("RADSSEA") authorizes a one-time $1 million payment to Pepco to cover these RAD costs.[739] Pepco indicates that the issue concerning Pepco's recovery of $1 million in unreimbursed RAD discounts is now moot.[740]

375. **OPC**, the **District Government**, and **WMATA** filed no testimony on this issue. **AOBA** agrees with Pepco that the issue is moot because of the new statute.[741]

376. **District Government.** However, the District Government raises other tariff design issues for the RAD surcharge. DCG argues that an automatic RAD adjustment clause

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735 The CAEA requires the Commission to consider "the economy of the District" in setting rates (*see* D.C. Code § 34-808.02). However, it does not specifically mandate that the Commission consider "the situation of low-income customers in the District of Columbia and their need for assistance." (DCG (A) at 18-19 (Petniunas)). The Commission has considered the situation of low-income Pepco customers as a matter well within its discretionary authority.

736 *See Formal Case No. 1017, In the Matter of the Development and Designation of Standard Offer Service in the District of Columbia*, Order No. 15709 (March 1, 2010) (SOS rates will be reduced by 1.2% effective June 1, 2010).

737 Designated Issue No. 15b asks, "Should the RAD surcharge be adjusted to accommodate Pepco's request to increase the RAD surcharge by roughly $1 million?"

738 Pepco (G) at 12-13 (Bumgarner).

739 The RADSSEA became effective on July 28, 2009 (D.C. Act 18-155, Bill 18-394).

740 Pepco Br. 108. Pepco (2G) at 8-9 (Bumgarner). *Accord* Tr. 655-657, 663 (colloquy between Chairman Kane and Pepco witness Bumgarner).

741 AOBA (A) at 108 (Oliver).

should be used to compensate Pepco for the RAD subsidy.[742] DCG explains that its RAD adjustment clause would be "similar to the old utility fuel adjustment clause," which would trigger quarterly or monthly adjustments to "alleviate the need to wait for an application for an increase in base rates before a change in the RAD income threshold could be implemented. DCG contends that this would also allow the Commission to monitor the subsidy, and ensure that Pepco recovers the subsidy through charges to other classes of customers."[743] DCG argues that its proposed automatic RAD adjustment clause would improve RAD program administration and speed Pepco's recovery of RAD surcharge amounts, whether federal LIHEAP certification standards for RAD are raised or lowered.[744]

DECISION

377. The specific designated issue here is moot. All the parties agree that the new statute authorizes a one-time $1 million payment to Pepco to cover its Fiscal Year 2008 unreimbursed RAD costs. We decline to act at this time on the District Government's request for a RAD adjustment clause, despite the claim that such a clause would allow quicker and easier registration of RAD participants. Except for the new RAD customer charge and changes in energy blocks that we order today, the Commission believes that the *status quo* should be preserved on all other RAD issues until and unless the Commission decides otherwise in Formal Case No. 813 or the Council adopts legislation that further addresses the design, funding, and other issues associated with the RAD program.

c. Impact of any increased participation in RAD from DDOE's proposed change to RAD eligibility criteria (Issue No. 15c)[745]

378. **District Government.** Tariff language for the RAD program currently states that RAD eligibility is based on federal guidelines for LIHEAP.[746] Eligibility criteria for LIHEAP give the District Government the option to use either 150 percent of the Federal Poverty Level

742 DCG Br. 26-27; DCG (A) at 45 (Petniunas). DCG also argues that its RAD Adjustment Clause would eliminate the flaws in the current RAD surcharge that is levied on a cents per kWh basis, which "penalizes those customers that only have energy rates and benefits those customers with demand and energy rates and that an across the board spread through a RAD Adjustment Clause might be more appropriate." DCG (A) at 34-35 (Petniunas).

743 *Id.* at 28; DCG (2A) at 19; DCG Br. 26.

744 DCG Br. 26-27; DCG (A) at 28, 34-35, 45 (Petniunas); DCG (2A) at 19-21; Tr. 1121- 1122 (DC Government witness Petniunas).

745 Designated Issue No. 15c asks, "Should RAD distribution rates or the RAD surcharge be adjusted to accommodate any increase in participation resulting from changing the RAD Utility Discount Program eligibility criterion as recently proposed by DDOE?" (This refers to DDOE's request to increase the eligibility criterion from 150% of the Federal Poverty Level to 60% of the D.C. Median Income.)

746 *See* Tr. 1139-1143 (colloquy between Chairman Kane and DCG witness Petniunas).

(FPL) or a higher income level (qualifying more people for LIHEAP) set at 60 percent (or 75 percent) of state median income (SMI).[747]

379. DCG submits that, in actual DDOE practice, "LIHEAP customers are certified eligible by DDOE at the 60 percent SMI income level," while "RAD customers are certified at the 150 percent FPL income level."[748] DCG's post-hearing brief indicates that there is currently no legal obstacle that would prevent DDOE from applying LIHEAP standards for eligibility in the RAD program.[749]

380. DCG contends that DDOE wants to increase RAD participation. However, DDOE is concerned about the availability of funding to pay Pepco for any increased RAD subsidy if the number of RAD customers is increased. Accordingly, DCG argues that "the RAD Rider surcharge should be modified to produce the revenue needed by Pepco to fund expected changes in RAD participation levels to meet the LIHEAP certification threshold."[750] DCG recommends that, if there is an increase in RAD participation, the resulting increase in the cost of RAD class subsidies should be allocated evenly, on an across-the-board basis, among all of Pepco's other rate classes.[751]

381. The case for increasing participation in the RAD program was presented by DCG witness Petniunas.[752] He testified that, historically, the "penetration rate" of the RAD program (*i.e.,* the percent of eligible persons participating in the program) has been about 20 to 30 percent, covering from 8,049 RAD customers (in 1983) to 17,656 RAD customers (in 2008).[753]

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747 DCG Br. 21. DCG states that LIHEAP provides grantee jurisdictions, including the District of Columbia, the option of using "150% of the poverty level as the maximum income level allowed in determining LIHEAP income eligibility, except where 60% of state median is higher." D.C. is eligible to use the 60% of state median income criterion because this value is higher than 150% of the federal poverty level. Furthermore, DC has been using the higher 60% criterion for LIHEAP since fiscal year 2007, to enable more District residents to qualify for that program. *Affidavit of Taresa Lawrence,* ¶¶ 6, 7. *See also* Tr. 1404 (DCG counsel summarizing *Affidavit of Taresa Lawrence* on LIHEAP eligibility). DCG's post-hearing brief states: "Indeed, most likely in response to the recent severe economic downturn, the federal government expanded LIHEAP eligibility for FY 2009, and for the first three months of FY 2010, to 75% of the SMI." DCG Br. 20-21. DCG states that it filed a November 4, 2009 motion in Formal Case 813 to ask that the eligibility criterion for participation in all Utility Discount Programs be tied to "the highest eligibility criterion available" under current LIHEAP guidelines. DCG Br. 21.

748 DCG Br. 23. *Accord* Tr. 1127 (DCG witness Petniunas) and Tr. 1139-1143 (colloquy between Chairman Kane and DCG witness Petniunas) (both suggesting that RAD eligibility is currently pegged to 150% of the Federal poverty level, and that DCG wishes to change the standards for RAD eligibility to 60% of median DC income).

749 DCG Br. 2. *Accord* DCG Br. 21.

750 DCG Br. 2. *Accord* DCG Br. 21.

751 DCG (A) at 5, 6, 28, 29 (Petniunas).

752 *See* DCG (A) at 26-45 and accompanying exhibits.

753 *See* DCG (A) at 31-35, 39, Tr. 1123-1126 (DCG witness Petniunas), and DCG (A)-4 (chart showing RAD penetration rates varying between 20 and 30%). *Accord* Tr. 681-682. According to the District Government, "The

Witness Petniunas stated that the Commission has expressed its desire to increase RAD participation levels, expressing concern that the program "would reach too few low income consumers."[754] He furthered testified that twice before, however, the Commission denied DDOE's requests to increase RAD participation by changing the program's income eligibility criteria. According to Petniunas, one set of Commission concerns was that DDOE did not have a plan for expanding the RAD program and did not show a cost benefit analysis, nor did it show any progress in increasing the participation rate of currently eligible RAD customers. He also stated that the Commission was concerned about the "anomalous results of requiring non-participating lower income customers to subsidize benefits for newly eligible customers," unless all parties do more to increase the number of lowest-income persons served.[755]

382. Addressing these concerns, District witness Petniunas testified that DDOE has done significant outreach work to expand RAD and, because of these activities, there has been a significant increase in the "penetration rate" of the RAD program, particularly during recent years (2006-2008) when the RAD penetration rate increased to an average of 29.6 percent.[756] Turning to a cost-benefit analysis, the District Government estimates that there might be an increase of as many as 3,500 new RAD customers (each receiving about a $350 annual benefit) if the income eligibility standard for RAD is set at the old "historical" level of 60 percent of D.C. median income. This would increase the cost of the RAD subsidies paid by all other District customer classes by $1,227,096 (an overall increase of 0.41 percent in other customers' bills if spread across-the-board).[757] Alternatively, the District Government estimates that there would be approximately 7,000 new RAD customers if the income eligibility standard for RAD is set at the level of 75 percent of D.C. median income. The impact on rates would be twice that of moving to 60 percent of D.C. median income.[758]

383. To be sure, DCG acknowledges the Commission's concerns that roughly 70 percent of eligible RAD consumers apparently are not served under the RAD rate and that non-

ratio of the RAD customers to the LIHEAP eligible customers is the penetration rate, and historically has been about 20%. The program today is tied to LIHEAP only because of its administrative simplicity." DCG (A) at 32.

754 *Id.* at 33.

755 *Id.* at 35, citing Commission comments in *Potomac Electric Power Company, Formal Case No. 813*, Order No. 14620 at 5 (November 8, 2007). *See also* Tr. 1125-1126, 1129.

756 DCG (A) at 35-38.

757 DCG Br. 23-25; DCG (A) at 38-42 and DCG (A)-5 at 8. *But cf.* Tr. 1131-1132 (colloquy between Commissioner Morgan and DCG witness Petniunas). After the hearing, in response to concerns raised by Commissioner Morgan about these calculations, DCG witness Petniunas performed a revised calculation to determine what the revenue impact would be to the non-RAD customers after removing the 3,500 new RAD customers from the revenue base. According to the District Government, the impact on other customers' bills from increasing RAD participation is still a 0.42% increase for the Residential class, and a 0.41% increase for all other rate classes. DCG Br. 25.

758 DCG (A) at 43.

participating lower income customers may be subsidizing RAD customers.[759] Yet DCG argues that eligibility for the RAD program should be expanded.[760] Pointedly, DCG argues that the RAD "penetration rate" is misleading and "greatly understates the success of DDOE in reaching RAD-eligible customers," because the "penetration rate" refers to the ratio of RAD customers to LIHEAP-eligible customers (not RAD-eligible customers). Not all LIHEAP-eligible customers are eligible for the RAD program. In particular, tenants in master-metered apartments (who represent as many as 30 percent of the District's low-income households) are LIHEAP-eligible, but not RAD-eligible because they are not direct Pepco customers.[761]

384. **Pepco.** Pepco witness Bumgarner testified that, if RAD eligibility criteria were set at 60 percent of D.C.'s median income, the RAD program might add 4,385 additional RAD participants, at a cost of $1.3 million (approximately 60 cents per month additional cost to each non-RAD customer).[762] He states that if there is an increase in RAD participation, Pepco would need to recover the resulting increased RAD subsidy either through the RAD surcharge or through the EATF surcharge. According to Bumgarner, "the RAD program is inadequately funded through the RAD and EATF surcharges at the present time. A legislative remedy will be needed to address the underfunding of the RAD program through the EATF surcharge provided in the Clean and Affordable Energy Act of 2008."[763]

385. **AOBA.** AOBA opposes the expanded availability of subsidized low RAD rates, indicating that "further expansion of eligibility for the Company's RAD rates will amplify the magnitude of existing subsidies and diminish the cost basis for, and equity of, the Company's overall rates for electric service in the District of Columbia." AOBA contends that expanding the RAD program as DDOE seeks would make it available to those whose needs for assistance are not as great as current RAD customers. If RAD participation is expanded, AOBA argues, "the only logical step is to allow for reduction of the average benefit provided to RAD customers as the size of the RAD class in terms of numbers is expanded."[764]

DECISION

386. DCG acknowledges that tariff language for the RAD program currently indicates that RAD eligibility is based on federal guidelines for LIHEAP. Under the statutory and regulatory system today (described above in DCG's briefs and testimony), DDOE asserts that it could set the eligibility criteria for LIHEAP and (derivatively) for the RAD program at the same

759 *See* DCG Br. 22.

760 DCG (A) at 44-45.

761 DCG Br. 22-23.

762 Tr. 637-639 (Pepco witness Bumgarner). *Accord* DCG Br. 21.

763 Pepco Br. 109; Pepco (2G) at 9 (Bumgarner).

764 AOBA (A) at 108-109 (Oliver); AOBA Br.52-53.

level. However, DDOE indicates that it seeks Commission approval before it changes DDOE practices about whom to certify as RAD eligible customer (from 150 percent FPL to 60 percent or 75 percent of SMI) to ensure that any expansion in the number of RAD customers is accompanied by adequate funding to pay Pepco for the increased RAD subsidy.

387. The subsidy for RAD customers paid by non-RAD customers is now approximately $5.4 million per year, according to Pepco's filings. Were the *status quo* changed, to set RAD eligibility at the level of 60 percent of D.C. median income, for example, then approximately 3,500 to 4,385 additional new RAD customers might enter the program, each receiving about a $350 annual benefit (under the old RAD rates) for a total additional cost of $1.2 million to $1.3 million.[765]

388. One interpretation of the EATF-RAD statute, which is disputed and is currently being considered by the Commission in Formal Case No. 813, is that the size and funding limits of the RAD program are set by the Council.[766] We think it wise to maintain the *status quo* on the RAD program, and to avoid any change in RAD eligibility or participation levels, until we receive further guidance from the Council. Once we obtain further guidance on the RAD program from the Council, the Commission will take appropriate action in Formal Case No. 813.

B. Small Commercial Classes (Issue No. 13a)[767]

1. General Service (GS)[768]

389. **Pepco.** To collect the class revenue target from the General Service (GS) class, Pepco proposes to increase each of the rate components in the current GS rate structure in a roughly proportionate manner.[769]

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765 *See* Tr. 637-639 (Pepco witness Bumgarner); DCG (A) at 38-43 (Petniunas); DCG (A)-5.

766 Pepco is seeking additional Council legislation on the RAD program, including provisions that would allow annual "true ups" of Pepco's RAD costs, subject to this Commission's review and approval. Tr. 664 (Pepco witness Bumgarner). The Company stated that its preference, in the interest of simplifying matters, would be to have the bulk of the RAD discount paid for by the legislative surcharge, not the regulatory surcharge. Tr. 666-668 (Pepco witness Bumgarner). The Company indicated that it also would consider whether it would be desirable to have the entire RAD funded through a legislative surcharge. *See* Tr. 668 (Pepco witness Bumgarner).

767 Designated Issue 13a asks, "Are the rate designs by classes reasonable?"

768 Pepco's General Service rates (GS) include a customer charge as well as energy-delivery charges ("all kilowatt hours") and "surcharges." "GS D LV" customers are subject to customer charges, as well as kWh charges (first 6000 kWh, additional kWh, surcharges) and demand charges (kW) (excess over 25 kW).

769 Pepco (2G) at 4-5 (Bumgarner). General Service rates (GS) include a customer charge as well as energy-delivery charges ("all kilowatt hours") and "surcharges." Schedule GS-LV is generally available to secondary voltage customers with average maximum monthly billing demands less than 100 kW. "GS D LV" customers are subject to customer charges, as well as energy-delivery charges (first 6000, additional, surcharges) and demand charges (kW) (excess over 25 kW). *See* Pepco (G)-2 (PEPCO rate schedules); Pepco (G)-3 (Bumgarner). *See also* GSA (A) at 7, n.4 (Goins).

390. **AOBA.** AOBA agrees with Pepco and supports keeping the same basic proportions among the component parts of the GS rate design to provide stability and avoid rate shock.[770]

DECISION

391. No party proposes any significant changes to the GS rate components. The Commission orders an across-the-board increase in the GS rate components as the parties agree, to collect the class revenue target. In Pepco's next rate case, consistent with gradualism, the Company is directed to submit proposed GS rate designs that move away from volumetric (energy-delivery) rates and toward a greater emphasis on recovery of GS class revenues through customer and demand charges.

1. Street Lighting (SL) (Issue No. 13e) [771]

392. **Pepco.** Pepco proposes to increase the SL "energy-delivery" rate to recover the class revenue target for SL.[772]

393. **District Government.** Witness Petniunas recommends that the SL rate schedule be frozen (or that any increase be limited to at most the Commission approved average percentage increase for all customers).[773] DCG contends that to recover Pepco's proposed 211 percent revenue increase from the SL class, the Company would increase the Standard Night Burning rate to a rate that is 74 percent greater than the current 24-hour Burning rate. DCG asserts that through this proposed increase, Pepco effectively seeks to rob the D.C. Department of Transportation ("DDOT") of the benefits of its significant efforts to achieve energy efficiency by shifting its load exclusively to night-burning only lamps.[774]

394. Tariff changes suggested by DCG include updating the power outage rates that are now stated in the SL and TS tariffs.[775] DCG argues that other outdated information in the SL and TS tariffs also should be eliminated, in particular, the references to old 1970s manuals about "Policy and Procedure for Providing Street Lighting Service in the District of Columbia" and "Policy and Procedure for Providing Traffic Signal Service in the District of Columbia."[776]

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770 AOBA (A) at 94-95 (Oliver).

771 Designated Issue 13e asks, "Is Pepco's proposed change in rate design to the rate schedule for Street Lighting (SL) reasonable?"

772 *See* Pepco (2G) at 4-5 (Bumgarner).

773 DCG (A) at 5 (Petniunas).

774 DCG Br. 13.

775 *See id.* at 23.

776 *Id.* at 23-24.

DECISION

395. DCG criticizes the tariff language that mathematically sets the Standard Night Burning and 24-hour Burning rates.[777] However, the mathematical figures in the SL rate tariffs are based on the class revenue target and will be adjusted by Pepco to reflect whatever the Commission decides about the SL class revenue requirement.

396. Tariffs for SL should eliminate unnecessary references to outdated 1970s policy manuals. Ordinarily, we would expect Pepco to resolve these kinds of tariff issues as a matter of good customer relations. The Commission encourages Pepco and DCG to redesign SL rates in the future so that they are not "energy only" rates. We direct Pepco to conduct an up-to-date study of power outage rates in the SL and TS tariffs. This study also should examine other DCG complaints about the way Pepco includes the costs of AMI smart meters (allegedly irrelevant to SL) and 24-hour Burning streetlights (now eliminated by DCG) in the SL rate.[778] The study should be part of Pepco's next base rate case.

2. Traffic Signals (TS) (Issue No. 13f)[779]

397. **Pepco.** Traffic Signal (TS) like Street Lights are "energy-delivery" rates. Pepco's proposal increases the "energy-delivery" rate to recover the class revenue target for the TS class.[780]

398. **District Government.** Witness Petniunas recommends no increase for the TS rate schedule or, at most, the Commission-approved average increase for all customers.[781] Though the District Government suggests that the SL and TS tariffs might be redesigned so that they are not "energy only" rates, witness Petniunas indicates that he is not advocating a demand rate for the SL and TS rate schedules at this time.[782]

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777 *See* DCG Br. 12. DCG states that it has eliminated all 24-hour Burning streetlights. However, DCG does not ask that the 24-hour Burning rate be deleted from Pepco's tariffs. There seems to be no harm in retaining this tariff language. (There might be a "straggler" 24-hour Burning streetlight, and the higher 24-hour rate encourages DCG to switch its streetlights to the lower Standard Night Burning rate.)

778 *See* DCG Br. 8-9.

779 Designated Issue No. 13f asks, "Is Pepco's proposed change in rate design to the rate schedule for Traffic Signals (TS) reasonable?"

780 Pepco (2G) at 5 (Bumgarner).

781 DCG (A) at 5 (Petniunas).

782 *Id.* at 22.

399. Tariffs proposed for traffic signal service contain a 1.5 percent reduction in monthly bills to account for "normal" power outages. DCG complains that this is an outdated figure that was calculated over 25 years ago and ignores DDOT's significant annual spending to mitigate the risks of Pepco power outages. DCG avers that in the past three years it has spent over $3.5 million to procure backup emergency generators, as well as $1.2 million in uninterruptable power supply investments (with an additional $2 million budgeted for implementation in the near future), and about $400,000 annually in personnel costs to respond to traffic signal power outages.[783] According to DCG, traffic signal service tariffs proposed by Pepco also improperly fail to make a reduction for the time traffic signals operate off-peak.[784]

400. **Pepco Rebuttal.** The Company stated that its TS rate contains a 1.5 percent reduction, calculated more than 25 years ago, that is intended to adjust the energy billing for power outages. However, Pepco denies that there is any basis for comparing this 1.5 percent "outage discount" with the millions of dollars that DCG spends each year to maintain traffic signals in the District.[785]

DECISION

401. As with SL, tariffs for TS should eliminate unnecessary references to old 1970s policy manuals, and Pepco and DCG should seek to design TS rates in the future so they are not "energy-only delivery" rates.

402. The power outage rates for TS tariffs, and whether Pepco adequately accounts for power outages in the TS rate, is a matter of contention between the District Government and Pepco. The Commission therefore directs Pepco to conduct an up-to-date study to determine what the appropriate power "outage discount" should be for TS. The same study should examine the merits of DCG's complaint that traffic signal service rates improperly fail to make a reduction for the time traffic signals operate off-peak. The study should be submitted as part of Pepco's next rate case.[786]

403. Although DCG is prudent in ensuring an uninterruptible power supply for its traffic signals and street lights, the Commission finds that these expenditures do not warrant any reduction in Pepco's SL/TS rates. DCG has no greater claim than any other customer or customer class to flawless power service.

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783 DCG Br. 14-15.

784 DCG Br. 15-16.

785 Tr. 1411-1412 (Pepco witness Bumgarner).

786 *See* DCG Br. 15-16.

C. Large Commercial Classes (Issue No. 13a)[787]

1. GT

404. **Pepco.** Pepco would apply an across-the-board increase to the current GT rate structures to collect the class revenue target from the large commercial classes (GT).[788]

405. **AOBA.** AOBA agrees with Pepco's proposal to increase the component parts of the GT rate schedule in "a roughly proportionate manner." This will provide stability and avoid rate shock.[789]

DECISION

406. No party disputes Pepco's proposal to leave GT rate components unchanged, and to increase them in a roughly proportionate manner to collect the GT class revenue target. The Commission adopts the unanimous view of the parties. In Pepco's next rate case, however, the Company is directed to submit proposed GT rate designs that move away from volumetric (energy-delivery) rates and toward a greater emphasis on recovery of GT class revenues through customer and demand charges.

2. Standby Service (GT-3A-S)(Issues 13c, 13d)[790]

407. **Pepco.** Under Pepco's proposal, the only standby customer on its system is GSA's central heating and refrigeration plant ("CHP facility").[791] Pepco argues that this one customer's "unique load characteristics," notably the "much lower load factor" and the "lower

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787 Designated Issue No. 13a asks, "Are the rate designs by classes reasonable?"

788 Pepco (2G) at 5 (Bumgarner). Schedule GT-LV is generally available to secondary voltage customers with maximum demands of at least 100 kW. The GT-LV rate is structured to include customer charges, demand charges (kW) ("on peak," "maximum"), energy-delivery charges (on peak, intermediate peak, off peak) and surcharges. Schedule GT-3A is available to primary voltage customers with maximum demands of 100 kW or greater. (GSA's combined heat and power ("CHP") facility, a central heating and refrigeration plant, is one of approximately 145 customers that are currently billed under Schedule GT-3A.) The GT 3A rate includes a customer charge, demand charges (kW) ("on peak" and "maximum"), energy-delivery charges (on peak, intermediate peak, off peak), and surcharges. The same rate structure holds for "GT 3B" rates (sometimes called GT-HV 69 kV), which cover WASA's Blue Plains facility. *See* Pepco (G)-2 (Pepco rate schedules); Pepco (G)-3 (Bumgarner); GSA (A) at 7-8 n.4, 19 (Goins).

789 AOBA (A) at 94-95 (Oliver).

790 Designated Issue No. 13c asks, "Is Pepco's proposal to eliminate the current Standby Service Schedule S tariff reasonable?" Issue No. 13d asks, "Is Pepco's proposed Standby Service Schedule GT-3A-S tariff properly designed?"

791 *See* GSA (A) at 7, 19 (Goins). Technically, the new standby rate (GT-3A-S) will apply only to primary voltage standby customers with average loads exceeding 100 kW that would generally be billed under Schedule GT-3A. *Id.* at 7. *Cf.* GSA (B) at 11-12 (Goins).

contribution to cost of service from the Plant relative to all other members of the GT-3A class" caused by the operation of its cogeneration facility, merit a separate rate classification in the new GT-3A-S.[792] According to the Company, this new rate schedule provides a fair cost-reflective rate and reflects PJM and Pepco requirements for interconnected operation of this customer's generator. Pepco indicates that the cost of service for the GT-3A-S customer was calculated in the same manner as for the other two current single customer classes, Metro and WASA's Blue Plains' facility. Each component of the present GT-3A rate was given an equal percent increase to arrive at the proposed new GT-3A-S rate. According to Pepco, this single-customer tariff addresses the interest of the Company, standby customers, and all other customers of Pepco.[793] Pepco contends that the impact of the new GT-3A-S tariff would be to increase this one customer's annual charges by $90,555, "revenue that other customers on Schedule GT-3A will not have to bear."[794]

408. The Company also proposes to eliminate its old schedule S for standby customers. Within its new Schedule S, Pepco proposes to replace what it characterizes as its old difficult-to-calculate Facilities Charge (calculating the carrying costs of the plant that provides standby service) with a simplified monthly calculation based on the actual metered usage of the standby service.[795] The Company's new Standby Service S tariff generally would be required for customers with behind-the-meter generation that is operated, not for emergency use, but instead in parallel with Pepco's delivery system for normal operations.[796] New Standby Service S would not cover smaller customers generating less than 100 kW. Pepco indicates that either the Company or an alternate supplier would need to provide full Generation requirements. Pepco notes that under the new Schedule S, customers would be billed on net usage and would need metering and communication equipment that allows the Company to monitor and meter the output of the customer's on-site generation."[797]

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792 Pepco Br. 104-105; Pepco (G) at 9 (Bumgarner); *see* Pepco (G)-1. Pepco states that the load factor of GSA's CHP plant is less than half that of the GT-3A class customer with the next lowest factor, and about 25% of the average for the class. "Its contribution to cost of service (on a rate of return basis) on the existing rate was 42% less than the contribution of all other members, and will still be 26% below the average contribution of those customers under the new tariff." Pepco Br. 104-105.

793 Pepco (G) at 9-10. Pepco clarified Schedule GT-3A-S "to indicate that [it] is applicable to customers who would otherwise qualify for GT-3A, but for the requirement for Standby Service." Pepco (2G) at 4; *see* Pepco (2G)-1 (revised tariff GT-3A-S).

794 Pepco (G) at 11.

795 Pepco Br. 103-104; Pepco (G) at 12. "All that is required for the customer to estimate his costs under the rider is an estimate of the load that the generator will serve." *Id.*

796 The requirement that new Standby S customers have on-site generation that "operates in parallel with the Company's delivery system" excludes customers with on-site generation used primarily for emergency purposes (such as hospitals, water pumping stations, and telephone facilities). Pepco (G) at 11-12.

797 Pepco (G) at 10-11; *see also* Pepco (2G) at 3-4.

409. **AOBA.** AOBA does not oppose the creation of a new GT-3A-S tariff for Pepco's one and only existing standby customer. However, AOBA argues that Pepco's tariff is too limited. AOBA submits that other potential users of standby service might include those who do not take service at primary voltage or those who might seek standby service for forms of renewable generation. To account for the possibility that such customers might wish to take Standby Service in the future, AOBA recommends that Pepco "be directed to develop a parallel rate offering for customers having 'behind the meter generation' that do not take service at primary voltage."[798]

410. **GSA.** GSA requests the current Standby Service Schedule S be left in place and opposes the new GT-3A-S tariff.[799] The only customer that would be covered by the new GT-3A-S tariff is GSA's fossil-fired CHP cogeneration facility that serves Federal buildings in the District of Columbia.[800] According to GSA, Pepco is currently recovering more than its cost of serving GSA's CHP standby facility, and will recover even more under its proposed standby Schedule GT-3A-S.[801]

411. GSA contends that the origin of Pepco's proposed new GT-3A-S rate is the Company's interpretation of a Maryland PSC ruling barring Pepco from applying a "facilities charge" to standby customers for facilities that were not specifically installed to provide standby service.[802] According to GSA, this Maryland ruling is already embodied (in effect) in Pepco's D.C. current tariffs for standby service. GSA indicates that it benefits from this because it installed its own interconnection facilities and equipment upgrades to facilitate cogeneration operations at its CHP plant; consequently, GSA's CHP plant incurs no "facilities charge:[803]

> The current Schedule S appropriately provides for the instance where a standby customer invests its own resources in interconnection facilities and necessary

798 AOBA (A) at 96 (Oliver). *Accord*: Tr. 789-790 (AOBA witness Oliver) ("The Company has, from my perspective, slowed or impeded the development of onsite generation by putting customers through a very difficult process of proving that they don't need additional facilities when there are no additional facilities required.")

799 GSA Br. 6, 14, 15; GSA R.Br. 2, 5; GSA (A) at 9, 25, 27, 27-8 (Goins).

800 *See* Tr. 1190-1191, 1198 (GSA witness Goins).

801 GSA (A) at 22; GSA (B) at 12; GSA Br. 12; GSA R. Br. 4. GSA claims that Pepco now recovers $74,000 (23%) more than the Company's standby cost of serving GSA's CHP facility, and this over-recovery would increase to $95,000 (25%) under the proposed Schedule GT-3A-S. GSA (A) at 22; GSA (B) at 12.

802 GSA Br. 9-10; GSA R.Br. 3-4.

803 Ordinarily Pepco would charge a standby customer like GSA under rate schedule GT-3A with an adjustment to reflect "a credit for the monthly facilities charge paid under Schedule S." The facilities charge is "for special facilities which Pepco builds in order to service a standby customer." GSA Br. 6; GSA R. Br. 3. However, "there would be no facilities charge for GSA's CHP facility, because Pepco was not required to build special facilities to service this customer's standby load." GSA Br. 8; GSA R.Br. 3-4.

> equipment upgrades to support the standby service it receives from Pepco. The revision Pepco has proposed does not recognize customer investments[804]

GSA challenges Pepco claims as weak *post hoc* rationales.[805] In particular, GSA argues that there are no "unique load factors" that justify the creation of this unusual new stand-alone rate class: "[e]ach GT-3A customer has a load factor that likely differs from the class's average load factor – the load factors of some customers are higher than the class average and some are lower."[806]

412. GSA also claims that the proposed GT-3A-S rate is overpriced and discriminatory and will create non-cost-based barriers to customers developing independent generating capability.[807] GSA submits that this would be contrary to the Commission's stated policy that "distributed generation" should be encouraged and that "the future development of DG [distributed generation] is crucial to electric reliability in the District of Columbia."[808]

413. GSA witness Goins expressed particular concern that Pepco's rate designs should not discourage investments in new distributed generation facilities.[809] He testified that eventually a 10 percent to 20 percent discount off of cost-based rates may be appropriate for distributed generation facilities like GSA's steam plant.[810] GSA stated that it is contemplating a major initiative to install solar generation in buildings in the District of Columbia and

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804 GSA R. Br. 4.

805 GSA argues that there is no merit in Pepco's claim that current standby schedule S creates undue burdens in calculating a facilities charge because GSA's CHP facility is the only customer covered by the current standby schedule S and GSA's CHP facility has no facilities charge. GSA Br. 8-9; GSA 2.

806 GSA Br. 10-12; GSA (A) at 21. GSA states Pepco's two other single customer rate classes - GT-RT (Metro) and GT-3B (Blue Plains) - are distinguishable from the situation of its CHP facility. *Id.* at 19-20; GSA Br. 7.

807 GSA (A) at 22 (Goins); GSA (B) at 12. GSA claims that "Pepco has an incentive as a monopoly supplier of distribution service to set the price of standby service as high as possible to discourage DG investments that might lower its distribution revenues and earnings." GSA (A) at 23. *Accord* GSA Br. 13; Tr. 1187-1188 (GSA witness Goins).

808 GSA (A) at 24-25, citing *Formal Case No. 1053*, Order No. 14712, ¶ 421. GSA states that "DG resources may create environmental and distribution-related benefits, including capacity upgrade deferrals, reliability enhancements, and equipment life extensions." The Commission said in Formal Case No. 1053 that "[w]hen DG is fully planned and deployed, long-term distribution benefits should be taken into account, and a discounted "standby" rate should be calculated. *Id.* But GSA states that Pepco's proposed new GT-3A-S rate reflects none of these values. GSA (A) at 24.

809 *See* GSA Br. 13 (a 2007 FERC report cited standby rates as one of the most common rate-related impediments to distributed generation); Tr. 1189, 1192, 1196-1197 (GSA witness Goins).

810 Tr. 1194 (GSA witness Goins).

recommends that the Commission develop rate designs that encourage development of solar energy and other distributed generation.[811]

414. If the Commission decides to approve a new GT-3A-S rate, GSA argues that the rate should be set at a "cost-based benchmark" that is no higher than Pepco's cost of providing standby service as determined from its CCOSS. GSA contends that this cost-based benchmark -- calculated on the basis of "backing out the interclass subsidy component of the rate" and imposing a $95,000 reduction in test year revenues for the new GT-3A-S class – would neither promote nor hinder the development of distributed generation.[812]

415. Based on this premise, GSA proposes an alternative GT-3A-S standby rate as follows:

Distribution Charge	Rate
Customer	$72.59 per month
Energy	$0.00688 per kWh
Maximum kW	$4.19 per kW

GSA states that, since its alternative standby rate "reflects no interclass revenue subsidy, customer, demand, and energy charges under the alternative rate are approximately 20 percent lower across the board" for its GT-3A-S rate.[813] GSA notes that its proposal involves only a 20.93 percent increase for the GSA steam plant, as opposed to Pepco's proposed 23.38 percent increase.[814]

DECISION

416. The Commission rejects Pepco's new standby tariff GT-3A-S and maintains the current standby Service Schedule S with Pepco's "facilities charge." The *status quo* shall be preserved, pending further study by the Commission on how best to structure Pepco's standby rates for cogeneration facilities.

417. The Commission is committed to ensuring that Pepco's rates do not discourage the development of distributed on-site generation.[815] Consistent with our Formal Case No. 1053 decision, a Working Group will be established to discuss all standby tariff issues.[816] Pepco

811 Tr. 1198-1200, 1192 (GSA witness Goins).

812 GSA Br. 14; GSA (A) at 25-28.

813 *Id.* at 27; GSA Br. 14.

814 *See* Tr. 1177-1181 (GSA witness Goins).

815 *See* Tr. 1192-1199, especially Tr. 1196-1197 (colloquy between Commissioner Morgan and GSA witness Goins).

816 *See* Order No. 14712, ¶ 421.

should chair the Working Group meetings. The Commission encourages the parties to discuss the standby tariff issues and to propose the appropriate credit for cogeneration and other distributed generation facilities in the District of Columbia. The goal of the Working Group shall be to develop an appropriate standby tariff which can be applied to both GSA facilities and other distributed generation. An initial report from the Working Group is due 120 days from the date of this Order.[817]

418. The Commission also directs (as the Maryland PSC has done) that Pepco's D.C. tariffs (Schedule S) shall not allow Pepco to charge cogeneration customers a "facilities charge" if those customers spend their own money to build the interconnection facilities and equipment upgrades needed to support a cogeneration facility. This directive hereby formalizes Pepco's current practice vis-à-vis GSA's CHP facility and ensures that self-funded cogeneration facilities are not discouraged by the imposition of a "facilities charge" in the District of Columbia.

3. GT-3B (WASA's Blue Plains Facility)

419. WASA's Blue Plains facility is the sole customer served under Schedule GT-3B, which is sometimes referred to as the GT-HV 69 kV rate.[818] WASA argues that a 29.3 percent decrease in WASA's rates (instead of Pepco's proposed 37.7 percent increase) is required to eliminate the subsidy presently paid by WASA.[819] WASA does not seek any change in the structure or relative importance of the rate components of the GT-3B tariff rate schedule, however.[820]

DECISION

420. The Commission's rulings on the class revenue target for the GT-3B rate appear above at p. 118 *supra*. Once the class revenue target is determined, there is no dispute about Pepco's proposed across-the-board approach to adjusting the rate components of the GT-3B rate to collect that class revenue target. The Commission approves that approach for this case. However, the Commission directs the Company to propose in its next rate case GT-3B rate designs that move away from volumetric (energy-delivery) rates toward a greater emphasis on recovery of GT-3B class revenues through customer and demand charges.

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817 *See* Order No. 14712, ¶ 420 ("When [distributed generation] is fully planned and deployed, long-term distribution benefits should be taken into account, and a discounted "standby" rate should be calculated.").

818 WASA (A) at 6 (Phillips).

819 WASA Br. 3, 9; WASA (A) at 14-16.

820 The GT-3B rate (sometimes called the GT-HV 69 kV rate) includes a customer charge, demand charges (kW) ("on peak" and "maximum"), energy-delivery charges (on peak, intermediate peak, off peak), and surcharges. *See* Pepco (G)-2 (Pepco rate schedules); Pepco (G)-3 (Bumgarner); GSA (A) at 7-8 n.4, 19 (Goins).

2. Metro-RT[821]

DECISION

421. WMATA's issues are addressed by the Commission's rulings on the class revenue target for the Metro-RT rate where WMATA focused its advocacy. Once the class revenue target for Metro-RT has been determined, there is no dispute about Pepco's proposed across-the-board approach to adjusting the rate components of the Metro-RT rate to collect that class revenue target. As previously pronounced, Pepco, in its next rate case should propose Metro-RT rate designs that move away from volumetric (energy-delivery) rates toward a greater emphasis on recovery of Metro-RT class revenues through customer and demand charges.

XIII. TARIFF CHANGES (Issue No. 14)[822]

A. Tariff Schedule CG-SPP: Impact of the Clean and Affordable Energy Act (CAEA) and final rules on Small Generator Interconnection Standards (Issue No. 14a)[823]

422. **Pepco.** Pepco's Tariff Schedule CG-SPP allows qualifying cogeneration/small power production facilities ("QF") to sell their electricity output, either as wholesale electricity providers in the PJM market or through a bilateral contract with another purchaser. Such arrangements for the sale by a QF of its output in the wholesale energy market go beyond the net energy metering rules proposed by the Commission, which specify that the electricity output of the facility is "to be purchased by" Pepco at the retail rate.[824] Pepco claims that "no revision is required to Schedule CG-SPP due to the issuance of the interconnection rules for small generators in Formal Case No. 1050" because the coverage of tariff CG-SPP already is broader than what is required by the Commission's net energy metering rules.[825]

423. Pepco notes that other Pepco tariffs may be affected by the new CAEA statute. The Company submits that, after the Commission issues final net metering rules in Formal Case

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821 Metro-RT rates have a customer charge as well as energy-delivery charges ("all kWh," surcharges) and demand charges ("all kW").

822 Designated Issue No. 14 asks, "Are Pepco's proposed tariff changes reasonable?" OPC takes no position in this case on Issue 14. OPC (F) at 7 (Smith).

823 Designated Issue No. 14a asks, "In view of the CAEA requirements to increase the net metering size and issuance of the final rules in Small Generator Interconnection Standards in *Formal Case No. 1050*, should Schedule CG-SPP be modified? If so, what should be the modification?"

824 Pepco (2G) at 6 (Bumgarner).

825 *Id.* at 6-7; Pepco Br. 107.

No. 945 to reflect the impact of the CAEA statute, it will submit a revised Net Energy Metering Rider (NEM), consistent with the new rules, for Commission approval.[826]

DECISION

424. The Commission finds that there is no immediate need to amend Pepco's CG-SPP tariff. However, throughout the hearings, several parties suggested that Pepco needs to formulate new tariffs that encourage and support the development of solar energy and scattered onsite generation.[827] As indicated herein, the Commission will establish a Working Group to discuss the standby tariff issues in Formal Case No. 1050.

B. CAEA's requirement to allow submetering for non-residential rental units (Issue 14b)[828]

425. **Pepco.** To allow submetering as required by the CAEA, Pepco proposes to modify its tariffs in Section 2(e) of its General Terms and Conditions.[829]

426. **AOBA.** To avoid what it characterizes as misleading non-residential customers who may not be aware of the fact that they now have the option of utilizing either sub-metering or energy allocation equipment in their buildings, AOBA recommends the following amendment to Section 2(e) of Pepco's General Terms and Conditions:

> Electric service furnished to the Customer shall be for the Customer's own use and may only be re-metered or sub-metered by a Non-residential Customer as authorized under Title VII- Submetering Provisions of the Clean and Affordable Energy Act.[830]

The Company states that it has no objection to this language.[831]

826 Pepco Br. 106; Pepco (2G) at 5-6.

827 *See, e.g.,* Tr. 1189, 1192, 1196-1199 (GSA witness Goins); Tr. 789-790 (AOBA witness Oliver). *See also Formal Case No. 1053*, Order No. 14712, ¶ 420 (when [distributed generation] is fully planned and deployed, long-term distribution benefits should be taken into account, and a discounted "standby" rate should be calculated).

828 Designated Issue No. 14b asks, "What changes to the tariffs are needed in order to address the CAEA requirement to allow submetering for non-residential rental units?"

829 Pepco (2G) at 7 (Bumgarner); *see* Pepco (2G)-2 ("General Provisions for Electric Service and Facilities") (tariff language) at Second Revised Page No. 8 (general ban on submetering amended by adding the language "except as authorized under Title II- Submetering Provisions of the CAEA).

830 AOBA (A) at 97-99 (Oliver).

831 Pepco Br. 107.

DECISION

427. We agree with AOBA's proposed tariff amendment to correct Section 2(e) of Pepco's General Terms and Conditions, containing Pepco's general ban on submetering, modified as follows:

> Electric service furnished to the Customer shall be for the Customer's own use and may be re-metered or sub-metered only by a Non-residential Customer as authorized under Title VII- Submetering Provisions of the Clean and Affordable Energy Act.

C. Temporary Service rate customers (Issue No. 14c)[832]

428. The Commission asked Pepco to clarify some basic facts about the Schedule T customer class in this case e.g., why is the T class characterized by large variations in kWh usage, as well as wide variations (ranging from less than a year to many years) in the time period during which customers remain and take service in this class? The Commission earlier concluded that the varying nature of usage patterns and length of service do not make this customer class suitable for the BSA at this time.[833]

429. **Pepco.** The Company proposes a new five-year maximum time limit for serving customers under its Temporary Service (T) rate. The T rate is designed to cover the higher cost of providing service to facilities during construction or to installations that are temporary. Pepco indicates that, in some cases, the application of the tariff relies on judgmental interpretations by field personnel as to what is temporary in nature. For instance, some customer installations on non-permanent foundations, such as parking lot kiosks, were originally classified as Temporary Service, but have persisted for many years." Pepco agrees that there should be a time limit on the application of Schedule T, and it proposes five years as a reasonable time limit.[834]

430. **AOBA.** AOBA supports Pepco's proposed five-year maximum time limit for serving customers under the Temporary Service (T) rate. AOBA indicates that, as of December 2008, there were 209 T class customers, three-fourths of whom (*i.e.* 153 out of 209) had been in

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832 Designated Issue No. 14c asks, "Does Pepco properly classify and bill Temporary Service rate customers? Should the Temporary Service rates (Schedule T) be changed? Should there be a maximum time period established for 'Temporary Service' rates?"

833 *See Formal Case No. 1053*, Order No. 15556, ¶ 51.

834 Pepco Br. 107; Pepco (2G) at 7-8 (Bumgarner); *see* Pepco (2G)-3 (tariff language) ("However, customers receiving Temporary or Supplemental Service on a continuous basis for five (5) years will normally be transferred to the appropriate General Service Low Voltage Schedule "GS LV" or "GS ND" based on the customer's maximum demand, in accordance with the availability provisions therein. Rate schedule transfers will be made annually and become effective with the billing month of June.") OPC takes no position on Issue 14 concerning Temporary Service customers. OPC (F) at 7 (Smith).

that service class for less than 5 years, and over 63 percent of whom had been on Rate T for less than 3 years. On the other hand, more than 20 percent of T customers have been on that service for greater than 10 years. According to AOBA, this suggests that the vast majority of T customers employ that service for temporary requirements; yet significant numbers have used Rate T essentially for permanent service.[835] AOBA recommends that the tariff language for Rate T be reviewed, to "eliminate all references to 'supplementary service,' and thereby be more clearly limited to service that is of a temporary nature (*e.g.*, construction projects, carnivals, and festivals)."[836]

431. The Company stated that it has no objection to amending the tariff removing language about "supplemental load" from its T tariff.[837]

DECISION

432. We approve the tariff amendment for T service as proposed by incorporating a five-year maximum time limit for serving customers under the T rate and eliminating references to "supplemental load."

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835 AOBA (A) at 99-100 (Oliver).

836 *Id.* at 100-101.

837 Tr. 1413 (Pepco witness Bumgarner).

XIV. OTHER MATTERS

A. Community Comments

433. More than 125 community witnesses submitted comments or testified at the Commission's community hearings in this Pepco rate case.[838] Their comments went beyond protesting higher Pepco rates, an overarching concern, to highlighting other important community concerns for the Commission's consideration.

1. Objections to Higher Pepco Rates, Requests for a 50 percent Rollback in Rates, a Moratorium on All Shutoffs, and Community Hearings on Three Successive Saturdays

434. Several senior citizens living in the District reference OPC's objections to the Company's proposed $51.7 million rate increase.[839] OPC's one-page flyer, attached to several senior citizens' comments, argues that Pepco is seeking to shift business risks to consumers, with no guarantee that service quality will be improved. Nor has Pepco explained how consumers will be educated to use a wave of future technologies, such as smart meters. The comments recite the flyer's statement that residential rates in the District have increased by 98 percent. Other senior citizens submit related comments stating that they were living on fixed incomes, and that increasing the cost of electricity would mean even less income available for other necessities. They complain that Pepco's service is increasingly poor. While power outages affected neighborhoods around the city, and neighbors were complaining about the accuracy of their meters, they stated that it was difficult to reach Pepco service representatives.

435. Testimony on behalf of the District's seniors was presented by Shirley C. Thorne, a member of the Ward 8 Mini Commission on Aging, Jacqueline Arguelles, Chair of the Commission on Aging for D.C., and Ann Wilcox, Executive Director of the Gray Panthers of Metropolitan Washington. They requested that the Commission deny Pepco's rate increase

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838 "Both ANCs [Advisory Neighborhood Commissions] as entities and ANC Commissioners as individuals may be heard by the PSC as part of the public at large." *Office of People's Counsel v. Pub. Serv. Comm'n*, 630 A.2d 692, 697 (D.C. 1993). The Commission is not required to give "great weight" (or any special weight) to advice it receives from ANCs in rate cases. *Id.* The Commission listens carefully to all public comments, however. We have carefully reviewed and considered all the comments from community witnesses, which are summarized in this section of the Opinion and Order, in determining Pepco's rate application.

839 OPC's one-page flyer (a "public notice alert" captioned "OPC opposes Pepco's $51.7 million rate increase bid, calls for decrease in Pepco's current rates by $10.4 million") was attached to written statements submitted by senior citizens Jay Johnson, Lawondua Jones, Tunisha Robinson, Ptasker Bennett, Carrie Sasberg, Diane Jackson, and Mary Wood. The Commission received similarly worded, or identical, letters of protest (without the OPC flyer) from senior citizens Renee Green, Josephine Givens, Anita C. Green, Joe Shelton, Thomas Perry, Elba Corley, Laura Malheur, Parnell Blas, Sean M. Leaked, Bonnie Day, Antoinette Cheek, Allan Breuer, James Crowell, Selena Brooks, Agnes L. Branch, Harriet D. Key, Hazel S.Whitby, Gwendolyn Goyhill, Evelyn C. Young, Roy Black, and Georgia Robinson.

because of its impact on nearly 100,000 fixed-income seniors living in the District.[840] Two disabled District residents, Darnise Henry-Bush and Edward Durham, oppose Pepco's rate increase because of its impact on the working poor, fixed-income disabled persons, and the unemployed.[841] Graylin Presbury, President of the Fairlawn Citizens Association (east of the Anacostia River), echo OPC's opposition to a Pepco rate increase, noting the importance of electricity in modern life and the impact of a rate increase on fixed income ratepayers.[842]

436. The Commission also received many comments demanding a 50 percent rollback in Pepco's rates, a moratorium on all shutoffs, and community hearings on Pepco's proposed rate increase on three successive Saturdays.[843] These comments emphasize that these are difficult economic times for ordinary citizens. While Pepco's rates have doubled in the last five years, they noted, workers' wages have not. The unemployment rate in the District of Columbia has doubled in the last two years. They state that electricity is a basic necessity, essential to good health and well-being in modern society. They oppose Pepco's proposed $51.7 million (6.1 percent) rate increase, pointing out that Pepco's 2008 Annual Report states that Pepco/PHI has a strong financial condition with $10.7 billion in PHI revenues, $300 million in PHI profits, $170 million in federal stimulus money, $140 million in tax refunds, and a 2008 salary for the Chairman and CEO of Pepco Holdings of over $9 million.[844] Pepco also recently received a $44.6 million award in federal funds for its AMI smart meter activities.[845] They complain that

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840 *See* Community Hearing Tr. 63-67 (Jacqueline Arguelles), Tr. 98-100 (Ann Wilcox) (November 20, 2009); Community Hearing Tr. 40 (Shirley C. Thorne) (November 19, 2009) and her written testimony to the Commission (November 19, 2009). *Accord* Community Hearing Tr. 108 (Melinda Everett, Consumer Utility Board), Tr. 110-112 (Commissioner Janet Myers, ANC 4C02) (November 20, 2009); Community Hearing Tr. 38 (Ashly Sauers, Baltimore ANSWER), Tr. 39 (Phillip Haughton) (November 19, 2009).

841 *See* Community Hearing Tr. 22-26 (Darnise Henry-Bush), Tr. 36-39 (Edward Durham) (November 20, 2009).

842 *See* Community Hearing Tr. 46-50 (Graylin Presbury) (November 19, 2009).

843 These sentiments were voiced by many people, including, among others, Crystal Kim who testified and submitted written comments on behalf of Justice First. *See* Community Hearing Tr. 11-15 (October 24, 2009); Community Hearing Tr. 11-15 (November 19, 2009); Community Hearing Tr. 5-10 (November 20, 2009). A one-page flyer from Justice First was also submitted for the record. Other residents and commenters also identified themselves as volunteers for, or supporting the views of, Justice First. *See* Community Hearing Tr. 16-24 (Caneisha Mills, representing the Party for Socialism & Liberation), Tr. 26-28 (Jonathan Miller, who also submitted a written statement), Tr. 29-32 (Matthew Murray, who also submitted a written statement), Tr. 36-37 (Natasha Persand, who also submitted a written statement) (November 19, 2009); Community Hearing Tr. 46-49 (Ronald Sheffer) (November 20, 2009). *See, e.g.*, Community Hearing Tr. 17-21 (Sarah Sloan, Washington, D.C., speaking for the ANSWER Coalition), Tr. 57-58 (Elizabeth Lowengard, with the ANSWER Coalition), Tr. 104 (David Schwartzman) (November 20, 2009).

844 Objections to the high salaries and bonuses of Pepco's CEO and other top Pepco employees were strongly expressed by several people. *See, e.g.* Community Hearing Tr. 33 (Sarah Sloan), Tr. 45 (Esteban Olivaro) (November 19, 2009); Community Hearing Tr. 32-34 (Commissioner Gigi Ransom, ANC 5C12), Tr. 69 (Evanna Powell); Tr. 71-74 (David Borrows), Tr. 76 (Sinelle Freeman), Tr. 90 (Commissioner Jacqueline Mitchell, ANC 4C), Tr. 103-104 (David Schwartzman) (November 20, 2009).

845 *See* Community Hearing Tr. 17 (Chairman Kane) (November 20, 2009).

Pepco is seeking a rate increase simply to increase the Company's profits. They state they were "in vehement opposition to Pepco's proposed rate hike."

437. Yvonne Moore, Chair of ANC 7B, opposes any Pepco rate increase. Observing that Commission public hearings should be scheduled to avoid conflict with ANC meetings, she questions the quality of Pepco's service in her neighborhood on issues relating to brown outs, cut backs in electrical power, and Pepco's response time. She indicates that Pepco should tighten its belt rather than be given a rate increase.[846]

DECISION

438. The Commission's decision in this case sets Pepco rates at levels that fairly balance the interests of both ratepaying consumers and Company investors. In deciding the specific designated issues, we have taken into consideration a wide variety of factors, and in all our decisions, we have always considered the economy of the District and the impact of our determination on ratepayers.

439. We note also that the Commission has convened a separate case to examine issues raised by Pepco's implementation of its smart meter program.[847] One of the issues in that case will be how Pepco can best insure that consumers are educated to handle the coming wave of future technologies.

440. Traditionally, the Commission has held three community hearings for each of its formal rate cases: one in the daytime on a weekday, one in the daytime on a Saturday, and one in the evening during the week.[848] Given the large number of public comments submitted in this Pepco rate case, the Commission will consider holding additional public comment hearings in future Pepco rate cases.

2. Quality of Pepco's Service in the District of Columbia

441. Two commercial customers complained about the quality of Pepco's service, particularly power outages and system reliability. The American Association for the Advancement of Science (AAAS), which owns a 200,000 square foot building in the District, stated that it experienced five power outages in just over a year – each of which caused equipment failures and other damage to its property. AAAS states that Pepco has no effective communication program and relies instead on an "outage" map to explain where outages are

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[846] *See* Community Hearing Tr. 9-10 (November 19, 2009) and Yvonne Moore's written statement (November 9, 2009).

[847] *See* Community Hearing Tr. 71 (November 20, 2009) (comments of Chairman Kane).

[848] *See* Community Hearing Tr. 113- 114 (November 20, 2009) (comments of Chairman Kane).

occurring and when they will be corrected. AAAS asks that "Pepco be required to provide a plan of action to correct these issues as part of any approved increase to their rates."[849]

442. Similar comments were submitted by Akridge, which manages over 6 million square feet of office space in downtown Washington, D.C. Akridge indicates outages and service interruptions have undercut productivity, and damaged its telephone equipment, network services and other equipment. Akridge complains that Pepco lacks a plan of action to ensure greater network reliability and better communication with its commercial customers:

> We need accurate and timely information from Pepco in order to implement contingency plans during service interruptions. An explanation from Pepco regarding weather related, specific equipment failures, or maintenance repairs that interrupt service and the Company's plan of action and timetable on the restoration of service is critically important information for all customers. Pepco needs to provide a strategy where the commercial sector can receive real-time information regarding any outage and the Company's plans for repairs and restoration of service. This plan must include direct personal points of contact for the downtown commercial sector.

Akridge urges the Commission to require Pepco to provide a plan that addresses these concerns.[850]

443. The Company's individual customers also criticize its poor service.[851] Testimony by Graylen Presbury, President of the Fairlawn Citizens Association, for example, indicates that Pepco's service has been declining, resulting in outages damaging appliances, and long waiting times when customers call Pepco to ask questions or report an outage.[852] Ruth Connolly, Chair of the citywide Tenant Advisory Council, also criticizes Pepco's service record on outages and long delays in restoring service.[853] Augusto Moreno testified about the adverse impact of a Pepco service interruption at his apartment, affecting his 70-year-old-mother who needs

849 AAAS's letter to the Commission (November 19, 2009). AAAS's letter also stated: "Because we cannot depend upon Pepco, we are investigating investing in larger generation (at significant expense), and other options to ensure continuity of service. It is unacceptable for the power supply system in the District of Columbia to be as unreliable as it has become."

850 Akridge letter to the Commission (November 19, 2009).

851 *See, e.g.*, Community Hearing Tr. 18-19 (Caneisha Mills) (November 19, 2009).

852 *See* Community Hearing Tr. 50 (Graylin Presbury) (November 19, 2009).

853 *See* Community Hearing Tr. 31-32 (Ruth Connolly) (November 20, 2009).

electrical power to operate a medical device.[854] Other commenters also briefly state that there are too many outages.[855]

444. Commissioner Gale Black, ANC 4A08, speaking for the Crestwood Citizens Association and ANC 4A08, criticizes Pepco's service reliability. Opposing the Company's rate increase, she states that Pepco customers in Crestwood have experienced longer and more frequent outages and "sags." She states further that this has damaged motors, disrupted telecommunications, and threatened the health of people using medical equipment. Ms. Black contends that Crestwood is served by Pepco feeder line 15197, which is the worst performing line in the city. Taking a look at a cross-section of North American Utilities, surveyed by Best Practices Group, Ms. Black states that Pepco's System Average Interruption Frequency Index (SAIFI) was 17th out of 23 ranked utilities. Using another indicator, the large city reliability survey, Pepco ranked 12th out of 19 utilities. The survey said that for calendar year 2006 Pepco's SAIFI rating was 13, compared to a 1.1 average rating for other North American utilities. Crestwood residents question why Pepco cannot improve reliability and lower costs, as Commonwealth Edison is doing. Ms. Black urges the Commission to "adopt a reliability index with performance measures and accountability." While supporting smart meters and smart grids, Crestwood residents question whether they will see any cost benefit if they change their usage patterns to off peak times. The Company is better able to bear the cost of Pepco's infrastructure upgrades, said Ms. Black, than seniors and residents on fixed incomes.[856]

445. These comments by Commissioner Black are supported by ANC 4A as a whole. After hearing from representatives of Pepco and OPC, as well as neighborhood residents, ANC 4A voted to oppose Pepco's requested rate increase, for three major reasons. First, thousands of homeowners represented by ANC 4A may be adversely impacted by a Pepco rate increase. Second, there are many seniors, living on fixed income, residing in 4A who may not be able to afford an increase. Third, ANC 4A stated that Pepco did not adequately justify an increase. OPC and Pepco presented conflicting, offsetting evidence. Pepco is attempting to shift some of its operational financial burdens and risks to consumers, without guaranteeing improved service. In particular, "ANC 4A questions why consumers must bear the brunt of current and future retirement fund losses to Pepco retirees. Many ANC 4A residents have had adverse impacts to their retirement funds without a safety net or someone else to shoulder the burden or risk."

854 *See* Community Hearing Tr. 44-45 (Augusto Moreno) (November 20, 2009).

855 *See, e.g.*, Community Hearing Tr. 80-81 (Sandra Mitchiner), 84-85 (Joyce Robinson-Paul, Hanover Area Civic Association, lower Shaw area of D.C.).

856 *See* Community Hearing Tr. 49-57 (November 20, 2009) (comments of Gale Black, President of the Crestwood Citizens Association and ANC 4A08 Commissioner). The Commission's Chairman noted that the Commission has updated its "consumer bill of rights" as well as the standards for electric quality of service and natural gas quality of service. She stated that the Commission also is receiving monthly outage reports from Pepco. *Id.* Tr. 56-57 (comments of Chairman Kane) (citing Commission *Formal Case No.982*, Electricity Quality of Service Standards).

Pepco did not fully explain the stimulus funds it recently received. Moreover, Pepco's services have not appreciably improved since the last rate increase.[857]

446. "Crestwood is plagued by outages and unscheduled service interruptions," according to comments submitted by the Crestwood Neighborhood League ("League"). Apart from major outages, "everyone regularly experiences short losses of service, as evidenced by the persistent need to reset clocks and electric devices on a monthly and frequently weekly basis." Televised news reports, neighbors and elected officials report a pattern of "erratic" Pepco service in the larger Washington community, with "room for much improvement in the quality of service being offered." Taking into account the limited ability of consumers to pay more, the League supports OPC's position seeking a $15.76 million reduction in Pepco's requested increase. They seek "steady, reliable service" at a reasonable rate.[858]

447. Commissioner Lenwood Johnson, ANC 1A, complains of electric power outages in southwestern Columbia Heights. Opposing the rate increase, he states that Pepco should be ordered to spend more money on solving outages and upgrading infrastructure.[859] One District resident indicates that she would like to avoid "the kinds of horror stories that have showed up" and that she would like to keep her bills "about the same."[860]

DECISION

448. While the Commission already has several proceedings investigating Pepco's service quality and reliability, given these widespread complaints from the public about the quality of Pepco's service, service quality issues could be ripe for consideration in Pepco's next rate case.[861] The Commission will review Pepco's plans to address outages, reliability and improved service throughout the City. We should be aided in this task by the fact that we have already adopted electric quality of service standards, and we are now receiving monthly outage reports from Pepco.[862] According to the community comments we received in this case, two areas in particular are in need of improved service; downtown Washington D.C. and the Crestwood area in Ward 4.

857 Chair Stephen A. Whatley, ANC 4A, letter to the Commission (December 9, 2009).

858 Ronald P. Bland, President, Crestwood Neighborhood League, letter to the Commission (December 21, 2009).

859 Community Hearing Tr. 86-88 (November 20, 2009) (comments of ANC Commissioner Lenwood Johnson, ANC 1A).

860 *See* Community Hearing Tr. 7-8 (October 24, 2009) (Deborah Fort).

861 The Commission already is considering issues about Pepco's reliability in *Formal Case Nos. 766, 982* and *1002* among others. In *Formal Case No. 766*, in particular, we are considering Pepco's efforts to improve its customer average interruption duration index (CAIDI) and its system average interruption duration index (SAIDI).

862 *See* Community Hearing Tr. 56-57 (November 20, 2009) (comments of Chairman Kane).

3. Consumer Education to Use Smart Meters, Smart Grid Initiatives

449. Other District residents like Barbara D. Morgan complain (among other things) that Pepco has not explained how consumers/ratepayers will be prepared and educated for a wave of future technologies, such as smart meters and the Smart Grid.[863]

450. Carlos Bright opposes Pepco's rate increase, as a disabled individual living on a fixed income. He questions why Pepco could not improve reliability and lower its costs. He supports the Smart Grid, but questions "whether there will be any financial benefit for us, if we adjust our uses to off-peak times. How will the costs of these new technologies be allocated?"[864]

451. In response to Evanna Powell's concern over whether and when smart grid/smart meters would be able to turn off her air conditioning, Chairman Kane stated that Pepco's load control programs would be voluntary.[865]

DECISION

452. The Commission has opened a separate case (Formal Case No. 1056) to examine Pepco's smart meter program. There we will address the proper structure of associated voluntary load control programs, how Pepco plans to use the $44.6 million in federal grant money it is receiving for its AMI smart meter programs, and the need for public information and education about these new technologies and programs.[866]

4. Pepco's Pension Costs and Other Expenditures

453. Mary Rowse and Jeff Hart complain that the Company's pension costs and other expenditures were too high. Opposing any rate increase, they suggest that Pepco might transfer its pension risk to its employees by offering them defined contribution, instead of defined benefits plans. They also suggest that Pepco should defer capital outlays and improvements to its network "until the capital markets have normalized and the cost of capital for Pepco is closer to historic norms."[867]

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863 Written Statement of Barbara D. Morgan (November 19, 2009).

864 Carlos Bright letter to the Commission (December 2, 2009).

865 *See* Community Hearing Tr. 69-70 (Evanna Powell), Tr. 71 (Chairman Kane) (November 20, 2009).

866 *See* Community Hearing Tr. 71 (November 20, 2009) (comments of Chairman Kane).

867 Email from Mary Rowse and Jeff Hart to the Commission (November 6, 2009).

454. Advisory Neighborhood Commission 4A submits objections to ratepayers paying for pension losses suffered by Pepco employees, as noted above,[868] and by Annie Winborne, a long-time member of the Consumer Utility Board.[869]

DECISION

455. The Commission's decision on Designated Issue No. 8 determines that traditional rate-making treatment, and not a surcharge or other special treatment, is appropriate for Pepco's pension costs, OPEB, and uncollectible expenses. We specifically considered community comments in reaching that decision.[870] Testimony submitted by Pepco in this case made it clear that the Company has postponed many capital outlays and improvements during these difficult economic times.[871]

5. Green Energy

456. David Schwartzman, representing the D.C. Statehood Green Party and D.C. Metro Science for the People, opposes Pepco's use of coal fuels. "Greater use should be made of wind turbines and renewable energy sources." To remedy high Pepco rates, he suggests the "municipalization" of Pepco's assets in the District. He also supports the views of OPC and Justice First, citing the regressive nature of utility bills, high unemployment levels in D.C., and the "depression" (not merely a recession) in the economy here in the District of Columbia.[872]

DECISION

457. Our currently-pending cases address a number of "green" initiatives. The Commission is committed to consider the conservation of natural resources in our regulation of Pepco and all other public utilities in the District. Today's decision considers the economy of the District of Columbia and awards Pepco less than half of the increase it requested.

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868 Chair Stephen A. Whatley, ANC 4A, letter to the Commission (December 9, 2009).

869 *See* Community Hearing Tr. 42 (Annie Winborne) (November 20, 2009).

870 *See supra* ¶ 195.

871 *See, e.g.*, Pepco's Application at 4-5 ("To address the impacts of the economic and financial crisis, the Company implemented significant cost containment measures, including a freeze on salaries for non-union employees, a cap on staffing levels, and postponement of several million dollars of capital expenditures."); Pepco (a) at 4-5 (Kamerick).

872 *See* Community Hearing Tr. 101-107 (David Schwartzman) (November 20, 2009).

6. Support for Pepco

458. The Company's proposed rate increase was supported by several residents as necessary to ensure safe and reliable electric service in the District of Columbia. Two District residents, James Lively, formerly an ANC Commissioner for 10 years, and Saymendy Lloyd, state that Pepco's rate increase is needed to improve service and address outage/reliability issues, as well as to improve equipment, participate in "smart grid" initiatives, and maintain Pepco's standing with rating agencies. Mr. Lively compliments Pepco on its community involvement and its development of a July 1, 2009 plan for addressing outages in Ward 3. The objective of this proceeding, he notes, is fair, just and reasonable rates.[873]

459. Marc Barnes supports Pepco's increase to facilitate the installation of smart meters and other measures to reduce costs, conserve energy and protect the environment.[874] Linda Perkins similarly supports Pepco's rate increase as a means to improve energy efficiency, with programs such as the Compact Fluorescent Program and the Smart Grid Initiative. She stresses the need for outreach and education to make sure that consumers actually benefit from these programs.[875]

460. Commissioner Reverend Thomas Alston, ANC 7C06, supports Pepco's proposed rate increase as necessary to meet the increased costs of providing safe and reliable electric service. The Company's administrative and operational costs have spiraled upwards, and the cost of capital has increased. Pepco must be able to demonstrate its financial health in order to access needed capital, he states, and it needs money to maintain its poles, wires and other equipment. Reverend Alston notes that Pepco is educating consumers about energy efficiency and that recently-received stimulus funds of $168.1 million will help ordinary customers monitor and save on electricity.[876]

461. Barbara Lang states that Pepco has undertaken significant cost containment measures, freezing salaries, capping staffing levels, and postponing several million dollars of capital expenditures. She states that Pepco has improved the reliability of its service in Ward 3. While the cost of capital and energy is rising, she notes that Pepco's responsibility to provide safe and reliable service has remained constant. This is only the second distribution rate increase the Company has proposed since 1995. To save ratepayers money, she points out that the Company recently applied for (and obtained) some $44 million in federal funding for AMI meters to allow customers to manage their own energy use efficiently.[877]

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873 *See* Community Hearing Tr. 51-56 (James Lively) (November 19, 2009); written comments of James C. Lively (November 19, 2009); Community Hearing Tr. 59-62 (Saymendy Lloyd) (November 20, 2009).

874 Written Statement of Marc Barnes (October 24, 2009).

875 Written Testimony of Linda Perkins (October 24, 2009).

876 Written Testimony of Reverend Thomas Alston (December 3, 2009).

877 *See* Community Hearing Tr. 11-17 (Barbara Lang) (November 20, 2009).

DECISION

462. The Commission's decision in this case sets Pepco rates at levels that fairly balance the interests of both ratepaying consumers and Company investors.

B. Motions to Correct Transcript

463. To correct typographical errors, garbles, misspellings, and other errors, Pepco filed a motion on November 18, 2009, to correct the transcript of the Commission hearings held from November 9 through November 13, 2009. No party opposes these proposed corrections. Accordingly, the Commission grants Pepco's motion to correct the transcript.

XV. FINDINGS OF FACT AND CONCLUSIONS OF LAW

464. Based on the evidence of record in this proceeding, the Commission makes the following findings of fact and conclusions of law:

a. That Pepco's proposed test year ending December 31, 2008, is reasonable;

b. That Pepco's use of a 13-month average rate base is reasonable;

c. That Pepco's District of Columbia rate base for the test period is $1,010,267,000;

d. That a fair rate of return (including capital costs and capital structure) on Pepco's District of Columbia rate base is 8.01 percent;

e. That the Commission's earlier decision, approving a 50 basis point reduction in Pepco's return on equity as part of the approval of the Company's Bill Stabilization Adjustment ("BSA"), continues to be reasonable;

f. That Pepco shall be allowed to earn a cost of common equity, including the BSA adjustment of 50 points, of 9.625 percent;

g. That Pepco's cost of long-term debt is 6.63 percent;

h. That the level of return when the 8.01 percent rate of return is applied to the adjusted rate base of $1,010,267,000 is $80,922,000;

i. That Pepco's adjusted District of Columbia net operating income of $69,317,000 for the test-year was deficient by the amount of $11,606,000;

j. That the adjustment which would increase Pepco's test-year revenue to the level of gross revenue requirements computed in accordance with the findings in this Opinion and Order is $19,833,000, which includes a proper allowance for taxes (*see* attached Schedules);

k. That the capital structure proposed by Pepco to develop its overall cost of capital is reasonable and appropriate for this proceeding;

l. That the Commission approves as reasonable the following uncontested ratemaking adjustments (RMA) affecting Pepco's Rate Base, which were proposed by Pepco and either stipulated or accepted by the parties:

Ratemaking Adjustment No. 2 ("RMA No."), CWIP in Rate Base;
RMA No. 3, Annualization of Northeast Substation;
RMA No. 5, Exclusion of Supplemental Executive Retirement Plans;
RMA No. 12, Reflection of FC 1076 Costs;

RMA No. 19, Annualization of Software Amortization;
RMA No. 20, Annualization of Deductible Mixed Service Cost Tax Method;
RMA No. 21, Exclusion of Capitalized Portion of Disallowed F.C. No. 939 Costs;
RMA No. 22, Reflection of Disallowance of Incentive Plan Costs;
RMA No. 24, Inclusion of Deferred Customer Education Costs; and
RMA No. 29, Reflection of New Method-Repair Categorizations.

m. That $886,640 Retirement Work in Progress (RWIP) for Benning Road relocation has been removed from Pepco's Rate Base and the remainder of RMA No. 4 is accepted;

n. That $635,000 should be removed from rate base, reflecting the retired portion of Pepco's 69 kV Emergency Overhead Feeders, and that Pepco is entitled to recover its costs plus a return on the remaining cost of those Emergency Overhead Feeders, which shall be reflected in Pepco's Rate Base as "emergency capitalized spare";

o. That to safeguard the safety and reliability of the electric distribution system in this area, Pepco shall not dismantle or remove what remains of the 69 kV Emergency Overhead Feeders, without first obtaining prior explicit Commission permission to do so;

p. That Pepco's Rate Base should include accruals recorded in accordance with Generally Accepted Accounting Principles;

q. That the Company's depreciation allowance (Issue No. 6) shall be calculated as specified by the Commission in this Opinion and Order. Among other things, we direct Pepco to adopt (1) the net salvage method that minimizes the collection of future inflation from current customers; and (2) SFAS 143 present-value calculations using formulas from Maryland Case No. 9092 and using inflation-based discount factors that Mr. Majoros presented and Pepco accepted (*see* Pepco (3F)-7). The Company is also directed to record scrap salvage as salvage and to resume recording capitalized third-party reimbursements as salvage and to resume crediting them into Account 108 (Accumulated Provision for Depreciation);

r. That the Commission approves as reasonable Pepco's Cash Working Capital requirements (originally a contested issue, but resolved in the hearings);

s. That weather normalization and its associated annualization of revenues should be calculated as directed by the Commission in this Opinion and Order;

t. That the Commission approves as reasonable the following uncontested Company ratemaking adjustments (RMA) affecting Pepco's test year Operating Income and Expenses:

RMA No. 2, Inclusion of Projects Completed and In Service;
RMA No. 3, Annualization of NE Substation Cut In;
RMA No. 5, Exclusion of Supplemental Executive Retirement Plans;
RMA No. 6, Exclusion of Industry Contributions and Membership Fees;
RMA No. 7, Exclusion of Advertising and Selling Expense;

RMA No. 8, Inclusion of Interest Expense on Customer Deposits;
RMA No. 10, Reflection of Non-Deferred Regulatory Costs at 3-Year Average Amount;
RMA No. 12, Formal Case No. 1076 Outside Counsel/Consulting Deferred Costs;
RMA No 18, Reflection of Change in PSC and OPC Budget Assessment;
RMA No. 19, Annualization of Software Amortization;
RMA No. 21, Reflection of FC939 Disallowance;
RMA No. 22, Reflection of Disallowance of Incentive Plan Costs;
RMA No. 23, Removal of Adjustments to Deferred Compensation Balances; and
RMA No. 24, Inclusion of Deferred Customer Education Costs.

u. That Pepco's RMA No. 28, proposing regulatory asset treatment and amortization of its 2009 pension costs, is rejected;

v. That Pepco's proposed surcharge for pension, OPEB and uncollectible expenses (Issue No. 8) is rejected, as is Pepco's proposed regulatory asset for these costs (Issue No. 8a);

w. That the Company's pension and OPEB expenses should be treated as described in this Opinion and Order, which (among other things) accepts OPC's two-year average method for treating Pepco's pension expenses, for this case only;

x. That Pepco's allowance for uncollectible expenses, the subject of Pepco RMA No. 16, will be recognized as reasonable as directed in this Opinion and Order, in the form of a two-year average for this case only;

y. That Pepco's RMA No. 13, proposing an annualization of wage increases, is accepted with the caveat that the recognized wage increase shall be limited to 1.5 percent;

z. That Pepco's RMA No. 14, concerning 2009 employee health and welfare costs, is accepted as reasonable;

aa. That the Company's start-up costs and annual maintenance fees incurred for ensuring access to PHI's credit facility, the subject of Pepco's RMA No. 9, are allowed as reasonable recurring test year operating expenses;

bb. That Pepco's deferred costs from Formal Case No. 1053, the subject of Pepco's RMA No. 11, should be treated as directed in this Opinion and Order, using the mid-point unamortized balance (equal to a 13-month average balance) for the first year of the rate effective period;

cc. That Pepco's proposed allowance for storm restoration expenses, the subject of Pepco RMA No. 17, is approved as reasonable; and that Pepco should report and document its incremental storm damage costs quarterly, when it files its quarterly reports of its weather normalized jurisdictional earned returns;

dd. That Pepco's RMA No. 27 for interest synchronization is approved as reasonable but must reflect the rate base and the weighted cost of debt approved in this Order;

ee. That Pepco employee club costs are removed from Pepco's test year operating expenses, as OPC proposed in its RMA No. 12;

ff. That the cost of Pepco's officers and directors liability insurance is accepted as a reasonable test year operating expense;

gg. That Pepco's on-going recurring "Utility of the Future" costs are accepted as reasonable test year operating expenses;

hh. That OPC's proposed Consolidated Tax Adjustments (Issue No. 10) are rejected;

ii. That the adjustment for bonus depreciation (and interest synchronization) that Pepco and OPC agreed upon, to show the actual amount (rather than a preliminary audit amount) of bonus depreciation that Pepco received for 2008, is reasonable;

jj. That PEPCO's proposed treatment of income taxes and other tax expenses, including those related to the operating budgets of the Commission and OPC, is reasonable and consistent with Commission precedent;

kk. That Pepco's 2007 and 2008 AMI start-up costs amounting to $911,000 should be capitalized, and amortized over 15 years;

ll. That Pepco's jurisdictional cost allocations (based on its established AED-NCP methodology) are reasonable;

mm. That Pepco's customer class revenue targets and rate designs shall be determined as directed in this Opinion and Order, making moderate progress toward reducing interclass subsidies and reducing the disparities that now exist in class rates of return;

nn. That the Residential Customer Charge shall be increased to $6.65, while the volumetric (energy-delivery) rates in Residential distribution charges shall be reduced, so that the Residential class pays no more than 36 percent of the total revenue increase, or the class revenue target of $7.14 million (approximately a 17.5 percent increase);

oo. That the Residential Aid Discount (RAD) rate structure shall be simplified and clarified, as set forth in this Opinion and Order, while still according RAD customers a very sizable discount compared to regular Residential customers (standard R and AE). The Commission finds that the following RAD rate structure is just and reasonable: The old RAD and RAD-AE "minimum charge" shall be replaced with a new $2.50 RAD Customer Charge. The old RAD 30 kWh/370 kWh rate blocks will be replaced with a single new initial RAD 400 kWh rate block. Tailblock energy rates for RAD and RAD-AE shall be adjusted as directed in this Opinion and Order, so that they are the same as the corresponding tailblock rates for standard R and AE and, overall, the RAD class revenues to be recovered from all RAD kWh rates will remain the same as they are now;

pp. That except for the changes we direct to RAD rate structure, the *status quo* should be preserved on all other RAD issues, until and unless the Commission decides otherwise in Formal Case No. 813 or the Council adopts legislation that further addresses the design, funding, and other issues associated with the RAD program. Pepco's request for an increase in the RAD surcharge is moot, in light of the statutory compensation given to PEPCO for its previously unreimbursed RAD costs by the Residential Aid Discount Subsidy Stabilization Emergency Amendment Act of 2009 (D.C. Act 18-155) (July 28, 2009);

qq. That an approximate 17.5 percent increase in the class revenue requirement for the streetlight class (SL and TS rate schedules), the same increase that is being imposed on the Residential class, is reasonable;

rr. That the Company's proposed methodology is reasonable for distributing among the commercial classes the remaining revenue burden of its revenue increase (*i.e.*, the overall \$19.833 million D.C. jurisdictional rate increase minus the \$7.14 million increase allotted to the Residential class minus the increase allotted to Streetlights and Traffic Signals);

ss. That increasing the Customer Charge for Residential Time-of-Use customers from \$9.09 to \$11.17 is reasonable;

tt. That tariffs for Street Lighting (SL) and Traffic Signals (TS) should be updated as directed in this Opinion and Order; that the District Government's expenditures to ensure uninterruptible power for its traffic signals and street lights do not warrant a reduction in Pepco's SL/TS rates; that Pepco should conduct an up-to-date study of SL/TS costs as directed in this Opinion and Order; and that Pepco and the District Government should seek to design SL and TS rates in the future so they are not "energy-only delivery" rates;

uu. That Pepco's proposal to delete its current Standby Rider, and to create a new "GT-3A-S" tariff that would apply to customers with behind-the-meter generation that runs in parallel with the Company's delivery system, is unreasonable and is rejected. The GT-3A rate is to be set as directed in this Opinion and Order. The Company's D.C. tariffs (Schedule S) shall be clarified to formalize Pepco's current practice vis-à-vis GSA's CHP facility and ensure that a "facilities charge" is not imposed on cogeneration customers that spend their own money to build the interconnection facilities and equipment upgrades needed to support a cogeneration facility. The Company is directed to convene a Working Group to discuss the standby tariff issues in *Formal Case No. 1050*. The Working Group report is due 120 days from the issuance of this Opinion and Order;

vv. That PEPCO's other proposed rate designs for other customer classes (GS, GT including GT-3B, and Metro-RT), generally increasing each rate component within each customer class rate by an "across-the-board" amount to reach the target revenue requirement for that customer class, are reasonable in this case, although in its next rate case Pepco is directed to submit proposed rate designs that move away from volumetric (energy-delivery) rates and toward a greater emphasis on recovery of class revenues through customer and demand charges to collect its "wires only" distribution costs;

ww. That tariff language in Section 2(e) of Pepco's General Terms and Conditions, containing Pepco's general ban on submetering is amended as provided for in this Opinion and Order;

xx. That tariff language for Temporary Service shall be amended, as the parties agree, to incorporate a five-year maximum time limit for serving customers under the T rate, and to eliminate language about "supplemental load"; and

yy. That the separate Commission case (Formal Case No. 1056) examining "smart meter" issues will consider the proper structure of associated voluntary load control programs, how Pepco plans to use the $44.6 million in federal grant money it is receiving for its AMI smart meter programs, and how Pepco can best ensure that consumers are educated to handle the new AMI programs and the coming wave of future technologies.

THEREFORE, IT IS ORDERED THAT:

465. On Pepco's District of Columbia rate base of $1,010,267,000 for the test year, a fair and reasonable rate of return (including capital costs and capital structure) is 8.01 percent;

466. The adjustment that would increase Pepco's test-year revenue to the level of gross revenue requirements computed in accordance with the findings in this Opinion and Order is $19,833,000, which includes a proper allowance for taxes;

467. Pepco is directed to file with the Commission quarterly reports of its weather normalized, jurisdictional earned returns. The reports should cover Pepco's most recent quarter and the year ending in that quarter, and provide both Pepco's earnings on average total capital and Pepco's earnings on average common equity. The reports (including workpapers) shall be filed with the Commission within 60 days following the end of each quarter. The reports shall document Pepco's incremental storm damage costs;

468. The motion of AOBA to exclude Pepco cross examination exhibits 11, 12, and 13, and to correct the transcript to show that these Pepco exhibits were never formally admitted into evidence, is **GRANTED**;

469. The motions of AOBA and the District Government to file their reply briefs one day late, on December 23, 2009, are **GRANTED**;

470. The motions of Pepco and OPC to correct the transcript are **GRANTED**; and

471. PEPCO is directed to file revised rate schedules and supporting exhibits, consistent with this Opinion and Order, no later than March 16, 2010. Rates authorized by this Opinion and Order shall be effective on March 23, 2010, at 12:01 a.m., unless otherwise ordered by the Commission.

A TRUE COPY: **BY DIRECTION OF THE COMMISSION:**

CHIEF CLERK: **DOROTHY WIDEMAN**
COMMISSION SECRETARY

DISTRICT OF COLUMBIA PUBLIC SERVICE COMMISSION

Docket: FC-1076
Schedule 1

Potomac Electric Power Company - District of Columbia Division
Twelve Months Ending December 31, 2008
Revenue Requirements

(in thousands)

Line	Description	PEPCO-DC Adjusted	Adjustments	Adjusted Totals
	(A)	(D)	(C)	(D)
1	**Rate Base**			
2	Electric Plant in Service	$ 2,133,573	$ (635)	$ 2,132,938
3	Accumulated Depreciation	(728,501)	4,011	(724,490)
4	Accumulated Amortization	(6,719)		(6,719)
5	Additions:			
6	Materials and Supplies	20,434		20,434
7	Cash Working Capital	12,194		12,194
8	Prepaid Pension / OPEB Liability (net of tax)	43,618	(9,825)	33,793
9	Pepco Portion of Servco Assets	4,161		4,161
10	Unamortized Credit Facility Costs	143		143
11	Unamortized Customer Education Costs	2,483		2,483
12	Unamortized Blueprint costs	759	121	880
13	Unamortized Case Costs	3,043	(487)	2,556
14	2009 Pension Asset Unamortized Balance	3,164	(3,164)	-
15	Subtractions:			
16	Accumulated Deferred Income Taxes	(448,762)	152	(448,610)
17	Customer Deposits	(19,495)		(19,495)
18	Total Rate Base	$ 1,020,095	$ (9,828)	$ 1,010,267
19	Rate of Return	8.53%		8.01%
20	Return Requirement	$ 87,014	$ (6,092)	$ 80,922
21	**Operating Revenues**			
22	Sale of Electricity	$ 370,575		$ 370,575
23	Other Revenues	2,877		$ 2,877
24	Total Operating Revenues	$ 373,452	$ -	$ 373,452
25	**Operating Expenses**			
26	O&M Expenses	$ 96,211	$ (3,300)	$ 92,911
27	Depreciation	59,009	(8,035)	50,974
28	Amortization	2,332	(2,406)	(74)
29	Taxes Other Than Income	134,199		134,199
30	Total Expenses	$ 291,751	$ (13,741)	$ 278,010
31	Net Operating Income Before Taxes	$ 81,701	$ 13,741	$ 95,442
32	DC Income Taxes	$ 4,395	$ 1,308	$ 5,703
33	Federal Income Taxes	16,340	4,082	20,422
34	Total Income Taxes	$ 20,735	$ 5,390	$ 26,125
35	Adjusted Net Operating Income	$ 60,966	$ 8,351	$ 69,317
36	AFUDC			-
37	**Operating Income for ROR Calculation**	$ 60,966	$ 8,351	$ 69,317
38	**Income Deficiency**	$ 26,048	$ (14,442)	$ 11,606
39	Revenue Multiplier	1.70893		1.70893
40	**Revenue Deficiency**	$ 44,514	$ (24,681)	$ 19,833
41	Revenue Deficiency Percent Change		-55.44%	44.56%

DISTRICT OF COLUMBIA PUBLIC SERVICE COMMISSION

Potomac Electric Power Company - District of Columbia Division
Twelve Months Ending December 31, 2008
Summary of Adjustments to Company's Proposed Test Year
Jurisdictional Rate Base

(in thousands)

Line	Description	Impact to Rate Base	Authorized Rate of Return: Impact on Return Requirement	Authorized Rate of Return: Revenue Requirement Impact
	(A)	(B)	(C)	(D)
1	**Electric Plant In Service**			
2	Retired 69kv Circuits Physically Removed	$ (635)	$ (51)	$ (87)
3	**Accumulated Depreciation**			
4	Change in Depreciation Rates	$ 4,011	$ 321	$ 549
5	**Other Rate Base Items**			
6	Prepaid Pension Asset	$ (9,825)	$ (787)	$ (1,345)
7	Deferred FC1053 Costs	$ (487)	$ (39)	$ (67)
9	Unamortized Balance of Deferred AMI	$ 121	$ 10	$ 17
8	Remove 2009 Pension Regulatory Asset	$ (3,164)	$ (253)	$ (433)
10	**Accumulated Deferred Income Taxes**			
11	Deferred FC1053 Costs	$ 202	$ 16	$ 28
12	Amortization of Deferred AMI Costs	$ (50)	$ (4)	$ (7)
13		$ 152	$ 12	$ 21
14	Total Change to Rate Base	$ (9,828)	$ (787)	$ (1,345)

Notes and Source

Col C:	Computed using Authorized Rate of Return		8.01%	
Col D:	Computed using Revenue Multiplier (See Below)			1.70893
	Revenue Requirement Gross-Up Factor	58.5163%		
	Revenue Multiplier	1.70893	=1/0.585163	

DISTRICT OF COLUMBIA PUBLIC SERVICE COMMISSION

Docket: FC-1076
Schedule 2

Potomac Electric Power Company - District of Columbia Division
Twelve Months Ending December 31, 2008
Summary of Adjustments to Company's Proposed Test Year
Jurisdictional Operating Revenue and Expenses

(In thousands)

Line	Description (A)	O&M Adjustment (B)	District Income Tax (C)	Federal Income Tax (D)	NOI Adjustment (E)	Estimated Revenue Requirement Impact (F)
1	**Expenses**					
2	Pension Expense	$ (3,064)	$ 319	$ 961	$ 1,784	$ (3,049)
3	Wages and Salaries	$ (42)	$ 6	$ 13	23	(40)
4	Reverse 2009 Uncollectible Accounts	$ (150)	$ 15	$ 48	87	(149)
5	Remove PEPCO Employee Club Costs	$ (44)	$ 4	$ 14	26	(44)
6	Interest Synchronization		$ 35	$ 110	(145)	248
7	Total Expenses	$ (3,300)	$ 379	$ 1,146	$ 1,775	$ (3,034)
8	**Depreciation**					
9	Retired 69kv Circuits Physically Removed	$ (13)	$ 1	$ 4	$ 8	$ (13)
10	Change in Depreciation Rates	$ (8,022)	$ 688	$ 2,174	$ 5,160	(8,818)
11	Total Depreciation	$ (8,035)	$ 689	$ 2,178	$ 5,168	$ (8,831)
12	**Amortization**					
13	Amortization of Deferred AMI Costs	$ (243)	$ 24	$ 77	$ 142	$ (242)
14	Remove 2009 Pension Regulatory Asset	$ (2,163)	$ 216	$ 681	$ 1,266	$ (2,163)
15		$ (2,406)	$ 240	$ 758	$ 1,408	$ (2,405)
16	**Tax totals**		$ 1,308	$ 4,082		

Notes and Source
Col F: Computed using Revenue Multiplier (See Below) 1.70893

Revenue Requirement Gross-Up Factor	58.5163%	
Revenue Multiplier	1.70893	=1/0.585163

1076-E-615 AH

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
1333 "H" STREET, N.W., SUITE 200, WEST TOWER
WASHINGTON, D.C. 20005

ORDER ON RECONSIDERATION

June 23, 2010

FORMAL CASE NO. 1076, IN THE MATTER OF THE APPLICATION OF THE POTOMAC ELECTRIC POWER COMPANY FOR AUTHORITY TO INCREASE EXISTING RETAIL RATES AND CHARGES FOR ELECTRIC DISTRIBUTION SERVICE, Order No. 15864

I. INTRODUCTION

1. This matter is before the Public Service Commission of the District of Columbia ("Commission") on petitions for reconsideration of Order No. 15710 filed by the Potomac Electric Power Company ("Pepco" or "Company"), the Office of the People's Counsel ("OPC"), and the District of Columbia Water and Sewer Authority ("WASA"). We grant, in part, and deny in part, Pepco's petition for reconsideration. We deny OPC's and WASA's petitions for reconsideration.

II. BACKGROUND

2. On March 2, 2010, the Commission issued its initial Opinion in this case.[1] In that Order, the Commission approved an increase in Pepco's distribution service rates in the amount of $19.8 million. The Commission allowed an overall rate of return for Pepco of 8.01 percent on a rate base of $1.010 billion.

III. DISCUSSION

3. The purpose of a petition for reconsideration is to identify and correct errors of law or fact in the Commission's initial order.[2] It is not a vehicle for the losing party to rehash arguments previously considered and rejected.[3] If there is substantial

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[1] *Formal Case No. 1076, In the Matter of the Application of the Potomac Electric Power Company for Authority To Increase Existing Retail Rates and Charges for Electric Distribution Service*, Order No. 15710 (March 2, 2010) ("Order No. 15710").

[2] *See* D.C. Code § 34-604(b) (2001).

[3] *See, e.g., GT04-01, In the Matter of the Application of Washington Gas Light Company for Authority to Amend its General Service Provisions*, Order No. 13854, ¶ 5 (January 9, 2006), citing *State of New York v. United States*, 880 F. Supp. 37 (D.C. 1995).

evidence in the record to support the decision of the Commission, that decision is not erroneous simply because there is substantial evidence that could support a contrary conclusion.[4] The Commission, however, may clarify relevant concerns raised by the parties concerning certain findings and conclusions set forth in its initial decision.

A. PEPCO's APPLICATION FOR RECONSIDERATION

4. The Company seeks reconsideration of those parts of Order No. 15710 which, in Pepco's view, improperly: (a) directs Pepco to remove from rate base the costs ($635,000) associated with the removed and retired portion of Pepco's 69 kV emergency overhead feeder lines; (b) authorizes an ROE of 9.625 percent; (c) fails to include the recovery of floatation costs; (d) bases pension costs on a blend of 2008 and 2009 pension cost levels and allegedly failed to reflect the $300 million contribution to the pension plan made in 2009 by Pepco Holdings, Inc. ("PHI"), Pepco's parent company; and (e) requires the filing of quarterly reports within 60 days following the end of each quarter.[5]

1. Retired Overhead 69 kV Emergency Lines

5. Pepco objects to the Commission's exclusion of 25 percent ($635,000) of the District's allocated costs of the 69 kV overhead emergency lines that were removed and retired from service, despite the Commission's acknowledgement that all the costs of these overhead emergency lines were prudently incurred. Pepco argues that this disallowance unfairly penalizes the Company and undermines the Commission's goal of fostering cooperation in emergency situations.[6] According to Pepco it has not been compensated for the risks that these overhead emergency lines would become obsolete,[7] and absent a compelling reason, these prudently incurred costs should be included in rate base. Moreover, the Company maintains that, assuming *arguendo* that the Commission remains convinced that 25 percent of the lines should be considered "retired," the accounting journal entry that will accomplish this retirement has no impact on rate base because it reduces both plant and accumulated depreciation by the same amount. The Company states that its revenue requirement will increase by $71,000 if this correction is made, because rate base is not in fact reduced by "retirement," but depreciation expense is.[8]

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[4] *See, e.g., Washington Gas Light Co. v. PSC*, 856 A.2d 1098, 1104 (D.C. 2004) ("[a]n agency's findings of fact that are supported by substantial evidence will be sustained 'even if there is substantial evidence in the record to support contrary findings.'")

[5] *See Formal Case No. 1076, Application of Potomac Electric Power Company for Reconsideration of Order No. 15710*, filed March 23, 2010 ("Pepco's Application").

[6] *Id.* at 2.

[7] *Id.* at 3.

[8] According to Pepco, the appropriate journal entry for retired plant is to debit accumulated depreciation and credit electric plant in service for the original cost of the retired plant ($635,000). *Id.* at 4, citing Pepco (4C) at 3 (Hook). *See also* Pepco (4C) at 2-3 (Hook).

6. OPC counters that $1 million (not just $635,000) should have been excluded from Pepco's rate base, to account for the portion of the 69 kV overhead emergency lines that has been physically removed, consistent with the testimony of Pepco witness Gausman. OPC argues that Pepco has not identified a legal error in the Commission's order.[9]

7. The Commission reaffirms its decision that all of Pepco's expenditures to construct the emergency overhead 69 kV lines were prudent and in the public interest. Our initial decision determined that Pepco is entitled to full recovery (*i.e.*, recovery of costs plus a rate of return) of the cost of the remaining physically intact portion of those emergency overhead lines, which we indicated should be placed in Pepco's rate base as "emergency capitalized spare."[10] What the parties continue to dispute is what portion of the emergency overhead lines, both assets and original cost, was physically removed and retired, and what ratemaking treatment is appropriate for the removed/retired portion.

8. There is conflicting evidence on how much of the emergency overhead line was physically removed and what the cost was (both absolute and relative) of the removed/retired portion. Testimony by Pepco witness Hook on cross-examination generally deferred to Pepco witness Gausman on the question of how much of the overhead emergency lines had been physically removed.[11] Witness Hook accepted (subject to check) that the total length of these overhead lines was 16,000 feet, of which 4,000 feet was over National Park Service land, so roughly a quarter of the length of the overhead lines has been physically removed and retired.[12] Pepco witness Hook agreed that it was proper to exclude from Pepco's plant in service "the portion that had been physically removed and retired on the company's financial records."[13] She stated that $61,000 was the cost of poles and attachments that were physically removed from the overhead emergency lines, and that other related costs (labor, engineering, and other costs such as overhead) were not included in her $61,000 figure.[14] She did not attempt to reconcile her testimony with the data responses and testimony of Pepco witness Gausman.[15] Pepco witness Gausman testified that he believed the original length of the overhead emergency lines (before any part of it was removed) "was just under 13,000

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9 *Formal Case No. 1076, Opposition of the Office of People's Counsel to the Application of the Potomac Electric Power Company for Reconsideration of Order No. 15710*, filed March 30, 2010 ("OPC's Opposition") at 2-3.

10 Order No. 15710, ¶¶ 22-26, 314.

11 *See* Tr. 1327-1346 (cross-examination of Pepco witness Hook).

12 *See* Tr. 1328-1330, *accord* Tr. 1333–1334, 1342-1343 (Pepco witness Hook).

13 Tr. 1328 (Pepco witness Hook).

14 Tr. 1340-1343 (Pepco witness Hook).

15 Tr. 1345-1346 (Pepco witness Hook).

feet."[16] Mr. Gausman also stated that the National Park Service segment of these overhead lines was approximately 4,600 feet long.[17] Mr. Gausman also stated that, out of the total project costs of roughly $6.2 million for the two overhead emergency lines, "approximately a million dollars" was the cost of the portion that was removed from National Park Service land.[18]

9. Thus, Pepco witness Hook's testimony suggests that roughly a quarter of the length of the overhead emergency lines (4,000 feet out of 16,000 feet) was physically removed and retired. Pepco witness Gausman's testimony suggests that roughly 35 percent of the length of these lines was physically removed and retired (4,600 feet out of 13,000 feet), with the physically retired portion accounting for approximately $1 million in costs out of the total project costs of $6.2 million for building the overhead emergency lines. There seems to be no dispute that the D.C. jurisdictional allocated cost of the overhead emergency lines is approximately $2,541,000. OPC argues that $1 million should be deducted from Pepco's D.C. rate base, relying on Pepco witness Gausman's testimony.[19]

10. The Commission determined that Pepco witness Hook's testimony was more credible and provides substantial evidence to support our determination that 25 percent of the emergency overhead lines was physically removed and retired. Pepco witness Gausman's testimony was vague and inconsistent. Witness Gausman's statements do not explain how 35 percent of the length of the overhead emergency lines, physically removed and retired (4,600 feet out of 13,000 feet) accounts for only 16 percent of the costs ("approximately $1 million" out of the total project costs of $6.2 million). OPC's proposed $1 million reduction from rate base relies on this unclear testimony. Accordingly, we reject OPC's proposed $1 million reduction from rate base, both because Mr. Gausman's testimony does not explain how his $1 million figure corresponds to his 35 percent figure and because it does not properly connect his $1 million figure to District jurisdictionally allocated amounts.[20] Weighing all the evidence, including the credibility of all of the witnesses, the Commission hereby reaffirms its

16 Tr. 1421-1422 (Pepco witness Gausman).

17 OPC Cross-Examination Exhibit 100 (originally numbered as OPC Cross-Examination Exhibit 68).

18 Tr. 1344 (Pepco witness Hook, cross-examined about statements made by Pepco witness Gausman); OPC Cross-Examination Exhibits 98, 99 (originally numbered as OPC Cross-Examination Exhibits 66, 67).

19 *See* discussion *supra* ¶ 6.

20 Were we to accept OPC's $1 million figure for the cost of the removed/retired portion of the emergency overhead lines, based on Pepco witness Gausman's data responses (*see* Tr. 1344), we also would have to accept witness Gausman's $6.2 million figure for the total project cost (*see* Tr. 1344), meaning that some 16 percent of the overhead emergency lines were physically removed and retired. This would result in a rate base reduction of $406,560, which is 16 percent of the D.C. jurisdictional amount of $2,541,000. This outcome would be a worse result for ratepayers than the Commission's initial decision making a 25 percent ($635,000) rate base reduction to account for the removed/retired portion of the lines.

finding that a 25 percent figure for the removed/retired portion of the overhead lines is fair, just, and reasonable, and is supported by substantial evidence.[21]

11. The Commission has reviewed our original decision which reflected our concern that Pepco's rate base includes assets that had in fact been physically removed and retired, and therefore were no longer "used and useful." We find, based on the record, that, for ratemaking purposes, roughly 25 percent (4,000 feet out of 16,000 feet) or $635,000 of the $2,541,000 D.C. jurisdictionally-allocated cost of the emergency lines should be retired on Pepco's books. The ordinary, straightforward treatment of retired plant should be applied to the 25 percent ($635,000) of the overhead emergency lines that have been physically removed and retired. This normal retirement of an asset does not impact rate base, since the retirement is offset in the depreciation reserve and, therefore, net plant does not change.

12. As Pepco indicates, 25 percent of the emergency overhead lines ($635,000) was removed and retired before these retired assets reached the end of their useful life. However, early retirement commonly arises for utilities, since for a variety of reasons (e.g., an event such as an accident causing early retirement/replacement) utility assets may not live out their full service life. By the same token, some assets live on well past their average service life and continue to be depreciated and included in rate base because they are used and useful. When this happens, the utility commonly takes the early retirement through the depreciation reserve into account in calculating the average service life of all utility plant assets for purposes of calculating new depreciation rates.[22] Pepco would have the potential to recover the depreciation of this removed/retired portion through averaging the service life of all of its utility plant (including the early-retired 25 percent portion of the overhead 69kV emergency lines) for purposes of calculating future depreciation rates. Pepco would lose some depreciation expense in the short run, but this would be taken into consideration, along with all other changes to the depreciation reserve, when the next Company's depreciation study is performed.

13. The Commission recognizes the fact, however, that Pepco manifestly acted in the public interest in constructing the overhead emergency 69kV lines. Without the installation of these 69kV lines, on an emergency basis, service reliability could have been negatively impacted in the District of Columbia. The Company should be encouraged, not discouraged, from taking such emergency actions. Accordingly, the Commission will exercise its broad discretion, in the public interest, to allow Pepco to

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21 *See, e.g., District of Columbia v. Public Ser. Comm'n*, 807 A.2d 373, 381 (D.C. 2002), citing *United Union, Inc. v. District of Columbia Bd. of Zoning Adjustment*, 554 A.2d 313, 315-316 (D.C. 1989) ("an agency as a finder of fact may credit the evidence upon which it relies to the detriment of conflicting evidence").

22 Utilities use average service life depreciation to depreciate assets, which takes into account the early retirement of assets in calculating the average service life of assets. It recognizes that some assets live beyond their average service life, while others do not. Therefore, some assets are depreciated more and others less. A true-up occurs when a company performs depreciation studies and changes its depreciation rates (either up or down) going forward to reflect the changes that have occurred in recognizing and recovering the costs-associated with depreciable assets.

retire a total of $635,000 under the ordinary rules for retired assets, where rate base does not change.

2. Pepco's Authorized ROE of 9.625 Percent

14. The Company argues that its authorized "return on equity" ("ROE") of 9.625 percent does not meet the standards in *Federal Power Commission v. Hope*[23] and *Bluefield Water Works & Improvement v. Pub. Serv. Comm'n*,[24] which Pepco contends requires a ROE that is equivalent or comparable to return on investments in other enterprises having similar risks.[25] Pepco argues that no witness had the opportunity to address the legality of the 9.625 percent ROE.[26] Pepco maintains that its authorized ROE at a minimum should be within the range allowed for most other utilities.[27]

15. Pepco claims that a 9.625 percent ROE is lower than the authorized ROEs for 131 of the 138 electric and gas utilities listed in Washington Metropolitan Area Transit Authority ("WMATA") witness Foster's testimony and every electric and gas utility included in the Apartment and Office Building Association of Metropolitan Washington ("AOBA") witness Oliver's comparable groups.[28] Pepco asserts that the Commission could not reasonably conclude that Pepco's risk is lower than that of many other utilities, given that unbundled transmission and distribution companies are by no means rare in the industry.[29] Pepco further contends that the ROE adjustment associated with Pepco's Bill Stabilization Adjustment ("BSA") decoupling mechanism does not support an allowed ROE near the bottom of the industry. Pepco asserts that decoupling mechanisms are becoming common. Pepco identifies 12 companies that either have a decoupling mechanism in place or pending.[30] Moreover, Pepco argues that OPC witness Woolridge, who advocated the lowest ROE of all the cost of capital experts in this case, suggested an ROE adjustment of only 25 basis points.[31]

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23 *Federal Power Commission v. Hope*, 320 U.S. 591 (1944) (a utility's return on equity should be commensurate with returns on investments in other enterprises having corresponding risks).

24 *Bluefield Water Works & Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679 (1923) ("The return [on equity] should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise money necessary to discharge its public duties.")

25 Pepco's Application at 4-6.

26 *Id.* at 5.

27 *Id.* at 6.

28 *Id.* at 5.

29 *Id.* at 6.

30 *Id.*, citing Pepco (3B) at 86 (Morin).

31 *Id.*

16. OPC contends that the Commission's authorized ROE of 10.125 percent, without the BSA, is within the zone of reasonableness of 10 percent to 10.25 percent;[32] the ultimate 9.625 percent figure reflects a 50 basis points reduction for the BSA.[33] OPC argues that, contrary to Pepco's assertions, the zone of reasonableness was consistent with the parties' recommendations. OPC argues that the Commission's ruling on ROE is supported by the record and consistent with the Commission's statutory authority.[34]

17. The Commission arrived at 9.625 percent in a two-step process. Based on the particular underlying assumptions and the methodology used, the parties' estimates for the appropriate ROE for Pepco varied from 9.50 percent to 10.75 percent (with Pepco arguing for a 10.75 percent ROE). We carefully evaluated the testimony of each ROE witness and the strengths and deficiencies in their respective analyses.[35] Based on our view of the relative risk of Pepco's distribution operations, our informed determination was that the zone of reasonableness for Pepco's ROE was between 10.00 percent and 10.25 percent (without the BSA), with 10.125 percent being the midpoint.[36] The Commission then adjusted the ROE downward by 50 basis points to reflect the BSA.[37]

18. We must reject Pepco's attempt to support a higher ROE with comparables that do not reflect "corresponding risks" nor include an adjustment for a BSA.[38] Pepco claims that, inasmuch as the authorized return of 9.625 percent differs from the parties' recommendation, no witness had occasion to address its legality directly. However, this is insignificant since the record reflects that the Company,[39]

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32 OPC's Opposition at 4-5.

33 *Id.* at 5 n. 20.

34 *Id.* at 4-5, citing *Washington Gas Light Co. v. Public Serv. Comm'n.*, 450 A.2d 1187, 1209-1210 (D.C. 1982) (citation omitted) ("[T]he Commission [is given] authority to formulate its own standards and to exercise its ratemaking function free from judicial interference, provided the rates fall with a zone of reasonableness which assures that the Commission is safeguarding the public interest -- that is, the interests of both investors and consumers.")

35 "The Commission properly may give more credence to certain evidence than it does to other evidence which it deems less reliable." *Washington Gas Light Co., supra* 450 A.2d at 1213.

36 Order No. 15710, ¶ 72.

37 *See id.* ¶¶ 70-76.

38 *See* WMATA Br. 3-6 (WMATA witness Foster recommended a 10.0 percent ROE, before consideration of the BSA, on the ground that Pepco had less business risk than the average electric utility) and Pepco (3B) at 88 (Pepco witness Morin criticizes WMATA witness Foster's testimony); AOBA (A) at 27, 29 (AOBA witness Oliver recommends an ROE no greater than 9.9 percent including floatation costs) and Pepco (3B) at 72, 73, 75 (Pepco witness Morin criticizes AOBA witness Oliver's testimony).

39 The impact of the BSA, according to Pepco witness Morin, is that ROE should be reduced by 25 basis points. According to Dr. Morin, 25 basis points was a conservative estimate based on his analysis which showed a range of 20 to 40 basis points. Pepco (3B) at 69-71 (Morin).

OPC,[40] AOBA,[41] and WMATA[42] all testified as to what each thought the appropriate ROE should be if a BSA were implemented. Pepco's testimony replicated the same proffer which we rejected on its comparables submitted in Formal Case No. 1053; namely, it included companies with greater risk than the risk associated with the Company's distribution activities due to the comparables' greater generation and unregulated operations.[43] Further, we concluded that the 12 companies that have decoupling mechanisms in place or pending, allegedly with higher ROEs, were not comparable to Pepco. The Company did not demonstrate how the "mechanisms in those jurisdictions are comparable to Pepco's BSA or that the overall focus and concerns in those proceedings were similar to those of this Commission."[44] Pepco has failed to articulate any basis that would warrant reconsideration of our ROE determination.

3. Floatation Costs

19. The Company argues that the Commission failed to include $807,000 (a $1.38 million increase in its revenue requirement) for floatation costs as an expense item in establishing Pepco's revenue requirement. Pepco states that $807,000 reflects its share of the costs actually incurred by Pepco Holdings, Inc. ("PHI") in its November 2008 issuance of common stock.[45] OPC recommends that the costs be amortized over at least a three-year period because these are not costs that occur annually.[46]

20. Our review of this issue substantiates Pepco's claim. Pepco's revenue requirement determination should include a flotation cost expense, consistent with the Commission's policy to treat floatation costs as a cost of service item.[47] However, Pepco's floatation costs are to be amortized over a two-year period, consistent with PHI's

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40 OPC adopted the 50 basis point reduction authorized in Formal Case No. 1053. Tr. 865-866.

41 AOBA recommended a 50 basis point reduction. AOBA (A) at 29-30 (Oliver).

42 WMATA recommended a 50 basis point reduction based on the Commission's decision in Formal Case No. 1053. WMATA (A) at 12-13 (Foster).

43 *See* Order No. 15710, ¶ 72.

44 Order No. 15710, ¶ 110.

45 Pepco's Application at 7-8, citing Pepco (C) at 25 (Hook) and Pepco (C)-8 (Hook).

46 OPC Opposition at 7.

47 Order No. 15710, ¶ 72. *See Formal Case No. 1053, In the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*, ("*Formal Case No. 1053*") Order No. 14712 (January 30, 2008); *Formal Case No. 889, In re Potomac Electric Power Co.*, Order No. 9509 (July 24, 1990); *Formal Case No. 869, In re Potomac Electric Power Co.*, Order No. 9216 (March 3, 1989).

record of common stock issuance in recent years.[48] OPC provides no basis for its recommended three-year amortization period. Further, the average unamortized balance of floatation costs should be included in rate base.[49] Pepco is directed to file a revised compliance filing which reflects these changes within seven (7) days from the date of this Order.

4. Pension Costs

21. Pepco argues that the Commission erred in failing to consider PHI's 2009 $300 million contribution to the Company's pension plan, which was reflected in Pepco's projected 2009-2011 levels of pension expense.[50] Although PHI's overall projected pension expense is expected to decline from $95.253 million in 2009 to $74.257 million in 2010 and $69.100 million in 2011, Pepco insists that these declines do not support the use of an average of 2008 and 2009 pension expenses in setting rates.[51] Pepco argues that, if the Commission believes that pension expenses were abnormally high in 2009, then an average of 2009 and 2010 projected pension costs (or even the projected 2010 level) would be a more equitable basis on which to set future rates. According to Pepco, its pension expense should decline from $25.196 million in 2009 to $19.64 million in 2010, with the average being $22.418 million.[52] Pepco states that the adoption of a 2009-2010 pension expense average would increase Pepco's revenue requirement by $2.03 million.[53] OPC contends that Pepco did not meet its burden of proof regarding its proposed pension rates and is simply rehashing evidence that was considered and rejected by the Commission.[54]

22. The Commission reaffirms its initial decision regarding Pepco's pension costs.[55] We reviewed the study by Watson Wyatt, which did include PHI's $300 million cash contribution in 2009 in developing its projections for Pepco's pension expense.[56] Our initial decision misstated Pepco's treatment of the $300 million contribution in 2009, but a fair consideration of that cash contribution does not change our decision. As Pepco acknowledged, PHI's cash contribution "reduced pension expense in 2009 and will

48 *See* Pepco Compliance Filing § 205.11, Attachment C.

49 *Formal Case No. 989, In re Washington Gas Co.*, Order No. 12589 (October 29, 2002).

50 Pepco's Application at 9.

51 *Id.*

52 *Id.*

53 *Id.* at 10.

54 OPC Opposition at 6.

55 Order No. 15710, ¶ 154.

56 *See* OPC (A)-2 (Ramas).

continue to do so in 2010."[57] Using only the 2009 amount would significantly overstate Pepco's expense during the rate-effective period. Therefore, we again reject Pepco's request to base future pension expense on the 2009 amount. The Company's proposed alternative to use either 2010 or the average of 2009 and 2010 is similarly inappropriate. The 2010 pension expense proposed by the Company is a projection derived using a number of assumptions that may or may not be realized. The 2010 pension expense is based upon a forecasted discount rate of 6.50 percent, an annual return on plan assets of 8.50 percent, and PHI funding of $200 million in 2010. Watson Wyatt stated that "this represents just one among many possible strategies."[58] We remain convinced that the Commission's decision, based on a two-year average of actual pension costs (in 2008 and 2009) better recognizes the Company's high pension expense in 2009 and that 2009 was an unusually bad year, while providing the Company an opportunity for a fair return going forward.

5. Quarterly Reports

23. In Order No. 15710, the Commission directed Pepco to file quarterly reports of its weather normalized, jurisdictional earned returns, and its incremental storm damage costs within 60 days following the end of each quarter.[59] Pepco asks the Commission to revise the due date to 30 days consistent with what the Commission ordered in Formal Case No. 1053.[60]

24. We grant Pepco's request. Pepco shall make these filings on a quarterly basis, within 30 days after the filing of its FERC data for the relevant time period.

B. OPC's PETITION FOR RECONSIDERATION

25. OPC seeks reconsideration of those parts of Order No. 15710 which: (a) refuses to consider the reliability of Pepco's distribution service in this rate case; (b) rejects OPC's proposal for a consolidated tax adjustment ("CTA") that would distribute to Pepco a portion of the tax savings realized by PHI from Pepco's participation in PHI's consolidated tax returns; (c) fails to require Pepco to exclude $1 million from rate base to reflect the costs of the 69 kV overhead emergency lines that were taken out of service (previously discussed at paragraphs five (5) through 13, where the Commission's decision on this issue is set forth); (d) allegedly fails to consider the impact of changes in Pepco's employee health and welfare costs; and (e) addresses Pepco's uncollectible expenses.[61] OPC also asks the Commission to clarify its order to ensure that Pepco's

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57 Pepco Br. 31.

58 OPC (A)-22 at 4 of 6 (Ramas).

59 Order No. 15710, ¶ 467.

60 Pepco's Application at 10; *see also Formal Case No. 1053*, Order No. 14796, ¶ 5 (April 28, 2008).

61 *Formal Case No. 1076, Application of the Office of the People's Counsel for Reconsideration of Commission Order No. 15710*, filed April 1, 2010 ("OPC's Application").

Ratemaking Adjustment No. 6 (exclusion of industry contributions and membership dues) has been properly implemented.[62]

1. Quality of Pepco's Service

26. OPC argues that the Commission erred in refusing to hear two additional issues in this rate case related to the reliability of Pepco's service.[63] OPC claims that it submitted testimony criticizing Pepco's reliability performance as "poor" and cited that as a reason for recommending a return on equity (9.50 percent) lower than it otherwise recommended (9.75 percent).[64] The Commission denied Pepco's motion to strike this OPC testimony and ultimately ruled that because "the Commission has deferred the issue of the reliability of service to another docket, it would not be appropriate to adjust the Company's ROE for reasons of poor performance when reliability is not an issue for determination in this proceeding."[65] OPC argues that none of the Commission's other case dockets considers the effect of Pepco's poor service quality on Pepco's rates and that the Commission's own opinion suggests that Pepco's quality of service is relevant to Pepco's rates and, therefore, that the Commission is compelled to consider quality of service issues in this case.[66]

27. Although OPC acknowledges the Commission's discretionary authority to manage its docket, OPC argues that the Commission's refusal to consider the quality of Pepco's service violates its non-discretionary statutory obligation to ensure, in this rate case, that Pepco furnishes "service and facilities" that are "reasonably safe and adequate and in all respects just and reasonable."[67]

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62 OPC's Application at 4.

63 *Id.* at 11, noting Order No. 15322, ¶ 8 (July 10, 2009). OPC's two rejected issues were:

Issue 1: "Are Pepco's proposed additions to rate base sufficient to improve the reliability of any facilities, e.g., feeders that have been problematic in recent years?"

Issue 4: "Are the reliability and quality of distribution service provided by Pepco safe, adequate and in all respects just and reasonable?"

64 OPC claims that it submitted "substantial evidence" showing that Pepco's service was not "reasonably safe and adequate." OPC's Application at 16, 19.

65 *Id.* at 11-12, citing Order No. 15710, ¶ 73.

66 *Id.* at 17.

67 *Id.* at 10, citing D.C. Code § 1-204.93; OPC's application at 11, 13-15, citing *DC Transit System, Inc. v. Washington Metropolitan Area Transit Comm'n*, 466 F.2d 394, 408, 419-420 (D.C. Cir. 1972) ("It has long been recognized that the caliber of a utility's service need not remain a neutral factor in determinations as to its allowable return. The cases have consistently said that superior service commands a higher rate of return as a reward for management efficiency; more importantly for present purposes, they have also maintained that inefficiency and inferior service deserve less return than normally would be forthcoming.")

28. Opposing OPC, Pepco argues that the Commission reasonably decided to consider reliability issues in other dockets.[68] According to Pepco, OPC overlooks the evidence in the record showing that the Company is in compliance with all current service quality benchmarks.[69] Pepco argues further that there is no statutory obligation for the Commission to address, in the same rate case, both service quality issues and the justness and reasonableness of utility rates. While the Commission *may* consider management efficiency issues in a utility rate case, Pepco argues that this is not *required* and that none of the cases cited by OPC holds otherwise.[70] Pepco notes the Courts have consistently rejected efforts to saddle agencies with procedural duties not found in a statute or the Constitution.[71] Pepco argues these court cases support the Commission's discretion to consider service quality issues separately from rate reasonableness issues.[72]

29. Traditionally, as noted in our prehearing order,[73] the Commission designates some proposed issues while rejecting others on grounds of law or policy, or on other grounds, including whether it would be more appropriate to consider an issue in another docket.[74] "Without this essential power to limit the issues, the Commission would have to 'reinvent the wheel' in every case and its complex general rate cases

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68 *Formal Case No. 1076, Opposition of Potomac Electric Power Company to Application of the Office of People's Counsel for Reconsideration of Order No. 15710,* filed April 7, 2010 ("Pepco's Opposition").

69 *Id.* at 2, citing Pepco (3D) at 3, 10-11 (Gausman).

70 *Id.* at 3, distinguishing *DC Transit System v. Washington Metropolitan Area Transit Comm'n*, 466 F.2d 394, 422 (D.C. Cir.), cert. denied, 409 U.S. 1086 (1972) (court states that "the caliber of a utility's service *need not*"– not must not – "remain a neutral factor in determinations as to its allowable rate of return").

71 *Id.* at 4, citing *SEC v. Chenery Corp.*, 332 U.S. 194 (1947), *Washington Urban League v. PSC*, 295 A.2d 906, 908 (D.C. 1972), and *San Antonio v. CAB*, 374 F.2d 326, 339 (D.C. Cir. 1967).

72 *Id.* at 4, citing *Western Coal Traffic League v. United States*, 677 F.2d 915, 927 (D.C. Cir.), cert. denied, 459 U.S. 1086 (1982) (court upholds the ICC's discretion to consider rate and productivity issues in separate proceedings, even though the two are interrelated).

73 Order No. 15322, ¶ 5 (July 10, 2009).

74 The Commission has wide discretion to manage its own case dockets, and to choose the procedures that are best suited for examining the issues before it. *See, e.g., FCC v. Pottsville Broadcasting*, 309 U.S. 134, 142-143 (1940) (opinion states that agencies have reasonable power "to control the range of investigation" and "should be free to fashion their own rules of procedure and to pursue methods of inquiry capable of permitting them to discharge their multitudinous duties"); *Ammerman v. DC Rental Accommodations Comm'n*, 375 A.2d 1060, 1063 (D.C. 1977) ("No principle of administrative law is more firmly established than that of agency control of its own calendar." "Agencies must be, and are, given discretion in the procedural decisions made in carrying out their statutory mandate."). *Cf. Vermont Yankee Nuclear Power Corp. v. NRDC*, 435 U.S. 519, 543-545 (1978) (absent constitutional constraints, administrative agencies "should be free to fashion their own rules of procedure and to pursue methods of inquiry capable of permitting them to discharge their multitudinous duties").

would become 'an intractable morass, without any corresponding benefit.'"[75] The D.C. Court of Appeals has recognized the importance of these principles and affirmed this Commission's reasonable discretion to limit the issues to be considered in a particular rate case.[76]

30. The Commission declined to address OPC's "reliability" issues, as originally proposed at the outset of this case[77] because OPC's proposed issues "address general reliability issues and electric quality of service standards ("EQSS") that the Commission is assessing in Formal Case Nos. 766, 982 and 1002, among others."[78] These other case dockets involve, among other things, the further development and refinement of EQSS standards, as well as procedures for assessing them. Given the pendency of several other Commission cases that are examining general reliability issues and further developing EQSS standards and procedures for assessing them, the Commission properly declined to designate OPC's general "reliability" issues for consideration in this Pepco rate case.[79]

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75 *Formal Case No. 989, Washington Gas Light Co.*, Order No. 12379 (April 12, 2002), 2002 WL 1277794 at n.34 (Commission rejects a proposed issue for consideration in a WGL rate case and transfers the issue, instead, to be considered in another Commission case docket).

76 *See, e.g., District of Columbia v. PSC*, 802 A.2d 373, 378 (D.C. 2002) (upholding the Commission's decision to approve a settlement without exploring all the issues presented in an earlier "issues list"). The Court of Appeals' opinion states that "[c]onsolidation, scope of the inquiry, and similar questions are housekeeping details addressed to the discretion of the agency and, due process or statutory considerations aside, are no concern of the courts * * * *see also American Iron & Steel Inst. v. OSHA*, 182 F.3d 1261, 1268 (11th Cir. 1999) ("Logic dictates that an agency must have some discretion in setting an agenda for rule-making and excluding some matters categorically."); *Cutler v. Hayes*, 818 F.2d 879, 896 (D.C. Cir. 1987) ("An agency has broad discretion to set its agenda and to first apply its limited resources to the regulatory tasks it deems most pressing.").

77 OPC's characterization of its proposed "reliability"/"service quality" issues has shifted significantly over the course of this case. At the outset of this case, OPC argued "that because Pepco is requesting $15.8 million for reliability improvement projects, the costs are at issue and the Commission needs to be certain that the requested amount is going to fix the problems that exist in the District of Columbia." Order No. 15322 at 4, ¶ 8 (July 10, 2009), citing Tr. 34-35 of the Prehearing Conference. *Accord* OPC's proposed issues 1 and 4. OPC's petition for rehearing at the end of this case takes an entirely different approach, based (with 20-20 hindsight) on the consumer complaints that emerged during the public hearings in Formal Case No. 1076, and the Commission's conclusion that "given these widespread complaints from the public about the quality of Pepco's service, service quality issues could be ripe for consideration in Pepco's next rate case." Order No. 15710, ¶ 448. OPC now suggests that its proposed issues were always aimed at reducing Pepco's ROE in Formal Case No. 1076 as a penalty for poor quality Pepco service. However, OPC's claim does not square with the record.

78 Order No. 15322, ¶ 8 (July 10, 2009).

79 OPC and Pepco went ahead and submitted some evidence on OPC's excluded issues. We agree with Pepco that OPC did not establish, by "substantial evidence" or otherwise, its criticisms of Pepco's reliability. *See, e.g., Portia Golding-Alleyne v. DC Department of Employment Serv.*, 980 A.2d 1209 (D.C. 2009) ("substantial evidence" entails a fair characterization of the whole record, not just parts of it).

31. In the course of the community hearings held later in this case, we received a number of consumer complaints about power outages, delays in fixing them, and other claimed shortcomings in Pepco's customer service. The Commission ruled that:

> given these widespread complaints from the public about the quality of Pepco's service, service quality issues could be ripe for consideration in Pepco's next rate case. The Commission will review Pepco's plans to address outages, reliability and improved service throughout the City. We should be aided in this task by the fact that we have already adopted electric quality of service standards, and we are now receiving monthly outage reports from Pepco.[80]

The Commission's initial decision on this matter indicates that (as compared with OPC's proposed issues) it is a significantly different, more focused set of "reliability/service quality" issues that the Commission may consider in Pepco's next rate case. The progress made in other Commission case dockets, in further developing EQSS standards and in requiring outage reports from Pepco, for example, may assist us in conducting a more focused examination of "service quality" issues in Pepco's next rate case.[81] Presumably, if such "service quality" issues are presented in Pepco's next rate case, the issues will be crafted to indicate from the beginning how they might impact Pepco's rates. We affirm our initial decision that OPC's "reliability" issues were properly excluded from consideration in this case.

2. Consolidated Tax Return ("CTA")

32. OPC claims that the Commission erred in rejecting its proposed CTA and failing to adequately explain its decision. While acknowledging that its proposed CTA might entail a $179.2 million adjustment to Pepco's rate base, OPC dismisses the Commission's concern that such a large adjustment might destabilize Pepco's financial condition as "unsupported speculation."[82]

33. In opposition, Pepco argues that the Commission properly found that "[g]iven the record before us, the Commission has decided to adhere to our traditional

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80 Order No. 15710, ¶ 448.

81 Whenever a utility rate case arises, there are always a great many potential issues involving various aspects of a utility's on-going operations that could be designated for examination by the Commission in that case. The Commission is not compelled to consider a proposed issue in a utility rate case, however, simply because it is arguably relevant to a utility's rates. It is an important discretionary policy judgment for the Commission to be able to determine whether standards are in place to assess a proposed issue like "reliability," whether the issue is sufficiently well defined and ripe for Commission review, and in what docket or proceeding the issue is most appropriately considered.

82 OPC's Application at 20-21.

approach regarding federal and district tax expense, which is widely followed by the majority of Commissions throughout the country."[83] This statement alone met the Commission's obligation to explain the basis for its decision, Pepco argues, since the Commission "is not required to rehash its reasons for adopting basic policies."[84] The Commission went further, Pepco notes, identifying several specific reasons for rejecting OPC's position, and stating that it was particularly persuaded by the sound tax and accounting arguments made by Pepco witness Warren which were reflected in the Minnesota and New Mexico Commission decisions cited by Pepco.[85] The Commission also cited a 2009 accounting textbook which strongly argues against CTAs.[86] In the face of this record evidence, Pepco argues that it is absurd for OPC to claim that the Commission did not adequately explain the bases for its decision.[87]

34. Two independent grounds support the Commission's decision to adhere to the traditional "stand-alone" approach to federal and District tax expense. ***First,*** the overwhelming weight of the evidence and authority in this record supports the stand-alone policy approach to setting Pepco's rates. ***Second,*** OPC's particular CTA proposal is flawed, and unsuitable for adoption, because OPC did not adequately explain its viability or how it would work in practice. While OPC stated that its proposal[88] was modeled after the CTA system in New Jersey, in fact it was significantly different from the CTA system in place in New Jersey.[89] OPC failed to meet its burden in justifying a switch away from our traditional, long-standing, recently reaffirmed policy that "a stand-alone approach is the most reasonable method of setting rates."[90]

35. The Commission's decision to adhere to the "stand alone" policy is consistent with, and supported by, prior Commission precedents, as well as the settled

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83 Pepco's Opposition at 5.

84 *Id.*, citing *Washington Gas Light Co. v. Public Serv. Comm'n*, 450 A.2d 1187, 1200 n.15 (D.C. 1982), and *DC Tel. Answering Comm. v. PSC*, 476 F.2d 1113, 1125 (D.C. Cir. 1984).

85 Pepco's Opposition at 5-6.

86 *Id.*

87 *Id.*

88 OPC appeared to modify its CTA proposal in the middle of the case, while its key witness was on the stand. *See* Order No. 15710, ¶263, noting Tr. 986-988, 992 (OPC witness Bright modifies OPC's CTA proposal by suggesting that a 50/50 split of benefits might be appropriate, between the unregulated loss companies (on the one hand) and Pepco and its ratepayers (on the other hand)).

89 *See* Order No. 15710, ¶ 276.

90 Order No. 15710 ¶ 255, quoting *Formal Case No. 1053*, Order No. 14712 ¶ 240 (January 30, 2008). *See, e.g., Formal Case No. 869,* Order No. 9216, 10 D.C.P.S.C. 22, 133 (1989) (burden is on the party seeking to change an earlier-approved Commission methodology); *Formal Case No. 813,* Order No. 8127, 5 DC PSC 259, 260-270 (1984) (same); *Formal Case No. 785,* Order No. 7716, 3 DC PSC 450, 528, 50 PUR 4th 500 (1982) (same).

ratemaking practices, policies and reasoning of the FERC, the Maryland Commission, and the overwhelming majority of other state commissions.[91] In sum, "[a]s was the case in Formal Case No. 1053, the Company proffers a more sound policy argument in favor of maintaining the stand-alone approach."[92] We affirm our initial decision.

3. Health and Welfare Costs

36. OPC claims that the Commission failed to address the effect of the changes and revisions Pepco made to its medical, dental, and vision plans that went into effect in 2009. OPC contends that these changes – increasing employee co-pay amounts, deductibles, and out-of-pocket contributions – will mitigate cost increases and lower future overall plan costs.[93]

37. Pepco counters that "the Commission squarely addressed this claim when it held that '[t]he actual 2009 employee health and welfare benefit costs support the accuracy of the Company's forecast. The costs are known and measurable."[94] Moreover, Pepco notes that OPC witness Ramas acknowledged that the forecast was accurate. Pepco argues that, in fact, the plans' costs were almost exactly as forecasted by the Company, which refutes OPC's claim.[95]

38. The Commission reaffirms its initial decision on employee health and welfare costs.[96] OPC's challenge was refuted by Pepco's evidence. The survey used by Pepco to estimate its employee benefits costs was 99 percent accurate based on annualized data reflecting eight (8) months of actual 2009 experience.[97] As noted by Pepco, OPC witness Ramas agreed that the information was 99 percent accurate and that

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91 Order No. 15710 reviews these supporting precedents at pp.88-93. *See, e.g., Formal Case No. 1053*, Order No. 14712, ¶ 240 (January 30, 2008) (Commission approves its "long-standing position that a stand-alone approach is the most reasonable method of setting rates"); *Formal Case No. 929*, Order No. 10423 at 55 (1994) (Commission decides to "continue to calculate Pepco's tax liability on a stand-alone basis ... [which is] the most accurate cost-of-service with respect to Pepco's tax liability on utility operations"); *Formal Case No. 912*, Order No. 10044 § I.3 (1992) (Commission rejects CTAs proposed by OPC, the District Government and WMATA as "vague" and "highly speculative"); *Columbia Gulf Transmission Co.*, 23 FERC ¶ 61,396 (1983); *In re Delmarva Power & Light*, Md. Case No. 9192, Order No. 83085 at 20-23 (December 30, 2009).

92 Order No. 15710, ¶ 277.

93 OPC's Application at 26.

94 Pepco's Opposition at 8, citing Order No. 15710, ¶ 168.

95 *Id.* at 8-9.

96 *See* Order No. 15710, ¶ 168.

97 Pepco (4C) at 32-33 (Hook); *see also In re Potomac Electric Power Co., Formal Case No. 889*, Order 9509, 11 D.C.P.S.C. 302 (1991) (Commission finds it appropriate to rely on annualization of post-test year increases in the costs of Pepco's employee benefits).

she had no information to refute the accuracy of the numbers.[98] The specific changes to Pepco's benefit plans, which OPC mentions, were known and measurable changes that went into effect in 2009. They were reflected in the Company's 2009 actual experience that was included in the outside expert's survey. OPC is attempting to rehash arguments and evidence that we have already considered. There is substantial evidence in the record to support our decision, and the decision is fully explained. We see no reason to disturb it.

4. Uncollectible Expenses

39. OPC claims that the Commission overlooked several flaws in the methodology Pepco used to calculate its uncollectible expense adjustment.[99] According to OPC, Pepco's methodology (a) is based on unsupported allocations of bad debt expense that penalize D.C. distribution customers for the higher bad debt rate of Pepco's other operations; (b) incorporates the Company's adjustments to its bad debt reserve (which are not specific to distribution service), rather than basing the expense on net write-offs of uncollectible accounts (which are specific to distribution service); and (c) fails to normalize the Company's uncollectible expense to account for annual fluctuations in uncollectible expense.[100] OPC contends that, with these errors corrected, Pepco would be entitled to only $1.2 million in uncollectible expense, $2.16 million less than the amount the Company proposed.[101]

40. Pepco responds that OPC's objections are rendered moot by the Commission's decision.[102] Pepco contends that the Commission did take specific note of OPC's objections, but it did not completely accept those objections.[103] Pepco argues that OPC's evidence lacks credibility, because OPC's proposed uncollectible amount of $1.28 million is less than one-half of the Company's actual uncollectible write-offs in 2009.[104]

41. The Commission relied upon actual results (from 2008 and 2009), not Pepco's proposed 2009 budgeted figures, to set Pepco's allowance for uncollectible expense. Although OPC obviously disagrees with our decision, it has not persuaded us that the decision is based on some clear error of law or fact. With respect to OPC's first claim, concerning the appropriate jurisdictional allocation of Pepco's bad debt expense, the Commission finds that the distribution portion of Pepco's uncollectible expense was

98 Tr. 901-902.

99 OPC's Application at 27.

100 *Id.* at 27-28.

101 *Id.* at 30.

102 Pepco's Opposition at 9.

103 *Id.*, citing Order No. 15710, ¶¶ 128-129, 132-133.

104 *Id.* at 9-10.

properly allocated jurisdictionally based on the actual jurisdictional split Pepco experienced in calendar year 2008.[105] The Company further supported its jurisdictional allocation by comparing its 2009 budgeted Bad Debt expense to its actual experience in the District of Columbia and Maryland.[106] In short, the Company's actual experience provided a reasonable estimate of the 2009 level of D.C. distribution uncollectible expense.[107]

42. As to OPC's bad debt reserve argument, the Company explained that, in accordance with Generally Accepted Accounting Principles, the balance in its Reserve for Uncollectibles account, which is an offset on the balance sheet to Accounts Receivable, must be adequate to cover the receivables that the Company is unlikely to collect. On a monthly basis, as revenue is billed, the reserve balance is increased by an accrual for bad debt expense, and decreased by amounts actually written off. On a quarterly basis, Pepco adjusts the reserve balance to ensure that it continues to cover the accounts receivable that ultimately will be written off. This system ensures consistency between revenues currently reported as income, the balance sheet offset for the portion of those revenues that ultimately will be written off, and the amounts recorded as bad debt.[108]

43. The Commission agreed with Pepco that the quarterly reserve is an important component of an adequate uncollectible reserve. The Company includes the reserve adjustment in determining the bad debt ratio from which it derives its annual bad debt expense accrual. OPC disregards the impact of these reserve adjustments, and uses only the actual write-offs of collections in determining the bad debt ratio from which the annual bad debt expense is estimated.[109] We reaffirm our finding that the Company's method is reasonable.

44. Notwithstanding the above, the Commission did agree with OPC, in part, regarding the normalization of uncollectible expense, OPC's last concern. The Company argued for a single year budgeted number to represent its uncollectibles during the rate effective period. The Commission disagreed with the use of a single year budgeted number, stating, "Pepco's 2009 uncollectible expense appears to be an anomaly and not reflective of rates to be expected in the rate-effective period. Therefore, we rejected Pepco's adjustment to use the 2009 budgeted uncollectible expense."[110]

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105 *See* Pepco (4C) at 13 (Hook).

106 *Id.* at 14.

107 *Id.*

108 Pepco (4C) at 12-13 (Hook).

109 *Id.* at 15.

110 Order No. 15710, ¶ 132.

45. OPC's proposed three-year average (covering the years 2006-2008) also was inappropriate because it reflects a period that occurred before the economic downturn that significantly increased Pepco's write-offs.[111] While a three-year average has been used in the past to normalize expenses that fluctuate, the record reveals that the economic crisis increased Pepco's uncollectibles. We reaffirm our adoption, for this proceeding only, of a two-year average (2008-2009) of the Company's uncollectibles as a proxy to represent its anticipated uncollectibles during the rate effective period.[112]

5. Industry Contribution and Membership Dues

46. OPC asks that the Commission clarify Order No. 15710 to make sure that it correctly reflects an agreed-upon OPC correction to Pepco's Industry Contribution and Membership Dues adjustment (Pepco Ratemaking Adjustment No. 6).[113] Pepco initially removed $232,000 from test-year operating expense for costs associated with industry memberships and contributions.[114] OPC identified an additional $20,044 that should be removed from test-year operating expense. Pepco agreed with OPC and included OPC's adjustment in the Company's revenue requirement.[115]

47. The Commission did not explicitly mention OPC's correction in the final Order since it was deemed an uncontested issue. However, the corrected adjustment (a downward adjustment of $253,000) is reflected in Pepco's cost of service.[116] OPC's correction was properly included in Pepco's cost of service adjustment as approved by the Commission.

C. WASA's REQUEST FOR RECONSIDERATION

48. WASA argues that the Commission erroneously increased the rate for WASA's Blue Plains facility (Rate Schedule GT-3B), based on a "slice-of-system cost allocation method" instead of the direct cost allocation method urged by WASA.[117]

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111 Pepco (4C) at 15 (Hook).

112 *See* Order No. 15710, ¶ 133.

113 OPC's Application at 31.

114 Except for those industry memberships and contribution costs associated with the American National Standards Institute which are specifically allowed by the Commission. *See In re Potomac Electric Power Co., Formal Case No. 889*, Order No. 9509, 11 D.C.P.S.C. 302 (1990).

115 *See* Pepco (4C)-6 (Hook); *see also* Pepco Exhibit No. 4, filed November 20, 2009, in response to the Commission's data request during the hearings (Tr. 1242).

116 *See* Order No. 15710, ¶ 112.

117 *Formal Case No. 1076, Request of the District of Columbia Water and Sewer Authority for Reconsideration of Order No. 15710*, filed April 1, 2010 ("WASA's Request for Reconsideration") at 1,

According to WASA, this violates sound cost causation principles. WASA contends that Blue Plains is served solely by two 69 kV underwater subtransmission lines, and that "Pepco's entire system does not, and cannot, serve Blue Plains."[118] According to WASA, "the GT3B rate resulting from Pepco's slice-of-system cost allocation method bears no relationship to the costs that Pepco actually incurs to provide service to Blue Plains."[119]

49. WASA claims that the Commission erred in invoking a general policy disfavoring direct assignment of costs for rate classes like Blue Plains. According to WASA, the National Association of Regulatory Utility Commissioners favors directly-assigned costs in developing rates. WASA asserts, for example, that for decades Pepco has directly assigned subtransmission costs to the Southern Maryland Electric Cooperative ("SMECO") in the course of setting rates in the District.[120] Moreover, WASA argues that the Commission's "slice-of-system" cost allocation method is appropriate only for similarly-situated Pepco customers, and that there are no other customers situated similarly to Blue Plains, which it contends is "unique insofar as subtransmission costs are concerned."[121]

50. WASA claims that the Commission's concern that rates established by direct assignment may be too volatile is no basis to reject WASA's proposal to revise the manner in which Blue Plains' rate is set.[122] Despite this possibility, WASA concludes that direct assignment of the Blue Plains Feeder costs is the most appropriate and reasonable method for setting the GT3B rate.[123] WASA asserts that its Blue Plains rate should be based on the directly assigned costs of the Blue Plains Feeders plus a proportionate share (determined under Pepco's class cost of service study ("CCOSS")) of the costs of the 69 kV emergency overhead feeders whose costs are shared by all Pepco customers.[124]

51. Pepco counters that the method for designing Blue Plains' rates has been in effect for many years, and there has been no change in circumstances (other than

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13. WASA claims that the Blue Plains facility (Rate Schedule GT-3B) received a 26 percent increase, the largest percentage increase experienced by any Pepco customer class, as compared to the average increase of about 8 percent. *Id.* at 1, 6.

118 *Id.* at 2, 5 n. 4. WASA asserts that "[t]he record contains no evidence whatsoever to support a finding that Blue Plains benefits from any other portion of Pepco's subtransmission system." *Id.* at 3.

119 *Id.* at 3, 6. *See id.* at 7-9.

120 *Id.* at 4, 11.

121 *Id.* at 4-5, 11-12.

122 *Id.* at 5, 12-14.

123 *Id.* at 5, 12-13. WASA notes that "the Blue Plains Feeders have been highly reliable and, further, each of the Blue Feeders has more than enough capacity to serve Blue Plains' load." *Id.* at 5.

124 *Id.* at 6, 15-16.

WASA's desire to shift costs to other customers) that warrants a redesign of that rate.[125] Pepco contends that the Commission is entitled to rely on its existing policy disfavoring single-customer rates based on direct assignment of a narrow base of costs, without rehashing the reasons for that policy.[126]

52. Pepco argues that WASA misreads the Commission's initial decision because WASA overlooks the fact that non-cost factors -- such as the policy against single customer rates based on narrowly-based directly-assigned costs -- were cited by the Commission as the reasons for rejecting WASA's proposed direct-cost-assigned Blue Plains rate.[127] Pepco points out that "the norm" and "universally accepted practice" is that class rates are designed based primarily on cost allocation rather than directly-assigned costs.[128] Pepco concludes that the Commission acted well within its discretionary authority in following its normal rate design policy.

53. Pepco avers that WASA's claim that it is "unique" and therefore entitled to a separate rate class is wrong:

> It will always be possible to find customers within a class who use distinctly different portions of the system, but that does not mean that rate classes including such customers are impermissible. It is only necessary that there be a "reasonable basis" for the classification. * * * Grouping Blue Plains with other customers that only use subtransmission facilities satisfies that requirement.[129]

Further, Pepco contends that WASA is also mistaken in arguing that Blue Plains is "uniquely situated." Though WASA claims that Blue Plains is served uniquely by two (2) under-river lines, Pepco points out that Blue Plains was served by emergency overhead 69 kV feeders in the past, and it could be served by a different configuration in

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125 *Formal Case No. 1076, Opposition of Potomac Electric Power Company to Request of the District of Columbia Water and Sewer Authority for Reconsideration of Order No. 15710,* filed April 7, 2010, ("Pepco's Opposition") at 1.

126 *Id.* at 2.

127 *Id.* at 3, citing Order No. 15710, ¶ 313 ("Such single customer rates, based on a very narrow base of cost information, may be subject to volatile changes if their directly-assigned CCOS changes suddenly because of future events.") and *Washington Gas Light Co. v. PSC,* 450 A.2d 1187, 1199 (D.C. 1982) ("the permissibility of relying on non-cost factors in rate design is beyond serious dispute").

128 *Id.* at 5, citing *In re New York State Council v. Public Serv. Comm'n,* 45 N.Y. 2d 661, 384 N.E. 2d 1281 (Ct. App. N.Y. 1978) ("rate design inherently involves an averaging process, with customers paying rates based not on their individual costs, but rather on their allocated share of the costs imposed by a group of customers.."); *see also People's Counsel v. Public Serv. Comm'n,* 462 A.2d 1105, 1113 (D.C. App. 1983) (allocation of costs "is not a matter for the slide rule. It has no claim to an exact science"); *Metropolitan Washington Board of Trade v. Public Serv. Comm'n,* 432 A.2d 343, 3611 (D.C. App. 1981) (noting arbitrariness inherent in rate classifications).

129 *Id.* at 5, citing *Metropolitan Washington Board of Trade v. PSC,* 432 A.2d 343, 359 (D.C. 1983).

the future.[130] Pepco argues that Blue Plains has no inherent right to have its current feeders dedicated to serve only Blue Plains.[131]

54. Pepco also argues that there is also a basic inequity in WASA's position because the two feeders whose costs WASA argues should be directly assigned to the Blue Plains facility are heavily depreciated, having been installed from 1956 to 1971. Therefore, Pepco contends that Blue Plains did not pay the full costs of those facilities in its rates in the earlier years of their service lives, when more of their costs were reflected in cost of service.[132] Pepco argues that WASA's claim for direct cost assignment now that the facilities are heavily depreciated is a "heads-I-win-tails-you-lose" proposition.[133]

55. Pepco asserts that the old age of the feeders currently serving Blue Plains is undeniable. Because the feeders are old, Pepco proffers that when and if replacement feeders become necessary, it would likely lead to a sudden jump in Blue Plains rates under a direct assignment approach, "even if (as WASA claims) there will be no need for additional, different facilities to ensure adequate service to Blue Plains."[134] Pepco argues that the mere fact that WASA considered and rejected rate volatility as a concern is not sufficient to overcome the deference due the Commission on this issue.[135]

56. Essentially, WASA is disagreeing with the Commission's findings of fact and/or rehashing its arguments. Pepco's opposition arguments succinctly support the rationale of our original decision rejecting WASA's request for direct cost assignment and we adopt it as part of our decision affirming the Blue Plains rate. We also explicitly find that WASA did not meet its burden in demonstrating the reasonableness of its suggested modifications to Pepco's CCOSS on the Blue Plains rate. WASA did not show that its modified CCOSS figures for Blue Plains should be adopted instead of the cost figures for Blue Plains from Pepco's CCOSS.[136] Moreover, the emergency situation that

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130 *Id.* at 6.

131 *Id.*

132 *Id.*

133 *Id.*

134 *Id.* at 2, 7-8.

135 *Id.* at 7, citing *General Serv. Admin v. PSC*, 469 A.2d 1238, 1241 (D.C. 1983) (noting deference due to the Commission "in those areas of utility regulation, such as rate design, in which the commissioners are particularly proficient").

136 Pepco's class cost of service study ('CCOSS") indicated that, before the present case, the Blue Plains rate class had a rate of return (ROR) of 6.77 percent (a percent (a "unitized rate of return" ("UROR") of 0.96) as compared to the 7.04 percent overall DC jurisdictional ROR. *See* Order No. 15710 at 107 (chart showing class RORs, listing the Blue Plains rate class as "GT-HV-69 KV"). When WASA "adjusted" Pepco's CCOSS, to support WASA's proposed "direct cost allocation approach" to setting Blue Plains rates, WASA used a narrow definition of facilities. WASA focused on subtransmission "plant" and did not adequately consider that Pepco as an organization provides other support—such as highly trained field forces, engineers and specialized equipment to maintain and be available to rapidly repair high voltage

arose in the years 2005 to 2007, when Pepco constructed emergency 69 kV overhead lines to ensure continuing service to both Blue Plains and other customers, confirms that Blue Plains is part of Pepco's integrated electric distribution system. Contrary to WASA's claims, Blue Plains is not a wholly separate service unconnected to the rest of Pepco's system and deriving no benefits from Pepco other than the very narrowly-defined costs of the Blue Plains feeders.

57. The Commission reaffirms its policy generally disfavoring single-customer rates that are set based solely on direct assignments of very narrowly-based costs, as opposed to costs that are determined by allocation from a wider pool of costs for similarly-situated customers.[137] WASA mischaracterizes the rationale behind this policy and our ruling on Blue Plains. It is not that all direct cost assignments are disfavored. Instead, our policy is that direct cost assignments are disfavored when they are the sole and exclusive method for setting a class rate and the only costs being considered are very narrowly-based. WASA's approach may undervalue systems integration cost effects. WASA's suggestion also would create potentially volatile Blue Plains rates, based on a very narrow cost base, so that any change in class costs in the future (as, for example, when repairs or replacements are required) would lead to abrupt increases in the class rate.

58. The Commission's methodology for designing Blue Plains rates, involving the allocation of a broader set of costs rather than direct assignments of very narrowly based costs, has been in place for many years.[138] WASA failed to carry its burden to justify replacing this well-established methodology.[139] Finally, WASA's disregard of

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cables—to support the two major high voltage lines crossing a river to serve Blue Plains. In "adjusting" Pepco's CCOSS, WASA appears to have reduced operating and maintenance ("O&M") expenses in direct proportion to WASA's reduction in Plant in Service. *See* WASA (A) at Table 1, line 1 (Phillips), WASA (A)-7 (Phillips). WASA did not make any direct allocation or study the corresponding, but potentially disproportionate, effects on Pepco's other costs of serving Blue Plains.

137 Our policy was evident not only when we declined to approve WASA's proposal for a narrowly-based Blue Plains rate, but also when we declined to approve Pepco's proposal for a narrowly-based new standby tariff GT-3A-S for GSA's CHP facility. *See* Order No. 15710, ¶¶407-418.

138 Our general policy is not undercut by the way in which wholesale SMECO costs are calculated (and excluded from D.C. jurisdictional retail costs) in the course of setting Pepco retail rates for DC. To be sure, as WASA alludes to, in *Formal Case No. 748*, Order No. 7457 (December 30, 1981), 2 DCPSC 401, 444 (1981), 45 PUR 4th 445, the Commission approved the direct cost assignment of some facility costs to SMECO where those SMECO facilities were "not part of PEPCO's integrated electric system." (SMECO's relationship with Pepco is a wholesale transaction relationship, regulated by the FERC, not a retail distribution relationship.) That some direct cost assignments were made to SMECO in Formal Case No. 748 does not undercut the Commission's general policy against basing a retail class rate solely on directly assigned costs from a very narrow cost base, which might be subject to sudden dramatic changes in the future.

139 *See, e.g., Formal Case No. 869*, Order No. 9216, 10 D.C.P.S.C. 22, 133 (1989) (burden is on the party seeking to change an earlier-approved Commission methodology); *Formal Case No. 813*, Order No. 8127, 5 D.C.P.S.C. 259, 260-270 (1984) (same); *Formal Case No. 785*, Order No. 7716, 3 D.C.P.S.C. 450, 528, 50 PUR 4th 500 (1982) (same).

rate volatility concerns supports our initial finding, particularly in light of the deficiencies in its proposed alternative approach. We also agree with Pepco that there is an inequity in WASA's position, in that WASA did not pay all the costs of constructing the Blue Plains Feeders but now seeks the benefit of switching to a new, direct-cost-allocation methodology now that the heavily-depreciated cost of those feeders is low.

59. Pepco's CCOSS indicated that the Blue Plains class had subpar earnings,[140] which warrants a greater-than-system-average increase in rates, under Pepco's methodology for allocating its revenue requirement among customer classes, to move the Blue Plains' rates gradually toward greater equality in class RORs. Pepco's allocation is reasonable. The Commission reaffirms the GT-3B Blue Plains rates set forth in our initial decision.

THEREFORE, IT IS ORDERED THAT:

60. Pepco's Application for Reconsideration is **GRANTED, in part, and DENIED, in part, as set forth herein;** Pepco is directed to file a revised compliance filing prescribed by paragraphs 13 and 20 *supra*, within seven (7) days from the date of this Order;

61. OPC's Application for Reconsideration is **DENIED**; and

62. WASA's Application for reconsideration is **DENIED.**

A TRUE COPY: **BY DIRECTION OF THE COMMISSION:**

CHIEF CLERK:

DOROTHY WIDEMAN
COMMISSION SECRETARY

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[140] *See* Order No. 15710 at 107 (chart showing that before this Pepco rate case, Blue Plains had a class ROR of 6.77 percent (a UROR of 0.96) as compared to the overall D.C. jurisdictional ROR of 7.04 percent).

11. a. List all state utility regulatory commissions that have rejected or denied consolidated income tax adjustments for rate-making purposes.

b. Provide a copy of all orders from the state utility regulatory commissions listed in the response to item 11(a) in which the commission has addressed the use of consolidated income tax adjustments for rate-making purposes.

RESPONSE:

a. We do not have the requested information. See the OAG response to Staff Request 10 for what we have.

b. See response to part a.

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF THE GAS AND ELECTRIC RATES, TERMS, AND CONDITIONS OF LOUISVILLE GAS AND ELECTRIC COMPANY	)))	CASE NO. 2003-00433

ORDER

On August 12, 2004, the Commission issued an Order granting in part the petition for rehearing filed by the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention ("AG"). The AG requested rehearing on four issues that were decided by the Commission's June 30, 2004 Order in conjunction with the calculation that Louisville Gas and Electric Company ("LG&E") had a revenue deficiency in its electric operations of $45,608,365. The Commission granted rehearing on one issue, which was whether LG&E's electric revenue deficiency should have been calculated by using the effective Kentucky income tax rate, as proposed by the AG, rather than the statutory Kentucky income tax rate, as proposed by LG&E. The scope of rehearing on this issue includes not only the appropriateness of using an effective Kentucky income tax rate, but also what that rate is and whether its use would have impacted the amount of additional revenue actually granted by the June 30, 2004 Order.

The Commission's December 15, 2005 Order established a procedural schedule providing for discovery and a date by which the parties could either file memoranda or request an evidentiary hearing. No party requested an evidentiary hearing. LG&E and

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the AG filed memoranda in support of their respective positions on the tax issue and these cases now stand submitted for a decision.

<u>AG's Position</u>

On March 3, 2006, the AG filed a joint memorandum in this case and in the pending Kentucky Utilities Company ("KU") rate case,[1] arguing that use of the effective Kentucky income tax rate is a benefit flowing from the merger of the "Companies" and "their" ability to file a consolidated income tax return.[2] He contended that the effective Kentucky income tax rate should be utilized even though he acknowledges that it lacks the certainty of the statutory Kentucky income tax rate. The AG noted that the statutory Kentucky income tax rate is higher than the effective Kentucky income tax rate for LG&E in 2002 and that the statutory tax rate does not reflect the actual income tax LG&E will pay while the existing electric rates are in effect. The AG argued that using the effective Kentucky income tax rate would be consistent with the Commission's most recent rate decisions for The Union Light, Heat and Power Company ("ULH&P") and Kentucky-American Water Company ("Kentucky-American").[3]

The AG also acknowledged that if the effective Kentucky income tax rate is used, the resulting change in LG&E's electric revenue deficiency would not change the level of additional revenue granted to LG&E since LG&E had agreed to accept less revenue

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[1] Case No. 2003-00434, An Adjustment of the Electric Rates, Terms, and Conditions of Kentucky Utilities Company.

[2] AG's Memorandum on Petition for Rehearing at 1.

[3] The AG cited Case No. 2001-00092, Adjustment of Gas Rates of The Union Light, Heat and Power Company, final Order issued January 31, 2002 and Case No. 2004-00103, An Adjustment of the Rates of Kentucky-American Water Company, final Order issued February 28, 2005.

than the Commission had calculated as the revenue deficiency. However, the AG urged the Commission to adopt the effective Kentucky income tax rate for calculating LG&E's revenue deficiency and, thereby, establish the proper methodology for this adjustment, just as the Commission established the proper methodology for all other adjustments addressed in the June 30, 2004 Order.[4]

LG&E's Position

LG&E's March 3, 2006 rehearing memorandum, filed jointly here and in Case No. 2003-00434, reiterated its prior position that it is appropriate to utilize the statutory Kentucky income tax rate to calculate its revenue deficiency and that the Commission's June 30, 2004 Order was correct in utilizing that methodology. LG&E noted that the effective Kentucky income tax rate is not only subject to fluctuations due to changes in property, payroll, and sales factors, but is also continuously impacted by tax credits and out-of-state activities which make its use more uncertain and complicated than the statutory rate. LG&E characterized the Kentucky statutory income tax rate as being "objective, known and measurable, easily understood and verified, and not distorted by non-recurring items or apportionment adjustments from out-of-state activities."[5]

While contending that the statutory Kentucky income tax rate should be utilized, LG&E stated that if an effective Kentucky income tax rate is used for its operations, the appropriate effective rate is 8.07 percent based on a combined Kentucky and Indiana

[4] AG's Memorandum on Petition for Rehearing at 2.

[5] LG&E's and KU's Memorandum Opposing Use of Effective Tax Rates at 2.

income tax rate.[6] Because LG&E only serves customers in Kentucky, LG&E asserts that it is appropriate to consider the combined states' tax rates since all of its operations inure to the benefit of its Kentucky customers. Using this effective income tax rate, LG&E recalculated its revenue deficiency to demonstrate that the revenue increase needed would still fall within the range of the revenue increase calculated as reasonable by the Commission's June 30, 2004 Order. Based upon this analysis, LG&E argued that even if the effective Kentucky income tax rate is used, the Commission's calculation of LG&E's revenue deficiency would still exceed the revenue increase authorized by the June 30, 2004 Order.

LG&E's March 13, 2006 joint reply rehearing memorandum claims that the AG has rendered moot his own argument to use LG&E's effective Kentucky income tax rate by acknowledging that to do so would not change the amount of additional revenue authorized by the June 30, 2004 Order. LG&E further claims that the ULH&P and Kentucky-American rate cases cited by the AG are distinguishable here because LG&E did not agree to use the effective Kentucky income tax rate in the determination of its revenue requirements and revenue increases.[7]

FINDINGS

Based on the evidence of record and being otherwise sufficiently advised, the Commission finds that our June 30, 2004 Order set forth a complete analysis of all proposed rate-making adjustments. Based on that analysis, including the decision

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[6] LG&E Rehearing Response to Commission Staff, filed January 20, 2006, Item No. 2.

[7] LG&E's and KU's Memorandum Opposing Use of Effective Tax Rates at 3-4.

therein to use the statutory Kentucky income tax rate, we determined that LG&E had a revenue deficiency in its electric operations of $45,608,365. Although LG&E would have been entitled to increase its electric revenues by that same amount, the Commission recognized LG&E's agreement, as set forth in the Partial Settlement Agreement, Stipulation, and Recommendation, to accept a lesser increase in its electric revenues. That lesser increase, which was granted by the Commission, was $43.4 million.

A recalculation of LG&E's revenue requirements based on its 2002 effective Kentucky income tax rate of 8.07 percent, rather than the statutory rate of 8.25 percent as previously used, would have reduced LG&E's revenue deficiency from $45,608,365 to $45,103,769. Since this recalculated deficiency still exceeds the $43.4 million revenue increase granted by the Commission in accordance with LG&E's agreement, the AG's proposed tax adjustment would have no impact on the amount of revenue increase granted by the June 30, 2004 Order. Thus, the AG's proposal on rehearing to use LG&E's effective Kentucky income tax rate is a moot issue. However, even though the AG's proposed tax adjustment is a moot issue, we will address the merits of the adjustment since the adjustment was previously analyzed and rejected in the June 30, 2004 Order.

The Commission is not persuaded that the two previous rate decisions cited by the AG establish a precedent for requiring the use of the effective Kentucky income tax rate over the objections of LG&E in this rate case. In the ULH&P gas rate case cited by the AG, the Commission did not require ULH&P to use the effective Kentucky income tax rate. Rather, ULH&P proposed to do so and the Commission accepted the proposal, but only on a trial basis due to concerns that there can be significant fluctuations in the effective rate. Specifically, the Commission stated that:

> This is the first proceeding in which the Commission has considered the use of the effective, rather than the stated, Kentucky income tax rate. The Commission has some concerns about using this approach, especially since the effective rate changed from 5.15 to 3.03 percent between two tax years. However, the Commission will accept the use of the effective Kentucky income tax rate of 3.03 percent in this proceeding, and will reflect that rate in the determination of ULH&P's revenue requirements. . . .
>
> The Commission is accepting the use of the effective Kentucky income tax rate on a trial basis. In ULH&P's next rate case, it should provide an analysis showing the effective Kentucky income tax rates experienced by ULH&P for the tax years between 2000 and the current tax year applicable to its application. The Commission will review this information at that time to determine whether the use of the effective rate should continue.

Case No. 2001-00092, January 31, 2002 Order at 59-60. Since issuing that Order, ULH&P did file a subsequent gas rate case which included the required analysis of its effective Kentucky income tax rate. ULH&P concluded from its analysis that:

> The effective Kentucky income tax rate could vary substantially from year-to-year. Notwithstanding ULH&P's last gas base rate case, the Commission has historically and consistently used the Kentucky statutory tax rate in past cases. ULH&P believes that the Commission's use of the statutory rate is the most proper approach and should be applied in this case as well. The statutory rate is known, easily verifiable and not distorted by non-recurring items or apportionment adjustments attributable to other entities participating in the filing of a consolidated tax return.[8]

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[8] Case No. 2005-00042, An Adjustment of the Gas Rates of The Union Light, Heat and Power Company, Direct Testimony of Alexander J. Torok, at 7.

The AG actively participated in that subsequent ULH&P gas rate case, but neither he nor ULH&P proposed to use the effective Kentucky income tax rate and the Commission did not require its use. The Commission calculated ULH&P's gas revenue deficiency based on the AG's proposal therein to use a 7.00 percent statutory Kentucky income tax rate.[9] Thus, contrary to the AG's claims, the Commission used the statutory Kentucky income tax rate, not the effective rate, to determine the revenue requirements and revenue increase in the most recent ULH&P rate case.

In the Kentucky-American rate case cited by the AG, the AG had proposed a federal "consolidated income tax" adjustment which would have prospectively allocated tax losses to companies that generated positive taxable income. The AG's proposed adjustment was calculated using a 3-year average of tax losses and the statutory federal income tax rate.[10] However, the income tax effect of the AG's adjustments in that case reflected the use of the statutory federal and Kentucky income tax rates. The Commission accepted the AG's federal consolidated tax adjustment based on a voluntary commitment, previously made by Kentucky-American in conjunction with its acquisition by RWE, that it would be able to file consolidated tax returns and achieve tax savings by doing so. As the Commission stated in that Kentucky-American rate case:

> Having previously indicated the savings resulting from the filing of a consolidated tax filing would be viewed as a merger benefit, subject to allocation, we do not believe that acceptance of the AG's proposal represents a radical departure from past regulatory practice. Moreover, Kentucky-American and its corporate parents having

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[9] Case No. 2005-00042, December 22, 2005 Order at 50.

[10] Case No. 2004-00103, Crane Direct Testimony at 74-75 and Schedule ACC-39.

> previously touted TWUS's filing of consolidated tax returns as a benefit to obtain approval of the merger transaction, have no cause to object if we now act upon their representation. Accordingly, we find that the AG's proposed consolidated income tax is reasonable and have reflected it in our calculation of federal income taxes.[11]

In the Kentucky-American rate case, the Commission adopted a dollar adjustment to the federal tax expense, but the statutory federal and Kentucky income tax rates were utilized to determine the revenue requirements and revenue increase. The AG did not propose to use an effective federal or Kentucky income tax rate in that case and the Commission did not require its use. Furthermore, the AG has not now cited any commitment, obligation, or representation by LG&E that it would use an effective Kentucky income tax rate or otherwise share with ratepayers the benefits of a consolidated tax return.

The Commission has previously expressed concerns about using an effective Kentucky income tax rate due to the annual fluctuations in the effective rate.[12] These fluctuations occur because the effective Kentucky income tax rate is determined from the total of all the tax income and tax losses of all the entities that file on the same consolidated income tax return. For LG&E, the majority of the entities other than KU included in the consolidated income tax return of LG&E's parent corporation, E.ON US Investment Corp., reflect activities which are not regulated by the Commission. By having to recognize tax losses and other tax credits related to these non-regulated activities to derive an effective Kentucky income tax rate could well be viewed as forcing

[11] Case No. 2004-00103, February 28, 2005 Order at 65-66.

[12] Case No. 2001-00092, January 31, 2002 Order.

the utility to use these non-regulated activities to subsidize the regulated utility operations. There is also a concern that because of the way the apportionment of certain tax transactions is performed, the resulting effective Kentucky income tax rate could exceed the statutory Kentucky income tax rate. Thus, establishing the effective tax rate as the guideline or precedent, as the AG has requested on rehearing, could in the future result in higher utility rates to pay for taxes on non-regulated activities.

There also appears to be a serious timing issue related to the utilization of an effective Kentucky income tax rate. Corporate tax returns are not due until 9 months after the end of the tax year, and the effective income tax rate cannot be determined until after the consolidated tax returns have been filed. The most recent effective Kentucky income tax rate that was available when this case was decided was for the 2002 tax year, even though the test year was the 12 months ending September 30, 2003 and the new electric rates were to be effective prospectively starting July 1, 2004. Under these facts, the Commission finds that it is not reasonable to calculate electric rates to be effective post-July 1, 2004 based on a 2002 effective tax rate which is subject to annual changes based on non-regulated activities.

The Commission further finds it reasonable to continue using the statutory Kentucky income tax rate for determining LG&E's revenue requirements in this case. The statutory Kentucky income tax rate is known and measurable and is not subject to fluctuations due to non-regulated tax losses or tax credits, or due to apportionment adjustments from non-regulated activities. The Commission has consistently utilized the statutory Kentucky income tax rate to determine utility revenue requirements absent an agreement or representation to the contrary by the utility. Here, the AG has not provided sufficient evidence to persuade us to modify our June 30, 2004 decision to calculate LG&E's revenue requirements based on the statutory Kentucky income tax rate.

The Commission did previously direct LG&E to address in detail the use of the effective Kentucky income tax rate for rate-making purposes in its next rate case. LG&E acknowledged this requirement in its joint reply memorandum, and the Commission will now reaffirm LG&E's obligation to do so as part of its next rate case. By the time its next rate case is filed, LG&E will have more experience with filing Kentucky consolidated income tax returns and the issue of whether to use the effective Kentucky income tax rate and, if so, what the appropriate effective rate is, can be revisited at that time.

In summary, the Commission finds that it is not appropriate to utilize the effective Kentucky income tax rate to determine LG&E's revenue requirements and revenue increase in this case, and the AG's proposal is denied. As a result of this finding, there are no changes to LG&E's revenue requirements, revenue deficiency, or the amount of revenue increase found reasonable in the June 30, 2004 Order.

IT IS THEREFORE ORDERED that the AG's proposal to use the effective Kentucky income tax rate to determine LG&E's revenue requirements and the amount of its revenue increase in this case is denied.

Done at Frankfort, Kentucky, this 31st day of March, 2006.

By the Commission

ATTEST:

Executive Director

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF THE ELECTRIC RATES, TERMS, AND CONDITIONS OF KENTUCKY UTILITIES COMPANY	)))	CASE NO. 2003-00434

O R D E R

On August 12, 2004, the Commission issued an Order granting in part the petition for rehearing filed by the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention ("AG"). The AG requested rehearing on four issues that were decided by the Commission's June 30, 2004 Order in conjunction with the calculation that Kentucky Utilities Company ("KU") had a revenue deficiency of $49,775,329. The Commission granted rehearing on one issue, which was whether KU's revenue deficiency should have been calculated by using the effective Kentucky income tax rate, as proposed by the AG, rather than the statutory Kentucky income tax rate, as proposed by KU. The scope of rehearing on this issue includes not only the appropriateness of using an effective Kentucky income tax rate, but also what that rate is and whether its use would have impacted the amount of additional revenue actually granted by the June 30, 2004 Order.

The Commission's December 15, 2005 Order established a procedural schedule providing for discovery and a date by which the parties could either file memoranda or request an evidentiary hearing. No party requested an evidentiary hearing. KU and the

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AG filed memoranda in support of their respective positions on the tax issue and these cases now stand submitted for a decision.

AG's Position

On March 3, 2006, the AG filed a joint memorandum in this case and in the pending Louisville Gas and Electric Company ("LG&E") rate case,[1] arguing that use of the effective Kentucky income tax rate is a benefit flowing from the merger of the "Companies" and "their" ability to file a consolidated income tax return.[2] He contended that the effective Kentucky income tax rate should be utilized even though he acknowledges that it lacks the certainty of the statutory Kentucky income tax rate. The AG noted that the statutory Kentucky income tax rate is higher than the effective Kentucky income tax rate for KU in 2002 and that the statutory tax rate does not reflect the actual income tax KU will pay while the existing electric rates are in effect. The AG argued that using the effective Kentucky income tax rate would be consistent with the Commission's most recent rate decisions for The Union Light, Heat and Power Company ("ULH&P") and Kentucky-American Water Company ("Kentucky-American").[3]

The AG also acknowledged that if the effective Kentucky income tax rate is used, the resulting change in KU's revenue deficiency would not change the level of additional revenue granted to KU since KU had agreed to accept less revenue than the

[1] Case No. 2003-00433, An Adjustment of the Gas and Electric Rates, Terms, and Conditions of Louisville Gas and Electric Company.

[2] AG's Memorandum on Petition for Rehearing at 1.

[3] The AG cited Case No. 2001-00092, Adjustment of Gas Rates of The Union Light, Heat and Power Company, final Order issued January 31, 2002 and Case No. 2004-00103, An Adjustment of the Rates of Kentucky-American Water Company, final Order issued February 28, 2005.

Commission had calculated as the revenue deficiency. However, the AG urged the Commission to adopt the effective Kentucky income tax rate for calculating KU's revenue deficiency and, thereby, establish the proper methodology for this adjustment, just as the Commission established the proper methodology for all other adjustments addressed in the June 30, 2004 Order.[4]

KU's Position

KU's March 3, 2006 rehearing memorandum, filed jointly here and in Case No. 2003-00433, reiterated its prior position that it is appropriate to utilize the statutory Kentucky income tax rate to calculate its revenue deficiency and that the Commission's June 30, 2004 Order was correct in utilizing that methodology. KU noted that the effective Kentucky income tax rate is not only subject to fluctuations due to changes in property, payroll, and sales factors, but is also continuously impacted by tax credits and out-of-state activities which make its use more uncertain and complicated than the statutory rate. KU characterized the Kentucky statutory income tax rate as being "objective, known and measurable, easily understood and verified, and not distorted by non-recurring items or apportionment adjustments from out-of-state activities."[5]

While contending that the statutory Kentucky income tax rate should be utilized, KU stated that if an effective Kentucky income tax rate is used for its operations, the appropriate effective rate is 7.98 percent, based on a Kentucky jurisdictionalized basis.[6]

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[4] AG's Memorandum on Petition for Rehearing at 2.

[5] KU's and LG&E's Memorandum Opposing Use of Effective Tax Rates at 2.

[6] KU Rehearing Response to Commission Staff, filed January 20, 2006, Item No. 2.

Since KU serves customers in Kentucky, Virginia, and Tennessee, KU asserts that a Kentucky jurisdictional only effective tax rate is appropriate since it matches KU's activities that benefit Kentucky customers with the Kentucky income tax cost of only those activities. Using this effective income tax rate, KU recalculated its revenue deficiency to demonstrate that the revenue increase needed would still fall within the range of the revenue increase calculated as reasonable by the Commission's June 30, 2004 Order. Based upon this analysis, KU argued that even if the effective Kentucky income tax rate is used, the Commission's calculation of KU's revenue deficiency would still exceed the revenue increase authorized by the June 30, 2004 Order.

KU's March 13, 2006 joint reply rehearing memorandum claims that the AG has rendered moot his own argument to use KU's effective Kentucky income tax rate by acknowledging that to do so would not change the amount of additional revenue authorized by the June 30, 2004 Order. KU further claims that the ULH&P and Kentucky-American rate cases cited by the AG are distinguishable here because KU did not agree to use the effective Kentucky income tax rate in the determination of its revenue requirements and revenue increases.[7]

FINDINGS

Based on the evidence of record and being otherwise sufficiently advised, the Commission finds that our June 30, 2004 Order set forth a complete analysis of all proposed rate-making adjustments. Based on that analysis, including the decision therein to use the statutory Kentucky income tax rate, we determined that KU had a revenue deficiency of $49,775,329. Although KU would have been entitled to increase

[7] KU's and LG&E's Memorandum Opposing Use of Effective Tax Rates at 3-4.

its revenues by that same amount, the Commission recognized KU's agreement, as set forth in the Partial Settlement Agreement, Stipulation, and Recommendation, to accept a lesser increase in its revenues. That lesser increase, which was granted by the Commission, was $46.1 million.

A recalculation of KU's revenue requirements based on its 2002 jurisdictionalized effective Kentucky income tax rate of 7.98 percent, rather than the statutory rate of 8.25 percent as previously used, would have reduced KU's revenue deficiency from $49,775,329 to $49,359,219. Since this recalculated deficiency still exceeds the $46.1 million revenue increase granted by the Commission in accordance with KU's agreement, the AG's proposed tax adjustment would have no impact on the amount of revenue increase granted by the June 30, 2004 Order. Thus, the AG's proposal on rehearing to use KU's effective Kentucky income tax rate is a moot issue. However, even though the AG's proposed tax adjustment is a moot issue, we will address the merits of the adjustment since the adjustment was previously analyzed and rejected in the June 30, 2004 Order.

The Commission is not persuaded that the two previous rate decisions cited by the AG establish a precedent for requiring the use of the effective Kentucky income tax rate over the objections of KU in this rate case. In the ULH&P gas rate case cited by the AG, the Commission did not require ULH&P to use the effective Kentucky income tax rate. Rather, ULH&P proposed to do so and the Commission accepted the proposal, but only on a trial basis due to concerns that there can be significant fluctuations in the effective rate. Specifically, the Commission stated that:

> This is the first proceeding in which the Commission has considered the use of the effective, rather than the

> stated, Kentucky income tax rate. The Commission has some concerns about using this approach, especially since the effective rate changed from 5.15 to 3.03 percent between two tax years. However, the Commission will accept the use of the effective Kentucky income tax rate of 3.03 percent in this proceeding, and will reflect that rate in the determination of ULH&P's revenue requirements. . . .
>
> The Commission is accepting the use of the effective Kentucky income tax rate on a trial basis. In ULH&P's next rate case, it should provide an analysis showing the effective Kentucky income tax rates experienced by ULH&P for the tax years between 2000 and the current tax year applicable to its application. The Commission will review this information at that time to determine whether the use of the effective rate should continue.

Case No. 2001-00092, January 31, 2002 Order at 59-60. Since issuing that Order, ULH&P did file a subsequent gas rate case which included the required analysis of its effective Kentucky income tax rate. ULH&P concluded from its analysis that:

> The effective Kentucky income tax rate could vary substantially from year-to-year. Notwithstanding ULH&P's last gas base rate case, the Commission has historically and consistently used the Kentucky statutory tax rate in past cases. ULH&P believes that the Commission's use of the statutory rate is the most proper approach and should be applied in this case as well. The statutory rate is known, easily verifiable and not distorted by non-recurring items or apportionment adjustments attributable to other entities participating in the filing of a consolidated tax return.[8]

The AG actively participated in that subsequent ULH&P gas rate case, but neither he nor ULH&P proposed to use the effective Kentucky income tax rate and the Commission did not require its use. The Commission calculated ULH&P's gas revenue deficiency based on the AG's proposal therein to use a 7.00 percent statutory Kentucky

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[8] Case No. 2005-00042, An Adjustment of the Gas Rates of The Union Light, Heat and Power Company, Direct Testimony of Alexander J. Torok, at 7.

income tax rate.[9] Thus, contrary to the AG's claims, the Commission used the statutory Kentucky income tax rate, not the effective rate, to determine the revenue requirements and revenue increase in the most recent ULH&P rate case.

In the Kentucky-American rate case cited by the AG, the AG had proposed a federal "consolidated income tax" adjustment which would have prospectively allocated tax losses to companies that generated positive taxable income. The AG's proposed adjustment was calculated using a 3-year average of tax losses and the statutory federal income tax rate.[10] However, the income tax effect of the AG's adjustments in that case reflected the use of the statutory federal and Kentucky income tax rates. The Commission accepted the AG's federal consolidated tax adjustment based on a voluntary commitment, previously made by Kentucky-American in conjunction with its acquisition by RWE, that it would be able to file consolidated tax returns and achieve tax savings by doing so. As the Commission stated in that Kentucky-American rate case:

> Having previously indicated the savings resulting from the filing of a consolidated tax filing would be viewed as a merger benefit, subject to allocation, we do not believe that acceptance of the AG's proposal represents a radical departure from past regulatory practice. Moreover, Kentucky-American and its corporate parents having previously touted TWUS's filing of consolidated tax returns as a benefit to obtain approval of the merger transaction, have no cause to object if we now act upon their representation. Accordingly, we find that the AG's proposed consolidated income tax is reasonable and have reflected it in our calculation of federal income taxes.[11]

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[9] Case No. 2005-00042, December 22, 2005 Order at 50.

[10] Case No. 2004-00103, Crane Direct Testimony at 74-75 and Schedule ACC-39.

[11] Case No. 2004-00103, February 28, 2005 Order at 65-66.

In the Kentucky-American rate case, the Commission adopted a dollar adjustment to the federal tax expense, but the statutory federal and Kentucky income tax rates were utilized to determine the revenue requirements and revenue increase. The AG did not propose to use an effective federal or Kentucky income tax rate in that case and the Commission did not require its use. Furthermore, the AG has not now cited any commitment, obligation, or representation by KU that it would use an effective Kentucky income tax rate or otherwise share with ratepayers the benefits of a consolidated tax return.

The Commission has previously expressed concerns about using an effective Kentucky income tax rate due to the annual fluctuations in the effective rate.[12] These fluctuations occur because the effective Kentucky income tax rate is determined from the total of all the tax income and tax losses of all the entities that file on the same consolidated income tax return. For KU, the majority of the entities other than LG&E included in the consolidated income tax return of KU's parent corporation, E.ON US Investment Corp., reflect activities which are not regulated by the Commission. By having to recognize tax losses and other tax credits related to these non-regulated activities to derive an effective Kentucky income tax rate could well be viewed as forcing the utility to use these non-regulated activities to subsidize the regulated utility operations. There is also a concern that because of the way the apportionment of certain tax transactions is performed, the resulting effective Kentucky income tax rate could exceed the statutory Kentucky income tax rate. Thus, establishing the effective

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[12] Case No. 2001-00092, January 31, 2002 Order.

tax rate as the guideline or precedent, as the AG has requested on rehearing, could in the future result in higher utility rates to pay for taxes on non-regulated activities.

There also appears to be a serious timing issue related to the utilization of an effective Kentucky income tax rate. Corporate tax returns are not due until 9 months after the end of the tax year, and the effective income tax rate cannot be determined until after the consolidated tax returns have been filed. The most recent effective Kentucky income tax rate that was available when this case was decided was for the 2002 tax year, even though the test year was the 12 months ending September 30, 2003 and the new rates were to be effective prospectively starting July 1, 2004. Under these facts, the Commission finds that it is not reasonable to calculate rates to be effective post-July 1, 2004 based on a 2002 effective tax rate which is subject to annual changes based on non-regulated activities.

The Commission further finds it reasonable to continue using the statutory Kentucky income tax rate for determining KU's revenue requirements in this case. The statutory Kentucky income tax rate is known and measurable and is not subject to fluctuations due to non-regulated tax losses or tax credits, or due to apportionment adjustments from non-regulated activities. The Commission has consistently utilized the statutory Kentucky income tax rate to determine utility revenue requirements absent an agreement or representation to the contrary by the utility. Here, the AG has not provided sufficient evidence to persuade us to modify our June 30, 2004 decision to calculate KU's revenue requirements based on the statutory Kentucky income tax rate.

The Commission did previously direct KU to address in detail the use of the effective Kentucky income tax rate for rate-making purposes in its next rate case. KU acknowledged this requirement in its joint reply memorandum, and the Commission will now reaffirm KU's obligation to do so as part of its next rate case. By the time its next rate case is filed, KU will have more experience with filing Kentucky consolidated income tax returns and the issue of whether to use the effective Kentucky income tax rate and, if so, what the appropriate effective rate is, can be revisited at that time.

In summary, the Commission finds that it is not appropriate to utilize the effective Kentucky income tax rate to determine KU's revenue requirements and revenue increase in this case, and the AG's proposal is denied. As a result of this finding, there are no changes to KU's revenue requirements, revenue deficiency, or the amount of revenue increase found reasonable in the June 30, 2004 Order.

IT IS THEREFORE ORDERED that the AG's proposal to use the effective Kentucky income tax rate to determine KU's revenue requirements and the amount of its revenue increase in this case is denied.

Done at Frankfort, Kentucky, this 31st day of March, 2006.

By the Commission

ATTEST:

Executive Director

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ELECTRIC AND GAS BASE RATES	)))	CASE NO. 2009-00549

INDEX

KAWC EXHIBIT 6

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND	)	
ELECTRIC COMPANY FOR AN ADJUSTMENT	)	CASE NO.
OF ELECTRIC AND GAS BASE RATES	)	2009-00549

ORDER

Louisville Gas and Electric Company ("LG&E"), a wholly owned subsidiary of E.ON US LLC ("E.ON US"), is an electric and gas utility that generates, transmits, distributes, and sells electricity to approximately 389,000 consumers in Jefferson County, Kentucky and in portions of eight other Kentucky counties.[1] It purchases, stores, transports, distributes, and sells natural gas to approximately 317,000 consumers in Jefferson County and in portions of 15 other Kentucky counties.[2]

BACKGROUND

On December 30, 2009, LG&E filed a letter giving notice of its intent to file an application for approval of an increase in its electric and gas rates based on a historical test year ending October 31, 2009. On January 29, 2010, LG&E filed its application, which included new rates to be effective March 1, 2010, based on requests to increase its electric and gas revenues by $94,973,371 and $22,598,160, respectively.[3] The

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[1] The eight counties are Bullitt, Hardin, Henry, Meade, Oldham, Shelby, Spencer, and Trimble.

[2] The 15 counties are Barren, Bullitt, Green, Hardin, Hart, Henry, Larue, Marion, Meade, Metcalfe, Nelson, Oldham, Shelby, Trimble, and Washington.

[3] LG&E's sister utility, Kentucky Utilities Company ("KU"), filed a rate application concurrently, which was docketed as Case No. 2009-00548, Application of Kentucky Utilities Company for an Adjustment of Base Rates.

application also included proposals to revise, add, and delete various tariffs applicable to its electric and gas services. To determine the reasonableness of the requests, the Commission suspended the proposed rates for five months from their effective date, pursuant to KRS 278.190(2), up to and including July 31, 2010.

The following parties requested and were granted full intervention: the Kentucky Industrial Utility Customers, Inc. ("KIUC"); the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention ("AG"); The Kroger Company ("Kroger"); the United States Department of Defense and Other Federal Executive Agencies ("DOD"); the Kentucky School Boards Association ("KSBA"); the Kentucky Cable Telecommunications Association ("KCTA"); AARP; and the Association of Community Ministries ("ACM").

On February 16, 2010, the Commission issued a procedural order establishing the schedule for processing this case. The schedule provided for discovery, intervenor testimony, rebuttal testimony by LG&E, an evidentiary hearing, and an opportunity for the parties to file post-hearing briefs.[4] Intervenor testimonies were filed on April 22 and 23, 2010. LG&E filed its rebuttal testimony on May 27, 2010.

On June 2 and 3, 2010, an informal conference was held at the Commission's offices to discuss procedural matters and the possible resolution of pending issues.[5] All of the parties, except the AG, participated in the conference. Also on June 2, 2010, the

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[4] After establishing the procedural schedule for the evidentiary portion of the case, the Commission scheduled and conducted four public meetings in the service territories of LG&E and KU. The public meetings were held on April 27, 2010, in Harlan; May 3, 2010, in Louisville; May 4, 2010, in Madisonville; and May 6, 2010, in Lexington.

[5] For administrative efficiency, the informal conference was a joint conference for this case and the rate case of KU, Case No. 2009-00548.

AG filed a motion to dismiss this case claiming that the pending acquisition of E.ON by PPL Corporation ("PPL") renders the historical test year proposed by LG&E unreasonable for use in setting rates.[6] On June 7, 2010, LG&E and KU filed a joint response in opposition to the AG's motion to dismiss. The Commission, in an Order issued June 8, 2010, denied the AG's motion without prejudice, stating that "[t]he AG may pursue this issue and renew his motion if he so chooses."

On June 8, 2010, LG&E, KU, and the intervenors in this case and Case No. 2009-00548, with the exception of the AG, filed a Stipulation and Recommendation ("Stipulation"), attached hereto as Appendix A, which was intended to address all of the issues raised in the two rate cases. Under the terms of the Stipulation, the utilities and signatory intervenors agreed to forego cross-examination of each other's witnesses at the evidentiary hearing.

Because the Stipulation was not unanimous, the hearing set for June 8, 2010, convened as scheduled for the purposes of hearing (1) testimony by LG&E and KU in support of the Stipulation and (2) testimony by LG&E, KU and the AG on contested issues related to the amount of the revenue increases sought by LG&E and KU.[7] On June 25 and 29, 2010, respectively, LG&E and the AG filed their post-hearing briefs. The AG also filed on June 29, 2010, a renewed motion to dismiss this case and the KU rate case, to which LG&E and KU filed a joint response on July 8, 2010. This matter now stands submitted to the Commission for a decision.

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[6] The AG's motion to dismiss also applied to KU's case, Case No. 2009-00548.

[7] The AG stated at the hearing that he did not object to the manner in which non-revenue requirement issues were addressed and resolved in the Stipulation.

AG'S RENEWED MOTION TO DISMISS

On June 29, 2010, the AG filed a renewed motion to dismiss both LG&E's rate application and KU's, which is pending in Case No. 2009-00548. The basis for the renewed motion is a claim that the announced acquisition of LG&E and its affiliate, KU, by PPL has created a material change which renders the historic test year no longer reasonable for use in setting rates in this case. The AG previously filed a similar motion on June 2, 2010, prior to the evidentiary hearing held on June 8, 2010. By Order issued on June 8, 2010, the Commission denied the AG's earlier motion based on the absence of any evidentiary support for his claim that the historic test period was no longer reasonable for setting rates. That denial was, however, without prejudice to his renewing the motion after the hearing if he could present evidentiary support either through the supplemental testimony of his own witnesses or through cross-examination at the hearing.

The AG's renewed motion cites to a number of references in the record, some of which predate the hearing, which he argues support his claim that LG&E's test year is unreliable for setting rates. He also argues that the use of known and measurable adjustments will not render the test period reliable, and that the evidentiary record is insufficient to determine whether the proposed acquisition by PPL is irrelevant and immaterial to the rate case. Finally, he argues that if the PPL acquisition is approved, it will result in a material change to LG&E, but LG&E has failed to address in this case the impacts of that change on its going-forward operations.

On July 6, 2010, LG&E and KU filed a joint response in opposition to the AG's renewed motion. LG&E states that the evidentiary record cited by the AG shows nothing more than vague allegations that if the PPL acquisition is consummated, it may have a potential impact at some time in the future. LG&E also dismisses the AG's claim that LG&E's witnesses were somehow remiss in failing to revise their testimony or data responses to reflect the impacts of the proposed PPL acquisition. No such revisions were necessary, according to LG&E, because the acquisition will have no impact on this rate case.

Based on the AG's renewed motion to dismiss and being otherwise sufficiently advised, the Commission finds that the evidentiary references cited by the AG do not demonstrate that the historic test year used in this case is unreliable for setting rates. At best, the AG's citations show that if the PPL acquisition is consummated, there is the mere potential for expenses to change at some indefinite time in the future.

The record does, however, contain other evidence, not cited by the AG, that demonstrates that the PPL acquisition has been structured to have no financial impact on LG&E.[8] Thus, any impacts of the proposed PPL acquisition are simply too far off and too remote to render unreliable LG&E's test year in this case, the 12 months ending October 31, 2009. The AG's evidentiary references do not persuade us to reject LG&E's test year for use in setting rates in this case. To the contrary, LG&E has shown its test year, with the pro forma adjustments, to be reliable as a starting point for setting rates.

The Commission also finds that, when a historic test year is used for setting rates, pro forma adjustments are allowed for changes that are known and measurable. But the mere fact that a future event, such as a proposed transfer of control, which is

[8] June 8, 2010 Hearing Video Transcript at 1:15:50 pm.

not now measurable, may cause changes in future revenues or expenses does not render the historic test year unreliable. There will always be future events that occur well beyond the end of the test year that may have an impact on the future revenues or expenses of a utility. If a test year was rendered unreliable due to the potential that future events might impact revenues or expenses, no utility would ever be able to adjust its rates.

However, should a future event occur which does adversely impact the revenues or expenses of a utility, KRS Chapter 278 provides ample protection to all those who might be affected. Under KRS 278.260(1), any person with an interest in the rates, including the AG, may file with the Commission a complaint against any utility that any rate is unreasonable, and the Commission may on its own motion initiate such a complaint. And if the utility believes that its rates are unreasonable, it is authorized by KRS 278.180(1) to file a revised schedule of rates.

Finally, there are other consumer protections afforded by KRS Chapter 278, such as for a transaction involving a transfer of control, where the Commission "may grant any application . . . in whole or in part and with modification and upon terms and conditions as it deems necessary or appropriate." KRS 278.020(6). As we stated in our June 8, 2010 Order, the financial impacts of a proposed transfer of control have traditionally been considered as part of an application for approval of the transfer, not as part of a concurrent rate application. The AG, and others, are parties to PPL's application to acquire LG&E, and issues of the future financial impacts of that acquisition are properly considered in that case.

AG'S MOTION TO COMPEL

During the discovery phase of this proceeding, LG&E objected to a data request from the AG requesting LG&E to "List each proposed pro forma entry which was considered in this filing but not made and state the reason(s) why the entry was not made."[9] The basis for LG&E's objection was that such information was protected by the attorney-client privilege and the work product doctrine. LG&E asserted that decisions relating to its rate case adjustments were made in consultation with legal counsel and the response to this request would divulge the contents of communications with counsel and the mental impressions of counsel.

Due to LG&E's objection to providing the information requested, the AG filed a motion to compel the responses, arguing that LG&E failed to provide specific reasons why the information requested would be covered by the attorney-client privilege. The AG contends that such privilege "does not automatically attach because legal counsel has reviewed a matter." The AG also requests that that the procedural schedule be suspended until this discovery dispute is resolved.

LG&E and its sister company, KU, filed a joint response objecting to the AG's motion to compel. LG&E asserts that compelling it to respond to the AG's request for information regarding adjustments contemplated but not included in the rate application would necessarily disclose privileged communications between the utility and its counsel, which are protected from disclosure under the Kentucky Rules of Evidence, KRE 503(b). LG&E contends that any discussions it had with its attorneys concerning the choice of which pro forma adjustments to exclude is not subject to discovery under

[9] AG's Initial Data Requests, Item AG 1-30.

the absolute privilege applicable to the opinion work product as that privilege is codified in the Kentucky Rules of Civil Procedure, CR 26.02(3).[10] LG&E notes that the creation of such adjustments and the determination of which adjustments to include in its rate application are always done in consultation with its counsel, making the facts and its counsel's opinions inseparable. Lastly, LG&E maintains that even if the information sought to be discovered were deemed to be fact work product rather than opinion work product, the AG has failed to establish that he has a substantial need of the materials in the preparation of his case and that he is unable to obtain the equivalent of the materials by other means entitling him to discovery of the information requested.

In his reply, the AG argues that LG&E's interpretation of the attorney-client and work product privileges was too broad. The AG avers that the privileges only protect disclosure of communications and not disclosure of the underlying facts by those communicating with the attorney. The AG states that the information requested is needed by his retained experts in order to properly and fully evaluate whether LG&E's proposed rate increase is fair, just, and reasonable. The AG further states that he cannot duplicate the information concerning possible pro forma adjustments based on the information in the application alone.

In its sur-reply, LG&E reiterated that the determination of which adjustments to include or exclude was based on the advice of counsel and made exclusively in the context of these legal proceedings. Thus, the information sought to be discovered is part and parcel privileged communications between LG&E and its counsel. LG&E

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[10] CR 26.02(3) provides, in relevant part, that, "[T]he court shall protect against disclosure of the mental impressions, conclusions, opinions, or legal theories of an attorney or other representative of a party concerning the litigation.

contends that the AG's claims of substantial need and undue hardship are insufficient to entitle him to discovery of information protected by the work product privilege. LG&E points out that it has produced significant amounts of actual data and documents in addition to the volumes of information contained in its application to allow the AG's experienced and capable legal team as well as his three retained experts to fully process and evaluate the reasonableness of LG&E's proposed rate increase.

Based on the AG's motion and being otherwise sufficiently advised, the Commission finds that, while our proceedings are not governed by either Kentucky's Rules of Evidence or its Rules of Civil Procedure, any privilege so established which shields the disclosure of attorney-client communications must be recognized and applied here. The AG has correctly asserted that the attorney-client privilege does not automatically attach to anything reviewed by counsel. However, under the facts as presented in this rate case, the information sought to be discovered is protected under the opinion work product privilege. The information that the AG seeks to discover – pro forma adjustments contemplated by LG&E but not included its rate application – was formulated by LG&E in consultation with its counsel solely in anticipation of filing this base rate case. LG&E does not create or maintain lists of possible pro forma adjustments and expenses as part of its ordinary business practices. Because LG&E's potential pro forma adjustments are made in contemplation of litigation in rate proceedings, such information is protected by the work product privilege.

The AG claims to seek discovery of only the underlying facts of the communication between LG&E and its counsel regarding potential pro forma adjustments. However, since LG&E consults with its counsel prior to making a determination of whether a pro forma adjustment passes legal ratemaking muster, the AG's request encroaches into an area which would require LG&E to disclose the mental impressions, conclusions, opinions or legal theories of its attorneys. While the AG characterizes his discovery request as one limited to underlying facts, the disclosure of such information would, in essence, reveal LG&E's counsel's impressions of the legal strengths, weaknesses, and best strategic approach in this rate proceeding because the determination of which adjustments to include or exclude are, at their roots, matters of legal strategy. The information sought to be discovered by the AG is absolutely protected under the opinion work product privilege.

The Commission notes that our decision on this issue is expressly limited to discovery of adjustments contemplated, but not filed, by a party in a rate case. Further, our decision applies with equal force to shield from discovery rate case adjustments considered by a utility in conjunction with its counsel, as well as those considered by an intervenor in conjunction with its counsel. Even though contemplated rate case adjustments, when considered in conjunction with counsel, are not subject to discovery, all other aspects of a utility's rate application and its financial records are subject to discovery. Thus, all parties to a rate case have ample opportunity to test and verify the accuracy of the test year and the adjustments proposed thereto, and the need for additional adjustments to ensure that rates are fair, just, and reasonable.

In light of the fact that discovery has been completed and the proceedings are at a conclusion, the Commission finds that the AG's request to suspend the procedural schedule is moot.

STIPULATION

The Stipulation reflects the agreement of the parties, except for the AG, on all issues raised in this case as well as the KU rate case. The main provisions of the Stipulation as they to relate to LG&E's revenues and rates are as follows:

- LG&E's electric revenues should be increased by $74 million and its gas revenues should be increased by $17 million effective August 1, 2010.
- The allocations of the increases in LG&E's electric and gas revenues, respectively, are set forth in Exhibits 2 and 3 to the Stipulation and are fair, just and reasonable rates for LG&E, the parties and LG&E's customers.
- The electric and gas rates in Exhibits 5 and 6, respectively, to the Stipulation are the fair, just, and reasonable rates for LG&E and those rates should be approved by the Commission.
- The monthly residential electric customer charge should be $8.50 and the monthly residential gas customer charge should be $12.50.
- A reasonable range for LG&E's return on equity is 10.25 to 10.75 percent, with 10.63 percent continuing to be used in LG&E's monthly environmental cost recovery filings.

The Stipulation addresses several other issues, including revenue allocation, rate design, tariffs, and contributions to various low-income assistance programs. The major provisions of the Stipulation for LG&E's operations are as follows:

- New curtailable electric service riders, CSR 10 and CSR 30, will be implemented as set forth in Exhibit 5 to the Stipulation.
- Upon request, customers on either CSR 10 or CSR 30 will be provided monthly explanations for any curtailments.
- Upon request, LG&E will provide CSR customers with good-faith, non-binding estimates of the duration of requested service interruptions under Riders CSR10 and CSR 30.
- LG&E will work with its curtailable customers to install needed

telecommunication and control equipment to allow for control of the customers' loads by LG&E.

- The minimum demand ratchet for transmission service under Rate FLS will be 40 percent.

- LG&E will withdraw its proposal for kVa billing for Rate ITODP in this proceeding; however, the parties agree not to object to kVa-based billing for commercial and industrial rates in LG&E's next base rate proceeding.

- LG&E should be permitted to recover its actual rate case expenses for this case over a three-year period to begin in the month after the month in which a final order in this case is issued.

- The costs related to LG&E's 2001 and 2003 environmental compliance plans are to be recovered in its base rates and removed from LG&E's monthly environmental surcharge filings effective with the August 2010 expense month.

- LG&E's request to establish and amortize over 24.75 years a regulatory asset for the costs associated with the interest rate swap agreement between LG&E and Wachovia Bank, N.A., with the amortization beginning in the month after the month in which the final order in this case is issued, should be approved.

- LG&E should be permitted to amortize over ten years the regulatory assets previously authorized by the Commission for the costs incurred in conjunction with the 2008 wind storm and 2009 winter storm, with the amortization beginning in the month after the month in which the final order in this case is issued.

- LG&E should be permitted to amortize over four years the regulatory asset previously authorized by the Commission for LG&E's participation in the Kentucky Consortium for Carbon Storage ("KCCS"), with the amortization beginning in the month after the month in which the final order in this case is issued.

- LG&E should be permitted to amortize over ten years the regulatory asset previously authorized by the Commission for LG&E's participation in the Carbon Management Research Group ("CMRG"), with the amortization beginning in the month after the month in which the final order in this case is issued.

- LG&E commits to propose, in its next Demand-Side Management application, to modify its existing commercial conservation and rebates program to broaden the financial incentives for qualifying commercial customers to replace relatively inefficient equipment.

- The parties acknowledge that LG&E has established a FLEX Option program to allow customers unable to pay their bills, due to the timing of receipt of a monthly check, 16 additional days to pay their bills, the details of which are shown in Exhibit 7 to the Stipulation.

- LG&E's residential electric customer deposit shall remain at $135 while its residential gas customer deposit shall be reduced to $115, with the deposit for a combined residential electric and gas customer being $250. All other customer deposit amounts will be as filed by LG&E in this case.

- LG&E shall continue its current policy of permitting customers required to make a deposit as a condition of reconnection after disconnection for non–payment to make their deposits in up to four monthly installments, upon request.

- Starting October 1, 2010, residential customers receiving a pledge or notice of low-income energy assistance from an authorized agency will not be assessed a late payment charge for a period of 12 months.

- The due date provisions of LG&E's tariffs will be modified to specify that the due date for payment is 12 <u>calendar</u> days from the date of the bill and that a late payment charge will be assessed if payment is not received within three <u>calendar</u> days of the due date.

- On and after August 1, 2010, LG&E will print on each bill issued to customers the date on which the bill was mailed.

- For 2011 and 2012, LG&E shall continue its current matching contribution from shareholder funds to the Wintercare program to match Wintercare funds collected from customers.

- For a period of two years beginning February 6, 2011, LG&E shall make dollar-for-dollar contributions from shareholders to its Home Energy Assistance ("HEA") program to match HEA funds collected from customers (up to $300,000 a year on a combined basis with KU).

- LG&E will continue its current matching contribution to the ACM/Metro Match program for two years after implementation of the rates included in the Stipulation. LG&E's contribution for each of the two years shall not exceed $225,000.

- By January 1, 2011, LG&E will have decreased the targeted window of time in which to read a customer's meter from five days to three days.

- LG&E's per-attachment annual rental charge under Rate CTAC for cable television attachments shall be $5.35.

- LG&E shall exempt locations that install back-up generators using less than 2,000 cf per hour from the application of Rate DGGS if the customers owning such generators agree to use them only to provide emergency power.

- Except as modified in the Stipulation and the attached exhibits, the rates, terms and conditions proposed in LG&E's application shall be approved as filed.

In its application, LG&E proposed annual increases in its electric and gas revenues of $94,973,371 and $22,598,160, respectively. The AG proposed an annual decrease in LG&E's electric revenues of $8,344,769 and no change in its gas revenues. With the exception of the AG, the parties agree that annual increases in electric revenues of $74,000,000 and gas revenues of $17,000,000, as provided in the Stipulation, are reasonable. Since all parties have not reached a unanimous settlement on the level of revenues, the Commission must consider the evidentiary record on this issue and render a decision based on a determination of LG&E's capital, rate base, operating revenues, and operating expenses as would be done in any litigated rate case.

TEST PERIOD

LG&E proposes the 12-month period ending October 31, 2009 as the test period for determining the reasonableness of its proposed rates. Although the AG has renewed his motion to dismiss this case based on the alleged unreasonableness of the proposed test year, he utilized the same test period in his analysis of LG&E's revenue requirements. Other than his argument that the recently announced proposed acquisition of LG&E by PPL Corporation renders the test year unreliable, the AG has provided no other challenge to the test year.

The Commission finds it reasonable to use the 12-month period ending October 31, 2009 as the test period in this case. That period is the most recent feasible period to use for setting rates, and the revenues and expenses incurred during that period are neither unusual nor extraordinary, except as have been adjusted by normalization and known and measurable changes. In using this historic test period, the Commission has given full consideration to appropriate known and measurable changes.

RATE BASE

Rate Base Allocation Ratio

LG&E proposed a test year electric rate base of $1,903,319,053. The electric rate base is divided by the total company rate base to derive a rate base allocation ratio ("allocation ratio"). This ratio is then applied to LG&E's total company capitalization to derive its electric capitalization, while the inverse of the allocation ratio is used to derive the gas capitalization. The allocation ratio uses the test-year-end rate base before any rate-making adjustments applicable to either electric or gas operations are recognized. LG&E used an allocation ratio of 79.62 percent.[11] The Commission has reviewed and agrees with the calculation of LG&E's test year electric rate base for purposes of establishing the rate base allocation ratio.

[11] Rives Direct Testimony, Exhibit 3.

Electric Rate Base

LG&E calculated a pro forma electric rate base of $1,848,557,684, which reflects the types of adjustments made by the Commission in prior rate cases to determine a utility's pro forma rate base. The AG did not address LG&E's proposed electric rate base in his testimony. The Commission has accepted LG&E's pro forma electric rate base for rate-making purposes except for the allowance for cash working capital, which is adjusted based on the adjustments to operation and maintenance expenses discussed later in this Order. Based on our findings, we have determined LG&E's pro forma electric rate base for rate-making purposes as of October 31, 2009 to be as follows:

Total Utility Plant in Service	$ 3,774,003,710
Add:	
Materials & Supplies	78,422,832
Prepayments	3,236,899
Cash Working Capital Allowance	75,535,857
Mill Creek Ash Dredging – Regulatory Asset	2,400,596
Subtotal	$ 159,596,184
Deduct:	
Accumulated Depreciation	$ 1,703,730,284
Customer Advances	1,848,625
Accumulated Deferred Income Taxes	338,384,167
SFAS 109 Accumulated Deferred Income Taxes	37,321,392
Asset Retirement Obligation – Net Assets	3,342,267
Asset Retirement Obligation – Regulatory Liabilities	703,529
Subtotal	$ 2,085,330,264
Pro Forma Electric Rate Base	$ 1,848,269,630

Gas Rate Base

LG&E calculated a pro forma gas rate base of $486,583,169 based on the inverse of the rate base allocation ratio used to develop the electric rate base and capitalization. The AG did not address LG&E's proposed gas rate base in his testimony. It reflects the types of adjustments made by the Commission in prior rate cases to determine the pro forma rate base. The Commission has accepted LG&E's gas rate base for rate-making purposes except for the allowance for cash working capital, which is adjusted based on the adjustments to operation and maintenance expenses discussed later in this Order. Based on our findings, we have determined LG&E's pro forma gas rate base for rate-making purposes as of October 31, 2009 to be as follows:

Total Utility Plant in Service	$ 726,844,571
Add:	
Materials & Supplies	60,055
Prepayments	659,791
Cash Working Capital Allowance	7,745,080
Gas Stored Underground	66,447,790
Subtotal	$ 74,912,716
Deduct:	
Accumulated Depreciation	$ 252,316,182
Customer Advances	7,485,292
Accumulated Deferred Income Taxes	48,874,215
SFAS 109 Accumulated Deferred Income Taxes	4,053,496
Asset Retirement Obligation – Net Assets	131,229
Asset Retirement Obligation – Regulatory Liabilities	2,353,476
Subtotal	$ 315,213,890
Pro Forma Gas Rate Base	$ 486,543,397

Reproduction Cost Rate Base

LG&E presented a total company reproduction cost rate base of $5,233,171,482, an electric operations reproduction cost rate base of $4,176,096,342 and a gas operations reproduction cost rate base of $1,057,075,140.[12] The costs were determined principally by indexing the surviving plant and equity using the Handy-Whitman Index of Public Utility Construction Costs and the Consumer Price Index.[13] The Commission has given appropriate consideration to the proposed reproduction cost rate base, but finds that using LG&E's historic cost for rate base is more appropriate and consistent with the precedents for LG&E as well as other jurisdictional utilities within Kentucky.

CAPITALIZATION

Electric Capitalization

LG&E proposed an adjusted electric capitalization of $1,805,791,767.[14] Included in its electric capitalization were adjustments for the Job Development Investment Tax Credit ("JDIC"), the removal of 25 percent of inventories associated with Trimble County Unit 1, the Advanced Coal Investment Tax Credit, LG&E's equity investment in the Ohio Valley Electric Corporation, the Trimble County joint use assets transferred from LG&E to KU, and removal of the environmental compliance investments which remain part of the environmental rate base included in LG&E's environmental surcharge mechanism. As with LG&E's rate base, the AG did not address LG&E's electric capitalization. LG&E

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[12] Id. Exhibit 5.

[13] Id. at 31.

[14] Id. Exhibit 2.

determined its electric capitalization by multiplying its total company capitalization by the rate base allocation ratio described earlier in this Order. This is consistent with the approach used by the Commission in previous LG&E rate cases. Based on our review of LG&E's adjustments, we will accept its proposed electric capitalization of $1,805,791,767.

Gas Capitalization

LG&E proposed an adjusted gas capitalization of $466,472,963.[15] The only adjustment included in LG&E's gas capitalization was for JDIC. The AG did not address LG&E's gas capitalization. LG&E determined its gas capitalization in the same manner as its electric capitalization based on the inverse of the rate base allocation ratio described earlier in this Order. This is consistent with the approach used by the Commission in previous LG&E rate cases. Based on our review of LG&E's adjustments, we will accept its proposed gas capitalization of $466,472,963.

REVENUES AND EXPENSES

For the test year, LG&E reported actual net operating income from its electric and gas operations of $133,953,246 and $19,920,343, respectively. LG&E proposed a series of adjustments to revenues and expenses to reflect more current and anticipated operating conditions, resulting in adjusted electric net operating income of $90,862,701 and adjusted gas net operating income of $24,681,748.[16] During the course of this case, LG&E identified and corrected errors and revised several of the adjustments included in its application. These changes resulted in increasing LG&E's adjusted

[15] Id.

[16] Id., Exhibit 1.

electric net operating income to $91,297,699 and increasing its adjusted gas net operating income to $25,000,038.[17] The AG opposed six of the proposed adjustments, five affecting LG&E's electric operations and one affecting its gas operations. The AG also proposed adjustments to the calculation of LG&E's income tax expense. We find that the adjustments proposed by LG&E and accepted by the AG are reasonable and should be accepted by the Commission. For the remaining adjustments, which relate to (1) the treatment of regulatory assets related to storm restoration costs, (2) the treatment of regulatory assets related to participation in carbon capture and storage projects, (3) electric weather normalization and (4) the appropriate income tax rate, the Commission makes the following findings and conclusions:[18]

Storm-Related Regulatory Assets

LG&E requests recovery of amortization of regulatory assets for storm removal costs related to the 2008 Wind Storm and 2009 Winter Storm.[19] Total electric expense adjustments related to the amortization of these items is $27,630,386 for the 2008 Wind Storm and $8,734,140 for the 2009 Winter Storm.[20] LG&E's gas expense adjustment related to the 2009 Winter Storm is $33,538.

[17] LG&E's Response to Commission Staff's Fourth Data Request, Item 2, Revised Exhibit 1, page 3 of 3.

[18] There are both electric and gas regulatory asset adjustments and income tax adjustments; hence, the earlier reference to six adjustments.

[19] The regulatory asset related to the 2008 Wind Storm was authorized in Case No. 2008-00456, while the regulatory asset related to the 2009 Winter Storm was authorized in Case No. 2009-00175.

[20] The adjustment related to the 2008 Wind Storm reflects reversing net credits during the test year to establish the regulatory asset along with a five-year amortization of the asset.

The AG claims it is unnecessary for the Commission to allow rate recovery of the amortization expenses because these costs were "prefunded" through recovery of the asset removal cost component of LG&E's depreciation. The AG argues that LG&E has recovered $259 million more in asset removal costs than its actual cost of removal expenses. Thus, he contends there are "excess" funds available to offset the deferred storm damage costs.[21]

LG&E contends that amortization of the storm damage costs is appropriate for rate recovery as these costs reflect prudently incurred expenses which the Commission authorized it to defer as regulatory assets. Further, LG&E points out that asset removal costs recovered via depreciation should only be used for their intended purpose, namely asset removal. Otherwise, the funds will not be available when assets require removal.[22]

We are not persuaded by the AG's arguments. The amounts deferred by LG&E were approved by the Commission in previous cases. The AG does not dispute the amounts that were deferred; he only challenges the rate treatment of these amounts. LG&E's proposal to amortize these amounts in this rate proceeding is in accordance with long-standing generally accepted rate-making practices employed by the Commission. The amounts collected by LG&E through depreciation for asset removal costs should only be used for their intended purpose, which is to fund the costs to remove assets. Any concerns the AG has regarding the alleged "excessive" recovery of

[21] Majoros Testimony at 4-6.

[22] Charnas Rebuttal Testimony at 5-9.

asset removal costs should be raised by the AG when LG&E files its next depreciation case with the Commission.

Carbon Project Regulatory Assets

LG&E requests recovery of the amortization expense for regulatory assets for research contributions paid to the KCCS and the CMRG. The total expense adjustments related to the amortization of these items is $343,330 for the KCCS and $(1,940) for the CMRG.[23]

Based on the same arguments he relies upon in contesting the storm-related adjustments, the AG contends the Commission should not allow rate recovery of these amortization expenses because these costs were "prefunded" through recovery of the asset removal cost component of LG&E's depreciation. As with the storm-related regulatory assets, the AG argues that LG&E has "excess" funds available to offset the deferred storm damage costs.[24]

LG&E argues that amortization of the KCCS and CMRG costs is appropriate for rate recovery given that they are prudently incurred costs which the Commission has authorized it to defer as regulatory assets. As in the case of the storm-related costs, LG&E states that asset removal costs recovered via depreciation should only be used for their intended purpose, asset removal, or the funds will not be available when assets require removal.[25]

[23] The KCCS adjustment includes reversing the credit during the test year to establish the regulatory asset in addition to the amortization of the asset. The CMRG adjustment reflects the net of the test year expense and the yearly amortization.

[24] Majoros Testimony at 6.

[25] Charnas Rebuttal Testimony at 9-11.

Again, the Commission is not persuaded by the AG's arguments. There is clearly no relationship between the costs of carbon capture and storage projects and the cost of removal component of LG&E's depreciation. The amounts deferred by LG&E were previously authorized by the Commission. LG&E's proposal to amortize these amounts in this rate proceeding is consistent with this Commission's long-standing generally accepted rate-making practices. The amounts collected by LG&E through depreciation for asset removal costs should only be used for their intended purpose, which is to fund to costs to remove assets. The AG can raise any concerns he has with alleged "excessive" recovery of asset removal costs when LG&E files its next depreciation case with the Commission.

Electric Weather Normalization

LG&E proposes an electric weather normalization adjustment which increases revenues by $5,151,223 and expenses by $1,899,644.[26] The AG opposes the proposed adjustment, arguing that LG&E's method is improper because it separates and analyzes each month of the year mutually exclusive from the other months and then adjusts only those months with significant temperature variations from the norm. This methodology ignores the fact that significant fluctuations in temperature in one month may be offset by less dramatic fluctuations in other months when considered on a combined basis.[27]

The Commission recognizes that LG&E's continued refinement to the method it uses to calculate the proposed adjustment has greatly improved its ability to measure

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[26] Rives Direct Testimony, Exhibit 1, Reference Schedule 1.11.

[27] Watkins Testimony at 3 – 5.

the impact of temperature on its sales of electricity. However, the Commission shares the concerns expressed by the AG regarding the exclusive nature of the methodology employed by LG&E to develop its electric weather normalization adjustment. Accordingly, we will not approve LG&E's proposed electric weather normalization adjustment.

Income Tax Rate

In past rate cases, LG&E has been allowed rate recovery of state and federal income taxes based on statutory tax rates. It requested the same rate treatment in this case, using a state tax rate of 6 percent and a federal tax rate of 35 percent.

The AG claims that this method of tax recovery is unreasonable and that the Commission should instead use the same "effective tax rate" methodology as it used for Kentucky-American Water Company ("Kentucky American") in Case No. 2004-00103.[28] The AG argues that LG&E does not actually pay the statutory tax rates because its profits are netted against losses of affiliated companies on a consolidated tax return filed by LG&E's intermediate parent, E.ON US. The AG calculated the effective federal tax rate paid by LG&E as 6 percent based on the average tax payments for the previous two years. The AG calculated the impacts of these adjustments as reductions to LG&E's electric and gas rate increases of $34.9 million and $4.3 million, respectively.[29]

LG&E's rebuttal to the AG contains several arguments: 1) the AG's proposal represents a radical and abrupt departure from 20 years of well-established, sound, and

[28] Adjustment of Rates of Kentucky-American Water Company (Ky. PSC Feb 28, 2005).

[29] Majoros Testimony, Exhibit MJM-1, Schedule 1.4.1 and Exhibit MJM-3, Schedule 3.3.1.

balanced policy prohibiting affiliate cross-subsidization;[30] 2) the AG's proposal violates LG&E's Corporate Policies and Guidelines for Intercompany Transactions, which require allocation of income tax liability on a "stand alone" basis; 3) the proposal violates the "benefits-burden" principal, meaning that, since its customers bore none of the risk of the losses incurred by the affiliates, which produced the tax losses, they should not benefit from those losses; 4) the proposal would preclude LG&E from the opportunity to achieve its authorized rate of return; 5) Case No. 2004-00103 should not be considered precedent setting in this case as the Commission approved the adjustment in that case because Kentucky-American promoted the tax savings as a benefit to merger in Case No. 2002-00317,[31] a fact that is absent in the current situation; and 6) in previous LG&E cases, the Commission rejected effective tax rate adjustments proposed by the AG where the AG used 2004-00103 as a precedent.[32]

We are not persuaded by the AG's arguments in this case on this issue any more than we were in Case No. 2003-00433.[33] Acceptance of the AG's proposal would preclude LG&E from the opportunity to earn its authorized rate of return; would violate the "stand-alone" rate-making principal the Commission has long employed; and would result in cross subsidization of LG&E and its ratepayers by its unregulated affiliates.

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[30] LG&E created a holding company approximately 20 years ago. Prior to then, it did not have non-utility affiliates and use of a consolidated tax return was not an issue.

[31] A Change of Control of Kentucky American Water Company (Ky. PSC Dec. 20, 2002).

[32] Rives Rebuttal Testimony at 15-19.

[33] Adjustment of the Gas and Electric Rates, Terms and Conditions of Louisville Gas and Electric Company (Ky. PSC June 30, 2004 and Mar. 31. 2006).

Net Operating Income Summary

After considering all pro forma adjustments and applicable income taxes, LG&E's adjusted net operating income is as follows:

Combined Operating Revenues	$ 1,028,519,781
Combined Operating Expenses	915,473,623
Combined Adjusted Net Operating Income	$ 113,046,158

RATE OF RETURN

Capital Structure

LG&E proposed an adjusted test-year-end capital structure containing 46.14 percent long-term debt and 53.86 percent common equity.[34] The absence of short-term debt reflects LG&E's use of such funds to reacquire, but not retire, approximately $150.7 million in bonds during the test year.

The AG recommends an adjusted capital structure for LG&E containing 50.0 percent long-term debt and 50.0 percent common equity based on his review of the capital structure ratios of electric and gas proxy groups.[35] LG&E opposes the AG's proposal, citing its long-standing objective of achieving an "A" corporate credit rating as defined by Standard & Poors ("S&P"), and the need to maintain a common equity ratio, as adjusted by S&P, of 50 to 55 percent. Given the consistent downward nature of S&P's adjustments, LG&E argues that a common equity ratio established at 50 percent, prior to recognizing such adjustments would, at best, result in it maintaining its current "BBB" rating. LG&E also points to its historic equity ratios (including both common stock and preferred stock, when it had preferred stock) over the past ten years as

[34] Rives Direct Testimony, Exhibit 2.

[35] Woolridge Testimony at 13.

ranging between 51.04 and 56.76 percent.[36] With its stated goal of achieving an "A" rating and its current equity ratio falling roughly at the mid-point of its historical equity ratios, the Commission finds that LG&E's capital structure for rate-making purposes should not be adjusted to reflect what would constitute a hypothetical capital structure, as proposed by the AG. Achieving an A rating will provide LG&E greater access to capital markets, access to lower cost debt and greater financial flexibility. We find that LG&E's capital structure for rate-making purposes should include 46.14 percent long-term debt and 53.86 percent common equity as proposed by LG&E.

Cost of Debt

LG&E proposed a cost of long-term debt of 4.61 percent.[37] LG&E filed updated financial information as of March 31, 2010 that included updated cost rates.[38] Based on this updated information, LG&E's cost of long-term debt is 4.60.

The AG used LG&E's cost of debt as filed in its application. The AG agreed that if interest rates or other capital cost rates change, such changes should be used to determine the rate of return so that LG&E will have a reasonable opportunity to earn its allowed return.

The Commission finds it appropriate to recognize the cost rate for LG&E's long-term debt as of March 31, 2010 when determining its overall cost of capital. Updates to LG&E's long-term debt cost rate constitute known and measurable adjustments and

[36] Arbough Rebuttal Testimony at 1-4.

[37] Rives Direct Testimony, Exhibit 2.

[38] LG&E's Response to Commission Staff's Fourth Date Request, Item 2, Revised Exhibit 2.

using these updates, rather than the test-year-end cost rates, is more representative of the period in which the rates established in this Order will be in effect. This cost rate will be applied to the capital structure determined herein. Therefore, the Commission finds the cost of LG&E's long-term debt to be 4.60 percent.

Return on Equity

LG&E estimated its required return on equity ("ROE") using the discounted cash flow method ("DCF"), the capital asset pricing model ("CAPM"), and the expected earnings approach.[39] LG&E included in its evaluation risks and challenges specific to jurisdictional utility operations in Kentucky, as well as flotation costs. Based on the results of the methods employed in its analysis, LG&E recommended an ROE range for its electric and gas operations of 10.5 to 12.5 percent.[40] LG&E recommended awarding the midpoint of the range, 11.5 percent, in order to support access to capital and recognize flotation costs.[41] Through settlement negotiations, the Stipulation contains an agreement by all the parties except the AG that a reasonable range for LG&E's ROE is 10.25 to 10.75 percent.[42]

LG&E employed a comparable risk proxy group in its analysis which consists of 14 electric utility companies classified by *The Value Line Investment Survey* ("Value Line") as having both electric and gas operations; S&P's corporate credit ratings of

[39] Avera Direct Testimony, at 5.

[40] Id. at 5.

[41] Id.

[42] Joint Motion for Leave to File Stipulation and Recommendation and Testimony, Bellar Testimony at 6.

"BBB", "BBB+", "A-", or "A"; a Value Line Financial Strength Rating of "B++" or higher; and published earnings per share ("EPS") growth projections from at least two of the following: Value Line; Thomson I/B/E/S; First Call Corporation; and Zacks Investment Research. LG&E also applied the DCF model to a proxy group of comparable risk non-utility companies followed by Value Line that pay common dividends; have a Safety Rank of "1"; have investment grade credit ratings from S&P; and have a Value Line Financial Strength Rating of "B++" or higher. The same criterion was applied to this group as the utility group of having published EPS growth projections from the sources listed above.

As part of its analysis, LG&E provided a discussion of fuel adjustment clause, gas supply clause, environmental cost recovery and weather normalization mechanisms that affect its rates for utility service. It also discussed the evolution of investors' risk perceptions for the utility industry due to erosion in credit quality, quoting S&P's identification of environmental compliance costs, decreasing demand, and increasing cost recovery filings as significant challenges for the utility industry.[43] LG&E's need for additional capital for maintenance, replacements, and facilities additions will require support for LG&E's financial integrity and flexibility, and this will be impacted by energy market volatility and environmental considerations, according to LG&E. In addition to these factors, LG&E points to investors' recognition of the global recession's impact on LG&E's service territory as evidence of LG&E's need to support its credit standing and financial flexibility through the opportunity to earn a return that reflects these realities.

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[43] Id. at 10.

The AG criticized LG&E's ROE estimates on several grounds. The AG stated that LG&E's proxy group of utility companies includes companies with a low percentage of regulated utility operations revenue, and that the use of a proxy group of non-utility companies is inappropriate. The AG's major disagreement with LG&E's DCF analysis is the reliance on projected EPS growth rates in developing the growth factor component, and contends that Value Line's estimated long-term EPS growth rates are overstated. The AG stated that the primary problem with LG&E's CAPM analysis is the market risk premium used in the analysis, which the AG contends is based on an expected stock market return which is not reflective of current market fundamentals. The AG disagreed with LG&E's expected earnings approach, and stated that it is subject to error and fails to provide a reliable estimate of LG&E's cost of equity capital. The AG also recommends against LG&E's proposed adjustment for flotation costs. The AG believes that LG&E's analysis overstates its required cost of equity.

The AG estimated LG&E's required ROE for its electric and gas operations separately using the DCF model and the CAPM. Based on the results of these methods, giving primary weight to the DCF, the AG determined an ROE range of 7.8 to 9.5 percent for LG&E's electric operations, recommending that the Commission award 9.5 percent, the upper end of the range.[44] The AG determined an ROE range of 7.6 to 9.0 percent for LG&E's gas operations, with a recommended award of 9.0 percent.[45]

The AG employed an electric proxy group in his analysis consisting of 20 utility companies listed as an electric or combination electric and gas utility by AUS Utility

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[44] Woolridge Testimony at 2.

[45] Id. at 2.

Reports; having regulated electric revenues of at least 80 percent of total revenues; with current data available in the Standard Edition of Value Line; having an investment grade bond rating; and having an annual dividend history of three years. The AG's gas proxy group consists of nine natural gas distribution companies listed as a Natural Gas Distribution, Transmission, and/or Integrated Gas Company in AUS Utility Reports; listed as a Natural Gas Utility in the Standard Edition of Value Line; having at least 50 percent of revenues from regulated gas operations; and having an investment grade bond rating by Moody's and S&P.

The AG supported his analysis with a discussion of current economic conditions, concluding that short- and long-term credit markets have "loosened" considerably,[46] and that the stock market has rebounded significantly from 2009's lows. The AG's discussion includes a reference to a study indicating that the investment risk of utilities is very low, and states that the cost of equity for utilities is among the lowest of all industries in the U.S. as measured by their betas.[47]

On rebuttal, LG&E addressed the AG's recommended ROE and his criticisms of LG&E's analysis. LG&E compared its DCF analysis to that of the AG's, stating that the AG presented historical results as being indicative of investors' future expectations, while LG&E used forward-looking data, which is a superior method due to specific trends in dividend policies and evidence from the investment community; that the AG considered analysts' EPS forecasts as being biased while LG&E's application of the DCF model recognizes the importance of considering investors' perceptions and

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[46] Id. at 11.

[47] Id. at 21.

expectations; that the AG relied upon personal views rather than the capital markets for investors' expectations; and that while LG&E excludes data in its analysis that would lead to illogical conclusions, the AG relies on averaging or using the median value to eliminate any bias. LG&E also addresses the AG's criticism of the use of a non-utility proxy group, saying that it would be inconsistent with the Hope[48] and Bluefield[49] cases to exclude non-utility company returns from consideration. LG&E counters the argument that the expected earning approach is not valid, saying that an allowed ROE for a utility company must be high enough to attract capital from investors who are looking for the best investment opportunity. LG&E recommended that the AG's CAPM analysis be disregarded, noting that the AG gave primary weight to its DCF analysis. LG&E defended the market return used in its CAPM analysis, saying that its analysis appropriately focuses on investors' current expectations. LG&E reiterates the need for a flotation cost adjustment in its ROE calculation, saying that there is no basis to ignore such an adjustment.

The Commission finds merit in both LG&E's and the AG's recommended ranges for ROE and their critiques of each other's analyses. The Commission takes note of several points made in each party's testimony and analysis. LG&E's argument concerning the appropriateness of using investors' expectations in performing a DCF analysis is more persuasive than the AG's argument that analysts' projections should be rejected in favor of historical results. The Commission agrees that analysts' projections

[48] *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. (1944).

[49] *Bluefield Waterworks and Improvement Company v. Public Service Commission*. 262 U.S. 679 (1932).

of growth will be relatively more compelling in forming investors' forward-looking expectations than relying on historical performance, especially given the current state of the economy. It also appears preferable to exclude extreme outliers in ROE analysis; for example, the AG's inclusion of negative results to calculate investors' required ROE does not comport with the constant growth assumption that is inherent in the DCF formula. Concerning the issue of using a non-utility proxy group in analyzing the required ROE for a utility, the Commission agrees with LG&E that investors are always looking for the best investment opportunity and that a utility is in competition with unregulated firms; however, the AG's discussion of the relative risk of electric and gas utilities as reflected in their Value Line Betas supports the attractiveness of utility investments in comparison to riskier alternatives. As to flotation costs, the Commission agrees with the AG's position that no upward adjustment to the equity cost rate is necessary and that this finding is consistent with past Commission practice.

After weighing all the evidence of record, the Commission finds that LG&E's required ROE for both electric and gas operations falls within a range of 9.75 to 10.75 percent with a midpoint of 10.25 percent.

Rate of Return Summary

Applying the rates of 4.60 percent for long-term debt and 10.25 percent for common equity to the capital structure produces an overall cost of capital of 7.64 percent. The cost of capital produces a return on LG&E's rate base of 7.44 percent.

REVENUE REQUIREMENTS

The Commission has determined that, based upon an electric capitalization of $1,806,059,614 and an overall cost of capital of 7.64 percent, the electric net operating income that could be justified by the record for LG&E is $138,038,764. Based upon a gas capitalization of $466,472,963 and an overall cost of capital of 7.64 percent, the gas net operating income that could be justified by the record for LG&E is $35,652,960. Based on the adjustments found reasonable herein, LG&E's *pro forma* electric net operating income and gas net operating income for the test year would be $88,046,120 and $25,000,038, respectively. It would need additional annual electric operating income of $49,992,644 and additional gas operating income of $10,652,922. After the provision for uncollectible accounts, the PSC Assessment, and state and federal income taxes, LG&E would have an electric revenue deficiency of $80,042,111 and a gas revenue deficiency of $17,056,157, for a total of $97,098,268.

The calculation of this overall revenue deficiency is as follows:

Combined Net Operating Income Found Reasonable	$173,691,724
Combined Pro Forma Net Operating Income	113,046,158
Net Operating Income Deficiency	$ 60,645,566
Gross Up Revenue Factor[146]	.6245793
Overall Revenue Deficiency	$ 97,098,268

The Commission has found that LG&E's required ROE falls within a range of 9.75 percent to 10.75 percent, with a mid-point of 10.25 percent. Applying the findings herein on the reasonable cost of debt and the return on common equity to LG&E's electric and gas capitalizations would result in the following revenue increases:

Electric Increase based on LG&E Alternative Proposal	$74,000,000
Electric Increase justifiable based on ROE mid-point	$80,042,111
Gas Increase based on LG&E Alternative Proposal	$17,000,000
Gas Increase justifiable based on ROE mid-point	$17,056,157

Based on the findings and conclusions herein, the Commission finds that the earnings resulting from the adoption of LG&E's alternative proposals for its electric and gas operations will produce a reasonable result for both LG&E and its ratepayers. The $74,000,000 electric revenue increase and $17,000,000 gas revenue increase that LG&E is willing to accept will result in fair, just, and reasonable rates for LG&E. Therefore, we will accept LG&E's alternative proposals to increase its electric revenues by $74,000,000, and increase its gas revenues be increased by $17,000,000, rather than the higher levels justified by the record.

FINDINGS ON STIPULATION

Based upon a review of all the provisions in the Stipulation, an examination of the entire case record, and being otherwise sufficiently advised, the Commission finds that the provisions of the Stipulation are in the public interest and should be approved since they will result in lower rate increases than justified by our traditional rate-making analysis. Our approval of the Stipulation is based solely on its reasonableness in toto and does not constitute precedent on any issue except as specifically provided for therein.

As noted above, LG&E's FLEX OPTION, described in detail in Exhibit 7 to the stipulation, will be continued. Upon questioning from the Commission at the hearing on June 8, 2010, LG&E indicated that it preferred that the FLEX OPTION not be made a part of the tariff, so as to enable LG&E the flexibility to make improvements to the program. The Commission will honor this request; however, before any change can be made to the FLEX OPTION, an informal conference with the Commission staff must be held whereby the rationale for the proposed change must be explained and justified to the satisfaction of the staff. The Commission appreciates the willingness of LG&E to develop and implement this plan which benefits its customers and does not want to limit the ability of LG&E to make necessary changes.

CUSTOMER SERVICE, BILLING AND COLLECTIONS

During the course of this proceeding, customers of LG&E filed with the Commission hundreds of complaints, in the form of letters, e-mails, and calls to the Commission, as well as comments presented at the local public meetings. While almost all of those complaints objected to the proposed rate increase, many raised issues related to LG&E's current billing and collection practices and procedures. The Commission also recognizes that last year LG&E brought on-line a new computerized system, known as its Customer Care System ("CCS"), to handle multiple customer related functions, including customer billing. The CCS system was under design and installation for a number of years prior to its implementation. Based on the customer complaints presented to the Commission, we find that, pursuant to KRS 278.255, a focused management audit of the efficiency and effectiveness of LG&E's customer service functions and all related supporting and operational functions that impact retail customers should be performed. The scope of the management audit should include, but not be limited to, a review of all customer service-related functions including meter reading, customer-related accounting functions, customer information systems, billing and collections, call center functions, as well as service installations, and disconnect and reconnect practices.

ORDERING PARAGRAPHS

The Commission, based on the evidence of record and the findings contained herein, HEREBY ORDERS that:

1. The rates and charges proposed by LG&E are denied.

2. The provisions in the Stipulation and Recommendation, attached hereto as Appendix A (without exhibits), are approved in their entirety.

3. The rates and charges for LG&E's electric and gas operations, set forth in Appendix B hereto, are the fair, just, and reasonable rates for LG&E to charge for service, and these rates are approved for service rendered on and after August 1, 2010.

4. A focused management audit shall be performed to review the efficiency and effectiveness of all of LG&E's customer service-related functions including all support and operational functions.

5. The AG's motions to dismiss and to compel data responses are denied.

6. Within 20 days of the date of this Order, LG&E shall file with this Commission its revised tariffs setting out the rates authorized herein, reflecting that they were approved pursuant to this Order.

By the Commission

ENTERED
JUL 30 2010
KENTUCKY PUBLIC SERVICE COMMISSION

ATTEST:

Executive Director

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES	)))	CASE NO. 2009-00548

INDEX

KAWC EXHIBIT

7

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES	)))	CASE NO. 2009-00548

ORDER

Kentucky Utilities Company ("KU"), a wholly owned subsidiary of E.ON US LLC ("E.ON US"), is an electric utility that generates, transmits, distributes, and sells electricity to approximately 513,000 consumers in all or portions of 77 counties in Kentucky.[1]

BACKGROUND

On December 30, 2009, KU filed a letter giving notice of its intent to file an application for approval of an increase in its electric rates based on a historical test year ending October 31, 2009. On January 29, 2010, KU filed its application, which included new rates to be effective March 1, 2010, based on a request to increase its electric revenues by $135,285,293.[2] The application also included proposals to revise, add, and delete various tariffs applicable to its electric service. To determine the reasonableness of these requests, the Commission suspended the proposed rates for

[1] See KU's application, pages 1-2, for a list of the 77 counties. Also, operating under the name of Old Dominion Power Company, KU generates, transmits, distributes, and sells electricity to approximately 30,000 consumers in five counties in southwestern Virginia. KU also sells wholesale electric energy to 12 municipalities.

[2] KU's sister utility, Louisville Gas and Electric Company ("LG&E"), filed a rate application concurrently, which was docketed as Case No. 2009-00549, Application of Louisville Gas and Electric Company for an Adjustment of Electric and Gas Base Rates.

five months from their effective date, pursuant to KRS 278.190(2), up to and including July 31, 2010.

The following parties requested and were granted full intervention: the Kentucky Industrial Utility Customers, Inc. ("KIUC"); the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention ("AG"); The Kroger Company ("Kroger"); the Kentucky School Boards Association ("KSBA"); the Kentucky Cable Telecommunications Association ("KCTA"); Community Action Council of Lexington-Fayette, Bourbon, Harrison and Nicholas Counties, Inc. ("CAC"); and Wal-Mart Stores East, LLP/Sam's East, Inc ("Wal-Mart").

On February 16, 2010, the Commission issued a procedural order establishing the schedule for processing this case. The schedule provided for discovery, intervenor testimony, rebuttal testimony by KU, a formal evidentiary hearing, and an opportunity for the parties to file post-hearing briefs.[3] Intervenor testimonies were filed on April 22 and 23, 2010. KU filed its rebuttal testimony on May 27, 2010.

On June 2 and 3, 2010, an informal conference was held at the Commission's offices to discuss procedural matters and the possible resolution of pending issues.[4] All parties except the AG participated in the conference. Also on June 2, 2010, the AG filed a motion to dismiss this case claiming that the pending acquisition of E.ON US by PPL Corporation ("PPL") renders the historical test year proposed by KU unreasonable

[3] After establishing the procedural schedule for the evidentiary portion of the case, the Commission scheduled and conducted four public meetings in the service territories of KU and LG&E. The public meetings were held on April 27, 2010, in Harlan; May 3, 2010, in Louisville; May 4, 2010, in Madisonville; and May 6, 2010, in Lexington.

[4] For administrative efficiency, the informal conference was a joint conference for this case and the rate case of LG&E, Case No. 2009-00549.

for use in setting rates.[5] On June 7, 2010, KU and LG&E filed a joint response in opposition to the AG's motion to dismiss. The Commission, in an Order issued June 8, 2010, denied the AG's motion without prejudice, stating that "[t]he AG may pursue this issue and renew his motion if he so chooses" following the conclusion of the evidentiary hearing.

On June 8, 2010, KU, LG&E, and the intervenors in this case and in Case No. 2009-00549, with the exception of the AG, filed a Stipulation and Recommendation ("Stipulation"), intended to address all of the issues raised in the two rate cases. Under the terms of the Stipulation, the utilities and intervenors agreed to forego cross-examination of each other's witnesses at the hearing.

Because the Stipulation was not unanimous, the evidentiary hearing set for June 8, 2010, was convened as scheduled for the purposes of hearing (1) testimony by KU and LG&E in support of the Stipulation and (2) testimony by KU, LG&E and the AG on contested issues related to the amount of the revenue increases sought by KU and LG&E.[6] On June 25 and 29, 2010, KU and the AG filed their post-hearing briefs, respectively. The AG also filed on June 29, 2010, a renewed motion to dismiss this case and the LG&E rate case, to which KU and LG&E filed a joint response on July 8, 2010. The instant matter now stands submitted to the Commission for a decision.

[5] The AG also filed an identical motion to dismiss in the LG&E rate case, Case No. 2009-00549.

[6] The AG stated at the hearing that he did not object to the manner in which non-revenue requirement issues were addressed and resolved in the Stipulation.

AG'S RENEWED MOTION TO DISMISS

On June 29, 2010, the AG filed a renewed motion to dismiss both KU's rate application and LG&E's, which is pending in Case No. 2009-00549. The basis for the renewed motion is a claim that the announced acquisition of KU and its affiliate, LG&E, by PPL has created a material change which renders the historic test year no longer reasonable for use in setting rates in this case. The AG previously filed a similar motion on June 2, 2010, prior to the evidentiary hearing held on June 8, 2010. By Order issued on June 8, 2010, the Commission denied the AG's earlier motion based on the absence of any evidentiary support for his claim that the historic test period was no longer reasonable for setting rates. That denial was, however, without prejudice to his renewing the motion after the hearing if he could present evidentiary support either through the supplemental testimony of his own witnesses or through cross-examination at the hearing.

The AG's renewed motion cites to a number of references in the record, some of which predate the hearing, which he argues support his claim that KU's test year is unreliable for setting rates. He also argues that the use of known and measurable adjustments will not render the test period reliable, and that the evidentiary record is insufficient to determine whether the proposed acquisition by PPL is irrelevant and immaterial to the rate case. Finally, he argues that if the PPL acquisition is approved, it will result in a material change to KU, but KU has failed to address in this case the impacts of that change on its going-forward operations.

On July 6, 2010, KU and LG&E filed a joint response in opposition to the AG's renewed motion. KU states that the evidentiary record cited by the AG shows nothing more than vague allegations that if the PPL acquisition is consummated, it may have a potential impact at some time in the future. KU also dismisses the AG's claim that KU's witnesses were somehow remiss in failing to revise their testimony or data responses to reflect the impacts of the proposed PPL acquisition. No such revisions were necessary, according to KU, because the acquisition will have no impact on this rate case.

Based on the AG's renewed motion to dismiss and being otherwise sufficiently advised, the Commission finds that the evidentiary references cited by the AG do not demonstrate that the historic test year used in this case is unreliable for setting rates. At best, the AG's citations show that if the PPL acquisition is consummated, there is the mere potential for expenses to change at some indefinite time in the future.

The record does, however, contain other evidence, not cited by the AG, that demonstrates that the PPL acquisition has been structured to have no financial impact on KU.[7] Thus, any impact of the proposed PPL acquisition are simply too far off and too remote to render unreliable KU's test year in this case, the 12 months ending October 31, 2009. The AG's evidentiary references do not persuade us to reject KU's test year for use in setting rates in this case. To the contrary, KU has shown its test year, with the pro forma adjustments, to be reliable as a starting point for setting rates.

The Commission also finds that, when a historic test year is used for setting rates, pro forma adjustments are allowed for changes that are known and measurable. But the mere fact that a future event, such as a proposed transfer of control, which is not now measurable, may cause changes in future revenues or expenses does not render the historic test year unreliable. There will always be future events that occur

[7] June 8, 2010 Hearing Video Transcript at 1:15:50 pm.

well beyond the end of the test year that may have an impact on the future revenues or expenses of a utility. If a test year was rendered unreliable due to the potential that future events might impact revenues or expenses, no utility would ever be able to adjust its rates.

However, should a future event occur which does adversely impact the revenues or expenses of a utility, KRS Chapter 278 provides ample protection to all those who might be affected. Under KRS 278.260(1), any person with an interest in the rates, including the AG, may file with the Commission a complaint against any utility that any rate is unreasonable, and the Commission may on its own motion initiate such a complaint. And if the utility believes that its rates are unreasonable, it is authorized by KRS 278.180(1) to file a revised schedule of rates.

Finally, there are other consumer protections afforded by KRS Chapter 278, such as for a transaction involving a transfer of control, where the Commission "may grant any application . . . in whole or in part and with modification and upon terms and conditions as it deems necessary or appropriate." KRS 278.020(6). As we stated in our June 8, 2010 Order, the financial impacts of a proposed transfer of control have traditionally been considered as part of an application for approval of the transfer, not as part of a concurrent rate application. The AG, and others, are parties to PPL's application to acquire KU, and issues of the future financial impacts of that acquisition are properly considered in that case.

AG'S MOTION TO COMPEL

During the discovery phase of this proceeding, KU objected to a data request from the AG requesting KU to "[l]ist each proposed pro forma entry which was considered in this filing but not made and state the reason(s) why the entry was not made."[8] The basis for KU's objection was that such information was protected by the attorney-client privilege and the work product doctrine. KU asserted that decisions relating to its rate case adjustments were made in consultation with legal counsel and the response to this request would divulge the contents of communications with counsel and the mental impressions of counsel.

Due to KU's objection to providing the information requested, the AG filed a motion to compel the responses, arguing that KU failed to provide specific reasons why the information requested would be covered by attorney-client privilege. The AG contends that such privilege "does not automatically attach because legal counsel has reviewed a matter." The AG also requests that that the procedural schedule be suspended until this discovery dispute is resolved.

KU and its sister company, LG&E, filed a joint response objecting to the AG's motion to compel. KU asserts that compelling it to respond to the AG's request for information regarding adjustments contemplated but not included in the rate application would necessarily disclose privileged communications between the utility and its counsel, which are protected from disclosure under the Kentucky Rules of Evidence, KRE 503(b). KU contends that any discussions it had with its attorneys concerning the choice of which pro forma adjustments to exclude is not subject to discovery under the absolute privilege applicable to opinion work product, as that privilege is codified in

[8] AG's Initial Data Request, Item AG 1-30.

the Kentucky Rules of Civil Procedure, CR 26.02(3)(a).[9] KU notes that the creation of such adjustments and the determination of which adjustments to include in its rate application are always done in consultation with its counsel, making the facts and its counsel's opinions inseparable. Lastly, KU maintains that even if the information sought to be discovered were deemed to be fact work product rather than opinion work product, the AG has failed to establish that he has a substantial need of the materials in the preparation of his case and that he is unable to obtain the equivalent of the materials by other means entitling him to discovery of the information requested.

In his reply, the AG argues that KU's interpretation of the attorney-client and work product privileges was too broad. The AG avers that the privileges only protect disclosure of communications and not disclosure of the underlying facts by those communicating with the attorney. The AG states that the information requested is needed by his retained experts in order to properly and fully evaluate whether KU's proposed rate increase is fair, just, and reasonable. The AG further states that he cannot duplicate the information concerning possible pro forma adjustments based on the information in the application alone.

In its sur-reply, KU reiterated that the determination of which adjustments to include or exclude was based on the advice of counsel and made exclusively in the context of these legal proceedings. Thus, the information sought to be discovered is, part and parcel, privileged communication between KU and its counsel. KU contends that the AG's claims of substantial need and undue hardship are insufficient to entitle

[9] CR 26.02(3) provides, in relevant part, that, "the court shall protect against disclosure of the mental impressions, conclusions, opinions, or legal theories of an attorney or other representative of a party concerning the litigation.

him to discovery of information protected by the work product privilege. KU points out that it has produced significant amounts of actual data and documents in addition to the volumes of information contained in its application to allow the AG's experienced and capable legal team as well as his three retained experts to fully process and evaluate the reasonableness of KU's proposed rate increase.

Based on the AG's motion and being otherwise sufficiently advised, the Commission finds that, while our proceedings are not governed by either Kentucky's Rules of Evidence or its Rules of Civil Procedure, any privilege so established which shields the disclosure of attorney-client communications must be recognized and applied here. The AG has correctly asserted that the attorney-client privilege does not automatically attach to everything reviewed by a person's counsel. However, under the facts as presented in this rate case, the information sought to be discovered is protected under the opinion work product privilege. The information that the AG seeks to discover – pro forma adjustments contemplated by KU but not included its rate application – was formulated by KU in consultation with its counsel solely in anticipation of filing this base rate case. KU does not create or maintain lists of possible pro forma adjustments and expenses as part of its ordinary business practices. Because KU's potential pro forma adjustments are made in consultation with counsel in contemplation of litigation in rate proceedings, such information is protected by the work product privilege.

The AG claims to seek discovery of only the underlying facts of the communication between KU and its counsel regarding potential pro forma adjustments. However, since KU consults with its counsel prior to making a determination of whether a pro forma adjustment passes legal rate-making muster, the AG's request encroaches into an area which would require KU to disclose the mental impressions, conclusions, opinions or legal theories of its attorneys. While the AG characterizes his discovery request as one limited to underlying facts, the disclosure of such information would, in essence, reveal KU's counsel's impressions of the legal strengths, weaknesses, and best strategic approach in this rate proceeding because the determination of which adjustments to include or exclude are, at their roots, matters of legal strategy. The information sought to be discovered by the AG is absolutely protected under the opinion work product privilege.

The Commission notes that our decision on this issue is expressly limited to discovery of adjustments contemplated, but not filed, by a party in a rate case. Further, our decision applies with equal force to shield from discovery rate case adjustments considered by a utility in conjunction with its counsel, as well as those considered by an intervenor in conjunction with its counsel. Even though contemplated rate case adjustments, when considered in conjunction with counsel, are not subject to discovery, all other aspects of a utility's rate application and its financial records are subject to discovery. Thus, all parties to a rate case have ample opportunity to test and verify the accuracy of the test year and the adjustments proposed thereto, and the need for additional adjustments to ensure that rates are fair, just, and reasonable.

In light of the fact that discovery has been completed and the proceedings are at a conclusion, the Commission finds that the AG's request to suspend the procedural schedule is moot.

STIPULATION

The Stipulation reflects the agreement of the parties, except for the AG, on all issues raised in this case as well as the LG&E rate case. The major provisions of the Stipulation as they to relate to KU's revenues and rates are as follows:

- KU's electric revenues should be increased by $98 million effective August 1, 2010.
- The allocations of the increases in KU's electric revenues are set forth in Exhibit 1 to the Stipulation and are fair, just and reasonable rates for KU, the parties and KU's customers.
- The electric rates in Exhibit 4 to the Stipulation are the fair, just, and reasonable rates for KU and those rates should be approved by the Commission.
- The monthly residential customer charge should be $8.50.
- A reasonable range for KU's return on equity is 10.25 to 10.75 percent, with 10.63 percent continuing to be used in KU's monthly environmental cost recovery filings.

The Stipulation addresses several other issues, including revenue allocation, rate design, tariffs, and contributions to various low-income assistance programs. The major provisions of the Stipulation for KU's operations are as follows:

- New curtailable electric service riders, CSR 10 and CSR 30, will be implemented as set forth in Exhibit 4 to the Stipulation.
- Upon request, customers on either CSR 10 or CSR 30 will be provided monthly explanations for any curtailments.
- Upon request, KU will provide CSR customers with good-faith, non-binding estimates of the duration of requested service interruptions under Riders CSR10 and CSR 30.
- KU will work with its curtailable customers to install needed telecommunication and control equipment to allow for control of the customers' loads by KU.

- The minimum demand ratchet for transmission service under Rate FLS will be 40 percent.

- The parties agree not to object to kVa-based billing for commercial and industrial rates in KU's next base rate proceeding.

- KU should be permitted to recover its actual rate case expenses for this case over a three-year period to begin in the month after the month in which a final order in this case is issued.

- The costs related to KU's 2001 and 2003 environmental compliance plans are to be recovered in its base rates and removed from KU's monthly environmental surcharge filings effective with the August 2010 expense month.

- KU should be permitted to amortize over ten years the regulatory assets previously authorized by the Commission for the costs incurred in conjunction with the 2008 wind storm and 2009 winter storm, with the amortization beginning in the month after the month in which the final order in this case is issued.

- KU should be permitted to amortize over four years the regulatory asset previously authorized by the Commission for KU's participation in the Kentucky Consortium for Carbon Storage ("KCCS"), with the amortization beginning in the month after the month in which the final order in this case is issued.

- KU should be permitted to amortize over ten years the regulatory asset previously authorized by the Commission for KU's participation in the Carbon Management Research Group ("CMRG"), with the amortization beginning in the month after the month in which the final order in this case is issued.

- KU commits to propose, in its next Demand-Side Management application, to modify its existing commercial conservation and rebates program to broaden the financial incentives for qualifying commercial customers to replace relatively inefficient equipment.

- The parties acknowledge that KU has established a FLEX Option program to allow customers unable to pay their bills, due to the timing of receipt of a monthly check, 16 additional days to pay their bills, the details of which are shown in Exhibit 7 to the Stipulation.

- KU's residential customer deposit shall be $135. All other customer deposit amounts will be as filed by KU in this case.

- KU shall continue its current policy of permitting customers required to make a deposit as a condition of reconnection after disconnection for non–payment to make their deposits in up to four monthly installments, upon request.

- Starting October 1, 2010, residential customers receiving a pledge or notice of low-income energy assistance from an authorized agency will not be assessed a late payment charge for a period of 12 months.

- The due-date provisions of KU's tariffs will be modified to specify that the due date for payment is 12 <u>calendar</u> days from the date of the bill and that a late payment charge will be assessed if payment is not received within three <u>calendar</u> days of the due date.

- On and after August 1, 2010, KU will print on each bill issued to customers the date on which the bill was mailed.

- For 2011 and 2012, KU shall continue its current matching contribution from shareholder funds to the Wintercare program to match Wintercare funds collected from customers. KU's annual contribution for each of calendar years 2011 and 2012 shall not be less than $100,000.

- For a period of two-years beginning February 6, 2011, KU shall make dollar-for-dollar contributions from shareholders to its Home Energy Assistance ("HEA") program to match HEA funds collected from customers (up to $300,000 a year on a combined basis with LG&E).

- By January 1, 2011, KU will have decreased the targeted window of time in which to read a customer's meter from five days to three days.

- KU's per-attachment annual rental charge under Rate CTAC for cable television attachments shall be $5.40.

- By July 1, 2011, KSBA's members located in KU's service territory will conduct an assessment to determine whether any school buildings could be more efficiently served under the now-frozen Rate AES rate schedule. KU will allow migration to the

AES rate schedule when appropriate that results in annual savings of up to $500,000.

- Except as modified in the Stipulation and the attached exhibits, the rates, terms and conditions proposed in KU's application shall be approved as filed.

In its application, KU proposed annual increases in its electric revenues of $135,285,293. The AG proposed an annual decrease in KU's electric revenues of $12,965,563. With the exception of the AG, the parties agree that an annual increase in electric revenues of $98,000,000, as provided in the Stipulation, is reasonable. Since all parties have not reached a unanimous settlement on the level of revenues, the Commission must consider all the evidentiary record on this issue and render a decision based on a determination of KU's capital, rate base, operating revenues, and operating expenses, as would be done in any litigated rate case.

TEST PERIOD

KU proposes the 12-month period ending October 31, 2009 as the test period for determining the reasonableness of its proposed rates. Although the AG has renewed his motion to dismiss this case based on the alleged unreasonableness of the proposed test year, he utilized the same test period in his analysis of KU's revenue requirements. Other than his argument that the recently announced proposed acquisition of KU by PPL Corporation renders the test year unreliable, the AG has provided no other challenge to the test year.

The Commission finds it is reasonable to use the 12-month period ending October 31, 2009 as the test period in this case. That 12-month period is the most recent feasible period to use for setting rates, and the revenues and expenses incurred during that period are neither unusual nor extraordinary, except as have been adjusted by normalization and known and measurable changes. In using this historic test period, the Commission has given full consideration to appropriate known and measurable changes.

RATE BASE

Jurisdictional Rate Base Ratio

KU proposed a test-year-end Kentucky jurisdictional rate base of $3,169,724,944. The Kentucky jurisdictional rate base is divided by KU's test-year-end total company rate base to derive the Kentucky jurisdictional rate base ratio ("jurisdictional ratio"). This jurisdictional ratio is then applied to KU's total company capitalization to derive KU's Kentucky jurisdictional capitalization. The jurisdictional ratio uses the test-year-end rate base before any rate-making adjustments applicable to either Kentucky jurisdictional operations or other jurisdictional operations.[10] KU used a jurisdictional ratio of 87.15 percent.[11] The Commission has reviewed and agrees with the calculation of KU's test year electric rate base for purposes of establishing the jurisdictional ratio.

Pro Forma Jurisdictional Rate Base

KU calculated a pro forma jurisdictional rate base of $3,085,279,594, which reflects the types of adjustments used by the Commission in prior rate cases to determine the pro forma rate base. The AG did not address KU's proposed rate base in

[10] KU's other jurisdictional operations reflect the Old Dominion Power Company operations in Virginia and the wholesale municipal energy sales subject to the jurisdiction of the Federal Energy Regulatory Commission.

[11] Rives Direct Testimony, Exhibit 3.

his testimony. The Commission has accepted KU's electric rate base for rate-making purposes except for the cash working capital allowance, which is adjusted based on the adjustments to operation and maintenance expenses discussed later in this Order. Based on our findings, we have determined KU's pro forma electric rate base for rate-making purposes as of October 31, 2009 to be as follows:

Total Utility Plant in Service	$5,157,750,801
Add:	
Materials & Supplies	105,261,354
Prepayments	3,231,585
Cash Working Capital Allowance	79,187,245
Subtotal	187,680,184
Deduct:	
Accumulated Depreciation	1,878,219,090
Customer Advances	2,365,522
Accumulated Deferred Income Taxes	288,218,304
Investment Tax Credit	83,532,076
Asset Retirement Obligation – Net Assets	3,839,326
Asset Retirement Obligation – Regulatory Liabilities	3,543,696
Emission Allowances	375,013
Subtotal	2,260,093,027
Pro Forma Rate Base	$3,085,337,958

Reproduction Cost Rate Base

KU presented a total company reproduction cost rate base of $6,547,011,443, and a Kentucky jurisdictional reproduction cost rate base of $5,768,178,028.[12] The costs were determined principally by indexing the surviving plant and equity using the Handy-Whitman Index of Public Utility Construction Costs and the Consumer Price

[12] Id. Exhibit 5.

Index.[13] The Commission has given appropriate consideration to the proposed reproduction cost rate base, but finds that using KU's historic cost for rate base is more appropriate and consistent with the precedents for KU as well as other jurisdictional utilities within Kentucky.

CAPITALIZATION

In its application, KU proposed an adjusted Kentucky jurisdictional capitalization of $3,054,543,620.[14] Included in its electric capitalization were adjustments to include KU's share of the Trimble County Joint Use Assets and to remove undistributed subsidiary earnings, the investment in Electric Energy, Inc., investments in the Ohio Valley Electric Corporation and others, and the environmental compliance investments which remain part of the environmental rate base included in KU's environmental surcharge mechanism. In its application, KU failed to remove the Investment Tax Credits related to its share of the Trimble County Joint Use Assets. Correction of this omission reduces KU's total adjusted Kentucky jurisdictional capitalization to $3,051,991,904.[15] The AG did not address KU's capitalization. KU determined its electric capitalization by multiplying its total company capitalization by the rate base jurisdictional allocation ratio described earlier in this Order. This is consistent with the approach used by the Commission in previous KU rate cases.

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[13] Id. at 28.

[14] Id. Exhibit 2.

[15] KU's Response to Commission Staff's Fourth Data Request, item 2, Revised Exhibit 2, Page 1 of 1.

REVENUES AND EXPENSES

For the test year, KU reported actual net operating income from electric operations of $191,120,145. KU proposed a series of adjustments to revenues and expenses to reflect more current and anticipated operating conditions, resulting in an adjusted net operating income of $169,167,271.[16] During the proceeding, KU identified and corrected errors in several of the adjustments originally proposed in its application. These changes resulted in increasing KU's adjusted net operating income to $170,557,613.[17] The AG opposed five of the adjustments proposed by KU and recommended an additional adjustment regarding KU's federal income tax rates. We find that the adjustments proposed by KU and accepted by the AG are reasonable and should be accepted by the Commission. With regard to the remaining adjustments, which relate to: 1) the treatment of regulatory assets related to storm restoration costs; 2) the treatment of regulatory assets related to participation in carbon capture and storage projects; 3) electric weather normalization; and 4) the appropriate income tax rate, the Commission makes the following conclusions:

Storm-Related Regulatory Assets

KU requests recovery of amortization of regulatory assets for storm removal costs related to the 2008 Wind Storm and 2009 Winter Storm.[18] Total electric expense

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[16] Rives Direct Testimony, Exhibit 1.

[17] KU's Response to Commission Staff's Fourth Data Request, item 2, Revised Exhibit 1, Page 4 of 4.

[18] The regulatory asset related to the 2008 wind storm was authorized in Case No. 2008-00457, while the regulatory asset related to the 2009 winter storm was authorized in Case No. 2009-00174.

adjustments related to the amortization of these items is $2,454,286 for the 2008 Wind Storm and $11,447,352 for the 2009 Winter Storm.[19]

The AG claims it is unnecessary for the Commission to allow rate recovery of the amortization expenses because these costs were "prefunded" through recovery of the asset removal cost component of KU's depreciation. The AG argues that KU has recovered $329.4 million more in asset removal costs than its actual cost of removal expenses. Thus, he contends there are "excess" funds available to offset the deferred storm damage costs.[20]

KU contends that amortization of the storm damage costs is appropriate for rate recovery as they reflect prudently incurred expenses which the Commission has authorized it to defer as regulatory assets. Further, KU points out that asset removal costs recovered via depreciation should only be used for their intended purpose, namely asset removal. Otherwise, the funds will not be available when assets require removal.[21]

We are not persuaded by the AG's arguments. The amounts deferred by KU were approved by the Commission in previous cases. The AG does not dispute the amounts that were deferred; he only challenges the rate treatment of these amounts. KU's proposal to amortize these amounts in this rate proceeding is in accordance with long-standing generally accepted rate-making practices employed by the Commission.

[19] The adjustment related to the 2008 Wind Storm reflects reversing the net credits during the test year to establish the regulatory asset in addition to the five-year amortization of the asset.

[20] Majoros Testimony at 4 – 6.

[21] Charnas Rebuttal Testimony at 1 – 5.

The amounts collected by KU through depreciation for asset removal costs should only be used for their intended purpose, which is to fund the costs to remove assets. Any concerns the AG has regarding the alleged "excessive" recovery of asset removal costs should be so stated by the AG when KU files its next depreciation case with the Commission.

Carbon Project Regulatory Assets

KU requests recovery of amortization of regulatory assets for research contributions paid to the KCCS and the CMRG. Total expense adjustments related to the amortization of these items is $360,504 for the KCCS and $1,940 for the CMRG.[22]

Based on the same arguments he relies upon in contesting the storm-related adjustments, the AG contends the Commission should not allow rate recovery of these amortization expenses because these costs were also "prefunded" through recovery of the asset removal cost component of KU's depreciation. As with the storm-related regulatory assets, the AG argues that there are "excess" funds available to offset the deferred research contributions.[23]

KU argues that amortization of the KCCS and CMRG costs is appropriate for rate recovery given that they are prudently incurred costs which the Commission has authorized it to defer as regulatory assets. As in the case of the storm-related costs, KU states that asset removal costs recovered via depreciation should only be used for their

[22] The KCCS adjustment includes reversing the credit during the test year to establish the regulatory asset in addition to the amortization of the asset. The CMRG adjustment reflects the net of the test year expense and the yearly amortization.

[23] Majoros Testimony at 6.

intended purpose, asset removal, or the funds will not be available when assets require removal.[24]

Again, the Commission is not persuaded by the AG's arguments. There is clearly no relationship between the costs of carbon capture and storage projects and the cost of removal component of KU's depreciation. The amounts deferred by KU were previously authorized by the Commission. KU's proposal to amortize these amounts in this rate proceeding is consistent with this Commission's long-standing generally accepted rate-making practices. The amounts collected by KU through depreciation for asset removal costs should only be used for their intended purpose, which is to fund the costs to remove assets. The AG can raise any concerns he has with alleged "excessive" recovery of asset removal costs when KU files its next depreciation case with the Commission.

Electric Weather Normalization

KU proposes an electric weather normalization adjustment which increases revenues by $2,986,579 and expenses by $1,489,506.[25] The AG opposes the proposed adjustment, arguing that KU's method is improper because it separates and analyzes each month of the year mutually exclusive from the other months and then adjusts only those months with significant temperature variations from the norm. This methodology ignores the fact that significant fluctuations in temperature in a given

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[24] Charnas Rebuttal Testimony at 5 – 7.

[25] Rives Direct Testimony, Exhibit 1, Reference Schedule 1.11.

month may be offset by less dramatic fluctuations in other months when considered on a combined basis.[26]

The Commission recognizes that KU's continued refinement to the method it uses to calculate the proposed adjustment has greatly improved its ability to measure the impact of temperature on its sales of electricity. However, the Commission shares the concerns expressed by the AG regarding the exclusive nature of the methodology employed by KU to develop its electric weather normalization adjustment. Accordingly, we will not approve KU's proposed electric weather normalization adjustment.

Income Tax Rate

In past rate cases, KU has been allowed rate recovery of state and federal income taxes based on statutory tax rates. It requested the same rate treatment in this case, using a state tax rate of 6 percent and a federal tax rate of 35 percent.

The AG claims that this method of tax recovery is unreasonable and that the Commission should instead use the same "effective tax rate" methodology as it used for Kentucky-American Water Company ("Kentucky-American") in Case No. 2004-00103.[27] The AG argues that KU does not actually pay the statutory tax rates because its profits are netted against losses of affiliated companies on a consolidated tax return. The AG calculated the effective federal tax rate paid by KU as 6 percent based on the average

[26] Watkins Testimony at 3 – 5.

[27] Case No. 2004-00103, Adjustment of Rates of Kentucky-American Water Company (Ky. PSC Feb 28, 2005).

tax payments for the previous two years. The AG calculated the impacts of these adjustments as reductions to KU's requested increase of $56.7 million.[28]

KU's rebuttal to the AG contains several arguments: 1) the AG's proposal represents a radical and abrupt departure from 20 years of well-established, sound, and balanced policy prohibiting affiliated cross-subsidization;[29] 2) the proposed adjustment violates KU's Corporate Policies and Guidelines for Intercompany Transactions, which require allocation of income tax liability on a "stand alone" basis; 3) the proposed adjustment violates the "benefits-burden" principal, meaning that, since its customers bore none of the risk of the losses incurred by the affiliates, which produced the tax losses, they should not benefit from those losses; 4) the proposed adjustment would preclude KU from the opportunity to achieve its authorized rate of return; 5) Case No. 2004-00103 should not be considered precedent-setting in this matter. In that case, the Commission approved the adjustment because Kentucky-American promoted the tax savings as a benefit to merger in Case No. 2002-00317,[30] a fact that is absent in the current situation; and 6) in previous KU cases, the Commission rejected effective tax rate adjustments proposed by the AG where the AG used 2004-00103 as a precedent.[31]

[28] Majoros Testimony at 6 – 7.

[29] KU created a holding company approximately 20 years ago. Prior to then, it did not have non-utility affiliates and use of a consolidated tax return was not an issue.

[30] Case No. 2002-00317, A Change of Control of Kentucky American Water Company (Ky. PSC Dec. 20, 2002).

[31] Rives Rebuttal Testimony at 1 – 19.

The Commission is not persuaded by the AG's arguments in this case on this issue any more than we were in Case No. 2003-00434.[32] Acceptance of the adjustment would preclude KU from the opportunity to earn its authorized rate of return; would violate the "stand-alone" rate-making principal that the Commission has long employed; and would result in cross subsidization of KU and its ratepayers by its unregulated affiliates.

Net Operating Income Summary

After considering all pro forma adjustments and applicable income taxes, KU's adjusted net operating income is as follows:

Operating Revenues	$1,159,331,577
Operating Expenses	989,718,050
Adjusted Net Operating Income	$169,613,527

RATE OF RETURN

Capital Structure

KU proposed an adjusted test-year-end capital structure containing 0.55 percent short-term debt, 45.60 percent long-term debt, and 53.85 percent common equity.[33] The AG recommends an adjusted capital structure for KU containing 50 percent long-term debt and 50 percent common equity based on his review of the capital structure ratios of proxy groups.[34] KU opposes the AG's proposal, citing its long-standing objective of achieving an "A" corporate credit rating as defined by Standard & Poors

[32] Case No. 2003-00434, Adjustment of the Electric Rates, Terms and Conditions of Kentucky Utilities Company (Ky. PSC June 30. 2006).

[33] Rives Direct Testimony, Exhibit 2.

[34] Woolridge Testimony at 13.

("S&P"), and the need to maintain a common equity ratio, as adjusted by S&P, of 50 to 55 percent. Given the consistent downward nature of S&P's adjustments, KU argues that a common equity ratio set at 50 percent, prior to such adjustments would, at best, result in it maintaining its current "BBB" rating. KU also points to its historic equity ratios (including both common and preferred stock, when it had preferred stock) over the past ten years as ranging between 52.73 and 57.33 percent.[35] With its stated goal of achieving an "A" rating and its current equity ratio falling at the lower end of its historical equity ratios, the Commission finds that KU's capital structure for rate-making purposes should not be adjusted as recommended by the AG. Achieving an A rating will provide KU greater access to capital markets, access to lower-cost debt and greater financial flexibility. We find that KU's capital structure for rate-making purposes should include 0.55 percent short-term debt, 45.60 percent long-term debt, and 53.85 percent common equity, as proposed by KU.

Cost of Debt

KU proposed a cost of short-term debt and long-term debt of .22 percent and 4.68 percent, respectively.[36] KU filed updated financial information as of March 31, 2010 that included updated cost rates.[37] Based on this updated information, KU's cost of short- and long-term debt is 0.21 percent and 4.68 percent, respectively.

The AG recommended that KU's cost of debt as proposed in its application be

[35] Arbough Rebuttal Testimony at 1 – 4.

[36] Rives Direct Testimony, Exhibit 2.

[37] KU's Response to Commission Staff's Fourth Data Request, item 2, Revised Exhibit 2.

used by the Commission.[38] The AG agreed that if interest rates or other capital cost rates change, such changes should be used to determine the rate of return so that KU will have a reasonable opportunity to earn its allowed return.

The Commission finds it appropriate to recognize the cost rates for KU's short-term debt and long-term debt as of March 31, 2010 when determining its overall cost of capital. Updates to KU's short-term debt cost rates and long-term debt cost rates constitute known and measurable adjustments and using these updates, rather than the test-year-end cost rates, is more representative of the period in which the rates established in this Order will be in effect. These cost rates will be applied to the capital structure determined herein. Therefore, the Commission finds the cost of short-term debt and long-term debt to be 0.21 percent and 4.68 percent.

Return on Equity

KU estimated its required return on equity ("ROE") using the discounted cash flow method ("DCF"), the capital asset pricing model ("CAPM"), and the expected earnings approach.[39] KU included in its evaluation risks and challenges specific to jurisdictional utility operations in Kentucky, as well as flotation costs. Based on the results of the methods employed in its analysis, KU recommended an ROE of 10.5 to 12.5 percent.[40] KU recommended awarding the midpoint of the range, 11.5 percent, in

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[38] Woolridge Testimony at 13. Note that although Mr. Woolridge states his acceptance and use of the cost of debt proposed in KU's application, he mistakenly states KU's cost of long-term debt at 4.61 percent in his testimony, which is the cost of debt proposed by LG&E in Case No. 2009-00549 and not the cost proposed by KU.

[39] Avera Direct Testimony at 4.

[40] Id. at 5.

order to support access to capital and recognize flotation costs.[41] Through settlement negotiations, the Stipulation contains an agreement by all the parties except the AG that a reasonable range for KU's ROE is 10.25 to 10.75 percent.[42]

KU employed a comparable risk proxy group in its analysis which consists of 14 electric utility companies classified by *The Value Line Investment Survey* ("Value Line") as having both electric and gas operations; S&P's corporate credit ratings of "BBB", "BBB+", "A-", or "A"; a Value Line Financial Strength Rating of "B++" or higher; and published earnings per share ("EPS") growth projections from at least two of the following: Value Line; Thomson I/B/E/S; First Call Corporation; and Zacks Investment Research. KU also applied the DCF model to a proxy group of comparable risk non-utility companies followed by Value Line that pay common dividends; have a Safety Rank of "1"; have investment grade credit ratings from S&P; and have a Value Line Financial Strength Rating of "B++" or higher. The same criterion was applied to this group as the utility group of having published EPS growth projections from the sources listed above.

As part of its analysis, KU provided a discussion of fuel adjustment clause and environmental cost recovery mechanisms that affect its rates for utility service. It also discussed the evolution of investors' risk perceptions for the utility industry due to erosion in credit quality, quoting S&P's identification of environmental compliance costs, decreasing demand, and increasing cost recovery filings as significant challenges for

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[41] Id.

[42] Joint Motion for Leave to File Stipulation and Recommendation and Testimony, Bellar Testimony at 6.

the utility industry.[43] KU's need for additional capital for maintenance, replacements, and facilities additions will require support for KU's financial integrity and flexibility, and this will be impacted by energy market volatility and environmental considerations, according to KU. In addition to these factors, KU points to investors' recognition of the global recession's impact on KU's service territory as evidence of KU's need to support its credit standing and financial flexibility through the opportunity to earn a return that reflects these realities.

The AG criticized KU's ROE estimates on several grounds. The AG stated that KU's proxy group of utility companies includes companies with a low percentage of regulated utility operations revenue, and that the use of a proxy group of non-utility companies is inappropriate. The AG's major disagreement with KU's DCF analysis is the reliance on projected EPS growth rates in developing the growth factor component, and he contends that Value Line's estimated long-term EPS growth rates are overstated. The AG stated that the primary problem with KU's CAPM analysis is the market risk premium used in the analysis, which the AG contends is based on an expected stock market return which is not reflective of current market fundamentals. The AG disagreed with KU's expected earnings approach, and stated that it is subject to error and fails to provide a reliable estimate of KU's cost of equity capital. The AG also recommends against KU's proposed adjustment for flotation costs. The AG believes that KU's analysis overstates its required cost of equity.

The AG estimated KU's required ROE using the DCF model and the CAPM. Based on the results of these methods, giving primary weight to the DCF, the AG

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[43] Id. at 9.

determined a ROE range of 7.8 to 9.5 percent for KU, recommending that the Commission award 9.5 percent, the upper end of the range.[44]

The AG employed a proxy group in his analysis consisting of 20 utility companies listed as an electric or combination electric and gas utility by AUS Utility Reports; having regulated electric revenues of at least 80 percent of total revenues; with current data available in the Standard Edition of Value Line; having an investment grade bond rating; and having an annual dividend history of three years.

The AG supported his analysis with a discussion of current economic conditions, concluding that short- and long-term credit markets have "loosened" considerably,[45] and that the stock market has rebounded significantly from 2009's lows. The AG's discussion includes a reference to a study indicating that the investment risk of utilities is very low, and states that the cost of equity for utilities is among the lowest of all industries in the U.S. as measured by their betas.[46]

On rebuttal, KU addressed the AG's recommended ROE and his criticisms of KU's analysis. KU compared its DCF analysis to that of the AG, stating that the AG presented historical results as being indicative of investors' future expectations, while KU used forward-looking data, which is a superior method due to specific trends in dividend policies and evidence from the investment community; that the AG considered analysts' EPS forecasts as being biased while KU's application of the DCF model recognizes the importance of considering investors' perceptions and expectations; that

[44] Woolridge Testimony at 2.

[45] Id. at 10.

[46] Id. at 19.

the AG relied upon personal views rather than the capital markets for investors' expectations; and that while KU excludes data in its analysis that would lead to illogical conclusions, the AG relies on averaging or using the median value to eliminate any bias. KU also addresses the AG's criticism of the use of a non-utility proxy group, saying that it would be inconsistent with the *Hope*[47] and *Bluefield*[48] cases to exclude non-utility company returns from consideration. KU counters the argument that the expected earning approach is not valid, saying that an allowed ROE for a utility company must be high enough to attract capital from investors who are looking for the best investment opportunity. KU recommended that the AG's CAPM analysis be disregarded, noting that the AG gave primary weight to its DCF analysis. KU defended the market return used in its CAPM analysis, saying that its analysis appropriately focuses on investors' current expectations. KU reiterates the need for a flotation cost adjustment in its ROE calculation, saying that there is no basis to ignore such an adjustment.

The Commission finds merit in both KU's and the AG's recommended ranges for ROE and their critiques of each other's analyses. The Commission takes note of several points made in each party's testimony and analysis. KU's argument concerning the appropriateness of using investors' expectations in performing a DCF analysis is more persuasive than the AG's argument that analysts' projections should be rejected in favor of historical results. The Commission agrees that analysts' projections of growth

[47] *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591 (1944).

[48] *Bluefield Water Works and Improvement Company v. Public Service Commission*, 262 U.S. 679 (1932).

will be relatively more compelling in forming investors' forward-looking expectations than relying on historical performance, especially given the current state of the economy. It also appears preferable to exclude extreme outliers in ROE analysis; for example, the AG's inclusion of negative results to calculate investors' required ROE does not comport with the constant growth assumption that is inherent in the DCF formula. Concerning the issue of using a non-utility proxy group in analyzing the required ROE for a utility, the Commission agrees with KU that investors are always looking for the best investment opportunity and that a utility is in competition with unregulated firms; however, the AG's discussion of the relative risk of electric utilities as reflected in their Value Line Betas supports the attractiveness of utility investments in comparison to riskier alternatives. As to flotation costs, the Commission agrees with the AG's position that no upward adjustment to the equity cost rate is necessary and that this finding is consistent with past Commission practice.

After weighing all the evidence of record, the Commission finds that KU's required ROE for electric operations falls within a range of 9.75 to 10.75 percent with a midpoint of 10.25 percent.

Rate of Return Summary

Applying the cost of debt and equity found appropriate herein to KU's capital structure produces a weighted cost of capital of 7.65 percent. The cost of capital produces a return on KU's pro forma rate base of 7.57 percent.

REVENUE REQUIREMENTS

The Commission has determined that, based upon KU's capitalization of $3,051,991,905 and an overall cost of capital of 7.65 percent, KU's net operating income that could be justified by the evidence of record is $233,477,381. Based on the adjustments found reasonable herein, KU's pro forma net operating income for the test year is $169,613,527. It would need additional annual operating income of $63,863,856. After the provision for uncollectible accounts, the PSC Assessment, and state and federal income taxes, KU would have an electric revenue deficiency of $101,680,163.

The calculation of this overall revenue deficiency is as follows:

Net Operating Income Found Reasonable	$233,477,381
Pro Forma Net Operating Income	(169,613,527)
Net Operating Income Deficiency	63,863,854
Gross Up Revenue Factor	.62808570
Overall Revenue Deficiency	$101,680,159

The Commission has found that KU's required ROE falls within a range of 9.75 percent to 10.75 percent, with a mid-point of 10.25 percent. Applying the findings herein on the reasonable cost of debt and the return on common equity to KU's capitalization would result in a justifiable revenue increase of $101,680,159. The alternative proposal provided in the Stipulation is $98,000,000. Based on the findings and conclusions herein, the Commission finds that the earnings resulting from the adoption of KU's alternative proposal will produce a reasonable result for both KU and its ratepayers. The $98,000,000 revenue increase KU is willing to accept will result in fair, just, and reasonable electric rates for KU and its ratepayers. Therefore, the Commission will accept KU's alternative proposal that its revenues be increased by $98,000,000 rather than the higher level justified by the record.

FINDINGS ON STIPULATION

Based upon a review of all the provisions in the Stipulation, an examination of the entire record, and being otherwise sufficiently advised, the Commission finds that the provisions of the Stipulation are in the public interest and should be approved since they will result in a lower rate increase than justified by our traditional rate-making analysis. Our approval of the Stipulation is based solely on its reasonableness in toto and does not constitute precedent on any issue except as specifically provided for therein.

As noted above, KU's FLEX OPTION, described in detail in Exhibit 7 to the stipulation, will be continued. Upon questioning from the Commission at the hearing on June 8, 2010, KU indicated that it preferred that the FLEX OPTION not be made a part of the tariff, so as to enable KU the flexibility to make improvements to the program. The Commission will honor this request; however, before any change can be made to the FLEX OPTION, an informal conference with the Commission staff must be held whereby the rationale for the proposed change must be explained and justified to the satisfaction of the staff. The Commission appreciates the willingness of KU to develop and implement this plan which benefits its customers and does not want to limit the ability of KU to make necessary changes.

CUSTOMER SERVICE, BILLING AND COLLECTIONS

During the course of this proceeding, customers of KU filed with the Commission hundreds of complaints, in the form of letters, e-mails, and calls to the Commission, as well as comments presented at the local public meetings. While almost all of those complaints objected to the proposed rate increase, many raised issues related to KU's current billing and collection practices and procedures. The Commission also recognizes that last year KU brought on-line a new computerized system, known as its Customer Care System ("CCS"), to handle multiple customer related functions, including customer billing. The CCS system was under design and installation for a number of years prior to its implementation. Based on the customer complaints presented to the Commission, we find that, pursuant to KRS 278.255, a focused management audit of the efficiency and effectiveness of KU's customer service functions and all related supporting and operational functions that impact retail customers should be performed. The scope of the management audit should include, but not be limited to, a review of all customer service-related functions including meter reading, customer-related accounting functions, customer information systems, billing and collections, call center functions, service installations, and disconnect and reconnect practices.

ORDERING PARAGRAPHS

The Commission, based on the evidence of record and the findings contained herein, HEREBY ORDERS that:

1. The rates and charges proposed by KU are denied.

2. The provisions in the Stipulation and Recommendation, as set forth in Appendix A hereto (without exhibits), are approved in their entirety.

3. The rates and charges for KU, as set forth in Appendix B hereto, are the fair, just, and reasonable rates for KU, and these rates are approved for service rendered on and after August 1, 2010.

4. A focused management audit shall be performed to review the efficiency and effectiveness of all of KU's customer service-related functions including all support and operational functions.

5. The AG's motions to dismiss and to compel data responses are denied.

6. Within 20 days of the date of this Order, KU shall file with this Commission its revised tariffs setting out the rates authorized herein, reflecting that they were approved pursuant to this Order.

By the Commission

ENTERED
JUL 3 0 2010
KENTUCKY PUBLIC
SERVICE COMMISSION

ATTEST:

Executive Director

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ELECTRIC AND GAS BASE RATES	)))	CASE NO. 2009-00549

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ORDER NO. 83085

IN THE MATTER OF THE APPLICATION OF DELMARVA POWER AND LIGHT COMPANY FOR AN INCREASE IN ITS RETAIL RATES FOR THE DISTRIBUTION OF ELECTRIC ENERGY	* * * *	BEFORE THE PUBLIC SERVICE COMMISSION OF MARYLAND
		CASE NO. 9192

To: Parties of Record and Interested Persons

INTRODUCTION AND EXECUTIVE SUMMARY

Two years after a comprehensive review of its electric distribution rates,[1] Delmarva Power & Light Company ("Delmarva" or "Company") asks us[2] to increase them and restructure them to allow it to recover certain costs through surcharges rather than base rates. After a new and equally thorough review – the record in this case included written testimony from 19 witnesses, a four-day evidentiary hearing, six public hearings throughout Delmarva's service territory and extensive post-hearing briefs – we grant in part and deny in part Delmarva's request for additional revenue, we decline Delmarva's invitation to move further toward a single issue style of ratemaking, and we reaffirm the importance of considering utility companies' costs, revenues and return together and in context.

[1] Distribution rates represent the portion of the monthly electric bill relating to the cost of delivering electricity from the source(s) to each customer. As a general matter, distribution charges in Maryland comprise approximately 20-25% of each customer's monthly bill. This Order does not address the cost of Standard Offer Service electricity itself, which Delmarva purchases through auctions we supervise.

[2] Commissioner Therese Goldsmith took no part in the consideration of this case or the preparation of this Order.

KAWC EXHIBIT
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This Order explains the basis for and provides additional details regarding the decision we announced in Order No. 83040 (Dec. 2, 2009). In that Order, we authorized the Company to file tariff pages yielding an additional $7,531,000 in annual base rate revenue based upon an overall rate of return of 7.96%.[3] Based upon the Company's cost of service studies, and in order to mitigate the impact of this decision on residential and small commercial customers (who as a class had been paying more than their fair share as compared to other customer classes) as well as larger commercial customers (who could face rate shocks if rates moved more aggressively to unity), we directed the Company to file tariffs that reduce the disparity between class rates of return and the overall rate of return by 70%.[4] We rejected the Company's customer charge and demand charge proposals and directed that the incremental authorized revenue should be recovered through volumetric rates,[5] and we rejected Delmarva's request to remove pension, other benefits and uncollectible expenses from rate base and allow it to recover those costs through a surcharge.[6]

We recognize that the current economic climate has proven challenging for Delmarva. As it is our charge to ensure that electric utilities provide reliable service, we have focused our inquiry here on whether Delmarva's current rates permit the Company to make the necessary investments in its electric infrastructure in order to provide safe and reliable service. On that basis, and given unavoidable increases in health care and related costs, we find that a modest rate increase is appropriate. But we decline to approve the rest of Delmarva's requests for increased revenues, we deny its request for a

[3] Order No. 83040 at 1.
[4] *Id.* at 2.
[5] *Id.*
[6] *Id.*

higher rate of return, and we remain unwilling to (over)react to short-term increases in certain costs by pulling those costs out of the normal ratemaking process. Put another way, the record supports modest additional investments in reliability, but not a more lucrative return for shareholders or a departure from fundamental ratemaking principles.

As a result of the decisions we reach in this case, a typical residential customer will pay an additional $1.98 in distribution charges per month; large commercial ratepayers, who as a class have been paying less than their aliquot share of the Company's costs, will bear a greater share of this increase. Although the increase we allow here represents approximately half of what Delmarva sought, we do not grant *any* increase lightly, but only to ensure that Delmarva can meet the public's expectations for safe and reliable service.

I. BACKGROUND

Delmarva sought, and the Commission granted, an increase in its base rates in Maryland in 2007 in Commission Case No. 9093.[7] On May 6, 2009, Delmarva filed an application pursuant to §§ 4-203 and 4-204 of the Public Utility Companies Article of the *Annotated Code of Maryland* ("PUC Article") for authority to increase its retail rates for the distribution of electric energy in Maryland.

Delmarva's application sought an increase of $14,145,000 based on a test year ending December 31, 2008.[8] In written testimony, the Company asserted that current rates only provided a return on equity ("ROE") of just 5.92%, far below the 10% ROE

[7] *Re Delmarva Power and Light Company*, 98 MD.PSC 288 (2007).

[8] Based upon its proposed rate base and operating income adjustments as well as its recommended rate of return, the Company indicates in its final position that its revenue deficiency is $13,634,000. See Comparative Summary Schedule, Docket No. 57. However, Delmarva has not modified its revenue request.

authorized in Case No. 9093. [9] The Maryland Office of People's Counsel ("OPC") argued that we should limit any increase to no more than $3,358,000. The Public Service Commission Staff ("Staff") recommended a rate decrease of $5,686,000, based largely on its proposal that we adopt a new rule regarding the treatment of consolidated tax adjustments.[10]

The Company, Staff and OPC all filed written testimony. Delmarva sponsored the testimony of Anthony J. Kamerick, Senior Vice President and Chief Financial Officer of Pepco Holdings, Inc. ("PHI"),[11] who testified on the general basis for the rate increase; Dr. Roger A. Morin, professor at Georgia State University and a principal in Utility Research International, who testified on cost of capital issues; W. Michael VonSteuben, Manager, Revenue Requirements, who testified about the revenue requirements; William M. Gausman, Senior Vice President Asset Management and Planning for PHI, who testified about capital expenditures; Joseph F. Janocha, Regulatory Affairs Manager with PHI, who testified about rate design matters; Kathleen A. White, Assistant Comptroller for PHI, who testified about accounting issues; Elliott P. Tanos, Manager Cost Allocation for PHI, who testified about the cost of service; Timothy J. White, Manager Policy Coordination with PHI, who testified about the cash working capital requirement; B. Anthony Snowball, the Global Benchmark Practice Leader of the Hackett Group, who testified regarding the benchmarking of service company costs; James I. Warren, a tax partner in the law firm of Winston & Strawn LLP, who testified on

[9] Direct testimony of Anthony J. Kamerick at 3.

[10] See Comparative Summary Schedule. Staff's consolidated tax adjustment reduces Delmarva's revenue requirement by $5,249,000, which essentially represents Staff's entire recommended rate decrease.

[11] Delmarva is a subsidiary of PHI.

tax matters; and Frank J. Salatto, Manager, Income Tax Accounting and Reporting for PHI, who also testified on tax issues.

Staff filed the testimony of Randy M. Allen, Director of the Commission's Accounting Investigations Division, who addressed the Company's overall revenue requirements; Preston D. Alderman, Jr., Senior Public Utility Auditor, who addressed cost of service and rate base issues; Jerry Hughes, Chief Engineer, who addressed reliability issues and the prudence of the Company's 2009 construction budget; Charles Ermer, Regulatory Economist in the Commission's Division of Electricity, who addressed cost of service issues; Gregory Campbell, also a Regulatory Economist in the Electricity Division, who addressed rate design issues; and Matthew Schultz, a Regulatory Economist in the Electricity Division, who addressed the cost of capital.

OPC submitted the testimony of David J. Effron, a consultant specializing in utility regulation, who addressed rate base and operating income issues and presented OPC's recommended revenue requirement; Jonathan Wallach, Vice President of Resource Insight, Inc., who addressed the proposed allocation to the residential class of the requested revenue increase, the customer class cost of service study and the proposed residential rate design; and Charles W. King, President of the economic consulting firm Snavely King Majoros O'Connor & Bedell, Inc., who addressed cost of capital and rate of return issues.

Staff and OPC filed their direct cases on August 24, 2009. Supplemental testimony addressing pension issues was filed by the Company on August 24, 2009, and by Staff and OPC on September 8, 2009. The Company filed its rebuttal testimony on September 11, 2009, and OPC and Staff filed surrebuttal testimony on September 17 and

18, 2009. During the hearings Delmarva presented rejoinder testimony. Evidentiary hearings were held on September 22 through 25, 2009, and evening hearings for public comment were held in the Company's service territory on October 13, 14 and 15, 2009. Because the Company's initial notices to the public of the evening hearings were deemed by the Commission to be deficient, new notices were issued and additional evening public hearings were held in the Company's service territory on November 9, 10 and 12, 2009, in Chestertown, Salisbury, and Wye Mills, respectively. Pursuant to the procedural schedule, initial briefs were filed on October 26, 2009, and reply briefs were filed on November 4 and 6, 2009.

II. DISCUSSION AND FINDINGS

A. Rate Base

Rate base represents the investment the Company makes in plant and equipment in order to provide service to its customers. The parties' rate base positions are, unless stated otherwise, based upon a test year for the twelve months ending December 31, 2008. The undisputed portion of the rate base, including agreed adjustments, totals $286,776,000. Some proposed adjustments are in dispute, however, and we resolve these below.

1. "Reliability" Plant Additions

Delmarva asks us to include in rate base $6,106,000 for reliability projects it placed in service during the 2008 test year *and* an additional $17,587,000 in plant investments it made between January and September 2009, *i.e.*, after the test year closed.[12] For the reasons set forth below, and on the specific facts, we will include these specific, known and measurable expenses in rate base.

According to Mr. Gausman, the post-test-year construction costs (43% of Delmarva's 2009 construction budget)[13] were incurred for: (1) system load relief work; (2) work designed to improve customer reliability; (3) emergency replacements and repairs; and (4) planned infrastructure replacements.[14] The Company claims that the post-test-year expenses have been incurred "to maintain system reliability"[15] and will not produce revenue.[16] Thus, Mr. VonSteuben argues that including the post-test year additions in rate base would result in matching the benefits customers receive with the cost associated with reliable service during the rate effective period.[17]

Staff supports the test period annualization, which allows Delmarva to reflect a full year's effect in rate base for the reliability projects placed in service during the test year. However, Staff opposes the post-test-year adjustments because they violate the matching principle, noting that the Company's proposed adjustments fail to take into account other post-test-year changes. Staff also noted that a portion of the post-test year project costs lack documentation and as a result are not known and measurable.[18]

OPC supports the use of an average test year rate base and therefore opposes both the test-year and post-test-year reliability adjustments. Mr. Effron notes that the first adjustment includes plant balances as of the end of the test year, December 31, 2008,

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[12] Direct testimony of W. Michael VonSteuben ("Von Steuben Direct") at 19-21. VonSteuben Rebuttal, Schedule WMV R-1, at 2 and Comparative Summary Schedule. (Delmarva divided the post-test year adjustment into several pieces).
[13] Revised direct testimony of William M. Gausman, at 13, see also Comparative Summary Schedule, lines 20-22.
[14] Direct testimony of William M. Gausman ("Gausman Direct") at 4.
[15] VonSteuben Direct at 7-8.
[16] Gausman Direct at 13.
[17] VonSteuben Direct at 20.

rather than the average balances for the twelve month period. He states that an average test year results in a proper matching of test-year investment, revenues and expenses, which achieves consistency in determining revenue requirements. OPC asserts that post-test-year adjustments distort the relationship between rate base and operating income, which is contrary to sound ratemaking practice. Mr. Effron notes that while the Company asserts that these projects will enhance reliability, it has not claimed that they are required to ameliorate dangerous conditions or actual safety problems. Furthermore, Mr. Effron states that if these plant additions do improve reliability, the Company has still failed to recognize the effect that reduced outages will have on revenues and expenses.[19]

In rebuttal, the Company asserts that its reliability plant adjustments reflect known and measurable changes that are representative of the rate effective period, which it argues is consistent with Commission policy. Mr. VonSteuben emphasizes that these plant additions are not necessary to meet the needs of any specific new customer and will not provide added revenue to the Company. He concludes that if these adjustments are not accepted that the Company will not have the opportunity to earn its authorized rate of return during the rate effective period.[20]

As a general rule, we are reluctant to deviate from the costs and revenues incurred in a test year. Adding post-test-year expenses to the rate base, and thus the revenue requirement, feels a little like a heads-I-win-tails-you-lose approach – the revenues (and thus rates) ought normally to match the costs the Company incurs over the course of a year, and the test year should represent a fair snapshot of costs and revenues. A possible

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[18] Direct Testimony of Preston D. Alderman, Jr. ("Alderman Direct") at 5-6.
[19] Direct Testimony of David J. Effron ("Effron Direct") at 3-7.

exception to the test year principle is reliability plant investment, but our willingness to consider and apply that exception depends on the nature of the improvements and the revenue they generate. Improvements in plant that increase the Company's revenues create an inappropriate mismatch between rate base and revenues – and including those costs in rate base without offsetting post-test-year revenue allows the Company to double-dip. If, however, the reliability investment is known and measurable and does not generate new revenue, including the incremental value in rate base does not create a mismatch – the new rates reflect the system value of the investment.

In this instance, we find that the reliability construction costs the Company seeks to recover are known and measurable and will not generate any additional revenue. The work already has been done and the costs are locked in, and we are comfortable that these projects will not generate or enhance the Company's revenues. Based on the specific facts before us, there is no cost-revenue mismatch here, and therefore the test year and post-test-year reliability construction expenses through September 2009 are properly included in rate base.[21] We are somewhat concerned that the Company's 2008 reliability investments seem low, particularly when compared to the nine months following the test year and the Company's uneven reliability performance in recent years. By allowing post-test-year recovery for these investments, we emphasize our expectation that the Company will make the cost-effective investments necessary to keep the lights reliably on for all of its customers.

2. Cambridge Environmental Costs

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[20] VonSteuben Rebuttal at 15-18.

[21] As a result of accepting these adjustments, rate base is increased by $23,693,000 and operating income is reduced by $420,000.

The Company seeks to recover environmental remediation costs attributable to the gas manufacturing activity of a predecessor company in Cambridge, Maryland ("Cambridge") some 100 years ago. In its last base rate case, the Commission denied recovery of the Cambridge environmental costs because "the evidence indicates that the property was not used for the provision of electric service to Delmarva's customers."[22] We find no basis to reverse course here, and we deny the Company's request to recover these costs.

In support of its request, Delmarva argues that the Commission has approved environmental clean-up costs previously, citing several Baltimore Gas and Electric Company ("BGE") gas rate cases (related to the Spring Gardens facility) and a Chesapeake Utilities case.[23] Delmarva asserts that Cambridge remediation efforts benefit current customers because it allows the Company to meet its legal obligations and continue to provide electric service. Delmarva states that the actual incremental external expenditures to complete the Cambridge remediation were $4,062,492.[24]

Staff opposes the Cambridge adjustment. Staff notes that the State-ordered remediation was caused by service provided to customers by the manufacturing of coal gas approximately 100 years ago. Staff asserts that only those long-ago customers benefited from the service and that the risk of such events should be placed solely on the Company's investors. Finally, Staff emphasizes that the property was not used and useful in providing electric service to Delmarva's customers.[25]

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[22] Order No. 81518 at 16.
[23] VonSteuben Direct at 15-17.
[24] VonSteuben Direct at 15.
[25] Direct Testimony of Randy M. Allen ("Allen Direct") at 13-14.

OPC argues that the Company has not provided any evidence that the Cambridge property was ever used for electric service, and thus opposes as well the Company's proposal to amortize these costs. However, if the Commission were to permit cost recovery, OPC argues that we should reject the Company's initial five-year amortization proposal and use a 10-year amortization period, which is consistent with BGE's amortization of environmental costs.[26]

In rebuttal, Mr. VonSteuben modified his position and proposed a 10-year amortization of the Cambridge costs, with the unamortized amount included in rate base. He argues that this is consistent with the treatment the Commission afforded BGE in Case No. 9036. Moreover, the Company emphasizes that it would have been impossible to have expected the gas service customers to have paid for the clean-up many years ago when the regulations requiring clean-up did not exist. Therefore, it argues that Staff's position places an unreasonable risk on shareholders. Delmarva concludes that the Cambridge costs are known and certain, Marylanders benefitted from the service and therefore a 10-year amortization of the costs is appropriate.[27]

In Case No. 9093, we denied recovery of the Cambridge costs because we found that they were not incurred for the purpose of providing electric service to Delmarva's customers. After a second bite at this apple, Delmarva has again failed to show how these costs benefit its electric service customers. Indeed, when asked specifically what new evidence or arguments supported recovery of these ancient expenses, the Company

[26] Effron Direct at 15-17.
[27] VonSteuben Rebuttal at 7-10.

offered only that the clean-up was finished, and thus the final cost was now known.[28] We cannot and will not saddle Delmarva's modern-day electric customers with the cost of cleaning up a predecessor gas company's mess when the Company cannot draw at least some connection between the remediated property and the service today's customers will receive from it. Therefore, we reaffirm our decision in Case No. 9093 to deny recovery of the Cambridge remediation costs.[29]

3. Pension and Other Post-Employment Benefits

As in its last base rate case, the Company asks us to restructure its rates to allow recovery of pension and other post-employment benefits ("OPEB") expenses through a surcharge rather than through base rates. The Company notes that adopting this proposal would reduce the revenue requirement in this case[30] – that would be true as far as it goes, but ignores the fact that ratepayers would pay an altogether new surcharge *above and beyond* the new distribution rates. The Commission rejected a similar proposal in Case No. 9093. Staff and OPC oppose the surcharge proposals in this case, and we reject it again here.

According to Delmarva, the recent downturn in the economy has caused an unusually large downward change in the fair value of its pension assets, which has significantly increased pension expense in 2009. According to Mr. VonSteuben, the increase in pension expense "has significantly and adversely affected Delmarva's financial results, thus preventing the Company from having an opportunity to earn its

[28] In response to questioning about what has changed since its last case, Mr. VonSteuben stated that the remediation was "done and finished in `08" and therefore "the costs are known and certain." Transcript at 148.

[29] Denying the Company's adjustment requires that operating income be restated by approximately $216,000. *See* Allen Direct at 14, Exhibit RMA-2, Schedule 3 and the Comparative Summary Schedule.

[30] Direct testimony of Anthony J. Kamerick ("Kamerick Direct") at 4-5. The Company also proposed a surcharge mechanism for uncollectible expenses.

authorized rate of return."[31] Delmarva contends that the increase in 2009 pension expense is the result of extraordinary events wholly beyond its control that could not have been anticipated or reflected in rates at the time of Delmarva's last case.[32] Mr. VonSteuben argues that the alternative averaging (surcharge) proposal would benefit the Company and customers because pension expense would not be set at a fixed level that might differ significantly from future experience and it would reduce the volatility of pension cost recovery.[33]

OPC disputes the Company's surcharge proposal. Through Mr. Effron, OPC argues that a surcharge mechanism "would guarantee virtual dollar for dollar recovery of OPEB and pension costs and would reduce the incentive to control those benefits costs."[34] In OPC's view, the Company has not explained why these costs should be treated differently from the other costs or how fluctuations in these costs cause unacceptable risks. OPC argues that reconciliation mechanisms are contrary to sound ratemaking practice as they minimize incentives to control costs and that such mechanisms should be reserved for expenses of exceptional magnitude and volatility, where unexpected fluctuations could cause irreparable financial harm, like purchased power costs. Moreover, Mr. Effron notes that any benefit from deferrals in this case would be offset by higher rates in later years, leaving customers no better off. For these reasons, OPC concludes that a surcharge for pension and OPEB costs is unnecessary and should not be authorized.[35]

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[31] VonStueben Supplemental at 2-3.
[32] VonSteuben Supplemental at 3-4.
[33] VonSteuben Supplemental at 4-5.
[34] Effron Direct at 20.
[35] Effron Direct at 19-22.

OPC also characterizes Delmarva's amortization proposal as a "textbook example of single-issue, selective ratemaking."[36] Mr. Effron argues that it is inappropriate to isolate one expense that has increased and treat it specially without consideration of other factors affecting the Company's revenue requirement. OPC concludes that doing so would circumvent the rate case process, in which all changes in costs are examined. Mr. Effron concludes that the Company has kept the benefits of decreases in pension expenses for shareholders and increases should be treated symmetrically.[37]

Staff also opposes the Company's "innovative ratemaking proposals." Mr. Allen notes that these costs can vary significantly from year to year, negating the need for innovative price mitigation. Nor, in Staff's view, is there a need for additional surcharge mechanisms, which would require additional resources to monitor.[38] Furthermore, he points out that the Company does not propose credit mechanisms for items like accumulated depreciation, deferred taxes, or decreases in salary expenses due to changes in incumbents.[39] Moreover, Mr. Allen states that the purported savings in this case would barely affect the Company's financial integrity. Staff concludes that any small benefit today would burden future customers and amounts to an intergenerational shift of costs.[40]

Staff similarly opposes the Company's pension amortization proposal. Mr. Allen notes that Delmarva only seeks amortization for 2009 levels and ignores the possibility that expenses could decline in the rate effective period. Lacking a true-up provision, the

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[36] Effron Supplemental at 1.
[37] Effron Supplemental at 1-3.
[38] Allen Direct at 22-24.
[39] Allen Supplemental at 4-5.
[40] Allen Direct at 20-24.

proposal is one-sided, which could result in customers paying higher rates than necessary.[41]

In rebuttal, Mr. VonSteuben admitted, as he must, that the pension amortization proposal would qualify as single-issue ratemaking. However, he likened recent increases in pension expenses to a major storm, and claimed that these expenses lie outside the Company's control. Although Mr. Allen is correct that Delmarva has input into the actuarial assumptions that affect the magnitude of the expense, Mr. VonSteuben states that the expense level provided by the actuary is appropriate for meeting the cost of this employee benefit.[42]

We rejected similar proposals in Delmarva's last rate case because surcharges guarantee dollar-for-dollar recovery of specific costs, diminish the Company's incentive to control those costs, and exclude classic, ongoing utility expenses from the standard, contextual ratemaking analysis.[43] We found before that tracker mechanisms, like the surcharge and amortization proposals in this case, represent an extraordinary form of ratemaking that we reserve only for very large, non-recurring expense items that have the potential to seriously impair a utility's financial well-being and that do not contribute to the Company's rate base.[44] Pension and OPEB expenses fail this test, even in a bad year – they are classic, ongoing costs of running a utility company, and cannot, in our view, qualify for specialized rate treatment. We find again, as we did in 2007, that a pension and OPEB surcharge breaches the historical ratemaking bargain, and the economic challenges of the last two years offer no reason for us to jettison these long-settled

[41] Allen Supplemental at 3.
[42] VonSteuben Rebuttal at 22-25.
[43] Case No. 9093, Order No. 81518 at 54.

principles. We therefore reject the Company's surcharge and amortization proposals and direct it to continue recovering these expenses through rates.

4. AMI

Although we have not authorized the Company to install an Advanced Metering Infrastructure ("AMI") system, it nevertheless seeks authority to recover the costs it has incurred up through the end of the test year, and related deferred costs, in rate base over a five year period.[45] These incremental expenses relate to installation and integration of a meter data management system, the AMI requirements development, AMI software applications and the overall management of the project.[46] The Company's adjustments would increase rate base by $322,000 and decrease earnings by $71,000.

Staff opposes these adjustments, arguing that the Company has not shown that its proposed AMI system is either appropriate or cost-justified. Mr. Allen notes that the Commission is examining Delmarva's AMI proposal in Case No. 9207. Therefore, he concludes, it is premature to allow AMI recovery at this time. Finally, he notes that if the recovery is approved, the Company should recover costs over the life of the new system, not a shortened period.[47]

Rather than putting the cost recovery cart before the programmatic horse, we will address cost recovery for any AMI programs we approve *after* we approve them. Accordingly, we decline to include any AMI-related costs in rate base at this time, without prejudice to the Company's position in Case No. 9207.

5. Plant Held For Future Use

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[44] Id.
[45] VonSteuben Direct at 21.
[46] Gausman Direct at 19.
[47] Allen Direct at 14-15 and 19.

Delmarva includes in its proposed rate base a parcel of land in Ocean City, Maryland that it purchased in 1984 for a proposed substation. Because, however, the Company has indicated that its plans for the property are currently on hold, Staff argues that it should be removed from rate base, which would result in a reduction of approximately $78,000.[48] We find that the land properly remains in rate base, at least at this point.

The testimony demonstrates, and nobody disputes, that the Company purchased the property during a period of high growth in Ocean City. Mr. VonSteuben states that it is still very valuable and that if it were sold that it is unlikely that Delmarva could acquire a similar piece at the current book value in the future when it will be needed for load growth or reliability.[49] Whether or not that is true, to exclude it would require us to adopt a more rigid standard of certainty of future use than we have followed in past rate cases, and we decline Staff's invitation to change course now.

6. Cash Working Capital

Staff takes issue with one element of the Company's cash working capital ("CWC") calculation – it argues that Delmarva failed to include the effect of check float. Consequently, Staff asks that we reduce the rate base for CWC requirements by approximately $841,000.[50] We disagree.

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[48] Allen Direct at 18-19.

[49] VonSteuben Rebuttal at 14-15.

[50] Allen Direct at 19-21.

The issue here is the impact of *The Check Clearing for the 21st Century Act* ("Check 21"), which became effective in October 2004, on float in 2009. And the question is complicated by the fact that the Company apparently provided Staff data from 2005 for purposes of determining revenue float, then contends that checks in 2009 clear in one day both for expenses and payments. The Company argues that revenue float should be negated by expense float and that Staff's adjustment fails to recognize the effects of electronic and credit card payments. Staff, on the other hand, says that it simply used the data the Company provided and that 2005 data should already reflect the effects of Check 21. Further, Mr. Allen notes that he applied the 7.17 day expense float only to $359,437 of operation and maintenance ("O&M") expense. Finally, Mr. Allen asserts that he only applied payment float to checks, which does not include payroll and affiliate transactions.[51]

In his rejoinder testimony Mr. White pointed out that the $359,437 of O&M expense is a daily figure, which when multiplied by 365 days yields the annual $131 million of O&M expenses.[52] Therefore, he claims that Mr. Allen applied his 7.17 float days figure to all O&M expenses. He argues further that $22 million dollars of O&M expenses represent employee direct deposits, which have no float,[53] and that affiliate transactions, which amount to $71 million of O&M expense, also have no float. Therefore, Mr. White concludes that only $38 million dollars of O&M expense could

[51] Allen Surebuttal at 14-15.
[52] Transcript ("T") at 912.

[53] T at 913.

arguably be subject to float. [54] Conceding this amount results in a CWC rate base reduction of $93,488.[55]

Based upon our review of the record, we agree with the Company's CWC adjustment for float, and we have reduced rate base for that purpose by approximately $93,000.

7. Miscellaneous Rate Base Adjustments

At the Commission's request, the parties developed a Comparative Summary Schedule that reflects their final positions in this proceeding. This process clarified and resolved disputes regarding certain proposed adjustments. Based on this final schedule, the parties now concur that rate base should reflect the inclusion of the OPEB deferral balance, which reduces rate base by $2,921,000. They also agree that rate base (and operating income) must be adjusted to reflect the 2008 increase in the Maryland State corporate income tax rate from 7% to 8.25%. This adjustment decreases rate base by $1,322,000.[56] The final cash working capital figure also includes two agreed adjustments that we find reasonable: we have increased rate base by $84,000 to reflect a CWC ratemaking change and by $135,000 for the CWC change for the test period.[57]

B. Operating Income

Operating income is derived by subtracting the costs the Company incurs in providing service to customers from the revenues it receives for electric service. Various adjustments to the test year revenues and expenses are proposed by the parties and are

[54] T at 917.
[55] T at 917-918.
[56] It increases operating income by $1,888,000.
[57] See Comparative Summary Schedule, lines 33 and 34. As noted previously, the parties do not agree on the CWC adjustment to reflect check float.

either accepted, rejected or otherwise modified by the Commission in order to determine operating income. In this case, the Company's uncontested operating income was $15,568,000 for the test year period. The parties dispute other operating income and expense adjustments that we discuss and decide below.

1. Consolidated Tax Adjustment

Staff proposes that we apply a consolidated tax adjustment ("CTA") to the Company's earnings in this case. According to Staff, this adjustment reflects the difference between what a consolidated group of companies would pay in current tax liability if they filed separate stand-alone tax returns compared to what they do pay based on filing a consolidated tax return. Staff asserts that a fair share of such savings needs to be recognized for rate making purposes because, but for the utility company, the corporate family would not realize a proportionate amount of these savings. In other words, but for Delmarva, the corporate tax losses would have less value. Based on the most current (2007) data available, Staff proposes that we reduce federal income taxes by $5,249,317, which results in an equal increase in operating income.[58]

Company witness James Warren offered a lengthy and detailed opposition to Staff's proposed CTA. Mr. Warren argued that a CTA confiscates shareholder property; violates generally accepted accounting principles ("GAAP"); represents an indirect reduction of the allowed return on equity; breaches the wall between regulated and non-regulated operations; is "fringe" ratemaking; and is inappropriate because the tax losses should be assigned to companies generating the losses.[59] Mr. Warren emphasizes that the purpose of the consolidated tax return process is to prevent the imposition of a tax cost on

[58] Allen Direct at 15-18 and Exhibit RMA-1, Schedule 2, p.1.
[59] Rebuttal testimony of James I. Warren ("Warren Rebuttal") at 10.

the consolidated group of companies, which would be frustrated by imposing a CTA, which creates a regulatory cost.[60] Moreover, the tax losses at issue are unrelated to the provision of utility service and would diminish the profitability of unregulated activities, such as alternative energy investments, which depend on these tax benefits.[61] OPC did not propose a consolidated tax adjustment.

Staff witness Allen responded in his surrebuttal testimony that the tax savings in the CTA do not represent tax benefits to the loss affiliates or corporations other than Delmarva. Without the utility's positive taxable income, he argued, the losses would not provide a benefit to be captured by PHI in its consolidated return. Staff states that the benefits the Company otherwise would lose should be treated as regulated tax benefits, which Staff argues is what IRS Project PS-107-88 envisioned.[62] Staff disputed the claim that a CTA adjustment would qualify as "fringe ratemaking," and claimed that this Commission has in the past adopted a CTA in a rate case. Additionally, Mr. Allen points out that approximately 20 regulatory jurisdictions have adopted a CTA in at least one proceeding.[63]

The Commission previously addressed the issue of a consolidated tax adjustment in a proceeding involving Washington Gas Light Company ("WGL").[64] The Commission noted that the basic theory for filing a consolidated tax return is that members of the corporate system pay taxes on their consolidated taxable income which permits the net operating income of some members to be used to offset the net operating

[60] Warren Rebuttal at 7.
[61] Warren Rebuttal at 8-9.
[62] Allen Surrebuttal to Warren at 2. Project PS-107-88 dealt with the tax normalization rules and CTAs.
[63] Allen Surrebuttal to Warren at 3-5 and 7-8. Staff cites *In Re Columbia Gas of Maryland, Inc.*, Case No. 7545, Order No. 65520, 72 MD PSC 575, (1981).
[64] *Re Washington Gas Light Company*, 73 MD PSC 751 (1982).

losses of other companies. Consequently, without taxable income, the tax losses cannot be translated into system-wide tax savings.

The Commission stated that it "is a rule of general application that the rates charged for a regulated utility should only reflect the costs associated with providing the utility service and should not reflect costs associated with other businesses ..."[65] Therefore, the Commission concluded that it must examine the relationship between the regulated entity, whose costs are included in its rates, and the enterprise generating the tax savings in order to determine whether to reflect the tax savings. Furthermore, the Commission noted that it is also relevant to consider whether the tax savings are sufficiently recurring before reflecting them in test year ratemaking.[66]

In order to adopt the Staff's recommended CTA, we would have to depart substantially from prior Commission decisions on this issue and join a very small minority of commissions. Staff's claim that twenty other jurisdictions apply CTAs did not survive cross-examination by the Company and questioning by the Commission – nearly all of the cases Staff cited in its testimony had been overruled or the policy allowing CTAs otherwise superseded. In our view, the important question is whether the parent's tax policies treat the regulated utility unfairly.

In the course of questioning Mr. Warren during the hearing, we became aware that the PHI companies have a collective tax sharing agreement that allocates tax benefits and liabilities within the corporate family. After the fact of this agreement came to light, we directed the Company to produce the agreement and a witness capable of answering questions about the agreement, and the Company complied. The terms of the agreement

[65] Id. at 757.
[66] *Id.* at 757.

raise confidentiality concerns, so we will not discuss the details of it here. But after reviewing the agreement itself and examining the Company's witness, Mr. Salatto, we find that Delmarva is treated fairly for tax purposes in the overall taxation structure of the corporate family, and that Delmarva's ratepayers are not subsidizing the parent or its unregulated affiliates. Accordingly, we find that the Staff's proposed consolidated tax adjustment is not necessary to ensure fairness, and we decline to apply it.

2. Facility & Real Estate Service Costs

During an on-site review at PHI offices in Washington D.C., Staff noticed that seemingly significant portions of the facilities were vacant. Staff then served a data request regarding the Company's occupancy rate, to which the Company responded only with regard to its Delaware facilities. Although Staff complains about the completeness of the Company's response, it sought no additional information or relief prior to the hearing. Instead, Staff extrapolated the Company's Delaware occupancy rate, 4.04% of which is not occupied, to the Company as a whole, and argues that we should reduce operating income by approximately $65,000 to account for $108,409 worth of unused space. Staff also recommends that a utilization study be performed on all property used or allocated to Delmarva.[67]

Delmarva offers no good reason why it answered Staff's data request with Delaware data, but counters that the Company occupies substantially all of its office space across its jurisdictions and, therefore, that no adjustments are appropriate. Finally, Delmarva argues that a utilization study would be an unnecessary expense.[68]

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[67] Allen Direct at 10-11.
[68] VonSteuben Rebuttal at 18-20.

We find that the record here does not support a special adjustment for Facility and Real Estate Service Costs in this case. Although we will not order a utilization study at this time, we do direct the Company to provide Staff an accurate estimate of facilities usage for each facility used by Delmarva or for usage costs assigned to Delmarva, and we reserve the right to address these issues in an appropriate future proceeding.

3. Liability Reserve Accruals

Staff describes liability reserves as a form of accounting for losses not covered by outside insurance policies. Delmarva has established reserves for auto and electric liabilities. Staff asserted in its direct testimony that Delmarva's reserve accrual amounts for both auto and electric liabilities are not reasonable.[69] However, in his surrebuttal testimony, Mr. Allen eliminated his original auto liability accrual adjustment due to auto liability losses in 2009.[70] That leaves only electric accruals for us to resolve.

According to Mr. Allen, reserve accruals should cover the ongoing average level of annual losses experienced. The accruals should, he argues, provide a reasonable reserve and should reflect any unreasonable surplus or deficiency in the reserve balance. Because the electric liability balance is sufficient to cover expected annual losses for six years, he contends that the balance is over-funded and that Delmarva can maintain a reasonable level with no additional accruals for several years.[71] Consequently, he eliminates the test period electric liability reserve accrual, which increases net operating income by $405,000.[72]

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[69] Allen Direct at 11.
[70] Allen Surrebuttal at 13.
[71] Allen Direct at 11and 12.
[72] Comparative Summary Schedule.

The Company argues that Staff's analysis is historical, not prospective, and that current and future liabilities must include known open claims and incidents incurred but not reported (IBNR) as well as historical averages. Furthermore, to provide a zero level of expense for the test year does not fairly represent the cost incurred during the period.[73]

Based on the Company's response, the parties now concur that the Company's auto liability reserve is appropriate. However, we concur with Staff that six years of electric liability reserves should be sufficient to cover the expected level of losses during the rate effective period, and we have increased net operating income by $405,000.

4. Proforma Benefits

The Company proposes an adjustment to reflect an 8% increase in employee medical expense and a 5% increase in vision and dental expenses expected for 2009. The adjustment decreases test year earnings by $150,000.[74]

Staff opposes the Company's adjustment because it is based on "expected" costs rather than a known and measurable increase. Furthermore, Staff argues that the Company did not provide data and documentation to support these post-test year increases.[75] Staff also argues that the Company has not demonstrated that prior projections have accurately forecasted actual expenses.[76]

Mr. VonSteuben responds that the Company did not arbitrarily make these adjustments, relying instead on an independent benefits consultant. The Company provided the consultant's survey as a rebuttal exhibit.[77] Furthermore, Mr. VonSteuben points out that the proposed adjustment reflects the low end of the range for benefit cost

[73] Kathleen White Rebuttal at 2-6.
[74] VonSteuben Direct at 10, Schedule WMV-5, p.2.
[75] Alderman Direct at 2-3.
[76] Alderman Surrebuttal at 1-2.

increases in the Mid-Atlantic region. Since the adjustment is supported and is similar to an adjustment in its last case, Delmarva concludes that it is appropriate.[78]

The Commission finds that the Company's adjustment for increases in benefit costs is supported by the study and that it represents the lower end of the expected range of cost increases. Therefore, the Commission includes the Company's adjustment in the calculation of operating income.

5. Rate Case Expense

The Company proposes an adjustment to amortize the anticipated incremental costs of this proceeding over five years, without including the unamortized portion in rate base.[79] According to Mr. Effron, the Company has two errors in its adjustment. *First*, OPC argues that the cost of the present case included in Delmarva's 2008 expenses is understated, which results in a correction reducing proforma expenses by $113,000. *Second*, Mr. Effron states that if amortization of the remaining one-half of Case No. 9093 regulatory expense is permitted, then this amount should also be amortized over five years which results in a $138,000 modification. Combining Mr. Effron's adjustments would reduce proforma regulatory expense by $251,000.[80] In rebuttal, Mr. VonSteuben notes that OPC and Delmarva agree on the rate case expense adjustment.[81]

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[77] VonSteuben Rebuttal, Schedule WMV R-4.
[78] VonSteuben Rebuttal at 12-14.
[79] VonSteuben Direct at 12; Schedule WMV-5, at 9.
[80] Effron Direct at 13-15; Schedule C-1.
[81] VonSteuben Rebuttal at 5 and Schedule WMV R-1 at 2. *See also* Comparative Summary Schedule. Rate case expense is amortized over a presumed period between rate cases. Thus, if the Commission orders a 5 year amortization the rate case expense is divided over the 5 years until the next rate case is expected, which yields a yearly expense for operating income calculations. This is what the Commission did in Case 9093. However, since only two and a half years elapsed until this Order is issued, there was 50% of the 9093 expense that the Company did not recover, so far, in rates. The Company and OPC finally agreed to roll the unamortized 9093 rate case balance into the rate case expense for this case. Since a certain level is already reflected in rates, this is why OPC witness Effron made the adjustments to get the correct amortization going forward for an expected 5 years. The Company agreed and the Commission is accepting this agreed (except for Staff) adjustment.

Staff argues – with no citation – that both shareholders and ratepayers benefit from a rate case and therefore such expenses should be shared equally. Therefore, Staff asks us to reduce the Company's rate case amortization by 50%.[82]

The Company responds that the cost of a rate case is a normal and necessary cost. Furthermore, the Company argues that these costs have always been included in a utility's cost of service and there is no reason to deviate from prior Commission practice.[83]

The Company is correct that rate case expenses have historically been recovered as part of a utility's cost of service. Although Staff's split-the-difference position has some visceral appeal – the Company's emphasis throughout the case on providing returns to shareholders and investors and safeguarding tax incentives for unregulated operations did occasionally give us pause – there is no legal or record support for a departure from historical practice in this case. However, OPC witness Effron did point out modifications that are required to the Company's original figures including the need to amortize the remaining balance from Case No. 9093 over the five years that will be authorized for rate case expenses in this proceeding. The Company agrees with OPC and the Commission accepts the rate case adjustment, which increases operating income by $99,000.[84]

In its brief, OPC encourages the Commission to reduce the amount of rate case expense by the total amount of external legal expense ($500,000). OPC maintains that it sees no reason why this sort of routine expense could not be handled by in-house counsel. Because OPC did not offer evidence or testimony demonstrating that the Company's

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[82] Alderman Direct at 3-4.
[83] VonSteuben Rebuttal at 5-6.

[84] See Comparative Summary Schedule, line 29.

outside legal expenses were excessive, we have no basis in this record on which to make such an adjustment (especially since we find that the Company's outside counsel represented it ably). Our decision not to adjust outside counsel expenses in this case should not be read as foreclosing the possibility in another case, on the right record.

6. Uncollectible Expense

Mr. VonSteuben testified that uncollectible expenses increased from the $392,000 reflected in rates now, as a result of Case No. 9093, to the test period amount of $1,374,366. But the Company does not stop there: Delmarva asks us to reflect its *estimated* 2009 uncollectible costs of $1,581,863 in rates.[85] We reject this request.

This particular departure from the test year is opposed universally. OPC witness Effron argues that the appropriate write-off ratio should be applied to the 2008 test year revenues, not the forecasted 2009 revenues since the Company is not proposing to include 2009 revenues in its operating income calculation. He argues that the uncollectible ratio must be modified because the Company underweighted 12 months of 2007 data and overvalued seven months of 2008 data in formulating its ratio.

Furthermore, Mr. Effron states that the addition to the reserve should not be included in determining the ratio, which is what Delmarva did, because this represents an estimate of write-offs, not actual experience. Mr. Effron recommends that we set the normalized uncollectible accounts ratio by averaging the net write-offs as a percentage of billed revenues for 2007 and 2008 because it recognizes only the actual net write-off experience. Applying the write-off ratio to proforma test year sales revenues results in proforma uncollectible accounts expense of $990,000.[86]

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[85] VonSteuben Direct at 11-12.
[86] Effron Direct at 11-13.

Staff also disagrees with the Company's adjustment because it restates the test year amount to a projected 2009 amount. Staff states that it was not able to determine the reasonableness of Delmarva's forecasts. Staff computed an uncollectible expense rate for the test year and applied it to Staff's adjusted revenue to compute uncollectible expense. Staff's uncollectible expense amount is $1,103,099.[87]

In rebuttal, the Company notes that the economy has taken a dramatic downturn during the test period. However, Mr. VonSteuben states that the adjustments proposed by Staff and OPC would reduce uncollectible expenses to an amount below the 2008 level of uncollectible expense. Mr. VonSteuben asserts that this is unreasonable given the increasing trend in uncollectible expenses.[88]

We find that the Company's uncollectible expenses in the test year of 2008 were higher than the expenses reflected in rates, and as a matter of principle and consistency we are willing to reflect the Company's test year experience in its new rates. We are not, however, willing to ignore the test year reality for individual cost or revenue items simply because the Company expects a different result going forward. Adopting the Company's theory here would create exactly the sort of cost/revenue mismatch that the reliability projects did not – it would allow the Company to recover in the future for projected, not known and measurable, expenses without accounting for corresponding revenue projections. The potential mismatch here is compounded by the fact that the Company's test period expense reflects not only actual write offs, but also an amount for its uncollectable reserve,[89] which forecasts future uncollectibles already. Based upon the

[87] Alderman Direct at 4-5.
[88] VonSteuben Rebuttal at 20-21.

[89] Transcript at 125.

record, we find that Staff's computation, which is based on an uncollectible rate solely for the test year, most accurately reflects uncollectable expense, which will increase operating income by $132,000.[90]

7. Interest Synchronization

Interest synchronization is a procedure that is used to adjust the interest deduction for state and federal income taxes, which results from various ratemaking decisions. The interest deduction is calculated by multiplying the rate base by the weighted cost of debt. Based upon the ratemaking decisions in this order, the appropriate interest synchronization adjustment is $858,000.

8. Miscellaneous Operating Income Adjustments

The parties have also reconciled certain operating income adjustments. They concur that operating income should be increased by $1,395,000 to reflect the elimination of some incentive expenses. The one-time adjustment for amortizing the increase in the Maryland corporate tax rate increases operating income by $1,888,000.[91] The Commission accepts these reconciled adjustments.

C. Cost of Capital

The cost of capital consists of two components: return on equity capital ("ROE"), *i.e.,* the Company's stock, and a return on debt capital, *i.e.,* the company's bonds. The proportion of common and preferred equity capital and the proportion of long term and short-term debt are combined to establish the company's capital structure.[92] To

[90] See Comparative Summary Schedule, line 19. ($236,000 - $104,000 = $132,000).
[91] This adjustment reduces rate base by $1,322,000.
[92] In this proceeding, the Company has not requested a return on preferred stock, nor has it requested a unique return on short-term debt.

determine the utility's overall cost of capital, *i.e.*, the metric used to determine a target percentage return to investors that will attract investors to purchase the Company's offerings, the proposed individual components of debt[93] and equity[94] are weighted according to their percentage in the utility's capital structure. From there, the weighted costs are summed to determine the utility's overall weighted cost of capital.[95]

1. The Company's Position

Delmarva's rate of return witness, Professor Roger Morin, citing unprecedented capital market conditions of turmoil and uncertainty, originally proposed a return on common equity of 11.00% without a Bill Stabilization Adjustment ("BSA") and 10.75% with his proposed BSA.[96] Dr. Morin noted in his direct testimony that "if substantial changes occur between the filing date [May 6, 2009] and the date my oral testimony is presented, I will update my testimony accordingly."[97] On the stand, Dr. Morin reduced the average result from his studies from 11.26% to 10.7%. His updated recommended ROE is 10.75%, with a recommended BSA adjustment of 25 basis points rather than the 50 basis point reduction the Commission applied in 2007. Dr. Morin argues that the proliferation of BSA mechanisms in the electric industry and the potential for a favorable consideration of BSA mechanisms by other Commissions diminish the need for a BSA-

[93] In this proceeding all parties agree that a reasonable cost of long-term debt is 5.93%. *See* DPL Exhibit No. 30 at Schedule RAM-16.
[94] There is no preferred stock included in the Company's equity calculation; therefore the ROE is the return on common equity, alone.
[95] The weighted cost of capital is one input in the interest synchronization adjustment for state and federal income taxes. *See* p. 29, above.
[96] T. at p. 753-54.
[97] DPL Exh. No. 30 at p. 82.

related ROE adjustment in this case.[98] Dr. Morin's updated overall cost of capital is 8.33%.[99]

Dr. Morin also argues that flotation costs should be recovered on an ongoing basis rather than expensing.[100] He argues that Delmarva may not have expensed flotation costs at the time it issued securities, and therefore the Company must recover them through a rate of return adjustment.[101] The Company argues that an upward adjustment of 30 basis points is necessary regardless of whether equity is issued by the utility itself or comes from its parent company, and regardless of whether equity issuances are anticipated soon.[102] In calculating his proposed adjustment, Dr. Morin did not rely on the actual flotation costs of Delmarva or its parent, but relied instead on a model. His adjustment also fails to recognize the 7 basis point adjustment for flotation costs the Commission allowed in Case No. 9093. Instead, Dr. Morin relies on an assumed flotation cost of 5%, applies it to the generalized results from empirical finance literature, and concludes that ratepayers should pay for the direct costs that the Company has in its discretion, written off in past years, as well as the indirect costs of market pressures from investors discounting the dilution of the company's equity. Dr. Morin agrees that without this accretion of cost recovery for prior period flotation costs, his estimate would be a much smaller flotation cost adjustment.

Finally, Dr. Morin adopts Delmarva's actual capital structure as of December 31, 2008, which reflects only common equity and long-term debt,[103] and argues that the

[98] DPL Initial Brief at 13.
[99] Comparative Summary Schedule, Delmarva column, line 38.
[100] DPL Exhibit 30 at p. 66.
[101] Id. at p. 62.
[102] DPL Brief at p. 14.

[103] DPL Exhibit 30 at p. 81.

Company's capital structure targets should be set to achieve a strong A rating, while noting that the legal definition of investment grade rating is BAA.[104]

2. OPC's Position

OPC's rate of return witness, Charles W. King, proposes a return on common equity of 10.47% without the BSA and 9.97% with his proposed BSA. Mr. King recommends an ROE of 10.0%, which he derives by taking the weighted average return from his comparison group of companies of 10.47%, which already includes 0.07 percent for flotation costs and subtracting 50 basis points for the BSA, then rounding the result (9.97%) up.[105] Under his proposed capital structure, Mr. King's overall cost of capital would be 7.68%.[106] Unlike Dr. Morin, Mr. King bases his flotation cost recommendation on Delmarva's actual flotation costs rather than a theoretical estimate of any and all flotation costs ever expensed, written off or incurred in any test year.[107] Indeed, Mr. King argues that Delmarva's proposed method would recover over half of all the flotation costs that Delmarva has incurred since its creation.[108]

3. Staff's Position

Staff's rate of return witness, Matthew Schultz, proposes a return on common equity of 9.85%, including a 50 basis point BSA adjustment and a flotation cost adder of 7 basis points.[109] In the context of his capital structure proposal, Mr. Schultz's recommendation translates to an overall cost of capital of 7.70%.[110]

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[104] DPL Exhibit 30 at p. 79.
[105] OPC Exhibit 3 at p. 25.
[106] OPC Exhibit 3 at p. 25. Comparative Summary Schedule, OPC column, line 38.
[107] OPC Exhibit 3 at p. 22.
[108] OPC Initial Brief at p. 24.
[109] Schultz Direct, Exhibit No. 12 at p. 2.
[110] *See* Staff Exhibit No. 12 at p. 2, and the Comparative Summary Schedule, Staff column line 38.

Staff used a similar variety of studies to develop a recommended ROE. The average of Staff's two market risk premium analyses is an ROE of 10.31%.[111] Witness Schultz also computed an empirical CAPM model, which, using the Company's inputs, resulted in an ROE of 9.20%.[112]

On brief, Staff notes:

> *Because the costs of equity capital is not directly observable, each of the witnesses presenting testimony on the cost of capital used several methodologies to indirectly estimate the return required by investors consistent with the regulatory standard. OPC relied most heavily on the DCF analysis. The Company conducted four DCF analyses, a CAPM and an E-CAPM as well as two DCF and a historical risk premium analysis...Staff used the DCF method in combination with an IRR, a CAPM, and an E-CAPM analysis....By the end of the hearing, the parties are separated by 90 basis points in their recommended returns on equity.*[113]

Mr. Schultz rounds up to a proposed ROE of 9.85% with a 50 basis point adjustment for the BSA. In stark contrast to the Company, Staff argues that a downward adjustment to the ROE of *at least* 50 basis points should be made to account for the stability offered by the BSA. Indeed, Staff cites cases in its brief that could support a downward BSA adjustment as large as 214 basis points.[114] And with regard to flotation costs, Staff argues that Delmarva has not benefited from nor shown a need in the immediate future for a significant amount of outside equity, and thus that the Commission should not adjust the Company's ROE for flotation costs at all.[115]

Staff's overall rate of return includes a short-term debt ratio of 4.33% at a cost of 3.51%. Staff argues that short-term debt should be included in the capital structure, after

[111] Staff Exhibit No. 12 at p. 9.
[112] Staff at p. 8.
[113] Staff Initial Brief at 32.

[114] Staff Reply Brief at 33.
[115] Surrebuttal at p. 5.

an allowance for CWIP, because the amount of short-term debt on Delmarva's books is, in its view, significant and there is no indication that Delmarva will dispense with the need for short-term debt during the rate effective period.[116]

4. Commission Decisions

Return on Common Equity

Based on the record in this case, we find that the appropriate ROE for the rate effective period should remain 10.00%, inclusive of adjustments for the BSA and flotation costs. Although we understand that recent economic conditions have challenged the Company's access to capital, we are unwilling as a general matter to reward the Company's shareholders with a higher rate of return, on the backs of ratepayers.

Pinpointing ROE targets is more art than science. All of the parties rely heavily on different, subjective approaches to weighting and adjusting the CAPM, DCF and risk premium analyses. All of the arguments before us were rational and, as Dr. Morin candidly acknowledged, the target is a moving one. In finding that the ROE should remain at 10.00%, we do not simply split the difference among the parties recommendation (even though it falls neatly in between Staff's recommendation of 9.85% and the Company's request for 10.43%) or fall back on our ruling in Case No. 9093. Instead, we have weighed the Company's requests in the context of its costs and revenues, current and prospective economic conditions, and the interests of the ratepayers. On this record, we find that 10.00% remains an appropriate rate of return, that there is no need to enhance or reduce the Company's return at this time, and, as we

[116] Reply Brief at 31.

explain in greater detail below, that the adjustments we made in 2007 to account for the BSA and for flotation costs remain appropriate.

Bill Stabilization Adjustment

The Commission agrees with OPC and will keep the 50 basis point BSA adjustment we approved in Case No. 9093 in place. As a general matter, the BSA has not truly served its intended purpose since we approved it in 2007. Although Delmarva has earned millions of dollars in revenue from the BSA since inception, we only approved comprehensive energy efficiency programs for the Company this past summer. Based purely on experience since Delmarva's last rate case, we find that the BSA has afforded Delmarva an enhanced opportunity to earn its rate of return, even though the Company has not faced in any meaningful way the business risks the BSA is meant to mitigate. Moreover, we reject the notion that other Commissions have baked BSA adjustments into the published ROEs of comparable utilities. By virtue of the EmPOWER Maryland Energy Efficiency Act of 2008, among other things, the utilities of this State are ahead of the energy efficiency curve, and the record does not support the claim that the ROE of comparable electric utilities includes a BSA adjustment. Although we find some merit to Staff's argument that the BSA adjustment should be larger,[117] we are content to leave it at 50 basis points at this time.

Flotation Costs

We also adopt, again, OPC's straightforward, reality-based approach to flotation cost recovery – which reaches the same result we reached in 2007 – and we reject the Company's theoretical calculation. Flotation cost recovery should be reasonably related to the actual costs associated with issuing new stock that are incurred in the test period or expected in the rate effective period.[118] We also reject any attempt by the Company to recover past discretionary write offs in prior rate effective periods. We find that the seven basis point adder the Commission applied in Case No. 9093, and supported here by Mr. King, remains reasonable and appropriate on the record before us.

Because the record in this proceeding shows that a 10.0% ROE is commensurate with returns on investments in other enterprises having corresponding risks, and is sufficient to assure confidence in the financial integrity of Delmarva, the Commission believes that it will permit Delmarva a reasonable opportunity to maintain its credit and to attract capital.

Capital Structure

The Company based its overall rate-of-return recommendation on its end-of-test-year actual capital structure of 50.13 percent long-term debt[119] and 49.87 percent common equity.[120]

In Case No. 9093, the Commission adopted the Company's actual capital structure, noting that short-term debt is a small part of the capital structure and may be omitted. Here, given the variability in short-term borrowings during the test year, and the absence of short-term debt in Delmvara's parent's capital structure, the Commission retains the exclusion of short-term debt from Delmarva's capital structure. In this proceeding however, OPC and Staff propose a rate of return based on the Company's actual capital structure in which they would reduce the overall rate of return by including

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[117] OPC Brief at p. 33.
[118] It has been a longstanding preferred ratemaking practice of the Commission to base a determination of annual revenue requirements on the actual results of operations for a test year, which is likely to be representative of the rate effective period. *In Re Baltimore Gas and Electric Company,* Case No. 8190, *80 Md. P.S.C. 380,* 385 (October 18, 1989).
[119] Staff and OPC agree with the Company's proposed cost of long-term debt.
[120] Delmarva Initial Brief at 5.

short-term debt at an average, rather than end-of-year amount, and at a cost lower than the cost of long-term debt and the ROE. In that way, Staff and OPC recognize the existence of short-term debt on the Company's books in the test year.

OPC's proposed overall rate of return includes a short-term debt ratio of 5.89% at a cost of 5.43%.[121] Mr. King asserts on rebuttal that the Company's proposed capital structure, which excludes short-term debt, fails appropriately to recognize that Company held large cash balances last year after issuing $250 million in short-term debt on November 25, 2008, at the end of the test year.[122]

Mr. Kamerick described short-term debt on rebuttal as follows:

> [S]hort-term debt as it is used by Delmarva is temporary funding for the Company's construction requirements, which are permanently financed with either long-term debt or common equity.[123]

Mr. Kamerick asserts that the financial crisis has had a severe negative effect on the short-term credit markets, necessitating Delmarva's borrowings under its bank credit facility and causing concerns over its ability to maintain its liquidity. He argues that Delmarva's short-term debt after netting cash needed for liquidity is more than consumed by funding construction work in progress (CWIP).[124]

OPC attempts unsuccessfully to rebut Mr. Kamerick by noting that there was up to $50 million in actual short term borrowing in 2008.[125] Staff notes on brief however, that an adjusted capital structure has been adopted when necessary to recognize the Company's actual capital structure during the rate effective period.[126]

[121] King Direct, Schedule 1.
[122] OPC Exhibit 4 at p. 3.
[123] Delmarva Exhibit No. 2 at p. 6.
[124] Delmarva Exhibit No. 2 at p. 7-8.
[125] OPC Exhibit 4 at p. 3.
[126] Staff Initial Brief at p. 30.

We decline to adjust Delmarva's capital structure to recognize short-term debt. All else being equal, rates should reflect reality. Because Delmarva does not issue stock of its own and PHI only has common equity and long-term debt, the Company's financial structure during the rate effective period will not include short-term debt, and PHI's emergency borrowings in late 2008 should not skew Delmarva's capital structure for the years to come.

Overall Rate of Return

The Commission determines that a reasonable overall rate of return for Delmarva in this proceeding is 7.96%,[127] which is based on a return on equity capital of 10.00%, a return on long-term debt of 5.93%, and a capital structure consisting of 50.13% long-term debt, and 49.87% common equity. The 10% ROE is based on seven basis points for flotation costs, a 50 basis point reduction for the BSA, and a weighing of the various methods used by the parties to calculate the unadjusted ROE. Although the ROE remains unchanged in this proceeding relative to Case No. 9093, the Company will receive a slight increase in the overall rate of return because of the slightly higher cost of long–term debt used in this proceeding and because the relative proportion of common equity versus long-term debt in the capital structure is slightly higher in this proceeding.

Revenue Requirement

When applying the 7.96% percent overall rate of return to the adjusted rate base of $306,352,000, the income requirement is $24,386,000. Based on the Company's adjusted test year net operating income of $19,991,000, we find the Company has a net

[127] In Case No. 9093, the ratios of long-term debt and short-term debt were 51.37% and 48.63%, and the cost rate for long-term debt was slightly lower at 5.48%, resulting in an overall rate of return of 7.678%.

operating income deficiency of $4,395,000, which becomes a gross revenue deficiency of $7,531,000, as detailed in Appendix I. For the reasons set forth above, we find that rates based on this revenue requirement amount of increase will result in just and reasonable rates for the Company and its customers.

D. Cost Allocation

The Company, through Mr. Tanos, offered jurisdictional and customer class cost of service studies ("COSS") based on a test year ending December 31, 2008. According to Mr. Tanos, the COSS assigns the Company's revenue requirement to the different customer groups based upon cost causation. Once costs are allocated appropriately, Mr. Tanos says they can then be used to develop applicable class rates of return, which guide the final rates charged to each customer class.[128]

The Company's proposed cost model began with the approach from its last base rate case,[129] but incorporated as well the Commission's directions from Case No. 9093. In accordance with Order No. 81518[130], Delmarva calculated the non-coincident peak ("NCP") demand for the residential heating and non-heating customers as a single class and combined these distinct groups in the COSS.[131] The average load factors for both the heating and non-heating customer groups were applied to Delmarva's residential customers' kWh sales to determine the customers' NCP.[132] Mr. Tanos also recommends using the customer load data base embodied in the Lodestar Profiling and Settlement

[128] Direct Testimony of Elliott P. Tanos ("Tanos Direct") at 3-5.
[129] Tanos Direct, at 10.
[130] *Re Delmarva Power and Light Company, 98 MD PSC 288 (2007).*
[131] Tanos Direct, at 10-11. The Commission also ordered Delmarva to perform load and peak studies on a biennial basis and to file a biennial report. According to Staff, the Company has not yet filed its first report but plans to do so in the first quarter of 2010. Ermer Direct at 6-7. The Commission directs Delmarva to file the report by April 1, 2010.

System ("LPSS") to calculate the demand allocation factors – he claims that it yields a valuable database that can be used to estimate the demand measures in the COSS.[133] Mr. Tanos summarized the Maryland jurisdictional distribution customer class COSS, then expressed as both rates of return and relative rates of return. According to Mr. Tanos, Delmarva's Maryland Distribution rate of return for 2008 was 7.83%.[134]

OPC witness Wallach argued that the Company's COSS may overstate the residential class's share of costs. If so, he argued, the increase necessary to bring the residential class to the requested rate of return would be less than indicated by Delmarva's COSS.[135] Although he concludes that the Company's allocations are "generally reasonable," Mr. Wallach identified two issues that tend to overstate residential customer costs.[136] *First*, he claimed, the allocation of line transformers based on a simple average of "Class MDD" (the class maximum diversified demand) and "Customer NCP" (the sum across customers in a class of maximum customer demands) may understate the diversity of load on these facilities. *Second*, he asserts that Delmarva's allocation of services based on Customer NCP does not account for sharing by several residential customers of a single service line to a multi-family building. Mr. Wallach also notes that Delmarva has not conducted a system load diversity study and concludes that such a study should be done to ensure that allocators reasonably reflect the impact of load diversity on distribution costs.[137]

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[132] Tanos Direct at 15.
[133] Tanos Direct, at 11-14.
[134] Tanos Direct at 4 and 22, and Schedule EPT-7.
[135] Wallach Direct at 7.
[136] Wallach direct at 9. See pages 8-9 for a discussion of the allocations.

[137] Wallach Direct at 12.

Mr. Tanos responds that Mr. Wallach's position regarding the use of allocation factors for secondary plant investment is one-sided and does not fairly reflect the distribution plant installation characteristics of the Delmarva system. Mr. Tanos challenged OPC's assumptions of customers per line transformer as neither realistic nor representative of each class. Mr. Tanos responded that the Company's COSS applies a 50/50 weight to the Class MDD and Customer NCP, an approach he characterized as reasonable and practical.[138] As for service conductors, Mr. Tanos argues that the vast majority of service drops can only be used by a single customer. Therefore, he claims, Delmarva has used customer maximum demands as a reasonable proxy in lieu of extensive and costly efforts to quantify all cost elements.[139]

Staff witness Ermer testified that the COSS was appropriately developed and yields reasonable results, albeit with one exception: he argues that part of the distribution plant in the COSS was not properly classified because a number of items have been classified only on a demand-related basis and do not contain a customer-related component as recommended in the NARUC Cost Allocation Manual.[140] Delmarva classified distribution plant components either on a demand-only basis or a customer-only basis. Meters and services were classified as customer-only related and poles, transformers and conductors as demand-only related.[141] However, Staff notes that NARUC guidelines recognize that poles, transformers, and conductors (as well as services, and meters) are required for service to customers regardless of their load

[138] Tanos Rebuttal at 7-9.
[139] Tanos Rebuttal at 10-11.
[140] Direct testimony of Charles Ermer ("Ermer Direct") at 3. NARUC is the National Association of Regulatory Utility Commissioners.
[141] Ermer Direct at 9.

requirements.[142] Since the Company's COSS classified poles, transformers and conductors on a demand-only basis, Mr. Ermer concludes that this may contribute to cross-subsidization between classes and contribute to the divergence of customer class rates of return from the total Company rate of return.[143]

Staff conducted a theoretical analysis in which it allocated a portion of the distribution plant line items based solely on the number of customers in each class, then allocated the remaining portion as demand-related according to the COSS.[144] Staff defines the customer component as the theoretical minimum distribution system required to serve customers at nominal load conditions.[145] Staff examined two scenarios, one where there was a 90% demand related and 10% customer related split and another based on a 70/30 demand/customer split. Staff's analysis resulted in shifting additional costs to the residential and street lighting classes while the general service secondary and general service primary classes showed reduced costs allocated to these classes. The largest cost shift resulted from the 70/30 split, which reduced the general service primary cost allocation by 42%. The residential class saw increases in cost allocations of about 3% with the 90/10 split and 9% with the 70/30 split.[146] Based on its analysis, Staff concludes that using an allocation method that relies more on customer-related allocators would reduce the imbalance between the class rates of return in Delmarva's COSS. Costs would be shifted from the general service classes to the residential and street lighting

[142] Ermer Direct at 16.
[143] Ermer Direct at 3. Staff does not take issue with the Company allocating services and meters on a customer-only basis. Staff also notes that the COSS presented by Mr. Tanos has not been adjusted for the rate base adjustments proposed by Company witness VonSteuben. Ermer Direct at 10.
[144] The allocation of meters and services was not changed because they are already classified as customer-related. Ermer Direct at 17.
[145] Ermer Direct at 16.

[146] Ermer direct at 17-18. *See* chart, at 18.

classes. Ultimately this would bring the classes closer to the total Company rate of return. Staff states that in its opinion at least 10% of costs are customer-related, and the percentage may be much higher. Consequently, Staff recommends that Delmarva be required to include a minimum-size system analysis in its COSS as outlined in the NARUC Manual in its next rate case.[147]

Staff notes that when it questioned the Company about not using a customer component in the COSS, Delmarva responded that for small users the theoretical minimum system can include a large portion of their load requirement and result in an over-allocation of costs for these accounts or double counting. The Company also noted that the NARUC Cost Allocation Manual cautions against using the minimum system method and over-allocations. Moreover, Delmarva noted that its allocation methods are consistent with those used in Case No. 9093.[148] Furthermore, Mr. Tanos asserts that Delmarva's approach to customer-related plant costs recognizes the weaknesses in other methods. Although there is a theoretical basis for assuming a very small customer component in investment in distribution lines and poles, he argues that it is extremely difficult to quantify and properly address all elements of related costs such as other plant and depreciation expenses where a simple ratio may be entirely inappropriate. Mr. Tanos argues that the demand-only classification approach for lines, poles and transformers is a common cost allocation approach, which avoids the double counting possible with a minimum-size system approach.[149]

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[147] Ermer Direct at 18-19.
[148] Ermer Direct at 17.

[149] Tanos Rebuttal at 4-5.

According to Mr. Wallach, Staff does not provide any theoretical or quantitative basis for its conclusion that at least 10% of distribution costs are customer-related. OPC also takes issue with Staff's recommendation that the Company undertake a minimum-size system analysis in a COSS in its next rate case. OPC explains that the minimum size analysis attempts to estimate the cost to install the same number of units as are currently on the system assuming that each unit is the smallest size currently used. Another method, the zero-intercept method attempts to estimate the cost of equipment required to connect existing customers, even if they have virtually no load. Using either method, the minimum system cost is deemed customer-related with the remaining costs classified as demand-related. Mr. Wallach argues that minimum-system methods do not produce reasonable classification results because, however estimated, such costs are neither properly classified as wholly customer-related or demand-related. In other words, minimum system costs are not driven by either changes in the number of customers or by changes in customer demand. Mr. Wallach concludes that small customers are unfairly burdened when a high percentage of these costs are characterized as solely customer related.[150]

No party suggests that the Company's COSS should not be used for determining customer class revenue requirements in this proceeding. However, both OPC and Staff recommend studies to refine the COSS analysis for the Company's next base rate case. OPC recommends that the Company conduct a system load diversity study and Staff recommends a minimum-size system analysis. Neither OPC nor Staff could quantify the costs for such studies.

[150] Rebuttal Testimony of Jonathan Wallach, at 1-4.

On the record before us here, we find that the Company's COSS fairly and reasonably distributes costs across the Company's customer classes, and we do not order further studies at this time. In Case No. 9093, the Commission declined to adopt Mr. Wallach's proposals regarding the allocation of transformers and services to account for load diversity, and we are not persuaded that such a study is necessary right now. The scope and cost of Staff's proposal for further cost allocation studies remains uncertain, and we are not presently persuaded that an extensive, expensive study is needed right away. We remain open to the possibility of further study at a later time.

E. Rate Design

1. Inter-Class Rates

Not surprisingly, the Company's proposed rate design incorporates the results of the Company's COSS. The Company's proposal is based upon three major principles:

(1) Minimize to the greatest extent possible the disparity between a class rate of return and the overall rate of return, thus matching class revenues and costs. The Company measures the disparity by the unitized rate of return ("UROR"), with one being unity. A number above one indicates the class is contributing a greater than average return and vice versa.

(2) Provide price signals that accurately reflect the class cost of service. Delmarva sends these signals by setting the customer, energy and (if applicable) demand charges so that they recover these particular pieces of the overall class cost of service to the greatest extent practicable.

(3) Apply the principle of gradualism to inter-and intra-class rate changes. In this regard, the Company took into account the level of changes approved by the Commission in Case No. 9093.[151]

In developing the Company's proposed rate design, Mr. Janocha began with the UROR results from the COSS. The Company proposes an allocation of the revenue requirement that would move the Telecommunications Network Service ("TN") classification from its current UROR of 0.92 to 1.00, which coincides with its class cost of service. For the Small General Service –Secondary ("SGS-S") and the Residential ("R") classes, which both have UROR's above 1.0, the Company proposes to close the difference between the current UROR and unity by 70%. This approach would result in the SGS-S class UROR moving from 1.21 currently to 1.06, and the Residential UROR moving from 1.05 currently to 1.02. In other words, these rate classes would receive less than the average proposed rate increase in this case. For the Large General Service-Secondary ("LGS-S"), General Service Primary ("GS-P") and the Street Ligthing classes, which all have URORs of less than 1.0, Mr. Janocha proposes revenue increases that would close the difference between the current URORs and unity by 70% for each. This would result in new URORs of 0.86 for LGS-S (up from 0.54 currently), 0.82 for GS-P (up from 0.39 currently) and 0.88 for Street Lighting services (up from 0.60 currently), which would be larger than the average rate increase.[152]

From these reallocations, Delmarva proposes to increase customer charges and demand charges to recover a greater percentage of customer and demand related costs.[153]

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[151] Direct testimony of Joseph F. Janocha ("Janocha Direct") at 2-4.

[152] Janocha Direct, at 6 and Schedule JFJ-1.

[153] Janocha Direct, at 6-10. Only the SGS-S class has demand charges.

The Company originally proposed to reduce the difference between the initial and trailing blocks for Residential winter rates, but subsequently agreed to consolidate the Residential winter rate blocks into a single winter rate, with adjustments to maintain a summer-winter differential.[154] Finally, the Company proposes some minor tariff clarifications and an adjustment to the revenue per customer levels based upon the proposed changes to the distribution rates.[155] Billing comparisons for the major rate schedules are contained in Schedule JFJ-2, which shows that a typical residential Standard Offer Service ("SOS") customer using 1,000 kWh per month would see a total monthly bill increase of $3.89 or 2.6% under the Company's revenue request (which is approximately double the amount we allow here).[156]

OPC challenges the Company's proposal, arguing that it would allocate to residential ratepayers more of the requested revenue increase than is necessary to achieve the requested rate of return. Through Mr. Wallach, OPC argues that the Company should only be permitted to allocate to residential customers as much of the approved revenue increase as is required to achieve the overall authorized rate of return, which would result in a UROR of 1.0.[157] Mr. Wallach contends that although the Company proposes to increase Residential class revenues for distribution service by 10.8%, the result would be a Residential rate increase of approximately 18% because of the decline in retail sales between 2006 and 2008 and the effect of the Bill Stabilization Adjustment ("BSA").[158] He concludes that the 18% increase "effectively folds the BSA surcharge recovery of the

[154] The Commission also finds this resolution appropriate.
[155] Janocha Direct, at 12-13. This affects the BSA. No party contested the tariff clarifications and they are approved.
[156] Janocha Direct, at 12.
[157] Wallach Direct at 2.
[158] Wallach Direct at 5-6.

sales-related deficiency into base rates."[159] Mr. Wallach concludes that in this time of economic distress, the Company should be minimizing residential rate increases to the greatest extent feasible.[160]

Mr. Campbell responds that Staff generally agrees with the revenue allocation technique Delmarva used, but that Staff's overall recommendation of a rate decrease here requires alterations to the Company's techniques to maintain revenue neutrality among the rate classes.[161] Staff recommends that the GS-P, Street Lighting, and LGS-S classes receive a minimal or no decrease in their revenue requirement, and that that other rate classes, including Residential, receive significant revenue requirement decreases.[162] Staff argues that maintaining revenue neutrality while lowering the revenue requirement of certain rate classes will increase the unitized rate of return for classes whose revenues remain unchanged. If we were to allow a rate increase, however, Staff considers the Company's allocations reasonable and proper.[163] Staff agrees with the Company that by eliminating 70% of the difference between the overall system rate of return and a given rate class rate of return, Delmarva will achieve consistency across rate classes without unduly discriminating against any class.[164]

There are, alas, wide disparities among the rate classes that need to be corrected at this point. But bringing all classes to unity in one fell swoop would stretch the important

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[159] Wallach Direct at 7.
[160] Wallach Direct at 2.
[161] According to Staff, revenue neutrality maintains the same level of class revenues regardless of intra-class allocations.
[162] OPC notes that Staff's allocation to the Residential Class of its proposed rate decrease in this case represents a 4.5% decrease to the revenue amount approved for the R class in Case No. 9093. However, because of the effect of the BSA and the lower electricity sales revenues today, the average rate for the R class would increase by 1.7% over current base rates. Wallach Rebuttal at 5.
[163] Campbell Direct at 6-7.
[164] Campbell Direct at 14-15.

principle of gradualism past its breaking point. In this economic climate, a one-shot return to unity would visit a severely disproportionate share of the new rates on the classes that are farthest away – in this case, the larger commercial classes. Although the overall increase we approve here is modest as compared to the amount of increase sought by the Company, there is still some potential to cause undue pain and burden if the smaller increase is not allocated reasonably. And this dynamic is compounded by the demographics of Delmarva's customer base, which skews heavily in terms of customer count and revenue to the Residential class.

We are sympathetic to OPC's recommendation that we bring residential ratepayers, who have been overpaying as a class, to unity. But although we decline to fix a rigid numerical standard, we find that moving all classes to unity now fails the gradualism standard. Reducing the disparities between class rates of return and the system average by 70%, as the Company suggests, raises large commercial customers' distribution rates approximately 23%. But bringing Residential customers to unity increases that large commercial customer impact to nearly 30%, while providing little incremental savings to the Residential class, only about 25 cents per month. None of these options is particularly satisfying, but on balance we find that the Company's proposal strikes a reasonable balance between a pure aliquot allocation and broader notions of fairness, particularly in these challenging economic times.

2. Intra-Class Rates

a. Customer Charges

The next question is whether to permit the Company to collect any portion of the incremental revenue through an increase in the fixed customer charge – a request we deny.

Delmarva argues that current rates do not recover all customer-related costs through the respective class customer charges. The Company proposes to narrow these disparities by raising the class customer charges by a higher percentage than its proposed overall rate increase. As the Company admits, the Commission approved a 25% increase in the residential customer charge in the Company's last rate case, and they ask us to do the same again, *i.e.*, to raise the current residential customer charge from $6.00 to $7.50.[165] Additionally, in Case No. 9093 the Commission approved customer charges for the SGS-S, LGS-S, GS-P and Street Lighting classes designed to recover one-half of the customer related costs. In this case Delmarva proposes to recover 75% of customer-related costs as identified in the COSS.[166]

OPC argues that the Company's proposal for a 25% increase in the customer charge disproportionately and unreasonably shifts the burden for the revenue increase onto low usage customers.[167] OPC states that increasing the customer charge more than the overall revenue increase allocated to the residential class effectively shifts recovery of sales-related revenue losses from the BSA to the customer charge.[168] OPC disputes the extent to which the customer charge includes costs that the COSS classifies as customer-related, but allocates as load related.[169] Ultimately, OPC concludes that the Company's customer charge proposal is unreasonable because it would effectively allocate to small

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[165] This increase would be for the R class. Residential Time-of-Use ("R-TOU") rates would also be increased by 25% from $8.50 to $10.63. See Campbell Direct at 30, 32-33 and Exhibit GMC-3.
[166] Janocha Direct at 8-9, Schedule JFJ-1, at 2.
[167] Wallach Direct at 16.

usage customers a larger share of the volumetric revenue losses than is their responsibility.[170]

Staff argues that the revenue currently collected through fixed charges is deficient and that an increase in customer charges is needed. However, Staff concedes that not all fixed costs can be collected through monthly customer charges without violating the principle of gradualism.[171] Staff notes that in Delmarva's last rate case, the Commission approved a 25% increase in the Residential customer charge, which resulted in 39% of customer costs being recovered by this fixed charge. Delmarva's proposal in this case would result in 43.59% of fixed costs being recovered.[172] Staff contends that the Residential class is currently collecting only 34.2% of customer costs while it is responsible for 43.6% of the total cost. As such, Staff argues that there is a "clear need" to allow the Company to collect more revenue through Residential monthly customer charges based upon the COSS results. However, following a gradual approach, Staff recommends a 16.67% increase, to $7.00, for the R subclass customer charge and a 17.6% increase, to $10.00, for the R-TOU subclass.[173] OPC opposes Staff's proposed increases in Residential customer charges for the same reasons it opposes the Company's proposed increase.

Staff notes that Delmarva's other customer charge proposals would result in an increase in the customer charge of 47.7% for the SGS-S class (from $15.43 to $22.79),[174]

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[168] Wallach Direct at 2-3 and 18.
[169] Wallach Surrebuttal at 3.
[170] Wallach Direct at 18.
[171] Campbell Direct at 22-23.
[172] Campbell Direct at 21 and 30.
[173] Campbell Direct at 30-33 and Exhibit GMC-3.

[174] For the General Service-Space Heating (GS-SH) and General Service-Water Heating (GS-WH) sub classes the Company proposes to only increase energy charges. Staff concurs that there should not be an

an increase of 79.1% for the LGS-S customer charge (from $104.78 to $187.63), an increase of 40% in the monthly GS-P customer charge (from $84.70 to $118.59) and increases of 79.8% for the Outdoor Recreational Lighting (ORL) customer charge (from $44.54 to $80.09) and 83% in the Outdoor Light (OL) customer charge (from $26.48 to $48.47).[175] Because of the removal of a meter tariff charge that was considered unnecessary, Delmarva proposes to reduce the TN customer charge by 21.7%, from $13.66 to $10.70.[176]

Staff also proposes increases in the customer charges for the other rate classes that reflect a more gradual approach than the Company seeks. Staff recommends a 23.1% increase in the SGS-S customer charge, to approximately $19.[177] Staff recommends raising Street Lighting customer charges by 12-13%.[178] For the LGS-S class, Staff recommends a very slight decrease of 0.2% or no change.[179] For GS-P customers Staff recommends a 0.25% decrease or no change in the customer charge.[180] Staff joins the Company's proposed decrease in the TN customer charge.[181]

Whether or not the customer charge captures the "fixed" portion of each class's costs, we decline to increase that charge at this time. We start from the fact that customer charges were increased by 25% just two years ago, and we find that another 25% increase now is too steep, too fast. Even more to the point, however, recovery through fixed

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increase in customer charges for these sub classes. Campbell Direct at 33-34. The Commission concurs as well.

[175] Campbell Direct at 22, 33, 36-38.

[176] Campbell Direct at 35.

[177] Campbell Direct at 34.

[178] Campbell Direct at 37.

[179] Campbell Direct at 37.

[180] Campbell Direct at 39. For the General Service Transmission class the Company proposes to keep the monthly customer charge in line with its direct costs on the system and decrease the rate 24.06% from $95.72 to $72.89. Staff concurs. Campbell Direct at 38. The Commission concurs as well.

[181] Campbell Direct at 35. The Commission also concurs.

customer charges is inconsistent as a matter of policy with the aggressive energy efficiency and conservation goals established by the General Assembly in the EmPOWER Maryland Energy Efficiency Act of 2008[182] and with the comprehensive programs we approved just this summer for Delmarva's customers.[183] Capturing this incremental revenue in volumetric charges leaves customers entirely in control of their usage and charges, and thus leaves each individual customer in control of the extent (if any) to which this modest rate increase affects him or her. Accordingly, we reject the Company's request to increase customer charges and direct it to recover all incremental revenue through volumetric charges.

b. Demand and Energy Charges

Once the appropriate customer charges have been established, the remainder of any class rate increase or decrease for Delmarva's customers is reflected in the volumetric (or energy) charges. The sole exception is the SGS-S class, the only customer class with a Demand Charge. Delmarva proposes increasing the SGS-S Demand Charge by 64.73%, then decreasing the proposed Energy Charge by 53.68%. Because these proposals are practically offsetting, the proposed 47.7% customer charge increase would represent essentially the total increase in revenue from this customer class.[184] Mr. Campbell recommends no change in the SGS-S Demand Charge.[185] However, because Staff recommends an overall rate decrease, with decreases in Energy Charges, maintaining the Demand Charge at its current rate increases the proportion of demand

[182] Chapter 131, Laws of Maryland, 2008. The Act amends Section 7-211 of the Public Utility Companies Article.
[183] See Case No. 9156, Order No. 82386, (2008) and Order No. 82835 (2009).
[184] Campbell Direct at 33-35.
[185] Campbell Direct at 6 and 34.

related revenue recovered through the Demand Charge, which is consistent with the tenor of the Company's proposal.[186]

We find that Delmarva's proposed increase in the SGS-S Demand Charge (with its offsetting Energy Charge decrease) is too dramatic a change, and we reject it. Instead, and consistent with our decision regarding customer charges, we direct the Company not to increase the SGS-S Demand Charge.

F. Benchmark Study of Service Company Costs

In Order No. 82168[187] , which resolved Phase II of the Company's last base rate case, the Commission directed Delmarva to file "a benchmark or industry study of the Service Company costs" in order "to support their reasonableness, itemized in sufficient detail to enable all parties to review and understand the individual component costs for those services."[188] Delmarva complied, and witness Anthony Snowball discussed the benchmarking study in detail in his direct testimony.[189] The study analyzed various service functions and details the processes included in each function. Additionally, the study presents the individual cost components of PHI Service Company services and compares those costs to a peer group of companies.

Mr. Snowball concludes that PHI Service Company costs are consistent with the peers studied and are therefore reasonable. Staff and OPC did not contest the analysis or Mr. Snowball's conclusions. We find that the PHI Service Company benchmark study satisfies our directive in Order No. 82168, although we will await the results of the

[186] Campbell Direct at 34.
[187] *Re Delmarva Power and Light Company, 99 MD PSC 125 (2008).*
[188] Order No. 82168 at 30.
[189] Delmarva Exhibit No. 17.

management audit, also required by Order No. 82168, before we reach any conclusions about the overall reasonableness of service company costs.

III. CONCLUSION AND ORDERED PARAGRAPHS

In conclusion, upon review of the record, we find that the application for a rate increase of $14,145,000 filed by Delmarva on May 6, 2009, will not result in just and reasonable rates and it is therefore rejected. Instead, we find that based on a test year of the 12 months ended December 31, 2008, as adjusted above, the Company is authorized to file revised rates and charges for an increase in revenues of $7,531,000, which amount will result in just and reasonable rates to the Company and its customers. Accordingly, the Company filed revised tariffs for such increase in accordance with the rate design and other decisions in this Order effective with service rendered on or after December 2, 2009, which we approved, subject to refund, at the Commission's Administrative Meeting on December 16, 2009.

IT IS THEREFORE, this 30th day of December, in the year Two Thousand and Nine, by the Public Service Commission of Maryland,

ORDERED: 1) That the application of Delmarva Power and Light Company, filed May 6, 2009, seeking to increase distribution rates for electric service by $14,145,000 in its Maryland service territory, is hereby denied, and that the Company is authorized to increase rates by $7,531,000, consistent with the findings in this Order.

/s/ Douglas R M. Nazarian

/s/ Harold D. Williams

/s/ Susanne Brogan

/s/ Lawrence Brenner
Commissioners

DELMARVA POWER & LIGHT COMPANY
CASE NO. 9192

Revenue Requirement
($000's)

Rate Base	$306,352
Rate of Return	7.96%
Required Income	$24,386
Adjusted Income	$19,991
Income Deficiency	$4,395
Conversion Factor	1.71344
Revenue Requirement	$7,531

Rate Base
($000's)

Per Books Balance	$286,644
Uncontested Adjs.	132
Uncontested Balance	$286,776
OPEB Deferral Balance	(2,921)
Amortize Deferred Tax Adj.	(1,322)
CWC Change for Ratemaking	84
CWC Change for Test Period	135
Annualize Reliability Plant	23,693
CWC Change for Float	(93)
Total Rate Base	$306,352

	Operating Income ($000's)
Per Books Balance	$22,456
Uncontested Adj.	(6,888)
Uncontested Balance	$15,568
Incentive Expense	1,395
Amortize Deferred Tax Adj.	1,888
Annualize Reliability Plant	(420)
Liability Reserve Accrual	405
Proforma Benefits	(150)
Rate Case Expense	99
Uncollectible Expense	132
Cambridge Adjustment	216
Interest Synchronization	858
Net Operating Income	$19,991

3. Does Mr. Smith agree or disagree that the Company must deploy capital to invest in CWIP? If Mr. Smith disagrees, please provide detailed reasoning supporting that disagreement.

RESPONSE:

In general, Mr. Smith agrees.

KAWC EXHIBIT
9

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ADJUSTMENT OF THE RATES OF KENTUCKY-AMERICAN WATER COMPANY) CASE NO. 2004-00103

I N D E X

KAWC EXHIBIT

10

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ADJUSTMENT OF THE RATES OF KENTUCKY-AMERICAN WATER COMPANY	))	CASE NO. 2004-00103

O R D E R

Kentucky-American Water Company ("Kentucky-American" or "KAWC") has applied for an adjustment in its base rates for water service to generate additional annual revenues of $6,625,443,[1] an activation charge that would generate annual revenues of $672,000, a discount to certain low-income ratepayers, and an increase in its tap-on fees.[2] By this Order, the Commission establishes rates for water service that will produce an annual increase in revenues from water sales of $3,611,302 and approves the requested increase in tap-on fees and the proposed activation charge.

BACKGROUND

Kentucky-American, a Kentucky corporation, owns and operates facilities that treat and distribute water to the public for compensation in Bourbon, Clark, Fayette, Gallatin, Grant, Harrison, Jessamine, Owen, Scott, and Woodford counties. It provides wholesale water service to the cities of Georgetown, Midway, Versailles, and

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[1] KAWC's Application, Exhibit 37, Schedule A at 1. $7,297,443 (Revenue Deficiency) - $672,000 (Activation Charge) = $6,625,443.

[2] In its original application, Kentucky-American requested rates that would generate an additional $6,625,443 from water sales annually. During the course of this proceeding, it amended its initial request to correct errors in its calculations and reduced its request to $6,618,776. *See, e.g.*, KAWC Brief at 5.

Winchester, Harrison County Water District, and Lexington-Elkhorn Water District. It is a utility subject to Commission jurisdiction. KRS 278.010(3)(d).

Kentucky-American is currently organized into two divisions: Northern Division and Central Division. The Northern Division consists of all facilities located in Gallatin, Grant, and Owen counties, Kentucky. The remaining facilities compose the Central Division.

PROCEDURE

On March 26, 2004, Kentucky-American notified the Commission in writing of its intent to apply for an adjustment of rates using a forecasted test period. On April 30, 2004, it submitted its application. Finding that further proceedings were necessary to determine the reasonableness of the request, the Commission suspended the proposed rates for 6 months from their effective date and initiated this proceeding.[3] We granted the Attorney General, through his Utility and Rate Intervention Division ("AG"), Lexington-Fayette Urban County Government ("LFUCG"), Community Action Council for Lexington-Fayette, Bourbon, Harrison, and Nicholas Counties ("CAC"), and Bluegrass FLOW, Inc. ("FLOW") leave to intervene in this proceeding.

After the parties engaged in extensive discovery,[4] the Commission held a public hearing in Lexington, Kentucky on November 4, 2004 to receive public comment on the

[3] See KRS 278.190(2).

[4] At Kentucky-American's request, we authorized the use of electronic filing procedures in this proceeding. While the parties and the Commission were served with paper copies of all pleadings and filings, each party also submitted an electronic version of these documents that was made available for public inspection through the Commission's Website.

proposed rate adjustment.[5] The Commission also held an evidentiary hearing in this matter on November 8-10, 12, and 23, 2004 in Frankfort, Kentucky.[6] Following these hearings, all parties submitted written briefs.

On November 30, 2004, Kentucky-American notified the Commission of its intent to place the proposed rates into effect for service rendered on and after December 1, 2004. The Commission subsequently directed Kentucky-American to maintain appropriate records of its billing to permit any necessary refunds.

ANALYSIS AND DETERMINATION

Test Period

Kentucky-American used as its forecasted test period the 12 months ending November 30, 2005. The base period used was the 12 months ending July 31, 2004.

Rate Base

Kentucky-American proposes a forecasted net investment rate base of $158,958,817.[7] This forecasted rate base is accepted with the following exceptions:

Utility Plant in Service ("UPIS"). Kentucky-American uses capital construction budgets to determine its forecasted UPIS amount of $287,861,620. Its construction budget is segregated into two categories: normal recurring construction and major investment projects. In prior rate proceedings involving a Kentucky-American

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[5] In our decision we have given the appropriate weight to the comments presented during the public comment session. The comments and documents presented during this session were not supported by written testimony or subjected to cross-examination or discovery.

[6] During this hearing, Kentucky-American presented the following witnesses: Mr. Patrick Baryenbruch, Ms. Linda Bridwell, Mr. Coleman Bush, Mr. Chris Jarrett, Mr. Bruce Lawson, Mr. Michael Miller, Dr. Kenneth Rubin, Mr. James Salser, Dr. Edward Spitznagel, Ms. Sheila Valentine, Mr. James Warren, and Dr. James Vande Weide. The AG presented the testimony of Ms. Andrea C. Crane, Mr. Scott Rubin, and Dr. J. Randall Woolridge.

[7] KAWC's Application, Exhibit 37, Schedule A at 1.

forecasted test period, the Commission has adjusted forecasted UPIS to reflect 10-year historical trend percentages.[8] These "slippage factors" serve as an indicator of Kentucky-American's accuracy in predicting the cost of its utility plant additions and when a new plant will be placed into service.

Citing the Commission's past practice, the AG proposes that a slippage adjustment be applied to Kentucky-American's UPIS in this proceeding. Although it continues to disagree with the concept of a slippage adjustment, Kentucky-American accedes to the use of the factor because of precedent.[9]

Using Kentucky-American's construction project information, we calculated the slippage factors for normal, recurring construction and major investment projects to be 105.43 percent and 86.12 percent, respectively.[10] By applying factors to its capital construction budgets, Kentucky-American recalculated its forecasted UPIS to be $287,853,455[11] or $8,165 less than its original forecast. The Commission agrees with this adjustment and has reduced Kentucky-American's forecasted UPIS by $8,165.

Utility Plant Acquisition Adjustments. Kentucky-American includes in its forecasted rate base the unamortized balance of three utility plant acquisition adjustments totaling $391,650. The acquisition adjustments represent the amounts that Kentucky-American paid in excess of book value and other incidental costs to purchase

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[8] *See, e.g.*, Case No. 2000-00120, The Application of Kentucky-American Water Company to Increase its Rates (Ky. PSC Nov. 27, 2000) at 2 - 4.

[9] KAWC Brief at 10.

[10] KAWC's Response to Commission Staff's First Set of Information Requests, Item 10.

[11] KAWC's Response to Commission Staff's Third Set of Information Requests, Item 44.

the assets of the Boonesboro Water Association ("Boonesboro"), Tri-Village Water District ("Tri-Village"), and Elk Lake Property Owners, Inc. ("Elk Lake").

In *Delta Natural Gas Co.*,[12] this Commission declared that "the net original cost of plant devoted to utility use is the fair value for rate-making purposes, unless the utility can prove, with conclusive evidence, that the overall operations and financial condition of the utility have benefited from acquisitions at prices in excess of net book value."[13] Any utility seeking recovery of an acquisition adjustment must justify its purchase decision based "on economic and quality of service criteria."[14]

To meet these criteria, a utility must present evidence that "the purchase price was established upon arms-length negotiations, the initial investment plus the cost of restoring the facilities to required standards will not adversely impact the overall costs and rates of the existing and new customers, operational economies can be achieved through the acquisition, the purchase price of utility and non-utility property can be clearly identified, and the purchase will result in overall benefits in the financial and service aspects of the utility's operations."[15]

The Boonesboro acquisition represents $77,217 of the requested acquisition costs. In Case No. 2000-00120,[16] we addressed the appropriateness of this acquisition and found that significant operational savings and greater economies of scale resulted

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[12] Case No. 9059, An Adjustment of Rates of Delta Natural Gas Company, Inc. (Ky. PSC Sep. 11, 1985) at 3.

[13] *Id.*

[14] *Id.*

[15] *Id.* at 3-4.

[16] Case No. 2000-00120, Application of Kentucky-American Water Company to Increase its Rates (Ky. PSC May 9, 2001) at 4 - 9.

from the purchase. We therefore allowed a 10-year amortization of the acquisition adjustment with the unamortized balance included in rate base. While the AG disagrees with the inclusion of the Boonesboro acquisition adjustment, he has acknowledged our earlier decision and has not proposed the removal of those costs.[17]

Kentucky-American's proposed adjustments for the Tri-Village and Elk Lake acquisitions are $208,310[18] and $106,123,[19] respectively. Kentucky-American advances several arguments in favor of the proposed adjustments. It asserts that both acquisitions benefit its Central Division customers by creating a larger customer base upon which certain expenses can be allocated and thus reducing the magnitude of any required rate adjustment.[20] Northern Division customers benefit as the acquisition provides them with access to Kentucky-American's expertise in water system operations and management and thus a more cost-effective resolution to their service and water quality problems.[21] Combining Tri-Village and Elk Lake with Kentucky-American's existing customer base also reportedly enables the Northern Division to reduce its costs through the use of Kentucky-American's national contracts to purchase materials.[22]

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[17] AG Brief at 4.

[18] KAWC's Response to Commission Staff's First Set of Information Requests, Item 1, W/P 1-2 at 2.

[19] *Id.*, Item 1, W/P 1-2 at 3.

[20] KAWC's Response to Commission Staff's Second Set of Information Requests, Item 82(c)(2).

[21] *Id.* at Item 82(c)(3).

[22] Direct Testimony of Linda Bridwell at 36.

Prior to the acquisition, Tri-Village experienced problems related to elevated levels of Trihalomethanes ("THMs"). It and its supplier, the city of Owenton, regularly issued public notices for elevated THMs. Kentucky-American made several changes to Owenton's and Tri-Village's systems that produced a significant reduction in Disinfection By-Product ("DBP") levels to enable Tri-Village to comply with new DBP restrictions and significantly improved water quality.[23]

In the case of Elk Lake, its water treatment facility was unable to meet new regulatory standards for turbidity levels that became effective on January 1, 2005.[24] By purchasing the Elk Lake and Tri-Village systems, Kentucky-American was able to tie the two water systems together, supply Elk Lake's customers through another source of water, and take Elk Lake's treatment facility out of service.[25] The purchases also enabled Kentucky-American to eliminate inadequate pressure areas within the service areas of the two systems,[26] extend service to unserved areas of Owen County,[27] and provide an emergency source of water to Peaks Mill Water District.[28]

The AG argues that, as the purchases of Tri-Village and Elk Lake represent "business development opportunities" for Kentucky-American, the acquisition adjustments are inappropriate. He maintains that business development costs should

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[23] Direct Testimony of Coleman Bush at 20-21.

[24] Rebuttal Testimony of Coleman Bush at 3.

[25] Direct Testimony of Linda Bridwell at 36.

[26] *Id.*

[27] Direct Testimony of Coleman Bush at 21.

[28] Direct Testimony of Linda Bridwell at 36.

not be borne by the ratepayers nor should the ratepayer be required to fund the profit recognized by Tri-Village and Elk Lake on the sale of their assets.[29]

Acquisition adjustments must be approached with caution to ensure that rates are not artificially inflated by excessive sales premiums. We recognize that Kentucky-American has resolved several deficiencies in the Tri-Village and Elk Lake systems and that has improved and expanded water service to the customers of those systems. We further recognize that Kentucky-American, as a subsidiary of a large international water utility, is better positioned to resolve operational and service deficiencies than smaller, non-profit water utilities. While we commend Kentucky-American for its efforts with the Tri-Village and Elk Lake systems, we find its efforts are not sufficient to meet the *Delta Natural Gas Co.* test.

Kentucky-American has failed to present adequate evidence to demonstrate that "the initial investment plus the cost of restoring the facilities to required standards will not adversely impact the overall costs and rates of the existing and new customers." To meet this standard, Kentucky-American must show that the premium paid plus the cost of restoration does not exceed what otherwise would have been incurred by the utility to remedy its operating deficiencies. Kentucky-American has not performed such analysis.[30] Absent such analysis we are unable to determine whether Kentucky-American successfully met this prong of the *Delta Natural Gas Co.* test.

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[29] Direct Testimony of Andrea C. Crane at 18.

[30] Transcript of Evidence ("T.E."), Vol. I at 163. Given that in the case of Tri-Village where the transfer of ownership was expressly conditioned upon the resolution of the water district's water quality problems, the lack of such analyses is perplexing.

Delta Natural Gas Co. also requires that the acquisition achieve operational economies and financial benefits. Expanding customer base through an acquisition does not satisfy this standard.[31] Kentucky-American has not shown where economies of scale have resulted in significant savings. While it points to savings realized through national purchasing contracts, it has not shown those savings to be significant. Moreover, in light of Kentucky-American's proposal to increase the current rates to customers previously served by Elk Lake and Tri-Village by 41.96 percent and 40.26 percent, respectively,[32] the record raises serious questions regarding the extent of the benefits that these customers have received.

In summary, we find that the Tri-Village and Elk Lake acquisitions do not meet the *Delta Natural Gas Co.* test and that the proposed acquisition adjustments should be removed from the requested revenue requirement. Our decision should not be considered as a retreat from our earlier pronouncements encouraging the development of regional water suppliers and the consolidation of smaller and less efficient water systems.[33] We continue to encourage larger water suppliers to expand their facilities and absorb smaller water systems that are incapable of meeting the rising costs of providing safe and quality water service.

Regardless of our decision today, the shareholders of Kentucky-American have benefited from the acquisitions. Kentucky-American has not only immediately expanded its rate base and thus increased its income, but also increased its potential

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[31] *See, e.g.*, Case No. 2000-00120, Application of Kentucky-American Water Company to Increase Its Rates (Nov. 27, 2000) at 7.

[32] KAWC's Application at 3.

[33] *See, e.g.*, Case No. 1989-00348, The Notice of Adjustment of the Rates of Kentucky-American Water Company Effective on January 28, 1990 (Ky. PSC Jun. 28, 1990).

for expansion into previously unserved areas for a larger rate base and greater income resulting from that expansion.

Accumulated Depreciation. The Commission has increased Kentucky-American's forecasted accumulated depreciation of $68,958,343[34] by $198,121[35] to reflect construction slippage and a reporting error. We reduced accumulated depreciation by $15,308 to reflect forecasted accumulated depreciation adjusted for construction slippage of $68,943,035.[36] We increased forecasted accumulated depreciation by $213,429 to adjust for Kentucky-American's omission of the accumulation of monthly forecasted depreciation expense. In the accumulated depreciation account included at W/P 1-3, Structures and Improvements, Kentucky-American stated the 13-month average balance as $962,615 while the corrected amount is $1,176,044.

Construction Work in Progress ("CWIP"). Kentucky-American forecasts CWIP includable in rate base as $6,124,953[37] which, after correction of an error, was restated at $5,537,960.[38] Construction slippage also impacts CWIP. Kentucky-American determined, and the Commission has accepted, the correct CWIP balance adjusted for slippage to be $5,529,656.[39]

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[34] KAWC's Application, Exhibit 37, Schedule B at 2.

[35] $198,121 = ($213,429 – $15,308).

[36] KAWC's Response to Commission Staff's Third Set of Information Requests, Item 44 at 6.

[37] KAWC's Application, Exhibit 37, Schedule B at 2.

[38] KAWC's Application, Corrected Exhibit 37 (filed August 25, 2004), Schedule B at 2.

[39] KAWC's Response to Commission Staff's Third Set of Information Requests, Item 44 at 6.

The AG proposes the elimination of the entire CWIP balance from rate base. He argues that CWIP does not represent facilities that are used or useful in the provision of utility service.[40] Including this plant in rate base, therefore, violates the regulatory principle of intergenerational equity by requiring current ratepayers to pay a return on plant that is not providing them with utility service and which may never provide current ratepayers with utility service. Allowing CWIP in rate base where a forecasted test period is utilized, he argues, "extends the time horizon on which the Company's rates are based even further out into the future."[41]

Generally, regulated utilities recognize the carrying costs of construction in rates through one of two methods: inclusion of CWIP in rate base or accrual of Allowance for Funds Used During Construction ("AFUDC"). This Commission has, in previous Kentucky-American rate proceedings, applied a hybrid approach that combines these two methods. This approach allows Kentucky-American to include all CWIP in rate base while accruing AFUDC on projects taking longer than 30 days to complete.[42] Under this approach, AFUDC revenue is reported "above the line." This approach eliminates the effects of including AFUDC bearing CWIP in rate base. It further allows Kentucky-American to accrue AFUDC as part of an asset's cost where appropriate and to earn a return on CWIP where AFUDC is not accrued.

We are not persuaded by the AG's argument that customers paying the rates approved in this case may never receive service from CWIP included in rate base.

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[40] Direct Testimony of Andrea C. Crane at 19.

[41] *Id.* at 20.

[42] KAWC's Response to Commission Staff's Fourth Set of Information Requests, Item 23.

Effectively, the only CWIP upon which Kentucky-American will earn a return is that which will be completed and placed into service within 30 days of its construction start date.

We find no merit to the AG's argument that CWIP should be eliminated because of Kentucky-American's use of a forecasted test year. Theoretically, the purpose of a forecasted test year is to reduce the regulatory lag experienced in historical test period rate cases by forecasting and matching revenue requirements and rates with the actual 12-month period for which the rates will first be placed into effect. Kentucky-American is entitled to a return on non-AFUDC bearing CWIP regardless of the test period employed.

Based upon the above, the Commission has included CWIP in the amount of $5,529,656 in determining Kentucky-American's forecasted rate base.

Working Capital. Kentucky-American calculates its working capital allowance using a lead/lag study based on the same methodology used in the "1996 study."[43] The Commission approved and applied this study in previous Kentucky-American rate proceedings. The AG does not dispute the reasonableness of this methodology. We find that it should be applied in this case.

Kentucky-American originally requested that $2,495,000[44] be included in rate base for working capital. It recalculated the amount as $2,479,737[45] after applying the construction slippage factors. Kentucky-American has acknowledged various errors in

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[43] Direct Testimony of James Salser at 2.

[44] KAWC's Application, Exhibit 37, Schedule B at 2.

[45] KAWC's Response to Commission Staff's Third Set of Information Requests, Item 44 at 73.

the forecasted revenues, expenses, and lead/lag days contained in its original working capital calculation. Correction of these errors results in a working capital allowance of $1,921,000.[46] This restatement does not account for construction slippage, correct the omission of payroll charges from net operating funds as stated at Exhibit 37 B, Page 82, nor correct the stated depreciation and amortization expense as shown on that exhibit. At page 82, depreciation and amortization expense is stated at $8,469,318 while the amount stated in the forecasted operating statement is $7,760,916.[47] The Commission's calculated working capital allowance takes all these omissions into account.

The restated expense lead/lag days is shown in Table I below.

TABLE I

Account	Original	Restated
Service Company	(1.34)	0.40
Group Insurance	(5.82)	(6.81)
OPEB	(0.50)	23.13
Insurance Other Than Group	(47.19)	(44.70)
Other	21.44	24.44
Federal Unemployment Taxes	69.11	69.86
Property Taxes	69.86	70.95
Current State Income Taxes	30.13	52.75
Long-Term Debt Interest	90.45	119.64
Short-Term Debt Interest	15.58	14.60
Preferred Dividends	45.49	46.40

The AG recommends that Kentucky-American be allowed a working capital allowance in the amount of $791,799. The AG calculated this amount by adjusting Kentucky-American's original calculation for: (1) the AG's recommended adjustments to forecasted revenues and expenses that are included in the lead/lag study, (2) the

[46] KAWC's Application, Corrected Exhibit 37 (filed August 25, 2004), Schedule B at 2.

[47] KAWC's Application, Exhibit 37, Schedule C at 5.

restated lead/lag days as shown in the table above except for Service Company, Group Insurance, Federal Unemployment Taxes, and Property Taxes, (3) lead/lag days different than originally used or restated by Kentucky-American for Chemicals and Service Company, and (4) elimination of depreciation expense from the study.

The Commission agrees with the AG that the lead/lag study should reflect the forecasted revenues and expenses as adjusted and found reasonable. Therefore, all adjustments to forecasted revenues and expenses found reasonable and appropriate in this Order have been incorporated into the working capital allowance approved in this case. The Commission finds that the restated lead/lag days as shown in the table above, and not contested by the intervenors, are appropriate and should be used to calculate Kentucky-American's working capital allowance.

For Group Insurance and Property Taxes the AG proposes that the original lead/lag days be used but gave no basis for such treatment. Kentucky-American has provided the basis for the restated days.[48] The Commission finds that the restated lead/lag days for Group Insurance and Property Taxes are appropriate.

The AG also proposes to use the lead/lag days as originally stated for Federal Unemployment Taxes. Kentucky-American failed to provide support for the restated days. The Commission finds that the original days for Federal Unemployment Taxes should be used to determine working capital.

Kentucky-American assigned 6.65 lag days to chemical expenses. The AG argues that a 30.49 lag day assignment is more appropriate. He states that the 6.65 lag days are the result of procurement practices in which chemicals are purchased every

[48] KAWC's Response to AG's Second Information Request, Item 29.

two days and paid for upon purchase. The AG further states that Kentucky-American has not provided any explanation for the change in chemical procurement and that generally utilities purchase chemicals on a monthly basis with payment being made the following month. He further states that its recommended 30.49 lag days reflects that of normal utility practice.[49]

Kentucky-American has not refuted the AG's arguments. We find that, absent evidence supporting a change in chemical procurement practices, all chemical expenses should be assigned 30.49 lag days in determining Kentucky-American's working capital allowance.

As shown in Table I, American Water Works Service Company ("Service Company") charges were originally assigned (1.34) lead days but were restated at 0.4 lag days. The AG proposes that 12 lag days be assigned to Service Company charges and that Kentucky-American's proposed lead/lag days represent the prepayment of those charges. He further argues that the Service Company was created to centralize duties that would otherwise be performed internally by utility personnel to create operating efficiencies for American Water Subsidiaries. Since the Service Company charges are primarily driven by payroll costs, he argues that there is no justification for prepaying those costs and that the same 12 lag days assigned to Kentucky-American's in-house payroll expenses should also be applied to Service Company charges.[50]

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[49] Direct Testimony of Andrea C. Crane at 23.

[50] *Id.* at 24.

Kentucky-American concedes that 71 percent of Service Company charges are payroll and payroll overhead costs,[51] but asserts that those charges also reflect other expenses including rent for an office building, equipment and computers, maintenance of computer software, telephones, and group insurance. It states that Service Company charges are less due to the overnight investment of prepaid funds. The Service Company off-sets its fees to American Water Works Company's ("AWWC") Subsidiaries with the return on overnight investments. For these reasons, Kentucky-American argues that its proposed (1.34) lead days is more appropriate to calculate working capital.[52]

The Commission finds that, although over 71 percent of Service Company charges are related to payroll costs, the AG has not convincingly demonstrated that 12 lag days is a more appropriate value. The Service Company operates separately from Kentucky-American and incurs expenses for which it bills American Water subsidiaries. Its expenses include not only payroll but many other costs. To assign 12 lag days to all payments to the Service Company based solely on payroll costs is not appropriate.

Based upon Kentucky-American's actual payments to the Service Company, the Commission finds that 0.4 lag days should be used for Service Company charges to determine working capital. We further find that, in its next rate case, Kentucky-American should fully justify the billing practices of the Service Company and show why prepayment of these expenses is necessary and appropriate.

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[51] T.E., Vol. I at 107.

[52] Rebuttal Testimony of James Salser at 1-2.

The AG takes exception to Kentucky-American's inclusion of forecasted depreciation expense in the determination of working capital. He argues that working capital is made necessary by the timing difference between when a utility expends cash for an expense incurred to provide service and when the utility receives the cash revenue in return for that service. While acknowledging that this Commission has historically allowed depreciation in the calculation of working capital, the AG states that its inclusion is inappropriate because no cash is actually expended as a result of the recording of depreciation expense. He notes that other jurisdictions, including Pennsylvania and West Virginia, exclude depreciation expense in the calculation of working capital for this reason.[53]

Kentucky-American responds that exclusion of depreciation expense from the working capital calculation would prevent its stockholders from earning a return on their full investment. It notes that the Commission has previously addressed this issue, found that it was appropriately included in working capital calculation, and had its decision affirmed on review.

The Commission finds that depreciation should be included in the determination of working capital. The Commission continues to hold its position as stated in previous Orders that "[w]hile it is true that recording depreciation does not require the expenditure of cash at the time the expense is recorded and charged to the customer, cash was expended at the time the property was acquired, and the recorded depreciation is used to reduce the investment in that property even though

[53] Direct Testimony of Andrea C. Crane at 26-27.

approximately one-and-one-half month's depreciation (equivalent to the revenue lag) has not yet been received from the consumer."[54]

After applying all the adjustments to Kentucky-American's forecasted working capital calculation found reasonable and necessary in this Order and correcting the errors noted herein, the Commission finds the appropriate working capital allowance to be $1,711,459.

Contributions in Aid of Construction ("CIAC"). Kentucky-American originally included CIAC in the amount of $34,547,915 as a reduction to rate base. The amount was restated at $33,064,060 for the construction slippage factors and the correction of recording errors.[55] The AG concurs with the restated amount and its use to establish rates. Accordingly, we find that forecasted CIAC should be reduced to $33,064,060.

Customer Advances. Kentucky-American originally stated customer advances as $15,220,324, then increased them to $15,359,373 after applying the construction slippage factors.[56] The Commission finds that Customer Advances as originally forecasted by Kentucky-American should be increased to $15,359,373.

Deferred Taxes. Deferred taxes have been adjusted as shown in Table II to account for all adjustments made herein related to items affecting deferred taxes.

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[54] Robert L. Hahne and Gregory E. Aliff, *Accounting for Public Utilities* § 5.08[2] (Matthew Bender Nov. 1991).

[55] KAWC's Response to Commission Staff's Second Data Request dated June 14, 2004, Item 115.

[56] KAWC's Response to Commission Staff's Second Set of Information Requests, Item 115.

TABLE II

Item	Rate Base Amounts	Deferred Income Taxes State	Federal	Total
Legal Settlement	$ 38,716	$ 3,194	$ 12,433	$ 15,627
Security Costs	$ 2,665,378	219,894	855,920	1,075,813
Shared Services Center	$ 529,630	43,694	170,077	213,772
CustomerCare/Call Center	$ 542,835	44,784	174,318	219,102
Rate Case Costs	$ 518,675	42,791	166,560	209,350
Acq. Costs Tri-Village	$ 213,532	17,616	68,570	86,187
Acq. Costs Elk Lake	$ 100,941	+ 8,328	+ 32,415	+ 40,742
Subtotal		$ 380,301	$ 1,480,292	$ 1,860,593
Slippage				+ 74,259
Total				$ 1,934,852

Absent is an adjustment for deferred taxes related to the elimination of the Boonesboro acquisition costs. Although Kentucky-American included unamortized acquisition costs for Boonesboro in forecasted rate base twice, as discussed below, it included the related deferred taxes only once. As the Commission has allowed rate recovery of the Boonesboro acquisition, the applicable deferred taxes are appropriate and no adjustment is required.

Kentucky-American has included deferred taxes for the Tri-Village and Elk Lake acquisition costs only once while including their unamortized balances twice in rate base. Therefore, while there are two adjustments eliminating the unamortized acquisition costs from rate base for each of these acquisitions, there is only one deferred tax adjustment in the above schedule.

Deferred Maintenance. Kentucky-American incurs many maintenance expenses (e.g., tank and hydrator painting and repairs, station cleaning) for which the Commission has historically allowed deferred treatment, permitted the unamortized balance included in rate base and permitted annual recovery of allowed amortization expense. All amounts allowed were based on actual costs from historical periods.

The AG requests that the Commission adopt a policy of normalizing maintenance and rate case costs.[57] Through normalization Kentucky-American would be entitled to recover not the historical amount of the expenditure but rather a future amount that the Commission deems reasonable. Much like the amortized historical amounts, the normalized costs would be divided by their estimated useful lives to determine the annual expense to be recovered through rates. The AG asserts that the normalization approach would eliminate the unamortized account balances from rate base since those accounts would no longer be recorded on Kentucky-American's books.

Switching to normalization would affect Kentucky-American's rates as the unamortized balances would be eliminated from rate base. Annual amortization/ normalization expense, however, would be higher through normalization since the annual expense is based on future costs that presumably would exceed historical costs. The AG presented no evidence regarding the appropriate level of normalized costs in this case. Absent such evidence, we cannot determine the reasonableness of the AG's proposal and must deny it.

The AG also questions the reasonableness of Kentucky-American's requested level of rate case expense. We find that introducing additional projected cost estimates into Kentucky-American's rate proceedings through normalization would only result in additional litigation in future rate cases and thus unnecessarily increase those rate case expenses even further. We therefore deny the proposed adjustment.

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[57] Direct Testimony of Andrea C. Crane at 77.

Deferred Debits. Kentucky-American requests a return on the unamortized balance of the deferred debits set forth in Table III:

TABLE III

Description		Balance
Cost-of-Service Study, Case No. 2000-00120	$	5,551
Cost-of-Demand Study, Case No. 2000-00120		5,855
Disinfection By-Product Study		9,325
Legal/Settlement Costs		38,716
Source of Supply		2,031,099
Acquisition Costs – Boonesboro		76,130
Acquisition Costs – Tri-Village		213,532
Acquisition Costs – Elk Lake		100,941
Security Costs		2,665,378
Shared Service Center		529,630
Customer Care/Call Center		542,835
Rate Case Cost	+	518,675
Total Unamortized Balance – Deferred Debits	$	6,737,667

The AG objects to the requested rate-making treatment. He contends that Kentucky-American isolates expenses from a prior period without any corresponding consideration of other factors from that period and then places those items in a forward looking test period. Such action, the AG contends, is inconsistent and contrary to the use of a forecasted test period.

In support of his position, the AG mistakenly relies upon our actions in Kentucky-American's last rate proceeding in which we denied certain deferred debits. In Case No. 2000-00120, Kentucky-American requested approval of 19 deferred debits unrelated to deferred maintenance or rate case expense. Of these 19, the Commission ultimately permitted rate recovery on 15 debits.

Moreover, our rejection of certain debits was not premised on the notion that deferred debits are contrary to the use of a forecasted test period, but on materiality of the proposed deferrals. We noted:

> A utility, pursuant to FASB [Financial Accounting Standard's Board Statement of Financial Accounting Standards No.] 71 is entitled to accrue a "regulatory asset" (an expense carried on the books as an asset) if it is probable that the cost will be allowed in rates and the revenue allowed is to recover the previously incurred cost rather than to provide for expected levels of similar future costs. None of these items warrant deferred treatment under FASB 71 due to their immateriality.[58]

Of the 19 deferred items, the single greatest deferred expense totaled $173,750 while the least totaled $1,003. The cost of accounting for many of the deferrals alone outweighed the benefits of their accrual.

To ensure a more orderly and appropriate use of deferrals, the Commission directed Kentucky-American to "formally apply for Commission approval before accruing an expense as a regulatory asset, regardless of the ratemaking treatment that the Commission has afforded such expense in previous rate case proceedings." Our action was intended to afford the Commission an opportunity to assess the reasonableness of each proposed deferral and its consistency with accounting standards, not its appropriate rate-making treatment.

Since our directive, Kentucky-American has made three requests for deferral treatment. On September 6, 2001,[59] it submitted a written request to the Commission's Executive Director for approval to accrue six expenses as regulatory items.[60] On September 24, 2003, Kentucky-American submitted a written request to the

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[58] Case No. 2000-00120, Application of Kentucky-American Water Company to Increase Its Rates (Ky. PSC Nov. 27, 2000) at 22.

[59] Letter of Lindsey W. Ingram, Jr., counsel for Kentucky-American, to Thomas Dorman, Executive Director, Public Service Commission (Sep. 6, 2001).

[60] Those expenses were: (1) Acquisitions; (2) Preliminary Service and Design; (3) Tank Painting; (4) Sludge Removal; (5) Customer Service Consolidation; and (6) Financial Service Consolidation.

Commission's Executive Director in which it sought the establishment of two additional regulatory assets to accrue expenses related to security costs and condemnation costs.[61] On December 18, 2003, Kentucky-American submitted a formal application[62] in which it requested formal approval to defer these expenses[63] for accounting treatment purposes.

The requests for deferrals remain pending before us. The Commission's records indicate that no action was ever taken on Kentucky-American's first request.[64] The Executive Director denied Kentucky-American's second request on October 15, 2003.[65] The Commission established a formal proceeding to address Kentucky-American's application and subsequently consolidated that proceeding into this proceeding.[66]

Before addressing the merits of each requested deferral, we first address LFUCG's general objection. LFUCG argues that all requested deferrals should be denied because Kentucky-American failed to comply with the Commission's directive

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[61] Letter from Lindsey W. Ingram, Jr., counsel for Kentucky-American, to Thomas Dorman, Executive Director, Public Service Commission (Sep. 24, 2003). The record reveals an earlier request for deferred treatment of security costs. See letter of Herbert A. Miller, Jr., counsel for Kentucky-American, to Thomas Dorman, Executive Director, Public Service Commission (July 2, 2002). There is no record of any Commission response to this letter. Commission Staff has indicated that it was unaware of the existence of this request. See T.E., Vol. III at 5 - 7.

[62] Case No. 2003-00478, Application of Kentucky-American Water Company for Approval of Accounting Deferrals.

[63] In its application, Kentucky-American omitted any request for approval to accrue condemnation costs as a regulatory asset.

[64] Commission Staff held an informal conference with representatives of Kentucky-American to discuss the request. No action resulted from this conference.

[65] Letter of Thomas M. Dorman, Executive Director, Public Service Commission, to Lindsey N. Ingram, Jr., counsel for Kentucky-American (Oct. 15, 2003).

[66] Case No. 2003-00120, Order of June 7, 2004.

regarding the establishment of regulatory assets. Noting that the Commission required the submission of a formal application before the accrual of any regulatory asset, LFUCG asserts that Kentucky-American failed to submit such application for any of the requested deferrals. While acknowledging that Kentucky-American submitted written requests, LFUCG argues that these letters did not constitute a formal application and did not meet the requirements for such application as set forth in Administrative Regulation 807 KAR 5:001. It further argues, Kentucky-American is a sophisticated and savvy utility that should recognize the difference between a letter and a formal application. It points to the utility's formal application in Case No. 2003-00478[67] in support of its argument.

Kentucky-American contends that it has fully complied with the Commission's directive. It states that it requested the establishment of regulatory assets by "formal letter" before accruing the expenses in question. It notes that, when Commission Staff failed to act upon these requests or acted upon them unfavorably, Kentucky-American submitted a formal application to the Commission for its requested relief.

We find no merit to LFUCG's objection. The record clearly demonstrates that Kentucky-American applied to the Commission for approval to establish the requested regulatory assets. Moreover, the record fails to indicate that the Commission's Executive Director or Commission Staff ever indicated that these letters were insufficient or inadequate to meet the Commission's directive. Insofar as other utilities had previously applied and obtained approval to establish regulatory assets for accounting purposes through letters, we are unable to find that Kentucky-American knowingly circumvented the requirements of our Order of November 27, 2000. To the

[67] *See* footnote 62.

contrary, given the conflict between the Commission's practices with other utilities, the lack of specific filing instructions in our Order of November 27, 2000, and Commission Staff's silence, confusion was a likely result. To avoid future misunderstandings, we have in this Order provided more specific instructions on the procedures that Kentucky-American should follow to obtain approval to establish regulatory assets for accounting purposes.

LFUCG also argues that the proposed deferrals are contrary to the conditions imposed upon Kentucky-American in Cases No. 2002-00018[68] and 2002-00317.[69] In those cases, we conditioned our approval of RWE Aktiengesellschaft's acquisition of control of Kentucky-American upon, *inter alia*, Kentucky-American making no filing before March 16, 2004 that would have the effect of increasing its rates for water service. LFUCG argues that the proposed deferrals are inconsistent with the Commission's intent by permitting the utility to recover expenses incurred prior to the base periods and thus permitting the utility to obtain a greater adjustment in rates than it would have been able to obtain had no rate moratorium been imposed.

We find no merit to this argument. LFUCG has failed to indicate a specific deferral that is directly related to the rate moratorium. While we agree that the rate moratorium may have affected a deferral's effect on Kentucky-American's rates as a

[68] Case No. 2002-00018, Application for Approval of the Transfer of Control of Kentucky-American Water Company to RWE Aktiengesellschaft and Thames Water Aqua Holdings GmbH (Ky. PSC May 30, 2002).

[69] Case No. 2002-00317, The Joint Petition of Kentucky-American Water Company, Thames Water Aqua Holdings GmbH, RWE Aktiensgeselschaft, Thames Water Aqua US Holdings, Inc., Apollo Acquisition Company and American Water Works Company, Inc. For Approval of a Change of Control of Kentucky-American Water Company (Ky .PSC Dec. 20, 2002).

result of timing considerations, we do not accept the argument that the moratorium caused additional deferrals and higher rates.

Cost of Service Study, Cost of Demand Study, Disinfection By-Product Study, Legal Settlement Costs, and Source of Supply. The Commission addressed the rate base treatment for these items in Case No. 2000-00120 and, except for legal/settlement costs, approved their inclusion in rate base. Kentucky-American has acknowledged that inclusion of legal/settlement costs in rate base in this proceeding is inappropriate.[70] Accordingly, the Commission has removed unamortized legal/settlement costs from the forecasted rate base.

Acquisition Costs for Boonesboro, Tri-Village, and Elk Lake. Kentucky-American erroneously included these costs in rate base as deferred debits.[71] It also included each of these deferred debits in its requested rate base as acquisition adjustments. Accordingly, the Commission has removed these items from deferred debits.

Security Costs. In response to the terrorist attacks of September 11, 2001, Kentucky-American began on September 12, 2001 to increase security at its facilities. Many of the associated costs were capital in nature and recorded by Kentucky-American as part of its utility plant in service. Those capitalized costs are reflected in the proposed rates by their inclusion in rate base as utility plant in service and depreciation expense. No party to the case has questioned the reasonableness of those costs. We have made no adjustments to them.

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[70] KAWC's Response to the AG's First Information Request, Item 66.

[71] *Id.* at Item 108.

Kentucky-American also deferred additional security costs totaling $2,805,66.79. Those deferred costs would normally have been recorded as an expense in the period incurred. Kentucky-American, however, chose to defer these costs (and their associated carrying cost) to have them included in the determination of rates in this proceeding. Table IV details the additional amounts deferred.

TABLE IV

DEFERRED SECURITY COSTS[72]			
Description	Date		Amount
LFUCG Police Direct	9/12/01-3/31/02	$	326,130.61
Alliance Staffing – LFUCG Police	4/1/02-8/19/03		1,854,128.42
Murray Guard – Lobby & Gate	9/12/03-4/30/04		88,355.94
Porta Potty Rental - Police Dam #9	2001		499.76
Securing Tanks	2001		152,581.00
Concrete Barriers	2001		15,918.90
Clearing Fence Lines	2001		6,230.55
KAW Labor	2001-2002		4,436.70
SCADA Program Change	2001		8,156.92
Inactive Account Lockout	2002		45,847.93
Security Lights – KRS	2001		9,171.49
Padlocks & Locksets	2001		3.163.04
Survey Work – Tank Sites	2001		9,300.00
Attorney Fees	2001		12,675.90
Communication Equip., Fees, & Misc.	2001-2004	+	194,665.41
Total Sch. KR3, – Prior to Submitting Application Current Proceeding		$	2,731,262.57
Murray Guard approx $11,201 per month (5/1/04 through 11/30/04)		+	74,399.22
Total Deferred Security Costs		$	2,805,661.79

The AG and LFUCG object to Kentucky-American's proposal to defer the security costs. Both argue that the proposed deferral is contrary to a condition that the Commission imposed upon Kentucky-American in Case Nos. 2002-00018 and 2002-00317. The Commission, *inter alia*, required Kentucky-American to withdraw its proposed Asset Protection Tariff and prohibited Kentucky-American from applying "for

[72] Direct Testimony of Kenneth Rubin at KR Schedule 3; KAWC's Response to Commission Staff's Second Set of Information Requests, Item 91.

recovery of costs associated with the protection of water utility assets except through adjustments in its general rates" for five years.[73] Permitting the accrual of security costs and allowing recovery of those costs, they argue, would effectively circumvent this condition and frustrate the clear intent of the Commission to ensure that ratepayers benefited from RWE's acquisition of Kentucky-American.[74]

LFUCG further argues that granting Kentucky-American's requested relief would be a reward for engaging in inappropriate *ex parte* contacts with Commission Staff. It notes that on at least three occasions Kentucky-American contacted Commission Staff without notice to any interested party and requested approval to establish the requested regulatory asset. It further notes that one of these contacts occurred while Case No. 2002-00018 was pending and that during this contact "advised the Commission's Executive Director that it intended to interpret an agreed to condition in a manner that would eviscerate that condition."[75] This contact, LFUCG asserts, was never revealed to any of the parties, would have dramatically altered the proceedings, and was clearly outside acceptable conduct. *See Louisville Gas and Electric Co. v. Comm. ex rel Cowan*, Ky.App., 862 S.W.2d 897 (1993).

Kentucky-American disputes that the conditions set forth in Case Nos. 2002-00018 and 2002-00317 prohibit the creation of a regulatory asset or rate recovery of the deferred security costs. It contends that the conditions required only the withdrawal of

[73] Case No. 2002-00018, Order of May 30, 2002, App. A at ¶ 2; Case No. 2002-00317, Order of December 20, 2002, App. A at ¶ 2.

[74] Commission Staff expressed similar reasoning in rejecting Kentucky-American's request for approval to establish a regulatory asset to accrue security expenses. *See* Letter from Thomas M. Dorman, Executive Director, Public Service Commission, to Lindsey W. Ingram, Jr., counsel for Kentucky-American (Oct. 15, 2003).

[75] LFUCG's Brief at 18.

its proposed Asset Protection Charge and expressly provided that the utility could recover costs for the protection of water utility assets "through adjustments in its general rates for water service." It further contends that the AG's and LFUCG's interpretation of the conditions is not reasonable.

Kentucky-American further disputes LFUCG's contention that it engaged in improper *ex parte* contacts with Commission Staff. It notes that all contacts with Commission Staff regarding the proposed deferrals were in written form, available to the public, and addressed to the Commission's Executive Director, who is not an "agency decision maker." These contacts, therefore, did not constitute an inappropriate *ex parte* contact. Finally, it asserts that, as no final decision has been made in response to its request for accruals, its actions cannot have influenced the ultimate decision and cannot be classified as improper.[76]

In Case No. 2002-00317, we imposed the following conditions upon Kentucky-American as necessary for finding that RWE's acquisition of control of the water utility was in the public interest:

> KAWC [Kentucky-American] will not apply to the Commission for a rate adjustment or make any other filing that has the effect of increasing its rates for water service before March 16, 2004, or one year following the date of the consummation of the proposed merger, whichever is later.
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> . . .
>
> At no time prior to May 30, 2007 will KAWC apply to the Commission for recovery of costs associated with the protection of water utility assets except through adjustments in its general rates for water service.[77]

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[76] KAWC's Reply to LFUCG Brief at 2-3.

[77] Case No. 2002-00317, Order of December 20, 2002, App. A at ¶ 1-2

These conditions were intended to preserve the status quo between the utility and its ratepayers.[78] We noted that as a result of RWE's acquisition the utility would likely experience a number of changes in operating practices that would produce corresponding changes in its cost of service. We found this possibility especially strong in the area of infrastructure security and further found that "the introduction of any new rate mechanism regarding security costs at this time is inappropriate."[79]

Based upon our review of the Commission's Orders in Case Nos. 2002-00018 and 2002-0317, we find that the conditions attached to RWE's acquisition of control of Kentucky-American effectively prohibit Kentucky-American's requested relief. Permitting the establishment of the regulatory asset for security expenses would disrupt the status quo that the conditions were intended to preserve. It would permit Kentucky-American to transfer costs incurred during the moratorium to a post-moratorium period and recover them from its ratepayers. It thus would undermine one of the conditions necessary to our finding that RWE's acquisition of control was in the public interest.

Likewise, we find that the proposed deferral of security costs constitutes a new rate recovery mechanism that Condition 2 was intended to prohibit. We note that at the time of the proposed transfer of control, Kentucky-American and RWE were readily aware of the additional security costs that Kentucky-American was incurring in response to the perceived terrorist threat. Each was further aware that Kentucky-American had been seeking recovery of the total amount of security expenses that it had incurred since the September 11, 2001 terrorist attacks. Kentucky-American's proposed Asset

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[78] Case No. 2002-00018, Order of May 30, 2002 at 17.

[79] *Id.* at 18.

Protection Tariff was only one of the mechanisms available to obtain recovery for the total amount of these expenses. Deferral of those expenses as a regulatory asset was another mechanism. Having been fully aware of the nature and extent of these security expenses and having agreed to waive any recovery of such expenses outside general rate adjustment proceedings, Kentucky-American may not properly assert a claim for recovery of those expenses through the use of deferral accounting.[80]

As to LFUCG's arguments regarding *ex parte* contacts between Kentucky-American and Commission Staff, we note that all previously known contacts between present Commission employees and Kentucky-American representatives have been disclosed. No attempts on the part of Commission employees to conceal such contacts have been alleged or discovered. No party, moreover, has provided any evidence to support the allegation of improper *ex parte* contacts between present Commission employees and Kentucky-American representatives. Insofar as LFUCG has adopted Commission Staff's arguments in support of its own objections to the establishment of regulatory accounts and has deferred to Commission Staff in the examination of the reasonableness of these expenditures during the course of this proceeding, we find little merit to the argument that our decision-making process has been improperly influenced. Accordingly, we do not adopt LFUCG's arguments as a basis for our rejection of Kentucky-American's requested relief.

Shared Service Center and Customer Care/Call Center. The costs deferred as Shared Service Center and Customer Call Center represent Kentucky-

[80] As we base our decision solely upon the provisions of our Order of December 20, 2002 in Case No. 2002-00317, we have not addressed the reasonableness of any of the proposed expenses or whether the circumstances under which these expenses were incurred should be considered as extraordinary circumstances.

American's allocated portion of the expenses necessary to establish those centers. Each center provides support services to Kentucky-American.

The Shared Services Center is located in Marlton, New Jersey. AWWC created this center to centralize general accounting, payroll, accounts payable, inventory, purchasing and accounts receivable functions for its subsidiaries. It has allocated to Kentucky-American for the establishment of this center costs totaling $704,179.[81] Kentucky-American began amortization of these costs in December 2003 at a monthly rate of $13,417 which was equal to the anticipated net monthly savings created by the center.[82] At the beginning of the forecasted test year, the unamortized balance stood at $557,505. At that time Kentucky-American began amortization of the unamortized costs over 10 years resulting in the average 13-month balance included in rate base of $529,630. Kentucky-American asserts that amortizing these costs at a rate equal to the anticipated savings until the beginning of the forecasted test period gives the ratepayers the benefit of those savings until rates reflecting such savings could be established.

The Customer Care/Call Center is located in Alton, Illinois. AWWC created this center to centralize and improve customer billing and inquiry services for its subsidiaries. It has allocated to Kentucky-American for the establishment of this center costs totaling $633,704.[83] Kentucky-American proposes the same amortization process for the Care Center as used for the Shared Services Center wherein amortization prior

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[81] KAWC's Response to Commission Staff's First Set of Information Requests, Item 1, Workpaper W/P 1-12 at 2.

[82] Kentucky-American reported the actual monthly savings as $13,454 ($161,445 / 12 months). See KAWC's Response to Commission Staff's Second Set of Information Requests, Item 76(d),

[83] KAWC's Response to Commission Staff's First Set of Information Requests, Item 1, Workpaper W/P 1-12 at 2.

to the forecasted test year was equal to the monthly savings created by the center. Kentucky-American then amortized the unamortized balance at the beginning of the forecasted test year over 10 years. Monthly amortization based on savings began in May 2004 in the amount of $8,900.[84] The unamortized balance at the beginning of the test year was $571,405 when the monthly amortization was restated at $4,762. The 13-month average balance included in rate base is $542,835.

When requested to provide a detailed explanation for all entries to the deferred debit accounts of the Shared Service Center and Customer Care Center,[85] Kentucky-American failed to provide adequate information about the entries. It identified the vendor for most entries, but provided no description of the service or allocation method. Absent more detailed information regarding these entries, we cannot determine the reasonableness or need for the deferred costs. As Kentucky-American has failed to meet its burden of proof regarding the reasonableness of these costs, they should be denied.

Rate Case Expense. Kentucky-American includes a provision for rate case expense recovery based on its initial cost estimate of $622,409.[86] It requests that the estimated amount be amortized over 3 years for an annual expense recovery of

[84] Kentucky-American reported the actual monthly savings as $8,912 ($106,941 / 12 months). See KAWC's Response to Commission Staff's Second Set of Information Requests, Item 76(b).

[85] See Commission Staff's Second Set of Information Requests to KAWC, Items 76(a) and (c); Commission Staff's Third Set of Information Requests to KAWC, Items 25 and 27.

[86] KAWC's Response to Commission Staff's First Set of Information Requests, Item 1, r W/P 3-8 at 1.

$207,470 ($622,409 / 3 years) with the average 13-month, unamortized balance of $518,675[87] included in rate base.

The AG proposes two revisions to Kentucky-American's proposal. First, he argues that unamortized rate case expense should not be included in rate base. In support of this argument, he notes that the Commission has historically not afforded such rate-making treatment to unamortized rate case expense.[88]

The AG also proposes a $70,000 reduction in rate case expense. In support of his proposal, the AG states that Kentucky-American's rate case expense is 35 percent more than its actual costs in the utility's last rate proceeding and considerably higher than in any of its last five rate proceedings. He also notes that the utility has made extensive use of both outside consultants and Service Company personnel. He suggests that outside consulting services could have been performed in-house and notes the absence of any competitive bidding process to procure outside services. The AG's proposed adjustment is not specific to any particular portion of requested rate case expenses, but is intended to cap the increase in that expense to 20 percent over the level incurred in Kentucky-American's last rate case proceeding.

Kentucky-American responds that actual rate case expenses in this proceeding have exceeded its estimates. It terms the AG's proposed adjustment as arbitrary and inappropriate. It asserts that the higher level of rate case expenses is related to "new" issues and more extensive discovery.[89]

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[87] *Id.*, Workpaper W/P 1-12 at 2.

[88] Direct Testimony of Andrea C. Crane at 33.

[89] KAWC Brief at 39.

We find that the unamortized portion of rate case expense should not be included in rate base.[90] The Commission has historically excluded this item from rate base to share the cost of rate proceedings between the stockholders and ratepayers. Kentucky-American has presented no evidence in this proceeding to support a change in this method. Therefore, we have eliminated unamortized rate case costs from the forecasted rate base.

We further find that the AG's proposed reduction of $70,000 is arbitrary and unsupported by the record. Notwithstanding our rejection of this proposed adjustment, we are deeply concerned with the increasing level of Kentucky-American's rate case costs.[91] We find that, in its next rate application, Kentucky-American should demonstrate fully its efforts to contain these expenses. Should we find these efforts to be inadequate, we will consider adjustments to rate case expenses to ensure the level of that expense is reasonable.

Based on the aforementioned adjustments to deferred debits, the Commission has decreased the amounts included in the forecasted rate base by $4,685,837 calculated as follows:

[90] The Commission has included $207,470 of rate case amortization in forecasted operations.

[91] See KAWC's Response to Commission Staff's Second Set of Information Requests, Item 64. Rate case expenses for KAWC's five most recent rate cases are:

Case Number	Amount
2000-00120	$459,817
1997-00034	$326,414
1995-00554	$389,982
1994-00197	$250,434
1992-00452	$437,125

TABLE V

Description	Balance
Legal/Settlement Costs	$ (38,716)
Acquisition Costs – Boonesboro	(76,130)
Acquisition Costs – Tri-Village	(213,532)
Acquisition Costs – Elk Lake	(100,941)
Security Costs	(2,665,378)
Shared Service Center	(529,630)
Customer Care/Call Center	(542,835)
Rate Case Cost	+ (518,675)
Total Unamortized Balance Deferred Debits	$ (4,685,837)

Authorization to Accrue an Expense as a Regulatory Asset. Kentucky-American requests that the Commission reconsider our prior directive that required Kentucky-American to make a formal application and obtain Commission authorization before accruing an expense as a regulatory asset.[92] In Case No. 2000-00120, we expressed our concern with Kentucky-American's frequent practice of deferring expenses as regulatory assets and imposed this requirement to ensure the proper level of regulatory oversight.[93]

Our directive represented a significant departure from past Commission practice. Previously utilities that sought to accrue an expense as a regulatory asset would make a written request to the Commission's accounting staff. No formal proceeding was established. Any approval was limited to the accounting treatment of the expense and did not address the reasonableness of the expense or the likelihood of its recovery in any future rate proceeding.

[92] Case No. 2003-00487, Application of Kentucky-American Water Company for Approval of Account Accruals (Ky. PSC filed Dec. 12, 2003), Application at 4.

[93] Case No. 2000-00120, Order of November 27, 2000 at 23.

Upon further consideration and review, we find that our directive should be revised. Our insistence upon a "formal application" has resulted in a cumbersome procedure that does not properly address principally accounting issues. Moreover, our use of a formal procedure may require us to prematurely address rate-making issues that are more appropriately deferred to the utility's next rate proceeding. Accordingly, we find that Kentucky-American should no longer be required to make a formal application to the Commission before accruing an expense as a regulatory asset.

We further find that Kentucky-American should make written request to the Commission's Executive Director for the approval of any proposed deferrals[94] and that Kentucky-American should also provide written notice of its request to the AG, LFUCG, and any other party who appeared in its most recent rate proceeding. Commission Staff's review of this request will be limited to accounting treatment of the proposed deferral and will not address the likelihood of recovery of the expense in any future rate proceeding. Commission Staff will apprise all interested parties of its decision and provide those parties the opportunity to respond. Moreover, any interested party, including Kentucky-American, that wishes to contest Commission Staff's determination may file a formal application to the Commission for review of that determination. Kentucky-American shall still be required to submit a formal application if it wishes to seek rate-making treatment at the same time it requests approval of the deferral of expenses. Except as noted above, Kentucky-American may not begin accruing any

[94] We exempt from this requirement any deferral related to recurring maintenance expenses that the Commission has previously afforded rate-making treatment. Kentucky-American may accrue these expenses as a regulatory asset for accounting purposes without obtaining any additional approvals.

expense as a regulatory asset until it has received an affirmative determination from either the Commission or Commission Staff.

This new process represents a more flexible and effective means of addressing requests for accounting deferrals. While it maintains a high level of regulatory oversight of Kentucky-American's accounting treatment of certain expenses, it will encourage more timely review of accounting treatment proposals without formal proceedings. Moreover, it affords significant protection to intervenors by providing timely notice of all requests for accounting treatment approvals and an opportunity to seek formal Commission review of any Commission Staff determination.

Other Rate Base Elements. In its application, Kentucky-American included a reduction to rate base for "other rate base elements" in the amount of ($2,154,343). Other rate base elements include contract retentions, unclaimed extension deposit refunds, accrued pensions, retirement work in progress, and deferred compensation. As Kentucky-American overstated other rate base elements by $609,399 in its initial filing and as the correct amount is ($1,544,944),[95] the Commission has reduced other rate base elements by $609,399.

Based on the aforementioned adjustments, the Commission has determined the Company's net investment rate base to be as shown in Table VI below.

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[95] Amended Exhibit 37 B at 2.

TABLE VI[96]

Rate Base Component	Kentucky-American Proposed 13-Month Average	Commission	
		Adjustments	Approved
UPIS	$ 287,861,620	$ (8,165)	$ 287,853,455
Utility Plant Acquisition Adj.	391,650	(314,433)	77,217
Accumulated Depreciation	(68,958,343)	(198,121)	(69,156,464)
Accumulated Amortization	+ (7,674)	+ 0	+ (7,674)
Net Utility Plant In Service	$ 219,287,253	$ (520,719)	$218,766,534
CWIP	6,124,953	(595,297)	5,529,656
Working Capital	2,495,000	(783,541)	1,711,459
Other Working Capital	462,149	0	462,149
CIAC	(34,547,915)	1,483,855	(33,064,060)
Customer Advances	(15,220,324)	(139,049)	(15,359,373)
Deferred Income Taxes	(26,561,822)	1,934,880	(24,626,942)
Deferred Income Tax Credits	(117,518)	0	(117,518)
Deferred Maintenance	2,453,718	0	2,453,718
Deferred Debits	6,737,667	(4,685,839)	2,051,828
Other Rate Base Elements	+ (2,154,343)	+ 609,399	+ (1,544,944)
Net Original Cost Rate Base	$ 158,958,818	$ (2,696,311)	$ 156,262,507

Income Statement

For the base period, Kentucky-American reported operating revenues and expenses of $44,246,522 and $33,460,201, respectively.[97] Kentucky-American proposed several adjustments to revenues and expenses to reflect the anticipated operating conditions during the forecasted period, resulting in forecasted operating revenues and expenses of $43,389,662 and $34,597,380, respectively.[98] The Commission's review of Kentucky-American's forecasted operations is set forth below.

[96] The amount set forth in Table VI for Deferred Income Taxes differs from that in Table II due to rounding differences.

[97] KAWC's Application, Exhibit 37 C, Schedule C-3 at 1.

[98] *Id.*

Residential and Commercial Sales. Kentucky-American projects daily residential consumption for the forecasted test period to be 165.42 gallons based upon normal weather conditions. This amount represents a reduction of approximately 19.4 gallons in daily customer usage from 1997 levels.[99] Kentucky-American's witness attributes this reduction in usage to more efficient appliances and greater consumer education.

The AG argues that Kentucky-American has understated consumption levels. His witness contends that the projections represent a significant departure from Kentucky-American's projections in other recent rate adjustment proceedings. She further contends that the projections are inconsistent with average actual residential customer usage levels for the past 5 years and projections in Kentucky-American's Strategic Business Plan. The AG proposes that projected daily residential consumption be adjusted to 174.68 gallons per day. He derives this projection by averaging the projected residential consumption level in Kentucky-American's last rate proceeding and the projected level in the current rate proceeding. The AG proposes a similar adjustment for average daily commercial consumption.

The AG also argues that Kentucky-American has understated the number of its commercial and residential customers. He recommends adjustments to the forecasted levels. The Commission has previously accepted the methodology that Kentucky-American used to derive its projected consumption levels. Notwithstanding his claims of erroneous projections, the AG has failed to identify any specific problem or error with this methodology or with the data that Kentucky-American used to make its projections.

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[99] KAWC Response to Commission Staff's Second Set of Information Requests at Item 49(a).

We further find the explanations that Kentucky-American's witness has provided regarding the decrease in consumption levels to be reasonable. Moreover, the AG has failed to provide any supporting authority for the methodology that he uses to derive his proposed adjustments. Given this lack of evidence, we decline to make his proposed adjustments.

Private and Public Fire Protection. In its application, Kentucky-American proposes forecasted revenues for fire protection in the Central Division of $2,641,175. It subsequently amended its forecast to reflect increases in fire connection installations and proposed increasing revenues from fire protection by $118,035 to $2,759,210.[100] The Commission finds that these revisions are appropriate and accepts them.

Account Activation Fee. Kentucky-American proposes to establish an account activation fee of $24 that will result in an annual increase to operating revenues of $672,000.[101] For reasons set forth below, we approve the proposed fee and have accepted the forecasted revenues resulting from this fee.

Allowance for Funds Used During Construction ("AFUDC"). In its application, Kentucky-American proposes to increase operating revenues by $470,940 to include its forecast of AFUDC. In calculating this forecast, however, Kentucky-American used 9.58 percent, the return on capital requested in its last rate proceeding, rather than the return on capital requested in this proceeding of 8.25 percent.[102] To reflect the effect of slippage on CWIP, Kentucky-American calculated an adjusted AFUDC of $417,280.

[100] KAWC's Response to LFUCG's First Information Request, Item 42.

[101] Direct Testimony of Coleman Bush at 11.

[102] KAWC's Response to Commission Staff's Post-Hearing Information Request, Item 4.

To correspond with his adjustment to eliminate CWIP from rate base, the AG proposes to reduce Kentucky-American's operating revenues by $470,940 to move AFUDC to "below-the-line" non-operating revenues. The AG states that if the Commission rejects his proposal to eliminate CWIP from rate base, then "AFUDC should be moved back to its above-the-line position for determining the revenue requirement."[103]

Kentucky-American accrues AFUDC on its forecasted construction projects that take longer than 30 days to complete.[104] The Uniform System of Accounts for Class A and B Water Companies requires AFUDC to be recorded in non-operating revenues or "below-the-line." However, for rate-making purposes the Commission allows Kentucky-American to earn a return on forecasted CWIP in rate base while offsetting the return by moving AFUDC to "above the line" operating revenues. This approach eliminates the effects of including the AFUDC bearing CWIP in rate base while allowing Kentucky-American to earn a return on CWIP where AFUDC is not accrued.

To be consistent with our decision to reject the AG's proposal to remove CWIP from rate base, the Commission finds that operating revenues should be adjusted to reflect the inclusion of AFUDC. The Commission has determined Kentucky-American's average forecasted CWIP available for AFUDC of $4,355,741[105] by dividing the AFUDC adjusted for slippage of $417,280 by Kentucky-American's AFUDC rate of 9.58 percent. By multiplying the average forecasted test period CWIP available for AFUDC of

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[103] AG Brief at 15.

[104] KAWC's Response to Commission Staff's Fourth Set of Information Requests, Item 23.

[105]

AFUDC Slippage	$	417,280
Divided by: Kentucky American AFUDC Rate	÷	9.58%
Average Forecasted Monthly CWIP Balance	$	4,355,741

$4,355,741 by the overall rate of return of 7.75 percent, the Commission calculates a forecasted level of AFUDC of $337,570. This action results in a decrease to Kentucky-American's forecasted operating revenues of $133,370.

Labor Expense. Kentucky-American includes in its forecasted operations labor expense of $5,343,663. In forecasting its labor expense, Kentucky-American uses 133 full-time equivalent employees, each scheduled to work 2,088 regular hours. Kentucky-American also includes overtime for some employees based upon historical levels. For salaried and non-union hourly employees, Kentucky-American adjusts the April 30, 2003 wage rates by 3 percent on April 1, 2004 and April 1, 2005. For union employees, the wage rate effective in the union contract is increased by 3 percent on the anniversary date of the contract. Labor costs for the non-regulated operations were removed from the forecasted labor expenses.[106]

The AG proposes to reduce Kentucky-American's labor expense by $178,181 to reflect the three vacant employee positions. He asserts that his proposal "[p]rovides a good balance between the need to provide flexibility to the company to decide when additional employees are necessary and the need to protect ratepayers from paying excessive rates."[107] It does not eliminate any specific employee position, but merely reflects that the utility never maintains a full complement of workers.

In support of his proposal, the AG notes significant change in employee vacancies while this case has been pending. When the AG filed the written testimony of his witnesses on August 27, 2004, Kentucky-American had three vacant positions.

[106] Direct Testimony of Coleman Bush at 3.

[107] Direct Testimony Andrea C. Crane at 50.

When the evidentiary hearing was conducted in November 2004, this number had increased to 15. He asserts that corporate reorganizations and realignments and the introduction of mobile technology is likely to continue this trend.

To quantify his adjustment, the AG calculated Kentucky-American's average salary and overhead payroll cost per employee to be $59,394.[108] He then multiplied the $59,394 by the 3 vacant positions to arrive at his proposed adjustment to Kentucky-American's labor expense forecast of $178,181.[109]

Kentucky-American counters that the AG's reasoning is flawed. "Implicit in this suggestion," Kentucky-American asserts, "is the idea that the quantity of work to be done can be accomplished by less than a full complement of employees."[110] It notes that its forecast includes only 14,899 hours of overtime or 69 percent of the annualized actual overtime hours worked in the 4-month period from September 2004 to December 2004. It also notes the fact that, during the first 9 months of 2004, its temporary labor expense was $120,060, but that only $90,872 was included in forecasted operations. According to Kentucky-American, the reduction in overtime hours and temporary labor costs in the forecasted period implicitly assumes that all employee vacancies are filled.[111]

The AG's adjustment recognizes only the effect of employee vacancies upon Kentucky-American's direct labor forecast. It does not consider the vacancies' effect on Kentucky-American's overtime and temporary/contract forecasts. The AG proposed a

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[108] Direct Testimony of Andrea C. Crane at ACC-22.

[109] *Id.*

[110] KAWC Brief at 33.

[111] *Id.*

similar adjustment to labor expense in Case No. 1995-00554 to reflect that, "[o]n average Kentucky-American's actual number of employees falls short of its 'authorized' level of employees."[112] Denying the AG's proposed adjustment, we stated:

> The AG's proposed adjustment is flawed because it did not take into consideration the total 1995 labor costs. As shown by Kentucky-American, when all labor costs are considered, there is no material difference between the actual and budgeted amounts.[113]

We continue to adhere to this position. If vacant employee positions exist, work will either be shifted to other employees and thus result in an increase in overtime costs or Kentucky-American will hire additional temporary/contract labor. Kentucky-American has shown that its forecasts for overtime and temporary/contract labor have been reduced to reflect a full-workforce. The vacant employee positions to which the AG refers will result in decreased direct labor costs, but that decrease will be offset by increases in overtime or temporary labor costs. Therefore, the overall impact of these vacancies on Kentucky-American's operating expenses and ultimately its revenue requirement is unknown. Accordingly, we deny the AG's proposed adjustment.

Condemnation. The AG proposes to adjust Kentucky-American's forecasted expenses to eliminate 90 percent of the labor, overhead costs and payroll taxes associated with Kentucky-American's President and his assistant. In support of this proposal, the AG points to statements of the Chairman of Kentucky-American's Board of Directors that Kentucky-American's President had been directed to devote his full time and energies to the utility's defense in condemnation proceedings that LFUCG had

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[112] Case No. 1995-00554, Application of Kentucky-American Water Company to Increase Its Rates (Ky. PSC Sep. 11, 1996) at 32.

[113] *Id.*

initiated against Kentucky-American. Since such efforts were solely related to "the promotion and protection of the interests of Kentucky-American shareholders," the AG asserts that ratepayers should not bear the internal costs associated with the President and his assistant.

The AG states that, because Kentucky-American did not track the individual employee hours spent working on condemnation issues during the base period, he is unable to identify specific costs included in Kentucky-American's forecast related to that issue. Because of the Board of Directors' direction, the AG has assumed that Kentucky-American's President was working full-time on this issue and recommended that 90 percent of the labor, overhead costs and payroll taxes for the President and his assistant, or $193,796, be removed from Kentucky-American's forecasted labor costs.[114]

Contending the AG has misinterpreted the statements of its Chairman, Kentucky-American has clarified those statements. It states that, as a result of condemnation, the workload of its President increased, but that he was continuing to perform his normal duties and responsibilities in addition to assisting the utility in its defense of the condemnation proceeding, and that this increase in duties was insufficient justification for the AG's proposal to decrease the expenses of the President's office. Kentucky-American further states that, given recent LFUCG council elections, the future of LFUCG's condemnation proceeding is uncertain.[115]

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[114] Direct Testimony of Andrea C. Crane at 53 and Schedule ACC-22.

[115] *Id.*

We find insufficient evidence in the record to support the AG's proposal. It is based upon a misstatement that was subsequently corrected. We further find that the proposed 90 percent allocation of the President's official duties to condemnation-related activities is arbitrary and without any supporting basis. The Commission is of the opinion, however, that Kentucky-American should, beginning as of the date of this Order, track all costs and employee time related to condemnation activities and be prepared to address questions on these activities at its next rate proceeding.

Incentive Compensation Plans. Kentucky-American has included in its forecasted operating expenses incentive compensation of $229,146, which is comprised of long-term incentive compensation of $23,427 ("LIP") and annual incentive plan compensation ("AIP") of $205,719.[116]

All full-time management, professional and technical employees (exempt from overtime) are eligible to participate in the AIP.[117] Kentucky-American bases AIP awards upon the following performance criteria: financial (60 percent); operational (25 percent); and individual (15 percent).[118] Approximately 40 Kentucky-American employees participate in the AIP.

The Compensation and Management Committee of American Water Works' Board of Directors administers the LIP and designates the employees who can participate. Kentucky-American's President recommends to this Committee who should

[116] Direct Testimony of Michael Miller at 51 - 53.

[117] *Id.* at 48.

[118] *Id.* at 49-50.

be designated for participation in LIP. Currently only Kentucky-American's President participates in the LIP.[119]

The AG proposes adjustment in the level of both incentive compensation plans. Since 60 percent of the AIP award is based upon Kentucky-American achieving certain financial targets, a criterion that the AG asserts directly benefits the shareholders,[120] he recommends that 60 percent or $137,488 of the AIP be allocated to Kentucky-American's shareholders. He recommends all costs related to LIP be removed because the sole criterion for its award is "achievement of cumulative net income."[121] The AG's overall adjustment to Kentucky-American's incentive plan forecast is a reduction of $160,915.

Kentucky-American opposes the proposed removals. It argues that the AG's proposed adjustment to AIP is based upon the faulty assumption that the financial health of Kentucky-American is in the best interest only of the shareholders.[122] Without a viable financial entity, Kentucky-American argues, it is unable to attract capital, meet unanticipated expenditures, provide a basis for ongoing infrastructure replacement, and provide reliable customer service. As further support of its incentive plans, Kentucky-American points to the findings of a 1991 comprehensive management and operations audit in which the auditors found that the utility required competitive compensation packages to attract and retain qualified individuals and that the cost of such packages are balanced by the likely costs of recruiting, hiring, and training replacements.

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[119] KAWC Brief at 34.

[120] Direct Testimony of Andrea C. Crane at 55.

[121] *Id.*

[122] KAWC Brief at 34.

In previous rate proceedings[123] when the appropriateness of recovery of the entire cost of its incentive compensation plans was questioned, Kentucky-American has asserted the plans were in response to the findings of a Commission-mandated management audit. While we initially accepted this argument, we rejected this position in Kentucky-American's last rate proceeding and placed the utility on notice that "in future rate proceedings, it must demonstrate fully why it should not bear a portion of these [incentive compensation plan] costs."[124]

Kentucky-American argues that its incentive plans motivate its employees to perform at high levels and to always place customer service and satisfaction at the forefront of its efforts. Despite requests for studies or analyses that would quantify these alleged benefits, Kentucky-American has failed to produce any evidence to support its position. It has provided only a report indicating that Kentucky-American's plans are in line with other surveyed utilities and that most surveyed utilities have incentive plans for upper and middle management. This report, however, does not address or quantify benefits that Kentucky-American's plans supposedly provide to ratepayers nor does it indicate how the costs of other utility plans are allocated between shareholders and ratepayers. The mere existence of such plans is insufficient to demonstrate that they benefit ratepayers and that their costs should be recovered through rates. The Commission, therefore, has eliminated the costs associated with the AIP and the LIP and reduced Kentucky-American's forecasted operating expenses by $229,146.

[123] *See, e.g.,* Case No. 1997-00034, Application of Kentucky-American Water Company to Increase Its Rates (Ky.PSC Sept.30, 1997).

[124] Case No. 2000-00120, Order of November 27, 2000 at 44.

Waste Disposal. Included in Kentucky-American's forecasted operations is waste disposal expense of $238,996. The waste disposal forecast reflects the third-party bids for cleaning Kentucky-American's treatment facilities amortized over a 24-month period.[125]

Kentucky-American acknowledges that the ongoing waste disposal costs for the Richmond Road Station have been overstated.[126] The AG asserts that the monthly amortization of these costs should be $2,500, not $3,500, and proposes to reduce waste disposal expense by $12,000.[127] We find that the AG's adjustment should be accepted and has reduced forecasted operating expenses by $12,000.

Kentucky-American's forecasted cost also includes $70,000 for the removal of solids from Lake Ellerslie. The AG argues that, as the Richmond Road Station is cleaned periodically, not annually, these costs should be recovered over a multi-year period. He proposes to reduce waste disposal cost by $46,667 to reflect the amortization of this cost over a 3-year period.[128]

Kentucky-American objects to the proposed adjustment. It states that in recent years it has experienced increased demands, greater requirements for turbidity removal, and increased use of Kentucky River water at the Richmond Road Station. These occurrences have resulted in increased amounts of sedimentation produced at that facility and a corresponding increase in sedimentation buildup at the adjacent

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[125] Direct Testimony of Sheila Valentine at 7.

[126] KAWC's Response to Commission Staff's Second Set of Information Requests, Item 99(d).

[127] Direct Testimony of Andrea C. Crane at 61.

[128] *Id.* at 62.

reservoir.[129] This buildup will likely require annual cleaning of Lake Ellerslie on a going forward basis.[130]

The record indicates that in August 2002 Kentucky-American removed 1,109,038 gallons of sediment from Lake Ellerslie and in 2004 removed 881,969 gallons in a one-month period. It further indicates that the increased demand and use of Kentucky River water at the Richmond Road Station has produced a faster buildup of sedimentation around the discharge point. Kentucky-American witnesses have testified that increased demand has resulted in the need for greater utilization of Lake Ellerslie on a going forward basis. In its budgets, Kentucky-American has projected that "[a]pproximately 900,000 gallons of solids containing water will be removed from either the sedimentation basins, washwater holding tanks, sludge thickeners, or reservoir in 2006 and 2007 until such time that improvements are made to the solids handling capabilities of RRS."[131] We find that the increased use of Lake Ellerslie and the resulting increase in sedimentation will likely require annual removal of sedimentation from Lake Ellerslie for the foreseeable future. Accordingly, we deny the AG's proposed adjustment.

Management Fees. Kentucky-American has included its forecasted operations management fee expenses of $3,800,310. Management fees represent the forecasted costs for the services that American Water Works provides to Kentucky-American. Reflected in the management fees are the costs for operating the National Customer Care/Call and Shared Services Centers. Kentucky-American has also included in its

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[129] Rebuttal Testimony of Linda Bridwell at 2.

[130] *Id.* at 3.

[131] KAWC's Response to Commission Staff's Fourth Information Request, Item 7.

management fee forecast $117,525 of business development costs allocated from American Water Works' regional office.

The AG proposes the reduction of management fees by $117,525 to eliminate the business development cost allocation. In support of this action, he argues that the provision of regulated water service in a franchised service territory is not a competitive situation requiring "business development." He asserts that the business development costs incurred should be booked by some entity other than Kentucky-American or borne entirely by Kentucky-American's shareholders.

Responding to this proposed adjustment, Kentucky-American observes that the Commission allowed the full recovery of a business development employee in its last rate case proceeding and that its business development costs are reasonable. "As a regional supplier of water and the most logical entity for consolidation of water purveyors," it argues that it is, "not only pursuing legislative mandates and Commission encouragements, but is attempting to obtain efficiencies through expansions."[132]

While we allowed the cost of a business development employee in Kentucky-American's last rate proceeding, we did so only after Kentucky-American clearly identified and documented that employee's duties. In this proceeding the Service Company is providing the services at issue, the fees are included in the management fee forecast, and the only description of the services is "Salary, salary overheads, and incidental expenses of the business development employees in the SE Region office who performed functions directly related to business development activities in Kentucky

[132] KAWC Brief at 40.

on behalf of Kentucky American Water."[133] Given Kentucky-American's inability to appropriately document and separate forecasted management fees between those that are directly assignable and those that are allocated, we find that Kentucky-American has failed to demonstrate that the forecasted business development costs are reasonable or are appropriately included in Kentucky-American's regulated operations and have reduced forecasted operating expenses by $117,525.

During the evidentiary hearing, the Chairman of Kentucky-American's Board of Directors disclosed the recent reassignment of several Kentucky-American employees to the Service Company's Southeast Region. In the previous rate proceeding, we advised Kentucky-American that it should provide assurances that "management of operations and policy decisions will remain under local control and that decisions are made in the best interests of the ratepayers of Kentucky."[134] The hearing disclosure increases this concern. While recognizing that certain organizational changes may create beneficial efficiencies, we remain concerned that the best interests of Kentucky-American's customers are prominently considered when the Southeast Region makes its decisions. Therefore, Kentucky-American should, within 60 days from the date of this Order, provide a detailed report in which it describes the organization of AWWC, the Southeast Region, and Kentucky-American. At a minimum, it should identify the functions performed by each entity, the development of strategic policy for each entity, and the role that Kentucky-American has in the formation and development of policies that affect its customers. It should also identify all services provided by the Southeast

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[133] KAWC's Response to Commission Staff's Fourth Set of Information Requests, Item 39.

[134] Case No. 2000-00120, Order of Nov. 27, 2000 at 18-19.

Region and other affiliated entities to Kentucky-American. Any planned but incomplete organizational changes that affect Kentucky-American should also be disclosed.

Group Insurance. Kentucky-American includes in its forecasted operations group insurance expense of $1,724,407. The forecasted expense is comprised of group insurance costs for the current associates and post retirement employee benefit costs ("OPEB") for both Kentucky-American's current and retired employees. To forecast the cost of current group insurance, Kentucky-American increased the current group insurance rates by 8.94 percent to reflect the rates that will be in effect on January 1, 2005. It then applied these rates to the number of Kentucky-American's full-time employees.[135] Towers Perrin prepared a report to update the 2003 actuarial report to estimate Kentucky-American's 2004 OPEB expense. Kentucky-American increased the 2004 OPEB estimate by 9 percent to arrive at its forecasted OPEB expense of $798,734.[136]

The AG proposes to reduce group insurance expense by $51,381. In support of his proposal, he argues that, because OPEB expense is dependent upon a variety of factors, forecasting annual OPEB is a complex process. Merely isolating one factor or assuming that OPEB expenses follow the same trends as health care costs does not produce a reliable forecast. The AG argues that an actuarial report is the best support for an OPEB projection. In this case, the most recent Towers Perrin report supports the

[135] Direct Testimony of Shelia Valentine at 7-8.

[136] KAWC's Response to Commission Staff's Fourth Information Request, Item 43.

use of $904,227 reduced by the amount capitalized by Kentucky-American,[137] or a reduction to group insurance expense of $51,381.[138]

Kentucky-American argues that it is generally recognized that health care costs, particularly for the age group covered by the OPEB, are increasing annually and dramatically. It refers to newspaper reports of predictions of increased health care costs.[139] Kentucky-American's average annual OPEB cost increase between 1999 and 2003 was 7.7 percent.[140]

We concur that budgeting for OPEB expense is a complex process that is dependent on many factors. Factors that would influence future OPEB costs are health care costs, return on assets investments, employment levels, and the ages of the employees being covered. The record does not demonstrate that Kentucky-American has considered those other factors in developing its forecast of future OPEB expenses. Moreover, as the forecast is based upon an estimate of 2004 OPEB costs, not actual costs, we have serious concerns about the reliability and accuracy of these forecasted costs.

The Commission notes that Commission Staff has requested on two occasions that Kentucky-American provide the 2004 actuarial report when such report becomes available. Kentucky-American has yet to file such report. While we recognize that the current trend in health care costs supports some level of increase in 2004 OPEB expense, we cannot accept a forecast that is mere conjecture. Absent the 2004

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[137] AG Brief at 20.

[138] Direct Testimony of Andrea C. Crane, Schedule ACC-26.

[139] KAWC Brief at 37.

[140] Rebuttal Testimony of Michael Miller at 39.

actuarial study, we find that Kentucky-American has failed to meet its burden of demonstrating that the forecasted expense level is reasonable and that the forecasted expense level should be reduced by $51,381.

Rents. Kentucky-American has included in its forecasted operations rent expense of $111,438, which reflects signed and anticipated agreements for copiers and postage machines.[141] The AG proposes to reduce forecasted rent expense by $58,295 to reflect the following changes to Kentucky-American's forecast: (1) eliminate lease payments for lab equipment that has been purchased; (2) remove the lease payment for a copier that is no longer leased; (3) eliminate lease payments for office equipment no longer at the Tri-Village office.[142] Kentucky-American agrees that its forecast for rent expense is overstated by that amount.[143] We find that this adjustment should be accepted and that forecasted operating expenses should be reduced by $58,295.

General Office Expense. Kentucky-American has included in its forecasted operations general office expense of $348,606. This expense includes, but is not limited to: dues and memberships; employee travel and meal expenses; office supplies; and general office utility costs. The forecast for customer accounting is below the base period amount and considerably less than the prior 3 years.[144]

The AG proposes to reduce general office expense by $5,228 to eliminate social club dues from Kentucky-American's forecast.[145] The forecasted amount includes

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141 *Id.*

142 Direct Testimony of Andrea C. Crane at 67.

143 KAWC's Response to the AG's First Information Request, Item 138.

144 *Id.*

145 Direct Testimony of Andrea C. Crane at 67.

social club dues for Spindletop Hall, the Keeneland Club, the University of Kentucky Faculty Club, the Lafayette Club, Rotary Club, Kiwanis, and Audubon Society. The AG contends that these dues are not necessary for the provision of safe and adequate utility service and therefore should not be borne by ratepayers.

Kentucky-American agrees that the dues paid for Spindletop Hall and the Keeneland Club should be excluded from forecasted operations.[146] It argues that memberships in the University of Kentucky Faculty Club and the Lafayette Club are for business purposes only. Since these locations have private rooms, Kentucky-American uses them for off-site business meetings, business luncheons, seminars, and training sessions. It notes that the Rotary Club and Kiwanis are minor expenses when compared to the benefits that are derived from the interaction of its employees with community business leaders. As to the Audubon Society's annual fee of $90, Kentucky-American claims this fee is an extension of its commitment to conservation and the environment.[147]

The Commission has previously found that community organization expenses benefit utility community relations and are a form of charitable contribution that should not be recovered through utility rates.[148] We find nothing in the record to require us to reconsider this holding. Accordingly, we have reduced operating expenses by $5,228.

<u>Miscellaneous</u>. Kentucky-American has included in its forecasted operations miscellaneous expense of $2,978,873. This category includes items that are necessary

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[146] Rebuttal Testimony of Coleman Bush at 5.

[147] *Id.*

[148] Case No. 1997-00034, Application of Kentucky-American Water Company to Increase its Rates (Ky PSC Sep. 30, 1997) at 42.

to carry out the normal day-to-day business functions such as: janitorial; legal; advertising; employee training programs; uniforms; telephone; amortizations; conservation; and security costs.[149]

The Commission, on its own motion, has decreased forecasted Miscellaneous Expense of $99,244 to remove the amortization of community education costs approved in Kentucky-American's rate proceeding in Case Number 2000-00120. In that proceeding, we provided that this allowance for community education costs "shall be allocated to developing more extensive conservation efforts than those anticipated for the forecasted test year."[150] FASB 71 provides that a deferral of an expense is appropriate only where "future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs." As our action in the last rate proceeding was clearly intended to provide future levels of similar costs, it clearly conflicted with the requirements of FASB 71 and was inappropriate.

The AG proposes to reduce miscellaneous expense by $72,415 to remove institutional advertising. He argues that the purpose of institutional advertising is to promote the corporate name of Kentucky-American or its parent, RWE. He refers to specific Kentucky-American advertisements that he views as constituting institutional advertising and asserts that they are totally unrelated to the provision of utility service.[151]

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[149] Direct Testimony of Shelia Valentine at 10.

[150] Case No. 2000-00120, Order of May 9, 2001 at 11.

[151] Direct Testimony of Andrea C. Crane at 68.

According to Kentucky-American, the source for the AG's proposed adjustment, Schedule F-4, was incorrectly prepared. Kentucky-American states that the actual amount of the forecasted advertising expense is $134,704 and that it can be found on W/P-3-13, page 1. Kentucky-American contends that the language cited by the AG is from past ads, which it does not believe constitutes institutional advertising. Kentucky-American further contends that the outline of its ads[152] for the forecasted period only includes advertising that is allowed for rate-making purposes and therefore, the AG's adjustment should be denied.[153]

Administrative Regulation 807 KAR 5:016 prohibits the recovery of institutional advertising in rates. As this proceeding involves a forecasted test period, the only information available regarding future advertisements is a brief outline of advertisements that Kentucky-American plans. The specific language of these advertisements has not yet been prepared. Based upon our review of the advertisement outline, we find that the advertisements set forth in Table VII are for community education purposes and should be included in forecasted operations.

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[152] Rebuttal Testimony of Coleman Bush at CDB Exhibit 1.

[153] *Id.* at 6.

TABLE VII

Description	Forecasted Cost
Customer Service Guide Inserts	$ 2,050
Public Education Materials	3,076
Newsletters Community	8,200
Hydrant Flushing	1,230
Water Quality Reprint	2,563
From the Tap	10,252
Consumer Confidence Report	20,500
Immunocompromised Customers	5,124
Customer Appreciation	5,127
TV Tips	27,587
TV Leak Detection	4,509
Conservation Radio	20,500
Conservation Bill Inserts	+ 10,247
Total Community Education	$ 120,965

We find that the remaining $25,035[154] of forecasted community education costs involves institutional advertising and should be eliminated.

Maintenance – Other. Kentucky-American has included in its forecasted operations its maintenance expense of $972,706. It states that maintenance expense included in its forecast is greater than in the base period amounts because of greater upkeep and maintenance activities on existing plant such as tank inspections and general plant maintenance."[155]

The AG proposes to decrease maintenance expense by $211,477.[156] He states that Kentucky-American has failed to provide adequate evidence to support the significant increase in maintenance expense. He proposed to use the 3-year average of

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[154] $146,000 (Community Education Forecast) - $120,965 (Allowable Community Education Advertisements) = $20,035.

[155] Direct Testimony of Sheila Valentine at 10.

[156] Direct Testimony of Andrea C. Crane at 64 and Schedule ACC-29.

maintenance costs for the period of 2001 through 2003 to establish the appropriate level of maintenance expense.

Kentucky-American opposes the use of a historical averaging of costs to adjust maintenance expense. It argues that the practice is unreasonable and arbitrary and fails to take into account the cost of necessary preventive maintenance.[157]

That a forecasted expense is higher than the amount reported in the base or a historical period is insufficient basis for an adjustment. While the AG's methodology of comparing the test period to the historical levels would be appropriate in a rate case using an historical test period, it is of limited value when a forecasted test period is used. In rate proceedings using a forecasted test period, the accuracy of a utility's ability to forecast or budget for an expense is the more critical issue. The accuracy of Kentucky-American's forecast can be gauged by comparing its maintenance budgets to its actual results. A comparison of Kentucky-American's maintenance expenses budgets to actual results for the calendar years 2000 through 2003,[158] which is set forth in Table VIII, shows that Kentucky-American has accurately forecasted its maintenance expense. In light of this comparison and in the absence of any evidence to demonstrate that a 3-year historical average is an accurate measure of future maintenance costs, we find that the AG's proposed adjustment should be denied.

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[157] Brief of KAWC at 38.

[158] KAWC's Response to Commission Staff's Fourth Set of Information Requests, Item 8. Maintenance expenses are net of the amortizations.

TABLE VIII

Maintenance Expense			
Year	Actual	Budget	Percentage of Actual to Budget
2000	$ 746,355	$ 795,290	93.8%
2001	897,888	776,886	115.6%
2002	701,080	719,673	97.4%
2003	+ 746,157	+ 909,557	82.0%
Total	$ 3,091,480	$ 3,201,406	96.6%

Low Income Discount. Kentucky-American proposes to discount its service charge by 25 percent for all residential customers whose household income is certified as being equal to or below the federal poverty level. For the reasons set forth later in this Order, we deny the proposed discount and decrease forecasted operating expenses by $30,000.

Depreciation. Kentucky-American includes depreciation expense of $7,065,762 in its forecasted operations. Based on the Commission's treatment of forecasted rate base with regard to slippage, an adjustment has been made to increase forecasted depreciation expense by $1,770.

Amortization Expense. Kentucky-American includes in forecasted test period operations amortization expense of $695,154. Of this amount, Kentucky-American includes $13,248 and $19,296 for its Boonesboro and Pineville acquisitions, respectively. In Case No. 2000-00120, the Commission included amortization expense of $13,051[159] for the Boonesboro acquisition, which is $197 less than the amount that Kentucky-American includes. The Commission has reduced amortization expense by $197 to correct for this error. We have further reduced forecasted amortization by an additional $19,296 to remove the amortization of the Pineville acquisition, which

[159] Case No. 2000-00120, Order of May 17, 2001 at 17.

Kentucky-American has acknowledged was incorrectly included in its amortization forecast.

General Taxes. Kentucky-American includes a forecast of general tax expense of $1,712,673, which includes property taxes and payroll taxes of $2,223,673 and $410,283, respectively, but was decreased to $2,221,770 after application of the construction slippage factors. Based on our treatment of forecasted rate base with regard to slippage, we have decreased forecasted property taxes expense by $1,903. We have also reduced payroll taxes by $17,530 to reflect the effects of our removal of the costs of incentive pay plans.

Income Taxes. The AG proposes that Kentucky-American's forecasted current and deferred income tax expenses be adjusted to reflect the use of a consolidated tax return. He notes that Kentucky-American calculates federal income taxes on a stand-alone basis.[160] Kentucky-American, however, is part of a consolidated group, which is held by Thames Water Aqua U.S. Holdings ("TWUS"), that files a combined federal income tax return to take advantage of the tax losses experienced by some of the group's members.[161] The use of a consolidated tax filing, the AG states, permits the tax loss benefits generated by one group of subsidiaries to be shared by the other consolidated group members, thus resulting in a reduced effective federal income tax rate. The AG proposes that these tax benefits should be flowed to Kentucky-American's ratepayers to reflect the actual taxes paid rather than calculate the amount of taxes based upon stand-alone methodology. To do otherwise, he argues, would

[160] Direct Testimony of Andrea C. Crane at 73.

[161] AG Brief at 27.

overstate Kentucky-American's federal income tax. Regulatory commissions in three other jurisdictions in which American Water Works affiliates are located[162] have adopted consolidated tax adjustments for rate-making purposes.[163] Use of the AG's consolidated tax adjustment results in a $551,151 credit to forecasted income available for federal income taxes and a decrease to federal income taxes of $192,903.

Kentucky-American describes the AG's proposal as "unprecedented and unique" and as representing a significant departure from established Commission precedent. It argues that the extraction of tax benefits from one subsidiary that participates in the filing of a consolidated tax return and transferring that benefit to another subsidiary in the "family" is a cross-subsidy. Its witness testified that the advantage of a consolidated return is only to the entity that actually incurs the tax loss as the tax benefit attributable to the operating loss is given to that entity. As Kentucky-American has not incurred a tax loss, it accrues actual benefit from the filing of a consolidated tax return. Imposing a consolidated tax adjustment, Kentucky-American argues, will only preclude it from earning its allowed rate of return. Kentucky-American further notes that the proposed adjustment raises serious extra-territorial jurisdictional issues.

We find that Kentucky-American's present position on this issue conflicts with its stated position in Case No. 2002-00317. In that proceeding, Kentucky-American and others sought approval of the transaction that enabled RWE's acquisition of control of Kentucky-American. One feature of this transaction was the creation of TWUS, an

[162] These jurisdictions are Pennsylvania, New Jersey, and West Virginia.

[163] Testimony of Andrea C. Crane at 73.

intermediate holding company that would hold the stock of American Water and all of Thames Water Aqua Holdings GmbH's other U.S. affiliates. Kentucky-American asserted the creation of TWUS would permit the filing of consolidated U.S. tax returns. The ability to file such a tax return, Kentucky-American argued, benefited the public because it would reduce administrative expenses by eliminating the need to file multiple tax returns and permit some tax savings by allowing payment of taxes calculated on the net profits of all entities within the consolidated group.

We note that when approving the proposed transaction, we rejected specific proposals to condition our approval on the Joint Petitioners treating any tax savings achieved through the write-off of losses incurred in unregulated U.S. operations against regulated U.S. earnings as a benefit of the transaction and sharing that benefit with Kentucky-American ratepayers. We took that action, not because the proposals were without merit, but because we had previously directed that a portion of any merger savings be allocated to Kentucky-American ratepayers and that additional conditions were unnecessary. Kentucky-American did not take exception to or protest our reasoning.

Having previously indicated the savings resulting from the filing of a consolidated tax filing would be viewed as a merger benefit, subject to allocation, we do not believe that acceptance of the AG's proposal represents a radical departure from past regulatory practice. Moreover, Kentucky-American and its corporate parents having previously touted TWUS's filing of consolidated tax returns as a benefit to obtain approval of the merger transaction, have no cause to object if we now act upon their representation. Accordingly, we find that the AG's proposed consolidated income tax is reasonable and have reflected it in our calculation of federal income taxes.

We further find certain errors in Kentucky-American's calculation of income taxes at present rates that result in an overstatement of those taxes. The overstatement resulted from adding amortization of plant acquisition adjustments for Tri-Village and Elk Lake in the amounts of $5,676 and $2,688, respectively, to the reconciling items shown at Exhibit 37-E, Pages 5 and 7. On those pages, these items were erroneously excluded from the stated depreciation and amortization expense making their inclusion as a reconciling item unnecessary and inappropriate. This adjustment is reflected in the Commission's calculation of forecasted income tax expense.

To reflect interest synchronization, Kentucky-American proposed a forecasted interest expense of $5,325,120 based on forecasted rate base and weighted cost of debt. The Commission has recalculated this expense to be $5,234,794[164] based on the rate base and weighted cost of debt found reasonable herein.

Adjusting Kentucky-American's income tax forecast, the Commission arrives at its current income tax expense of $2,761,192 as shown in Table IX below.

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[164]

Commission Approved Rate Base	$	156,262,507
Commission Approved Weighted Cost of Debt	+	3.35%
Interest Synchronization	$	5,234,794

TABLE IX

Item	Commission Adjustments	Current Income Tax Expense State	Federal	Total
Kentucky-American's Forecasted Taxes		$ 492,887	$ 1,939,211	$ 2,432,098
Public Fire Hydrants	$ 89,015	7,344	28,585	35,929
Private Fire Hydrants	$ 29,020	2,394	9,319	11,713
Activation Charges	$ 672,000	55,440	215,795	271,235
AFUDC	$ (133,370)	(11,003)	(42,828)	(53,831)
Incentive Pay Plans	$ (229,146)	18,905	73,584	92,489
Waste Disposal	$ (12,000)	990	3,854	4,844
Business Development	$ (117,525)	9,696	37,740	47,436
OPEB's	$ (51,390)	4,240	16,503	20,743
Rents	$ (58,295)	4,809	18,720	23,529
Social Club Dues	$ (5,228)	431	1,679	2,110
Advertising	$ (25,035)	2,065	8,040	10,105
Low Income Discount	$ (30,000)	2,475	9,634	12,109
Depreciation	$ 1,770	(146)	(568)	(714)
General Taxes	$ (19,433)	1,603	6,240	7,843
Interest Synchronization	$ (90,326)	7,452	5,629	36,458
Income Tax Consolidation	$ (551,151)	+ 0	+ (192,904)	+ (192,904)
Commission Current Income Tax Expense		$ 599,582	$ 2,161,610	$ 2,761,192

Based upon the adjustments to deferred debit amortization and community education amortization, the Commission arrives at its level of deferred income tax expense of $(12,084) shown in Table X.

TABLE X

Item	Commission Adjustments	Deferred Income Tax Expense State	Federal	Total
Kentucky-American's Forecasted Tax Expense		$ (9,636)	$ (209,182)	$ (218,818)
Community Education	$ (99,243)	8,188	31,869	40,057
Deferred Security Costs	$ (280,566)	23,147	90,097	113,244
Shared Service Transition	$ (55,751)	4,599	17,903	22,502
Customer Care/Call Center	$ (57,141)	4,714	18,349	23,063
Acquisition - Boonesboro	$ (197)	16	64	80
Acquisition – Pineville	$ (19,296)	+ 1,592	+ 6,196	+ 7,788
Commission Deferred Income Tax Expense		$ 32,620	$ (44,704)	$ (12,084)

Based on the aforementioned adjustments to forecasted revenues and expenses the Commission has determined Kentucky-American's forecasted net operating income at present rates to be $9,971,59 as shown in Table XI.

TABLE XI

Category	Kentucky-American's Forecasted Income Taxes	Commission Adjustments	Adjusted Income Taxes
Operating Revenues			
Water Sales	$ 41,803,9866	$ 118,035	$ 41,922,001
Other Operating Rev.	+ 1,585,696	+ 538,630	+ 2,124,326
Total Operating Rev.	$ 43,389,662	$ 656,665	$ 44,046,327
Operating Expenses			
Operation & Maintenance	$ 21,910,724	$ (1,021,320)	$ 20,889,404
Depreciation & Amort.	7,760,916	(17,723)	7,743,193
General Taxes	2,712,460	(19,433)	2,693,027
Income Taxes	+ 2,213,280	+ 535,828	+ 2,749,108
Total Operating Exp.	$ 34,597,380	$ (522,648)	$ 34,074,732
Net Operating Income	$ 8,792,282	$ 1,179,313	$ 9,971,595

Rate of Return

Capital Structure. Kentucky-American's proposed capital structure based on the projected 13-month average balances for the forecasted test period and the costs assigned to each capital component is shown Table XII.

TABLE XII

Components	Ky-American's Capitalization	Assigned Costs
Short-Term Debt	3.719%	2.700%
Long-Term Debt	51.376%	6.330%
Preferred Stock	3.780%	7.720%
Common Equity	+ 41.125%	11.20%
Total Capitalization	100.000%	

The AG proposes adjustments in the capital structure used to calculate rates. He contends that Kentucky-American consistently uses short-term debt as a capital source. In reviewing the period of 2001 through 2003, the AG found that the average quarterly short-term debt as a percentage of capitalization was 7.78 percent. In comparing this average to the proposed percentage of 3.719 percent, the AG concludes that Kentucky-American's forecast of short-term debt is understated. The AG argues that the requirement of 807 KAR 5:001, Section 10, that rate base and capitalization be based upon a 13-month average for the forecasted period does not preclude the examination of the reasonableness of Kentucky-American's proposed capital structure. He proposes adjusting the capitalization to reflect the quarterly averages for the calendar years 2001 through 2003. This adjustment would produce the capital structure shown in Table XIII:[165]

TABLE XIII

Components	AG's Capitalization
Short-Term Debt	7.780%
Long-Term Debt	46.410%
Preferred Stock	4.600%
Common Equity	+ 41.210%
Total Capitalization	100.000%

Kentucky-American contends that its capital structure has been formulated with a careful consideration of the expected capital demands in the forecast period and of the most efficient and cost-effective means to meet those demands. It asserts that the AG's proposed capital structure ignores financing the $14 million of long-term debt in March 2004, the refinancing of the $5.5 million debt that matures in September 2005, and retained earnings that has been generated in 2004 and will be generated in 2005. It further asserts that the AG's proposed capital structure is a hypothetical capital structure that does not exist and is not reflective of Kentucky-American's capital needs.[166]

[165] AG Brief at 32-33.

[166] KAWC Brief at 49-50.

The Commission declines to accept the AG's proposed capital structure. As previously noted, we find the use of historical averages to be of limited relevance. Our central focus is with Kentucky-American's ability to forecast its capital requirements rather than comparisons of a forecasted capital structure with historical quarterly averages. The record shows that Kentucky-American's forecast is based upon current projections of its construction investment and capital requirements. The Commission finds that Kentucky-American's capital structure, after adjustments to reflect the effects of slippage, is shown in Table XIV below.

TABLE XIV

Components	Commission Capitalization
Short-Term Debt	3.697%
Long-Term Debt	51.388%
Preferred Stock	3.781%
Common Equity	+ 41.134%
Total Capitalization	100.000%

Short-Term and Long-Term Debt. Kentucky-American proposes short-term debt and long-term debt rates of 2.77 percent and 6.33 percent, respectively. No party objected to these forecasted cost rates. We find the proposed cost of debt is reasonable and should be accepted.

Preferred Stock. Kentucky-American proposed an embedded cost of preferred stock of 7.72 percent. No party objected to this forecasted cost rate. We find that the proposed embedded cost of preferred stock proposed by Kentucky-American appears reasonable and should be accepted.

Return on Common Equity. Kentucky-American recommends a return on equity ("ROE") of 11.2 percent based on its discounted cash flow model ("DCF"), the ex ante risk premium method and the ex post risk premium method. Kentucky-American applied these models to two proxy groups, one consisting of water distribution companies and the other comprised of natural gas local distribution companies ("LDC"). Kentucky-American claims that its estimate is conservative because, in comparison to the proxy companies, it has greater financial risk because of its higher financial leverage.[167]

Kentucky-American used both water companies and LDCs because of the low number of analysts following water companies. Kentucky-American argues that LDCs are similar in risk to water companies and supply a larger number of analyst-followed companies that can act as a reasonableness measure for the water company results. In support, Kentucky-American provided an example from the Florida Public Service Commission, which uses LDCs as proxies for water companies.[168] DCF analyses on both sets of proxy companies produce a result of 10.7 percent cost of equity, which includes a five percent allowance for flotation costs.[169] Kentucky-American's two risk premium analyses, the ex ante risk premium and the ex post risk premium method, were performed on only the natural gas LDCs, since Kentucky-American believes there is insufficient information on the water companies to perform this type of analysis. The ex ante approach produces a cost of equity of 11.45 percent and the ex post method produces a range of 10.9 to 11.5, which includes a flotation cost adjustment of 25 basis-points.

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[167] Direct Testimony of Dr. James H. Vander Weide at 4.

[168] KAWC's Response to Commission Staff's Second Set of Information Requests, Item 11(d).

[169] *Id.* at 28.

The AG recommends an ROE of 8.75 percent using a DCF analysis and the Capital Asset Pricing Model ("CAPM"). The AG uses two comparison groups for its analysis, a Small Water Company Group and a Large Water Company Group. Both contain companies listed as water companies by C.A. Turner Utility Reports and are limited to companies whose water revenues are at least 80 percent of total revenues. The AG includes a discussion of three economic factors that have influenced the cost of equity recently: (1) the declining yields on A rated public utility bonds, (2) the declining dividend yields for the fifteen utilities in the Dow Jones Utilities Average over the past decade and (3) the increasing average earned returns on equity and market to book ratios. The AG argues that the overall investment risk of public utilities is below most other industries.[170]

The AG identifies three primary errors in Kentucky-American's cost of equity analysis: 1) the growth rates used in the DCF analysis; 2) the flotation cost adjustment; and 3) upwardly biased ex ante and ex post risk premium studies. The AG also takes issue with Kentucky-American's choice of comparison companies. Finally, he argues that lower interest rates are also indicators of a need for a lower cost of equity than that proposed by Kentucky-American.[171]

In its rebuttal testimony, Kentucky-American criticizes the AG's proxy companies, stating that most of the proxy companies are small and not widely followed in the investment community. Kentucky-American notes that only two of the AG's five small proxy companies are followed by Value Line and that Value Line presents growth

[170] Direct Testimony of Dr. J. Randall Woolridge at 13.

[171] *Id.* at 49 - 73.

forecasts for only three of the AG's nine companies in both the small and large proxy groups. It also takes issue with the AG's use of only water companies in its analysis. It argues that the small, thinly traded and not widely followed companies in the AG's analysis indicate the need to employ equity models on other proxy companies that are similar in risk to water companies and are more widely followed in the investment community.

Kentucky-American also disagrees with the AG's approach in the DCF Model. It argues that the DCF model should have been modified to account for the quarterly payment of dividends by the proxy companies. Kentucky-American also states that the AG's method of estimating the dividend yield and his use of historical growth rates to estimate an investor's expectation of future growth are incorrect.

In critiquing the AG's CAPM analysis, Kentucky-American disagrees with the AG's use of the 10-year Treasury note to estimate the risk-free rate and the risk premium used by the AG. It suggests that the AG should have included a small company premium because of the size of the companies used in the proxy groups. It asserts that if the AG's analysis had used the correct factors and methodology described earlier, the result would have been a cost of equity of 13.5 percent.

The Commission agrees with some of Kentucky-American's criticisms of the AG's methodology employed in the DCF analysis. The use of ten-year Treasury bills as the risk free rate in the AG's CAPM analysis does not appear to be the most appropriate risk free rate for the model. While awards to American Water affiliates in other states is not a basis for an award for Kentucky-American, the Commission notes that the AG's ROE recommendation of 8.75 percent is significantly below most awards in 2004.

While the available data on water companies is limited, we find that the use of other industries, such as gas, to determine the return needed for a water company to be inappropriate. The Commission has addressed this issue on another occasion when asked to consider analysis performed on electric companies to determine the cost of equity for a gas company.[172] The fact that Kentucky-American's DCF analysis on both water and gas companies produces the same result indicates there is still merit in using water companies.[173]

In addition, the Commission is reluctant to consider a flotation cost adjustment when the subsidiary involved does not actually incur such cost and Kentucky-American was unable to provide any information on how RWE itself treats these costs. Furthermore, the Commission is not persuaded that Kentucky-American faces any greater risk as a result of its high degree of fixed costs or demand uncertainty compared to most other water companies. Kentucky-American has a history of filing rate cases on a regular basis. Frequent rate cases, coupled with its use of a forecasted test-year, mitigate some of the risk that Kentucky-American contends requires a higher return on equity.

Having considered the evidence of record, the Commission finds that Kentucky-American's cost of equity falls within a range of 9.5 percent to 10.5 percent. We further find that the midpoint of that range, 10 percent, is a reasonable level and should be used to determine Kentucky-American's overall revenue requirement.

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[172] Case No. 2000-00080, The Application of Louisville Gas and Electric Company to Adjust its Gas Rates and to Increase Its Changes for Disconnecting Service, Reconnecting Service and Returned Checks (Ky. PSC Sep. 27, 2000).

[173] Direct Testimony of Dr. James H. Vander Weide at 28.

Weight Cost of Capital. Applying the rates of 6.33 percent for long-term, 7.72 percent for preferred stock, 2.70 percent for short-term debt, and 10.00 percent for common equity to the adjusted capital structure produces an overall cost of capital of 7.75 percent. We find this cost to be reasonable.

Authorized Increase

The Commission finds that Kentucky-American's net operating income for rate-making purposes is $12,110,344. We further find that this level of net operating income requires an increase in forecasted present rate revenues of $3,611,302.[174]

Rate Determination

Kentucky-American proposes to increase water rates across the board by 15.3 percent for its Central Division customers, 42 percent for Northern Division customers that Elk Lake previously served, and 40.3 percent for customers that Tri-Village previously served. Kentucky-American did not perform a cost-of-service study to determine these increases. It states that the level of the increase for Northern Division customers would have been greater had all costs and expenses related to providing service to this division been allocated to that division.

The AG proposes that the Northern Division's rates remain at their current level and that only the rates for the Central Division customers be increased across the board. He argues that as a cost-of-service study has not been performed, Kentucky-

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Net Investment Rate Base	$	156,262,507
Multiplied by: Weighted Cost-of-Capital	x	7.75%
Net Operating Income	$	12,110,344
Less: Forecasted Operating Income	-	9,971,595
Operating Income Deficiency	$	2,138,749
Multiplied by: Gross-up Factor	x	1.6885112
Revenue Requirement Increase	$	3,611,302

American cannot reasonably assign costs with the proposed across the board increase when the percentages differ from division to division. Noting that Kentucky-American intends to seek a unified rate in its next rate proceeding and that such action would likely produce a significant reduction in the rates charged to Northern Division customers, the drastic fluctuations would produce confusing and inappropriate pricing signals to Northern Division customers and be inconsistent with generally accepted rate design principles.[175]

The Commission agrees with the AG that the rates assessed to Northern Division customers should remain at their current level. Given Kentucky-American's intent to unify its rates in its next rate proceeding, we find that the dramatic shifts in the rates assessed to Northern Division customers that are likely to occur are inconsistent with generally accepted principles of sound rate design. We further find that an across-the-board percentage increase should be applied to Central Division rates.

The AG proposes that all revenues collected from the Account Activation fee be used to reduce or eliminate any increase to the 5/8-inch customer charge. We find that, as the activation fee is assessed to all customer classes, applying all the revenues from the fee to benefit one customer class is inappropriate. Moreover, it is contrary to the very purpose for which Commission regulations permit the assessment of non-recurring charges. We decline to follow the AG's proposal.

LFUCG argues that the proposed percentage increase applied to public-owned fire hydrants without a cost-of-service study is unreasonable. It asserts that, based upon the previous cost-of-service study submitted in Kentucky-American's last rate proceeding, public-owned fire hydrants generate only 4 percent of the total water sales

[175] Direct Testimony of Scott J. Rubin at 16.

revenue from rates. In the absence of a new cost-of-service study, LFUCG argues, any adjustment to public-owned fire hydrant rates should not increase this share above 4 percent.[176] We find no evidence within the record to support LFUCG's argument and further find that the across-the-board increase should apply to public-owned fire hydrant rates.

Other Issues

Activation Fee. Kentucky-American proposes to establish an account activation fee of $24 that will result in an annual increase to operating revenues of $672,000. The activation fee will be assessed when a new account is established at a pre-existing service location. The costs associated with the account activation fee include field costs to turn on service and office costs to set up the account.[177] Kentucky-American argues that the cost incurred to provide the service should be recovered from the individual who receives the service.

The AG opposes the fee contending that lower-income customers are statistically more likely to move and thus incur the fee. He asserts that the fee will fall more heavily on those who are less likely to have the ability to pay it.[178] He contends that the proposed fee fails to meet all of the standards for special charges set forth in the American Water Works Association's ("AWWA") *Manual M1*.[179] Finally, the AG

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[176] LFCUG Brief at 7-8.

[177] *Id.*

[178] Direct Testimony of Scott J. Rubin at 10-13.

[179] *Id.* at 10-11.

contends that Kentucky-American has failed to adequately demonstrate the reasonableness of the proposed fee.[180]

LFUCG opposes the account activation fee on the basis of its negative effect on low-income customers. It argues that the fee should be approved only if (1) the increased revenue from the fee is used to reduce or eliminate any increase in the 5/8-inch meter charge, (2) Kentucky-American agrees that the fee is subject to LFUCG's franchise fee, and (3) households qualifying for the proposed low-income tariff are excluded from the fee's coverage.[181]

The proposed activation fee is a non-recurring charge. Non-recurring charges are

> charges to customers due to a specific request for certain types of service activity for which, when the activity is completed, no additional charges may be incurred. Such charges are intended to be limited in nature and to recover the specific cost of the activity. Nonrecurring charges include reconnection charges, late payment fees, service order changes and hook-on or tap fees.

Administrative Regulation 807 KAR 5:011, Section 10. The Commission's regulations permit a utility to assess such charges to "recover customer specific costs incurred which would otherwise result in monetary loss to the utility or *increased rates to other customers to whom no benefits accrue from the service provided or the action taken.* Administrative Regulation 807 KAR 5:006, Section 8(1) (emphasis added). They expressly list an activation fee or "turn-on" charge as a permissible charge.[182]

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[180] AG Brief at 45.

[181] LFUCG Brief at 23-24.

[182] 807 KAR 5:006 at Section 8(3).

While we acknowledge that the proposed fee may affect those social groups that are more likely to change residences, we find that effect is not sufficient to find the proposed fee unreasonable or deny its assessment. The fee is facially neutral and does not distinguish between any social group. It focuses solely on the costs directly imposed by a customer's specific actions. Moreover, to deny the fee is to require customers to subsidize the cost of another's service.

We found no evidence to support the AG's contention that the proposed charge fails to comply with accepted standards. The AWWA has established six guiding principles to consider when establishing various service charges.[183] Our review indicates that the proposed charge is consistent with at least four of these principles. We find nothing within the AWWA's guidelines that requires that all guidelines must be met. Moreover, the AWWA recognizes the proposed charge as a charge common to many water utilities.[184]

Our review of the record shows adequate evidence to support the reasonableness of the proposed charge. Kentucky-American has provided evidence to demonstrate all activities included within the proposed charge and the cost of each

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[183] These principles are:

- Beneficiaries of a service should pay for that service.
- Services provided for the benefit of a specific individual, group, or business should not be paid from general utility revenues.
- Services provided to persons or entities that are not customers of the utility should not be paid from water revenues or other general utility revenues.
- Services for which there are charges are generally voluntary.
- The price of services may be used to change user behavior and demand for the good or service.
- The level of the charges should be related to the cost of providing the service.

American Water Works Association, *Principles of Water Rates, Fees and Charges AWWA Manual M1* (5th ed. 2000) at 246.

[184] *Id.* at 255.

activity. The record reflects that the proposed charge does not exceed the cost of these activities.

We find that LFUCG's proposed conditions should not be attached to the assessment of the activity fee. We note that LFUCG's dispute with Kentucky-American regarding the applicability of LFUCG's franchise fee to revenue generated from the proposed charge is not within the Commission's jurisdiction and is more properly addressed in other forums. Second, as discussed below, KRS 278.170 does not permit the exclusion of low income customers from the charge's applicability. Third, while all revenue from the proposed charge will not be used to reduce or eliminate any increase in Kentucky-American's 5/8-inch meter charge, a portion of such revenue will be used for that purpose.

Low Income Water Discount. Kentucky-American proposes a 25 percent discount in the meter charge of Central Division residential customers whose annual income is equal to or below the federal poverty level and in the initial blocks of similar Northern Division customers. The estimated cost of this discount is estimated at $30,000.

Kentucky-American sets forth two reasons for the proposed discount. First, it argues that the discount is consistent with the utility's social conscience and its position as an integral part of the central Kentucky community. "Permanently discontinuing water service to the neediest customers," it argues, "is not an acceptable option because potable water is a necessity of life."[185] Second, it suggests that, by assisting low-income customers to meet their obligations, the proposed discount is likely to

[185] KAWC Brief at 44.

reduce costs associated with disconnection notices, late payments, and bad debt write-offs and thus reduce the cost of service for all customers.

The AG argues that the proposed discount is unlawful. He states that KRS 278.170 establishes the factors under which the Commission may permit a utility to free or reduced rate service. KRS 278.170 does not list the level of a person's income as one of those factors. As the Commission is a creature of statute and has only those powers statutorily granted and as it has no express statutory authorization to permit discounts based upon a customer's income level, it does not have the authority to authorize the proposed discount.[186]

Disputing the AG's interpretation, CAC argues that 278.170(1) expressly permits a utility to grant reasonable preferences or advantages to persons within the same class, even if the service provided is substantially the same.[187] It contends that because of the size of the proposed discount and because of the additional costs that low-income customers impose upon Kentucky-American, the proposed discount is a reasonable preference. CAC notes that the cost of the proposed discount is only $30,000 or approximately 0.3 of one percent of the overall rate increase. It further notes that the discount, by making water service more affordable to persons who have difficulty paying for such service, is likely to reduce reconnection and collection costs. CAC further argues that, as "rising utility costs, particularly the increased rates and fees proposed in this case, place those living below the federal poverty level in 'dire

[186] AG's Response to Commission Staff's First Set of Information Requests, Item 3.

[187] CAC Brief at 4.

distress,'"[188] low-income customers fall within the groups for which KRS 278.170(2) permits free service or reduced rate.

Noting that the "cost is minimal and the potential benefit for the proposed recipients is great," LFUCG does not oppose the proposed discount.[189] LFUCG asserts that, given its minimal cost, the proposed discount does not appear to create an unreasonable preference or advantage for any customers. LFUCG further advocates that any Commission approval of the proposed charge should clearly state that "the proposal will not create any precedent to be used to argue for similar programs."[190]

Based upon our review of the proposed discount, we find insufficient support to establish a new customer class based solely on customer income. None of the proponents of the proposed discount have provided any convincing empirical data to demonstrate that Kentucky-American's cost of providing water service to residential customers whose annual income is equal to or less than the national poverty level significantly differs from those whose annual income is greater than the national poverty level. Discount proponents have also failed to provide any statutory or decisional authority for the proposition that customer income levels may constitute a reasonable basis to distinguish customers for cost-of-service purposes. In the absence of both empirical evidence and statutory or decisional legal authority, we must conclude the proposed discount is a unreasonable preference or advantage to a class of customers

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[188] *Id.* at 7.

[189] LFUCG Brief at 29.

[190] *Id.*

for "a like and contemporary service under the same or substantially the same conditions" and is one that KRS 278.170(1) prohibits.

We find the reliance of Low Income Water Discount proponents on Commission acceptance of other income assistance programs to be misplaced. Both programs to which proponents refer involve home energy assistance plans. The General Assembly has expressly authorized the use of such programs. *See* KRS 278.285(1) and (4). No such authorization has been extended to programs involving water utilities. Moreover, the programs in question were implemented as part of unanimous settlement agreements in rate proceeding. Such agreement is lacking in the present case.

The Commission further finds no merit to the contention that KRS 278.170(2) authorizes the Low Income Water Discount. That statute provides:

> Any utility may grant free or reduced rate service to its officers, agents, or employees, and may exchange free or reduced rate service with other utilities for the benefit of the officers, agents, and employees of both utilities. Any utility may grant free or reduced rate service to the United States, to charitable and eleemosynary institutions, and to persons engaged in charitable and eleemosynary work, and may grant free or reduced rate service for the purpose of providing relief in case of flood, epidemic, pestilence, or other calamity.

While the effects of low-income may present significant hardship, we do not accept CAC's argument that it is a "calamity" that permits a utility to grant reduced rate service. Our review of the statute indicates that the General Assembly intended this statute to address the results of natural disasters and other similar calamities, not socio-economic conditions.

The Commission questions the reasonableness and effectiveness of the proposed discount. Assuming an average monthly customer consumption of 5,000 gallons of water, the average customer's monthly bill under the proposed rates is $21.31. The proposed monthly discount would be only $2.11. As this discount represents less than 10 percent of an average monthly bill, we fail to see how the discount will achieve any of the objectives for which it is intended.

While we applaud Kentucky-American for its willingness to search for solutions to the problems of its low-income customers, the Commission is of the opinion that any successful low-income assistance program requires greater effort from the utility. Funding for the proposed discount comes completely from ratepayers.[191] Kentucky-American provides no shareholder contribution. If a proposed assistance program is to be more than merely a transfer of income from one customer group to another, the utility must also make significant contributions.[192]

Based upon the above, we find that the proposed Low Income Water Discount is unreasonable and deny Kentucky-American's request to implement the proposed reduced rate.

Tapping Fees. Kentucky-American proposes to increase tapping fees assessed to Central Division customers and to establish tapping fees for 1-inch meters and 2-inch meters for Northern Division customers who Tri-Village previously served. Kentucky-American states that the increase is due to increased costs of supplies, materials, insurance and labor costs. Kentucky-American uses a 3-year average in setting the

[191] We acknowledge that Kentucky-American contributes $5,000 annually to its "Water For Life Fund." This amount, however, represents only one-sixth of the ratepayer contribution for the proposed low-income water discount.

[192] *See, e.g.,* Case No. 2001-00323, Joint Application of Louisville Gas and Electric Company, Metro Human Needs Alliance, People Organized and Workers for Energy Reform, Kentucky Association for Community Action, and Jefferson County Government for the Establishment of a Home Energy Assistance Program (Ky. PSC Dec. 27, 2001).

charges for the tap fees for the 5/8-inch meters, 1-inch meters, and 2-inch meters. The Commission has historically accepted this methodology.[193] We find the proposed fees reflect the actual cost of providing the service and are reasonable.

New and Expanded Economic Development Tariff. In its application, Kentucky-American submitted a proposed New and Expanded Economic Development Tariff. It subsequently advised the Commission at hearing that its submission of the tariff was for discussion purposes only and that it did not presently intend to implement the tariff.[194] We take no position on the submission, but we admonish Kentucky-American that it should avoid in future rate proceedings the submission of extraneous matters that are not ripe for review. Other forums outside a rate proceeding, such as informal conferences, are readily available for Kentucky-American to solicit the comments of interested parties and Commission Staff. Kentucky-American should use those forums to the fullest extent before submitting its proposals for formal review.

Emergency Pricing Tariff ("EPT"). In its application, Kentucky-American proposes an EPT. On June 15, 2001, Kentucky-American filed its water shortage response plan ("Demand Management Plan") with the Commission. This plan outlines the steps and procedures to be implemented in the event Kentucky-American lacks system capacity to meet customer demand. The EPT portion of the plan was in development when Kentucky-American filed its Demand Management Plan.

Kentucky-American's proposal revises the Demand Management Plan. It adds public notification to the emergency phase of the Demand Management Plan to alert

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[193] Direct Testimony of Linda Bridwell at 29-31.

[194] T.E., Vol. III at 85.

customers of the emergency pricing tariff rates that would become effective during the rationing phase. On an individual customer basis, a base usage amount will be determined during the rationing phase. The method used to determine the base usage amount differs by classification of customer. Customer usage in excess of the base will be billed at a multiple of the regular tariff rate.[195]

Noting that its current billing software is incapable of performing the calculations necessary to implement the proposed EPT and that the estimated programming cost to make the necessary upgrades to its billing software is approximately $165,600, Kentucky-American requests that the Commission also authorize the accrual of the programming costs as a regulatory asset to be considered for recovery in future rate proceedings.[196]

The AG and LFUCG oppose the EPT tariff. The AG argues that Kentucky-American has failed to demonstrate that the proposal is a cost-effective method to reduce demand during an emergency. He notes that the tariff does not contain a method for a customer to appeal the fairness of the base usage determination. He asserts that the proposal fails to address significant regulatory consequences and risk of over-collection and under-collection.[197] While not opposing the concept of an EPT, LFUCG argues that the parties should develop a mutually agreeable EPT and urges the Commission to establish an administrative proceeding separately from this case to address the subject.[198]

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[195] Direct Testimony Coleman D. Bush at 11 - 19.

[196] KAWC Brief at 46-48.

[197] AG Brief at 40-41.

[198] LFUCG Brief at 24-25.

The Commission accepts Kentucky-American's proposed EPT as a starting point. Its provisions concerning entitlement usage levels and conservation rates are consistent with practices of other jurisdictional water utilities that we have accepted. We stress that additional efforts in this area are necessary and that a collaborative process should be used to refine and improve the existing EPT. We therefore direct Kentucky-American to meet with all interested parties and develop a consensus on such outstanding issues as an appeals process for the determination of the base usage and the over-collection, under-collection of revenue. It should seriously consider and to the fullest extent possible address the concerns that the AG and LFUCG have raised in this proceeding. Kentucky-American should file periodic reports on the progress of its efforts.

As to the cost of billing software revisions, we deny without prejudice Kentucky-American's request to establish a regulatory asset. At such time as the level of costs become known, it may renew its request for deferral treatment. We place Kentucky-American on notice that the costs in question will be closely reviewed to ensure their reasonableness. Nothing in this Order should be construed or interpreted as approval of any level of expense.

SUMMARY

After consideration of the evidence of record and being otherwise sufficiently advised, the Commission finds that:

1. Kentucky-American's proposed rates would produce revenues in excess of that found reasonable herein and should be denied.

2. Kentucky-American's proposed activation charge and tap-on fees are reasonable and should be approved.

3. The rates in Appendix A are the fair, just, and reasonable and should be charged by Kentucky-American for service rendered on and after December 1, 2004.

4. Kentucky-American should within 60 days of the date of this Order refund to its customers with interest all amounts collected from December 1, 2004 through February 27, 2005 that are in excess of the rates that are set forth in Appendix A. Interest should be based upon the average of the Three-Month Commercial Paper Rate as reported in the Federal Reserve Bulletin and the Federal Reserve Statistical Release.

IT IS THEREFORE ORDERED that:

1. Kentucky-American's proposed rates are denied.

2. The rates set forth in Appendix A, are approved for service rendered on and after December 1, 2004.

3. Within 60 days of the date of this Order, Kentucky-American shall refund to its customers all amounts collected from December 1, 2004 through February 27, 2005 that are in excess of the rates that are set forth in Appendix A. Kentucky-American shall pay interest on the refunded amounts at the average of the Three-Month Commercial Paper Rate as reported in the Federal Reserve Bulletin and the Federal Reserve Statistical Release. Refunds will be based on each customer's usage while the proposed rates were in effect and shall be made as a one-time credit to the bills of current customers and by check to customers that have discontinued service since December 1, 2004.

4. Within 75 days of the date of this Order, Kentucky-American shall submit a written report to the Commission in which it describes its efforts to refund all monies collected in excess of the rates that are set forth in Appendix A.

5. Within 20 days of the date of this Order, Kentucky-American shall file its revised tariff sheets containing the rates approved herein and signed by an officer of the utility authorized to issue tariffs.

6. In its next application for rate adjustment, Kentucky-American shall provide a full and complete description of the Service Company's billing practices and a detailed explanation why any prepayment of expenses related to the Service Company is appropriate and necessary.

7. Kentucky-American shall not accrue any expense, except recurring maintenance expenses that the Commission has previously afforded rate-making treatment, as a regulatory asset for accounting purposes without prior written authorization from Commission Staff or an Order of the Commission.

8. Kentucky-American shall make any request for authority to accrue an expense as a regulatory asset for accounting purposes in writing to Commission Staff and at the time of making such request shall serve a copy of its request upon all persons or entities that were parties to its most recent rate proceeding. Kentucky-American may also request such authority by formal application to the Commission in accordance with the general procedures set forth in Administrative Regulation 807 KAR 5:001.

9. Starting from the date of this Order, Kentucky-American shall track all costs and employee time related to activities involving its defense in condemnation proceedings that LFUCG has initiated.

10. Within 60 days of the date of this Order, Kentucky-American shall submit to the Commission a written report containing a description of the organization of Kentucky-American, the Southeast Region, and the American Water System. At a minimum, this report shall

a. Identify the functions that each entity performs, the development of strategic policy for each entity, and Kentucky-American's role in the formation and development of policies that affect its customers;

b. Identify all services that the Southeast Region and other affiliated entities provide to Kentucky-American; and,

c. Describe all planned organizational changes that affect Kentucky-American.

11. Kentucky-American's request to accrue expenses related to the computer software revisions to implement EPT pricing is denied without prejudice.

12. Kentucky-American shall engage in discussions regarding its EPT with the AG, LFUCG, and all other interested parties for the purpose of developing a consensus on the implementation of EPT Tariff.

13. Within 90 days and 180 days of the date of this Order, Kentucky-American shall file written reports with the Commission in which it describes its efforts to obtain a consensus on the EPT, such as an appeals process for the base usage determinations and the use of over-collections of revenue. This report shall identify each of the parties

involved in these efforts, the issues that have been examined as a result of these efforts, each party's position on those issues, and the areas of agreement.

14. Subject to the filing of timely petition for rehearing pursuant to KRS 278.400, these proceedings are closed. The Executive Director shall place any future filings in the utility's general correspondence file or shall docket the filing as a new proceeding.

Done at Frankfort, Kentucky, this 28th day of February, 2005.

By the Commission

ATTEST:

Executive Director

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2004-00103 DATED February 28, 2005

The following rates and charges are prescribed for the customers in the area served by Kentucky American Water Company. All other rates and charges not specifically mentioned herein shall remain the same as those in effect under authority of the Commission prior to the effective date of this Order.

Monthly Water Rates
Central Division

SERVICE CHARGE

5/8"	$7.95
3/4"	$11.94
1"	$19.89
1 1/2"	$39.77
2"	$63.64
3"	$119.32
4"	$198.86
6"	$397.73
8"	$636.36

RATES FOR CONSUMPTION CHARGE

	Per 100 Cubic Feet	Per 1000 Gallons
RESIDENTIAL	$1.82375	2.43167
COMMERCIAL	$1.68873	2.25164
INDUSTRIAL	$1.37803	1.83737
OPA	$1.61771	2.15695
SALE FOR RESALE	$1.61771	2.15695

FIRE SERVICE CHARGES

	Per Month	Per Annum
2" DIAMETER	$4.35	$52.23
4" DIAMETER	$17.41	$208.93
6" DIAMETER	$39.13	$469.57
8" DIAMETER	$69.56	$834.67
10" DIAMETER	$108.69	$1,304.23
12" DIAMETER	$156.53	$1,878.39
14" DIAMETER	$213.09	$2,557.02
16" DIAMETER	$278.24	$3,338.93
PUBLIC FIRE HYDRANTS	$26.07	$312.87
PRIVATE FIRE HYDRANTS	$39.13	$469.57

Account Activation Fee $24.00

TAP FEES

Central Division	
5/8" Meter	$510.00
1" Meter	$945.00
2" Meter	$4,250.00
Northern Division	
Tri-Village	
1" Meter	$945.00
2" Meter	$4,250.00

Susan L Lancho/KAWC/AWWSC
07/30/2010 01:31 PM

To Nick Rowe
cc A W Turner/ADMIN/CORP/AWWSC@AWW, "Lindsey Ingram III" <L.Ingram@skofirm.com>, Takisha D Walker/KAWC/AWWSC@AWW
bcc
Subject Meeting with Customer Service Council representatives

Nick --

This is to confirm that I met with Charlie Lanter and Cameron Minter of the Community Action Council today to brainstorm tactics for a refreshed community awareness plan for our H20 Help to Others program. At the same time I delivered two checks (one for $10,000 from the company and the other, around $300, from customer donations) for the program. We discussed a variety of ideas for increasing brand awareness for this program so that we can encourage more people to donate to it as well as to make sure those in need know that it is available. Possible tactics include distribution of premium items with the H20 logo on them, media partnerships, newsletter articles. etc, as well as opportunities to participate in CAC programs such as Winter Blitz, whereby volunteers visit pre-selected homes to assist residents in preparing their homes for the winter months through very simple but effective activities (educating about preventing frozen pipes, putting plastic on windows, etc.)

I will be following up with Sam andTakisha when I get back from vacation to flesh out a plan, but for now I wanted to let you know that this was a very productive meeting at their offices, and Charlie indicated he was very pleased that we would be working together to enhance awareness of the program.

Please let me know if you have questions or need more information. Otherwise, I will follow up with you later in August re: our plans for the rest of the year.

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Susan Lancho, External Affairs Manager
Kentucky American Water
2300 Richmond Road . Lexington, KY 40502
susan.lancho@amwater.com
P 859.268.6332 M 859.537.0736
www.kentuckyamwater.com
Follow us on Twitter at kyamwater

We Care About Water. It's What We Do.

K.A.W.C. EXHIBIT 11
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