Attachment A

**BEFORE THE
PUBLIC SERVICE COMMISSION OF UTAH**

In the Matter of the Application of Rocky Mountain Power for Authority To Increase its Retail Electric Utility Service Rates in Utah and for Approval of Its Proposed Electric Service Schedules and Electric Service Regulations.	DOCKET NO. 09-035-23
In the Docket on Rocky Mountain Power's Deferred Income Tax Normalization Method	DOCKET NO. 09-035-03 **STIPULATION REGARDING CHANGE IN INCOME TAX TREATMENT OF REPAIR DEDUCTIONS AND BASIS NORMALIZATION.**

I. INTRODUCTION

1. This Stipulation ("Stipulation") in the Revenue Requirement Phase of Docket 09-035-23 and in resolution of Docket 09-035-03 related to a deferred income tax review is entered into by and among the parties whose signatures appear on the signature pages hereof (collectively referred to herein as the "Parties").

2. The terms and conditions of this Stipulation are set forth herein. The Parties contend that this Stipulation is in the public interest and recommend that the Public Service Commission of Utah (the "Commission") approve the Stipulation and all of its terms and conditions. The Parties request that the Commission make findings of fact and reach conclusions of law based on this Stipulation and issue an appropriate order thereon.

II. REGULATORY TREATMENT OF DEFERRED INCOME TAXES ON TEMPORARY BOOK-TAX DIFFERENCES

3. With the exception of deferred income taxes on certain property related book-tax basis differences, the Company accounts for deferred income taxes on a fully normalized basis on its regulated books of account, meaning that the Company recovers deferred income taxes through the cost-of-service component of ratemaking with a corresponding rate base reduction or addition for the related accumulated deferred income tax liability or asset, respectively.

4. In the Company's 1982 general rate case (Docket No. 82-035-13), the Company began the process of normalizing deferred income taxes on property-related book-tax basis differences. For various reasons, the book-tax differences giving rise to deferred income taxes on property-related book-tax differences were never normalized beyond forty percent and they remain at that level in the 2009 general rate case (Docket No. 09-035-23) as originally filed by the Company.

5. The Company filed its 2007 general rate case (Docket No. 07-035-93) using a normalized level one-hundred percent for all deferred income taxes, including property related book-tax basis differences. Ultimately, in that case, this approach was deferred for future consideration. The Commission subsequently opened Docket No. 08-999-02 and Docket No. 09-035-03 to audit the Company's regulatory treatment of deferred income taxes and to analyze the effects of a future change to full normalization.

6. As the result of the recent activity and exchange of information in the 2007, 2008, and 2009 general rate case dockets and several detailed discussions by and among the parties, an ongoing policy recommendation has been agreed to for the regulatory treatment of income taxes in Utah. The recommended regulatory policy calls for the normalized treatment of all book-tax timing differences giving rise to deferred income taxes on the Company's regulated books, with the exception of book-tax differences reported on the Allowance for Equity Funds Used During

Construction ("Equity AFUDC") which will be accounted for on a flow-through basis. Under flow-through accounting, deferred income tax is not recovered through the cost-of-service component of ratemaking, nor is the related accumulated deferred income tax liability or asset included as rate base reduction or addition, respectively. The proposed regulatory policy is compliant with the normalization requirements of the Internal Revenue Code (IRC).

III. UPDATE FOR CHANGE IN METHOD OF ACCOUNTING FOR INCOME TAX PURPOSES: REPAIRS DEDUCTION

7. On December 30, 2008, the Company filed Form 3115, Application for Change in Accounting Method, with the Internal Revenue Service (IRS) requesting permission to change its method of accounting for routine repairs and maintenance costs associated with electric generation, transmission, and distribution assets. The new accounting method ("repairs deduction") will permit PacifiCorp to expense costs associated with the repair and maintenance of generation, transmission, and distribution assets in the taxable year paid or incurred. Currently these costs are being capitalized for both book and tax purposes and are recovered through depreciation. The IRS granted consent to the Company's proposed change in accounting method on October 2 and 7, 2009.

8. The change in accounting method is reflected in the Company's 2008 federal income tax return. The Company's 2008 federal income tax return contains a repairs deduction for the calendar year ended December 31, 2008 and a one-time adjustment (tax deduction) known as an IRC Section 481(a) adjustment. The IRC Section 481(a) adjustment is meant to prevent amounts from being duplicated or omitted in transition from the old method of accounting to the new method of accounting, and is generally determined as if the new method of accounting had always been used.

9. The repairs deduction was not included with the initial filing of the Company's 2009 Utah general rate case due to a combination of significant uncertainties regarding: 1)

whether or not the IRS would consent to the Company's proposed change in accounting method; 2) whether or not the new method and the IRC Section 481(a) adjustment would be reflected in the Company's 2008 federal income tax return; and 3) how much of the originally filed 2008 repairs deduction and IRC Section 481(a) adjustment will be sustained upon final examination by the IRS. As noted in paragraph 7, the Company has subsequently received IRS consent for the change in accounting method, and as noted in paragraph 8, the IRC Section 481(a) adjustment and a repairs deduction for the calendar year ended December 31, 2008 were taken in the Company's 2008 federal income tax return. These subsequent events do not eliminate the uncertainty associated with the IRS examination.

IV. TERMS OF STIPULATION

10. The Parties agree that the recommended ongoing regulatory policy for deferred income taxes in the Company's Utah jurisdiction is: 1) normalized treatment of all book-tax differences giving rise to the Company's deferred income taxes, with the exception of book-tax differences associated with Equity AFUDC; and, 2) flow-through treatment of book-tax differences associated with Equity AFUDC. The Parties request that the Commission approve the implementation of this policy coincident with the test period in this Docket beginning July 1, 2009. The estimated amount of this adjustment is $2.18 million as provided for in Attachment 1 of the Stipulation and based on the Company's filed weighted average cost of capital "WACC". This adjustment will be updated based on the Commission ordered WACC in Docket No. 09-035-23.

11. The Parties agree that the 2009 Utah general rate case, Docket No. 09-035-23, shall be updated to reflect the IRC Section 481(a) adjustment and the 2008 repairs deduction taken in the Company's 2008 federal income tax return and an estimate of the repairs deduction from January 1, 2009, through June 30, 2010, consistent with the test year ended June 30, 2010. The estimated amount of this adjustment is $7.35 million as provided for in Attachment 2 of the

stipulation and based on the company's filed WACC. This adjustment will be updated based on the Commission ordered WACC in this Docket, No. 09-035-23.

12. The Parties agree that customers and the Company shall be held harmless from the impacts of over/under estimates of the repairs deduction projected for tax years 2009 and 2010 that are incorporated in Attachment 2 of the Stipulation. Accordingly, differences between the Utah revenue requirement calculation made for the repairs deduction as ordered by the Commission in this Docket, as calculated in Attachment 2 of this Stipulation, updated for the actual repairs deductions taken in the Company's 2009 and 2010 originally filed federal income tax returns, will be recorded as a regulatory asset or liability and included in rate base. The same calculation methodology as that presented in Attachment 2 will be employed in deriving the amount of the regulatory asset or liability, with the WACC estimate included in Attachment 2 of 11.979% being replaced with the WACC approved by the Commission in this docket. The Company will begin amortization of the regulatory asset or liability in its next general rate case over a period not to exceed five years.

13. The Parties agree that customers and the Company shall be held harmless from interest paid to the IRS upon the final determination of the repairs deduction. Final determination means the final determination by the IRS of the IRC Section 481(a) adjustment and 2008 repairs deduction as filed in the 2008 federal income tax return. Accordingly, after final determination by the IRS, a regulatory asset or liability will be established for the interest paid to the IRS with respect to the adjustments made by the IRS to the IRC Section 481(a) adjustments for 2008 and the 2008 repairs deduction (as conceptually illustrated in Attachment 3, Table 1). With respect to that portion of the IRC Section 481(a) adjustment related to retirements, and spread equally over the four-year period beginning December 31, 2008, a regulatory asset or liability will be established for the product of: 1) the difference between the annual spread as reported in the Company's 2009 and 2010 federal income tax returns and the annual spread for 2009 and 2010

as finally determined by the IRS, and 2) the statutory interest rate assessed by the IRS on tax deficiencies for the respective tax years through the duration of the projected assessment period (as conceptually illustrated in Attachment 3, Table 2). Additionally, a regulatory asset or liability will be established for the product of: 1) the disallowance ratio on the 2008 repairs deductions as finally determined by the IRS, 2) the 2009 and 2010 repairs deduction updated and described in Paragraph 12, above, and 3) the statutory interest rate assessed by the IRS on tax deficiencies for the respective tax years through the duration of the projected assessment period (as conceptually illustrated in Attachment 3, Table 3). The disallowance ratio is the amount of the 2008 repairs deduction disallowed by the IRS upon final determination as a ratio of the 2008 repairs deduction as originally filed in the 2008 federal income tax return (as conceptually illustrated in Attachment 3, Table 3). After final determination by the IRS, the Company will begin amortization of the regulatory asset or liability in its next general rate case over a period not to exceed five years.

14. If the Stipulation is approved by the Commission, the Company will update the revenue requirement in the 2009 rate case, Docket No. 09-035-23, to reflect the impacts of the Stipulation as described in paragraphs 10 and 11, the computations for which are provided in Attachments 1 and 2 to this Stipulation. In the event the Stipulation is rejected by the Commission, the parties request that they be allowed the opportunity to file additional direct testimony in this docket to present recommendations regarding (1) the tax normalization issue, (2) the IRC Section 481(a) adjustment, (3) the 2008 repairs deduction taken on the Company's 2008 federal income tax return, and (4) projected 2009 and 2010 repairs deductions. This will include updates to the parties overall revenue requirement recommendations as impacted by the above identified four (4) items. In addition, the Commission's approval of this Stipulation will result in the resolution and conclusion of Docket 08-999-02 and Docket 09-035-03 related to a deferred income tax review.

V. GENERAL TERMS AND CONDITIONS

15. All negotiations related to this Stipulation are privileged and confidential and no Party shall be bound by any position asserted in negotiations. Neither the execution of this Stipulation nor the order adopting this Stipulation shall be deemed to constitute an admission or acknowledgment by any Party of any liability, the validity or invalidity of any claim or defense, the validity or invalidity of any principle or practice, or the basis of an estoppel or waiver by any Party other than with respect to issues resolved by this Stipulation; nor shall they be introduced or used as evidence for any other purpose in a future proceeding by any Party except a proceeding to enforce the approval or terms of this Stipulation.

16. The Company, the Division and the Office each agree to make one or more witnesses available to explain and support this Stipulation to the Commission. Such witnesses will be available for examination. So that the record in this Docket is complete, the Parties may move for admission of evidence, comments, position statements or exhibits that have been filed on the issues resolved by this Stipulation; however, notwithstanding the admission of such documents, the Parties shall support the Commission's approval of the Stipulation and the Commission order approving the Stipulation. As applied to the Division and the Office, the explanation and support shall be consistent with their statutory authority and responsibility.

17. The Parties agree that if any person challenges the approval of this Stipulation or requests rehearing or reconsideration of any order of the Commission approving this Stipulation, each Party will use its best efforts to support the terms and conditions of the Stipulation. As applied to the Division and Office, the phrase "use its best efforts" means that they shall do so in a manner consistent with their statutory authority and responsibility. In the event any person seeks judicial review of a Commission order approving this Stipulation, no Party shall take a position in that judicial review opposed to the Stipulation.

18. Except with regard to the obligations of the Parties under the two immediately preceding paragraphs of this Stipulation, this Stipulation shall not be final and binding on the

Parties until it has been approved without material change or condition by the Commission. This Stipulation is an integrated whole, and any Party may withdraw from it if it is not approved without material change or condition by the Commission or if the Commission's approval is rejected or materially conditioned by a reviewing court. If the Commission rejects any part of this Stipulation or imposes any material change or condition on approval of this Stipulation or if the Commission's approval of this Stipulation is rejected or materially conditioned by a reviewing court, the Parties agree to meet and discuss the applicable Commission or court order within five business days of its issuance and to attempt in good faith to determine if they are willing to modify the Stipulation consistent with the order. No Party shall withdraw from the Stipulation prior to complying with the foregoing sentence. If any Party withdraws from the Stipulation, any Party retains the right to seek additional procedures before the Commission, including cross-examination of witnesses, with respect to issues addressed by the Stipulation and no Party shall be bound or prejudiced by the terms and conditions of the Stipulation.

19. The Parties may execute this Stipulation in counterparts each of which is deemed an original and all of which only constitute one original.

20. The Parties agree that this Stipulation is in the public interest and that all of its terms and conditions, considered together as a whole, will assist in producing fair, just and reasonable Utah retail electric utility rates in the 2009 general rate case that provide Rocky Mountain Power a reasonable opportunity to earn its authorized return.

BASED ON THE FOREGOING, the Parties request that the Commission issue an order approving this Stipulation and adopting the terms and conditions of this Stipulation.

Respectfully submitted this ___ day of October , 2009.

ROCKY MOUNTAIN POWER

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WAL-MART STORES, INC.

Holly Rachel Smith
Russell W. Ray, PLCC

For the Twelve Months Ended June 30, 2010			
Basis Difference Description	**Flow-Through Variance**		
	07/01 - 12/31/2009	**01/01 - 06/30/2010**	**Total**
ACRS_Fed	0	0	0
AFUDC_Debt_Fed	2,027,823	3,561,498	5,589,321
AFUDC_Equity_Fed	(2,626,190)	(4,552,257)	(7,178,447)
Avoided_Cost_Fed	0	0	0
CIAC_Fed	0	0	0
Coal_Ext_Dev_Fed	154,609	28,432	183,041
Total	**(443,758)**	**(962,327)**	**(1,406,085)**

Total Decrease to Income Tax Expense	(1,406,085)
Gross-Up Factor = 1/(1-Tax Rate) Tax Rate = 37.951%	1.6116
Revenue Requirement Decrease for Income Tax Expense	**(2,266,088)**

Total Decrease to Net Accumulated Deferred Income Tax Liability	1,406,085
Beginning/Ending Average	703,043
Weighted Average Cost of Capital (UT GRC: 09-035-23)	11.979%
Revenue Requirement Decrease for Rate Base	**84,218**

Reduction to Revenue Requirement	**(2,181,870)**

Utah Allocated Accumulated Deferred Income Tax Liability: Repairs Deduction in Excess of Tax Depreciation						Annual Activity	
	IRC Section 481(a)	Annual Repairs Deduction					
Tax Year	Adjustment	12/31/2008	12/31/2009	12/31/2010	Total	January 1 - June 30	July 1 - December 31
12/31/2008	(81,995,460)	(11,304,307)	0	0	**(93,299,767)**	0	0
12/31/2009	(75,424,956)	(10,402,235)	(9,587,198)	0	**(95,414,389)**	(1,057,311)	(1,057,311)
12/31/2010	(69,293,409)	(9,575,720)	(8,821,674)	(18,261,328)	**(105,952,131)**	(5,268,871)	(5,268,871)

Weighted Average Cost of Capital: 2009 UTAH GRC						
Item	Capital Structure	Embedded Cost	Weighted Cost	Tax Gross-Up	Pre-Tax Cost	After Tax Cost
DEBT	48.70%	5.98%	2.912%	1.0000	2.912%	1.807%
PREFERRED	0.30%	5.41%	0.016%	1.6116	0.026%	0.016%
COMMON	51.00%	11.00%	5.610%	1.6116	9.041%	5.610%
TOTAL	**100.000%**		**8.538%**		**11.979%**	**7.433%**

Revenue Requirement Calculation	**Amount**
Beginning Balance: June 30, 2009	(94,357,078)
Change in Balance	(6,326,182)
Ending Balance: June 30, 2010	**(100,683,260)**
Beginning Ending Average	**(97,520,169)**
Weighted Average Cost of Capital (UT GRC 09-035-23)	11.979%
Reduction to Revenue Requirement before Proration	**(11,681,968)**
Pro-rata percentage	62.917%
Reduction to Revenue Requirement	**(7,350,000)**

TABLE 1

2008 Tax Return					
	IRC Section 481(a) Adjustment			2008	
Description	Repairs	Retirements	Subtotal	Repairs Deduction	Total
As Originally Filed	(250,000,000)	5,000,000	**(245,000,000)**	(50,000,000)	**(295,000,000)**
As Finally Determined by IRS	(200,000,000)	4,000,000	**(196,000,000)**	(40,000,000)	**(236,000,000)**
Increase / <Decrease> to Taxable Income	**50,000,000**	**(1,000,000)**	**49,000,000**	**10,000,000**	**59,000,000**
Federal & State Blended Statutory Tax Rate	37.951%	37.951%		37.951%	
Income Tax Underpayment / <Overpayment>	**18,975,500**	**(379,510)**	**18,595,990**	**3,795,100**	**22,391,090**
IRS Statutory Interest Rate	5%	5%		5%	
Annully Assessed Interest <Income> / Expense	**948,775**	**(18,976)**	**929,799**	**189,755**	**1,119,554**
Actual Assessment Period (Years)	3	3		3	
Regulatory Asset / <Liability>	**2,846,325**	**(56,928)**	**2,789,397**	**569,265**	**3,358,662**

TABLE 2

IRC Section 481(a) Adjustment: Retirements					
		Four-Year Spread			
Description	Total	2008	2009	2010	2011
As Originally Filed	**20,000,000**	5,000,000	5,000,000	5,000,000	5,000,000
As Finally Determined by IRS	**16,000,000**	4,000,000	4,000,000	4,000,000	4,000,000
Increase / <Decrease> to Taxable Income	**(4,000,000)**	**(1,000,000)**	**(1,000,000)**	**(1,000,000)**	**(1,000,000)**
Federal & State Blended Statutory Tax Rate			37.951%	37.951%	
Income Tax Underpayment / <Overpayment>			**(379,510)**	**(379,510)**	
IRS Statutory Interest Rate			5%	5%	
Annully Assessed Interest <Income> / Expense			**(18,976)**	**(18,976)**	
Projected Assessment Period (Years)			3	2	
Regulatory Asset / <Liability>			**(56,928)**	**(37,952)**	

TABLE 3

Forecasted Repairs Deductions			
	2009	2010	
Description	Repairs Deduction	Repairs Deduction	Total
As Originally Filed	(45,000,000)	(45,000,000)	**(90,000,000)**
Disallowance Ratio	20%	20%	
Increase / <Decrease> to Taxable Income	**9,000,000**	**9,000,000**	**18,000,000**
Federal & State Blended Statutory Tax Rate	37.951%	37.951%	
Income Tax Underpayment / <Overpayment>	**3,415,590**	**3,415,590**	**6,831,180**
IRS Statutory Interest Rate	5%	5%	
Annully Assessed Interest <Income> / Expense	**170,780**	**170,780**	**341,560**
Projected Assessment Period (Years)	3	2	
Regulatory Asset / <Liability>	**512,340**	**341,560**	**853,900**

Disallowance Ratio			
	As Filed	Disallowed	Ratio
2008 Repairs Deduction	(50,000,000)	10,000,000	**20%**

- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations	DOCKET NO. 09-035-23
In the Matter of the Division of Public Utilities' Review and Audit of Rocky Mountain Power's Deferred Tax Normalization Method	DOCKET NO. 09-035-03 ORDER APPROVING STIPULATION REGARDING CHANGE IN INCOME TAX TREATMENT OF REPAIR DEDUCTIONS AND BASIS NORMALIZATION

ISSUED: December 8, 2009

By The Commission:

INTRODUCTION

On October 26, 2009, the Commission received a Stipulation Regarding Change in Income Tax Treatment of Repair Deductions and Basis Normalization (Stipulation) in the Revenue Requirement portion of Docket No. 09-035-23 and in resolution of Docket No. 09-035-03, *In the Matter of the Division of Public Utilities' Review and Audit of Rocky Mountain Power's Deferred Tax Normalization Method.* The Stipulation was entered into by and among Rocky Mountain Power, (Company) the Division of Public Utilities (DPU), the Office of Consumer Services (OCS), UAE Intervention Group (UAE), Utah Industrial Energy Consumers (UIEC), and Wal-Mart, Inc. (Wal-Mart). The purpose of the Stipulation is to address and settle issues pertaining to the regulatory treatment of deferred income taxes on temporary book-tax differences, and to address and settle issues pertaining to a change in the method of accounting for repairs deduction for income tax purposes.

On Tuesday, November 3, 2009, at a duly noticed hearing, the Commission considered whether to accept or reject the settlement proposal stated in the Stipulation. Yvonne R. Hogle, counsel for Rocky Mountain Power, appeared on behalf of the Company. Ryan Fuller testified for the Company. Michael Ginsberg, Assistant Attorney General, appeared on behalf of the DPU. Dr. Artie M. Powell testified for the DPU. Paul Proctor, Assistant Attorney General, appeared on behalf of the OCS. Robert Reeder appeared on behalf of UIEC. Gary Dodge appeared on behalf of the UAE Industrial Group, and Joshua Mauss appeared on behalf of Wal-Mart.

BACKGROUND

In the Company's 1982 general rate case (Docket No. 82-035-13) the Company began the process of normalizing deferred income taxes on property-related book-tax basis differences. However, the book-tax differences giving rise to deferred income taxes on property-related book-tax differences were never normalized beyond forty percent and they so remain in the 2009 general rate case (Docket No. 09-035-23) as originally filed by the Company.

In the Company's 2007 general rate case, Docket No. 07-035-93, the Company used a normalized level of one-hundred percent for all deferred income taxes, including property related book-tax basis differences. In Docket No. 07-035-93, this approach was deferred for future consideration. In Docket No. 08-999-02, a miscellaneous docket, the DPU, by letter dated July 8, 2008, notified the Commission it was preparing to audit and analyze the Company's proposed Deferred Tax Normalization method, with the assistance of an outside auditor. The Commission subsequently opened Docket No. 09-035-03 to allow the DPU to present its analysis and allow interested parties to study the regulatory treatment of deferred income taxes and to analyze the effects of prospective changes to full normalization.

As a result of the activity and exchange of information in the 2007, 2008, and 2009 general rate case dockets and several continued detailed discussions by and among the Company, the DPU, the OCS, UAE, UIEC and Wal-Mart, an ongoing policy recommendation was agreed to for the regulatory treatment of this aspect of income taxes in Utah. The recommended regulatory policy calls for the normalized treatment of all book-tax timing differences giving rise to deferred income taxes on the Company's regulated books, with the exception of book-tax differences reported on the Allowance for Equity Funds Used During Construction ("Equity AFUDC"), which the parties recommend be accounted for on a flow-through basis. Under flow-through accounting, deferred income taxes are not recovered through the cost-of-service component of ratemaking. Nor is the related accumulated deferred income tax liability or asset included as rate base reduction or addition, respectively. The parties represent that the proposed regulatory policy complies with the normalization requirements of the Internal Revenue Code (IRC).

In addition to the policy recommendations presented in the Stipulation, the Parties also testified or represented that the Stipulation requires an update to the 2009 Utah general rate case, Docket No. 09-035-23, to reflect the IRC Section 481(a) adjustment and the 2008 repairs deduction taken in the Company's 2008 federal income tax return and an estimate of the repairs deduction from January 1, 2009, through June 30, 2010, consistent with the test year ended June 30, 2010. The adjustment estimated in the Stipulation is to be updated based upon the final outcome for weighted cost of capital to be made in the 2009 general rate case.

The Parties to the Stipulation testified or represented to the Commission that the settlement proposal is just and reasonable, and that the settlement proposal is in the public interest and the interest of other affected persons. The Parties recommended that the Commission approve the Stipulation and all of its terms and conditions.

DISCUSSION AND CONCLUSIONS

Based on examination and review of the Stipulation, consideration of the public interest and the interests of other affected persons, and based upon the evidence contained in the record of Docket No. 09-035-03 and Docket No. 09-035-23 as well as the analysis and the recommendations of the parties, and because no party offered evidence in opposition to the Stipulation, we conclude that the terms of the settlement proposal as set forth in the Stipulation are just and reasonable.

ORDER

We therefore order as follows:

1. The Stipulation Regarding Change in Income Tax Treatment of Repair Deductions and Basis Normalization is approved. The Stipulation is attached to this order as Attachment A.

2. Effective July 1, 2009, the ongoing regulatory policy for deferred income taxes in Utah is normalized treatment of all book-tax differences arising after June 30, 2009, giving rise

to the Company's deferred income taxes, with the exception of book-tax differences associated with Equity AFUDC, and flow-through treatment of book-tax differences associated with Equity AFUDC.

3. Pursuant to Utah Code 63G-4-301 and 54-7-15, agency review or rehearing of this order may be obtained by filing a request for review or rehearing with the Commission within 30 days after the issuance of the order. Responses to a request for agency review or rehearing must be filed within 15 days of the filing of the request for review or rehearing. If the Commission fails to grant a request for review or rehearing within 20 days after the filing of a request for review or rehearing, it is deemed denied. Judicial review of the Commission's final agency action may be obtained by filing a Petition for Review with the Utah Supreme Court within 30 days after final agency action. Any Petition for Review must comply with the requirements of Utah Code 63G-4-401 through -403 and the Utah Rules of Appellate Procedure.

DATED at Salt Lake City, Utah, this 8th day of December, 2009.

/s/ Ted Boyer, Chairman

/s/ Ric Campbell, Commissioner

/s/ Ron Allen, Commissioner

Attest:

/s/ Julie Orchard
Commission Secretary
G#64428 Docket No. 09-035-23
G#64429 Docket No. 09-035-03

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	**DOCKET UE-090704**
	)	**DOCKET UG-090705**
	)	***(consolidated)***
Complainant,	)	
v.	)	
	)	**MULTIPARTY SETTLEMENT RE:**
PUGET SOUND ENERGY, INC.,	)	**ELECTRIC RATE SPREAD AND**
	)	**ELECTRIC RATE DESIGN**
Respondent.	)	
	)	
	)	

A. INTRODUCTION

1 This Multiparty Settlement is entered into pursuant to WAC 480-07-730(3) to compromise and settle all issues concerning electric rate spread and rate design that have been raised in this consolidated proceeding between the Settling Parties. This Multiparty Settlement sets forth the rate spread and rate design that the Settling Parties agree should be applied to any electric revenue requirement the Commission determines at the conclusion of litigation on contested revenue requirement issues.

B. SETTLING PARTIES

2 This Multiparty Settlement is entered into by: Puget Sound Energy, Inc. ("PSE"); The Staff of the Washington Utilities and Transportation Commission ("Staff"); the Public Counsel Section of the Attorney General's Office ("Public Counsel"); the Industrial Customers of Northwest Utilities ("ICNU"), and The Kroger Co., on behalf of its Fred Meyer

Stores and Quality Food Centers divisions ("Kroger") (collectively referred to hereinafter as the "Settling Parties" and each individually as a "Settling Party").

C. BACKGROUND

3 On May 8, 2009, PSE filed with the Washington Utilities and Transportation Commission ("Commission") certain tariff revisions designed to effect a general rate increase in its rates for electric service (Docket UE-090704) and gas service (Docket UG-090705) to customers in Washington. The proposed revisions provide for a general rate increase of $148.4 million (7.4 percent) for the electric tariffs. The Commission suspended operation of the tariffs by Order 01 entered in these dockets following the open meeting on May 28, 2009. The Commission consolidated these dockets by Order 02, entered on June 8, 2009 (collectively referred to hereinafter as the "General Rate Case").

4 A prehearing conference in the General Rate Case was held on June 22, 2009. The Commission granted petitions to intervene of ICNU and Kroger[1]

5 On September 28, 2009, PSE filed a Motion for Leave to File Supplemental Testimony. These supplemental direct testimony and exhibits increased the proposed electric revenue deficiency from $148.4 million to $153.9 million. The Commission granted PSE's Motion for Leave to File Supplemental Testimony by Order 08, entered on October 20, 2009.

6 On December 17, 2009, PSE filed rebuttal testimony and exhibits. These rebuttal testimony and exhibits decreased the proposed electric revenue deficiency from $153.9 million to $113.5 million.

[1] Other interveners that are not parties to this Multiparty Settlement are Northwest Industrial Gas Users, Seattle Steam Company, Nucor Steel Seattle, Inc., Federal Executive Agencies, the Energy Project, Cost Management Services, Inc., and Northwest Energy Coalition.

7 The Settling Parties have reached a Multiparty Settlement pursuant to WAC 480-07-730(3) and now wish to present their agreement for Commission approval. In the interests of expediting the orderly disposition of the General Rate Case, the Settling Parties therefore adopt the following Multiparty Settlement, which is entered into by the Settling Parties voluntarily to resolve matters in dispute among them regarding electric rate spread and rate design.

8 The Settling Parties understand that only Sections D and E of this Multiparty Settlement are subject to Commission approval and hereby respectfully request that the Commission issue an order approving Sections D and E of this Multiparty Settlement. The Settling Parties request that the Commission hear evidence concerning their stipulation of electric rate spread and rate design as part of the hearings scheduled to commence before the Commission on January 19, 2010. The Settling Parties to this Multiparty Settlement are also filing Joint Testimony in support of their agreement, pursuant to WAC 480-07-740(2).

D. AGREEMENT – ELECTRIC RATE SPREAD

9 This Section D describes how the total electric revenue requirement increase determined by the Commission will be applied to each class of electric customers at the conclusion of the General Rate Case. For illustrative purposes only, page 1 of the Attachment to this Multiparty Settlement shows the Settling Parties' agreed rate spread associated with a hypothetical final electric revenue requirement increase of $113 million.

10 Schedule 40 rates shall be determined in accordance with the calculated rate methodology, in which Schedule 40 rates for power supply (generation and transmission) are set equal to Schedule 49 charges (adjusted for power factor and losses). In addition,

delivery-related charges shall be derived based on customer specific costs of PSE distribution facilities used to provide delivery services directly to each Schedule 40 customer.

11 The revenue requirement increase for all other rate schedules will be equal to the Proposed Revenue Increase Percent shown in column F of the Attachment, page 1, multiplied by the Pro forma Revenue shown in column B of the Attachment, page 1.

12 In deriving the Proposed Revenue Increase Percent, the Settling Parties agree to the following rate spread metrics:

- Schedules 5, 7, 24, 26, 31, 35, 43, 46, 49, 50-59, 448, and 449 shall each receive a uniform percentage increase; and
- Schedules 25 and 29 shall each receive a percentage increase equal to 75 percent of the uniform percentage increase assigned to the other rates schedules above.

13 For the purpose of preparing the Attachment, page 1, an estimated increase for Schedule 40 assuming the $113 million hypothetical revenue increase used in this Multiparty Settlement is used as a placeholder.

14 Nothing in this Multiparty Settlement shall limit the ability of any Settling Party to advocate any methodology with respect to the use of revenue received by PSE from the sale of Renewable Energy Credits ("RECs") and Carbon Financial Instruments ("CFIs") in any other proceeding. This Multiparty Settlement does not establish any principle or precedent regarding the methodology with respect to the use of revenue received by PSE from the sale of REC and CFIs.

E. AGREEMENT – ELECTRIC RATE DESIGN

15 This Section E describes how electric rates will be designed at the conclusion of the General Rate Case. The Settling Parties' rate design follows the methods proposed by PSE

and detailed in PSE's direct testimony at Exhibit Nos. DWH-1T, JKP-25T and supporting exhibits, except for the one phase basic charge for residential service under Schedule 7. The rate design for Schedule 26 will follow the method agreed to by PSE in Exhibit No. JKP-25T. The one phase basic charge for residential service under Schedule 7 shall increase from $7.00 to $7.25. The rate design agreement is detailed in the Attachment and summarized in the Attachment, page 2.

F. MISCELLANEOUS PROVISIONS

16 The Settling Parties agree to support the terms and conditions of this Multiparty Settlement as a settlement of all contested issues between them in the above-captioned consolidated proceedings regarding electric rate spread and rate design.

17 This Multiparty Settlement represents an integrated resolution of electric rate spread and rate design. Accordingly, the Settling Parties recommend that the Commission adopt and approve Sections D and E of this Multiparty Settlement in their entirety, including the Attachment.

18 The Settling Parties shall cooperate in submitting this Multiparty Settlement promptly to the Commission for approval of Sections D and E above, and shall cooperate in developing supporting testimony as required in WAC 480-07-740(2)(b). The Settling Parties agree to support the Multiparty Settlement throughout this proceeding, provide witnesses to sponsor such Multiparty Settlement at a Commission hearing, and recommend that the Commission issue an order adopting the Multiparty Settlement in its entirety.

19 In the event the Commission rejects Sections D or E of the Multiparty Settlement, the provisions of WAC 480-07-750(2)(a) shall apply. In the event the Commission accepts Sections D or E of the Multiparty Settlement, subject to conditions not proposed herein, each

Party reserves the right, upon written notice to the Commission and all other Settling Parties to this proceeding within five (5) days of the Commission order, to state its rejection of the conditions. In such event, the Settling Parties immediately will request that hearings be held on the appropriateness of the conditions or upon other electric rate spread proposals of the Settling Parties. In any further proceedings triggered by this paragraph, the Settling Parties agree to cooperate in development of a hearing schedule that concludes such proceeding at the earliest possible date. Any further proceedings triggered by this paragraph shall not delay any compliance filing of PSE ordered by the Commission and such compliance filing shall remain in effect pending any further proceeding.

20 The Settling Parties enter into this Multiparty Settlement to avoid further expense, uncertainty, and delay. By executing this Multiparty Settlement, no Party shall be deemed to have approved, admitted, or consented to the facts, principles, methods, or theories employed in arriving at the terms of this Multiparty Settlement, and except to the extent expressly set forth in this Multiparty Settlement, no Party shall be deemed to have agreed that this Multiparty Settlement is appropriate for resolving any issues in any other proceeding. No Party shall represent that any of the facts, principles, methods, or theories employed by any Party in arriving at the terms of this Multiparty Settlement are precedents in any other proceeding or as to any matter remaining in dispute in this proceeding.

21 This Multiparty Settlement may be executed in counterparts, through original and/or facsimile signature, and each signed counterpart shall constitute an original document.

22 All Settling Parties agree:

i. to provide all other Settling Parties the right to review in advance of publication any and all announcements or news releases that any other Party intends to make about the Multiparty Settlement. This right of advance review includes a reasonable opportunity for a Party to request changes to the text of such announcements. However, no Party is required to make any change requested by another Party; and

ii. to include in any news release or announcement a statement that Staff's recommendation to approve the settlement is not binding on the Commission itself. This subsection does not apply to any news release or announcement that otherwise makes no reference to Staff.

DATED this 15th day of January, 2010.

Respectfully submitted,

PERKINS COIE LLP

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BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	**DOCKET UE-090704**
	)	**DOCKET UG-090705**
	)	***(consolidated)***
Complainant,	)	
v.	)	
	)	**MULTIPARTY SETTLEMENT RE:**
PUGET SOUND ENERGY, INC.,	)	**NATURAL GAS RATE SPREAD**
	)	**AND NATURAL GAS RATE DESIGN**
Respondent.	)	
	)	
	)	

A. INTRODUCTION

1 This Multiparty Settlement is entered into pursuant to WAC 480-07-730(3) to compromise and settle all issues concerning natural gas rate spread and rate design that have been raised in this consolidated proceeding between the Settling Parties. This Multiparty Settlement sets forth the rate spread and rate design that the Settling Parties agree should be applied to any natural gas revenue requirement the Commission determines at the conclusion of litigation on contested revenue requirement issues.

B. SETTLING PARTIES

2 This Multiparty Settlement is entered into by: Puget Sound Energy, Inc. ("PSE"); The Staff of the Washington Utilities and Transportation Commission ("Staff"); the Public Counsel Section of the Attorney General's Office ("Public Counsel"); the Northwest Industrial Gas Users ("NWIGU"), Seattle Steam Company ("Seattle Steam"), and Nucor

Steel Seattle, Inc. ("Nucor") (collectively referred to hereinafter as the "Settling Parties" and each individually as a "Settling Party").

C. BACKGROUND

3 On May 8, 2009, PSE filed with the Washington Utilities and Transportation Commission ("Commission") certain tariff revisions designed to effect a general rate increase in its rates for electric service (Docket UE-090704) and gas service (Docket UG-090705) to customers in Washington. The proposed revisions provide for a general rate increase of $27.2 million (2.2 percent) for the gas tariffs. The Commission suspended operation of the tariffs by Order 01 entered in these dockets following the open meeting on May 28, 2009. The Commission consolidated these dockets by Order 02, entered on June 8, 2009 (collectively referred to hereinafter as the "General Rate Case").

4 A prehearing conference in the General Rate Case was held on June 22, 2009. The Commission granted petitions to intervene of NWIGU, Seattle Steam, and Nucor.[1]

5 On August 3, 2009, PSE filed a Motion for Leave to File Supplemental Testimony. These supplemental direct testimony and exhibits increased the proposed natural gas revenue deficiency from $27.2 million to $30.4 million. The Commission granted PSE's Motion for Leave to File Supplemental Testimony by Order 06, entered on August 12, 2009.

6 On December 17, 2009, PSE filed rebuttal testimony and exhibits. These rebuttal testimony and exhibits decreased the proposed natural gas revenue deficiency from $30.4 million to $28.5 million.

[1] Other interveners that are not parties to this Multiparty Settlement are Industrial Customers of Northwest Utilities, The Kroger Co., the Federal Executive Agencies, the Energy Project, Cost Management Services, Inc., and Northwest Energy Coalition.

7 The Settling Parties have reached a Multiparty Settlement pursuant to WAC 480-07-730(3) and now wish to present their agreement for Commission approval. In the interests of expediting the orderly disposition of the General Rate Case, the Settling Parties therefore adopt the following Multiparty Settlement which is entered into by the Settling Parties voluntarily to resolve matters in dispute among them regarding natural gas rate spread and rate design.

8 The Settling Parties understand that only Sections D and E of this Multiparty Settlement are subject to Commission approval and hereby respectfully request that the Commission issue an order approving Sections D and E of this Multiparty Settlement. The Settling Parties request that the Commission hear evidence concerning their stipulation of natural gas rate spread and rate design as part of the hearings scheduled to commence before the Commission on January 19, 2010. The Settling Parties to this Multiparty Settlement are also filing Joint Testimony in support of their agreement, pursuant to WAC 480-07-740(2).

D. AGREEMENT – NATURAL GAS RATE SPREAD

9 This Section D describes how the total natural gas revenue requirement increase determined by the Commission will be applied to each class of natural gas customers at the conclusion of the General Rate Case. For illustrative purposes only, page 1 of the Attachment to this Multiparty Settlement shows the Settling Parties' agreed rate spread associated with a hypothetical final natural gas revenue requirement increase of $28 million, which shall be termed the Baseline Case.

10 The revenue requirement increase for all rate schedules except special contracts will be equal to the Proposed Revenue Increase shown in column H of the Attachment, page 1

multiplied by the Pro Forma Margin at Existing Rates shown in column D. The increase for special contract customers will be based on the terms of their contracts.

11 In deriving the Proposed Revenue Increase for the Baseline Case, the Settling Parties agree to the following rate spread metrics:

- Schedules 16, 23, 31, 61, 53, 71, 72, and 74 shall each receive a uniform percentage increase based on the overall increase to margin;
- Schedules 41 and 41T shall each receive a percentage increase equal to 75 percent of the uniform percentage increase assigned to Schedules 16, 23, 31, 61, 53, 71, 72, and 74; and
- Schedules 85, 85T, 86, 86T, 87, and 87T shall each receive a percentage increase equal to 50 percent of the uniform percentage increase assigned to Schedules 16, 23, 31, 61, 53, 71, 72, and 74.

E. AGREEMENT – NATURAL GAS RATE DESIGN

12 This Section E describes how natural gas rates will be designed at the conclusion of the General Rate Case. The Settling Parties' rate design follows the methods proposed by PSE and detailed in PSE's direct testimony at Exhibit No. JKP-1T and supporting exhibits, except for the basic charge for residential service under Schedules 23 and 53. Under the agreement, the basic charge for residential service under Schedules 23 and 53 shall remain at $10.00 per month. The rate design agreement is summarized in the Attachment, page 2.

F. MISCELLANEOUS PROVISIONS

13 The Settling Parties agree to support the terms and conditions of this Multiparty Settlement as a settlement of all contested issues between them in the above-captioned consolidated proceedings regarding natural gas rate spread and rate design.

14 This Multiparty Settlement represents an integrated resolution of natural gas rate spread and rate design. Accordingly, the Settling Parties recommend that the Commission adopt and approve Sections D and E of this Multiparty Settlement in their entirety, including the Attachment.

15 The Settling Parties shall cooperate in submitting this Multiparty Settlement promptly to the Commission for approval of Sections D and E above, and shall cooperate in developing supporting testimony as required in WAC 480-07-740(2)(b). The Settling Parties agree to support the Multiparty Settlement throughout this proceeding, provide witnesses to sponsor such Multiparty Settlement at a Commission hearing, and recommend that the Commission issue an order adopting the Multiparty Settlement in its entirety.

16 In the event the Commission rejects Section D or E of the Multiparty Settlement, the provisions of WAC 480-07-750(2)(a) shall apply. In the event the Commission accepts Section D or E of the Multiparty Settlement, subject to conditions not proposed herein, each Party reserves the right, upon written notice to the Commission and all other Settling Parties to this proceeding within five (5) days of the Commission order, to state its rejection of the conditions. In such event, the Settling Parties immediately will request that hearings be held on the appropriateness of the conditions or upon other natural gas rate spread proposals of the Settling Parties. In any further proceedings triggered by this paragraph, the Settling Parties agree to cooperate in development of a hearing schedule that concludes such proceeding at the earliest possible date. Any further proceedings triggered by this paragraph shall not delay any compliance filing of PSE ordered by the Commission and such compliance filing shall remain in effect pending any further proceeding.

17 The Settling Parties enter into this Multiparty Settlement to avoid further expense, uncertainty, and delay. By executing this Multiparty Settlement, no Party shall be deemed to have approved, admitted, or consented to the facts, principles, methods, or theories employed in arriving at the terms of this Multiparty Settlement, and except to the extent expressly set forth in this Multiparty Settlement, no Party shall be deemed to have agreed that this Multiparty Settlement is appropriate for resolving any issues in any other proceeding. No Party shall represent that any of the facts, principles, methods, or theories employed by any Party in arriving at the terms of this Multiparty Settlement are precedents in any other proceeding or as to any matter remaining in dispute in this proceeding.

18 This Multiparty Settlement may be executed in counterparts, through original and/or facsimile signature, and each signed counterpart shall constitute an original document.

19 All Settling Parties agree:

i. to provide all other Settling Parties the right to review in advance of publication any and all announcements or news releases that any other Party intends to make about the Multiparty Settlement. This right of advance review includes a reasonable opportunity for a Party to request changes to the text of such announcements. However, no Party is required to make any change requested by another Party; and

ii. to include in any news release or announcement a statement that Staff's recommendation to approve the settlement is not binding on the Commission itself. This subsection does not apply to any news release or announcement that otherwise makes no reference to Staff.

DATED this 15th day of January, 2010.

Respectfully submitted,

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____

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KURT J. BOEHM
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[Service Date April 2, 2010]

BEFORE THE WASHINGTON STATE
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND	)	
TRANSPORTATION COMMISSION,	)	DOCKETS UE-090704 and
	)	UG-090705 *(consolidated)*
Complainant,	)	
v.	)	ORDER 11
	)	
PUGET SOUND ENERGY, INC.,	)	REJECTING TARIFF SHEETS;
	)	AUTHORIZING AND REQUIRING
Respondent.	)	COMPLIANCE FILING
. . . .	)	

***Synopsis**: The Commission rejects revised tariff sheets Puget Sound Energy, Inc. (PSE or the Company) filed on May 8, 2009, by which the Company proposed to increase electric rates by 7.4 percent and natural gas rates by 2.2 percent. In lieu of the Company's proposed increases in rates, the Commission authorizes and requires PSE to file tariff sheets that will result in fair, just, reasonable and sufficient increases of approximately 2.8 percent for electric rates and 0.8 percent for natural gas rates. The Commission accepts a number of uncontested pro forma adjustments proposed by PSE and approves and adopts two uncontested settlement agreements that resolve, respectively, issues of electric and natural gas rate spread and rate design. Among several contested issues, the Commission denies the Company's proposed pro forma adjustments that were not demonstrated to be known and measurable and not offset by other factors. The Commission, for example, rejected PSE's proposal to reduce electric load to account for conservation load loss the Company claimed was not accounted for in the 2008 test year. However, the Commission adjusted rates through the application of a "production factor" to account for the reduced load PSE projects for the2010-2011 rate year, including load loss attributable to conservation. The Commission sets the Company's authorized rate of return, allowing a 10.1 percent return on the 46 percent of PSE's capital structure that represents equity investment, a 6.7 percent cost of long-term debt that represents 50 percent of the Company's capital structure and a 2.5 percent cost of short-term debt that represents the balance of PSE's capital structure. Overall, this results in an 8.10 percent rate of return for the Company. The Commission determines that PSE's acquisition of the Mint Farm combined cycle combustion turbine generation facility was prudent and allows for recovery of the associated costs in rates. In addition, the Commission finds prudent on the basis of uncontested evidence the Company's acquisition of a number of other power assets and finds reasonable the sale of PSE's White River assets.*

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SUMMARY

1 **PROCEEDINGS:** On May 8, 2009, Puget Sound Energy, Inc. (PSE or the Company), filed with the Washington Utilities and Transportation Commission (Commission) certain tariff revisions designed to increase its general rates for electric service (Docket UE-090704) and gas service (Docket UG-090705) to customers in Washington. The proposed revisions provided for a general rate increase of 7.4 percent for the electric tariffs and 2.2 percent for the gas tariffs. The Commission suspended operation of the tariffs by Order 01, entered in these dockets following the May 28, 2009, open meeting. By Order 02, entered on June 8, 2009, the Commission consolidated these dockets.

2 At various times established in its procedural schedule and by several orders the Commission accepted prefiled testimony and exhibits from the Company, the Commission's regulatory staff (Commission Staff or Staff),[1] and other parties. The Company revised its as-filed proposal several times, both up and down, during the pendency of these proceedings, finally proposing to recover additional revenue of $110,303,260 in electric rates and $28,464,116 in natural gas rates.[2]

3 The Commission conducted evidentiary hearings on January 19 – 21, 2010. In addition, the Commission conducted public comment hearings in separate locations in PSE's service territory on December 7 and 10, 2010, and on January 19, 2010, during which it received into the record oral comments and exhibits from interested members of the public.[3] The parties filed briefs and reply briefs on February 19, 2010, and March 2, 2010, respectively.

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[1] In formal proceedings, such as this, the Commission's regulatory staff participates like any other party, while the Commissioners make the decision. To assure fairness, the Commissioners, the presiding administrative law judge, and the Commissioners' policy and accounting advisors do not discuss the merits of this proceeding with the regulatory staff, or any other party, without giving notice and opportunity for all parties to participate. *See RCW 34.05.455.*

[2] PSE Initial Brief at ¶ 1.

[3] The Commission also received written comments from members of the public through the close of the record on January 25, 2010. These comments are identified in the formal record as Exhibit B-1.

4 **PARTY REPRESENTATIVES:** Sheree Strom Carson and Jason Kuzma, Perkins Coie, Bellevue, Washington, represent PSE. Simon ffitch, Assistant Attorney General, Seattle, Washington, represents the Public Counsel Section of the Washington Office of Attorney General (Public Counsel). Robert D. Cedarbaum, Senior Assistant Attorney General and Michael Fassio, Assistant Attorney General, Olympia, Washington, represent the Commission Staff.

5 S. Bradley Van Cleve and Irion Sanger, Davison Van Cleve, Portland, Oregon, represent the Industrial Customers of Northwest Utilities (ICNU). Chad M. Stokes, Cable Huston Benedict Haagensen & Lloyd LLP, Portland, Oregon, represents Northwest Industrial Gas Users (NWIGU). Elaine L. Spencer, Graham & Dunn PC, Seattle, Washington, represents Seattle Steam Company (Seattle Steam). Michael L. Kurtz and Kurt J. Boehm, Boehm, Kurtz & Lowry, Cincinnati, Ohio, represent the Kroger Co., on behalf of its Fred Meyer Stores and Quality Food Centers divisions (Kroger). Norman Furuta, Associate Counsel, Department of the Navy, San Francisco, California, represents the Federal Executive Agencies (FEA). Ronald L. Roseman, Attorney, Seattle, Washington, represents the Energy Project. John A. Cameron, Davis Wright Tremaine LLP, represents Cost Management Services, Inc. Damon E. Xenopoulos, Brickfield, Burchette, Ritts & Stone, PC, Washington, D.C., represents Nucor Steel Seattle, Inc. (Nucor). David S. Johnson, attorney, represents the Northwest Energy Coalition (NWEC).

6 **COMMISSION DETERMINATIONS**: The Commission suspended and set for hearing the rates PSE originally proposed. Based on the record of this proceeding we find that neither the Company's as-filed rates, nor the revised rate requests by PSE made at the conclusion of the advocacy phase, are fair, just and reasonable. Accordingly, we must determine fair, just, reasonable and sufficient rates based on the record before us.[4] We find on the basis of the evidence presented that PSE requires rate relief and therefore determine that the Company should be authorized to file rates in compliance with our decisions, as discussed in detail below. When implemented via a compliance filing we require the Company to make, the resulting rates will be fair, just, reasonable and sufficient, and neither unduly discriminatory nor preferential. The precise revenue deficiency for electric service must be determined during the compliance filing phase of this proceeding because the disallowances to power costs that must be reflected for Tenaska and March Point depend on our decisions in this Final Order concerning power costs and the

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[4] RCW 80.28.020.

production factor.[5] We find a revenue deficiency of $10,149,229 for natural gas and authorize PSE to file rates to recover additional revenue in this amount. The Company's new rates will be effective no earlier than April 7, 2010.

MEMORANDUM

I. Background and Procedural History

7 PSE filed revised tariff sheets on May 8, 2009, that would have increased its rates for electric and natural gas service provided to customers in Washington by, respectively, $148,148,000 (7.4 percent) and $27,199,177 (2.2 percent), if allowed to become effective as proposed. The Commission, however, suspended operation of the tariffs by Order 01 entered in the respective electric and natural gas dockets (*i.e.,* Dockets UE-090704 and UG-090705) following its regularly scheduled Open Meeting on May 28, 2009. The Commission consolidated these dockets by Order 02, entered on June 8, 2009. Following a prehearing conference held at Olympia, Washington on June 22, 2009, the Commission entered Order 04 - Prehearing Conference Order in which it granted several petitions to intervene and set a procedural schedule.[6]

8 In addition to its initial direct testimony filed with the proposed tariff sheets, PSE filed three motions requesting leave to file supplemental direct testimony: the first on August 8, 2009[7]; the second on August 25, 2009[8], and the third on September 28, 2009.[9] The Commission granted these motions. With the filing of its supplemental testimony on September 28, 2009, the Company's requests for increased revenue increased to $153,640,326 for electric and $30,408,378 for natural gas.

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[5] Reviewing the evidence available to us at this time, we estimate a revenue deficiency of $56,204,849 for electric. This amount will be adjusted modestly to account for the Tenaska and March Point 2 disallowances and other matters affecting the production factor adjustment, as discussed later in this Order.

[6] Order 03 in this proceeding is a protective order, entered to facilitate the discovery process by providing appropriate treatment for commercially sensitive information.

[7] Order 06 - Granting Leave to File Supplemental and Revised Testimony and Exhibits, August 12, 2009.

[8] Order 07 - Granting Leave to File Supplemental and Revised Testimony and Exhibits, September 10, 2009.

[9] Order 08 - Granting Leave to File Supplemental and Revised Testimony and Exhibits; Shortening Response Time for Discovery, September 20, 2009.

9 On November 17, 2009, Staff, Public Counsel, ICNU, Kroger, NWIGU, NUCOR and FEA filed their respective response testimonies and exhibits. Staff and Public Counsel sponsored full revenue requirements cases including cost of capital witnesses. The other intervening parties sponsored witnesses addressing a limited scope of issues. Staff filed its motion requesting leave to file supplemental testimony on December 11, 2009, which the Commission granted in Order 09, entered on December 28, 2009.

10 The Company filed rebuttal testimony on December 17, 2009. After accepting some adjustments proposed by the responding parties and updating or correcting certain other information, the Company revised its electric revenue requirement request downward to $113,299,963, resulting in a proposed 5.7 percent average increase in electric rates.[10] PSE also revised its natural gas revenue requirement request downward to $28,464,116, resulting in a proposed 2.3 percent average increase in natural gas rates.[11]

11 Tables 1 and 2 show, respectively, the electric and natural gas revenue requirement requests and recommendations supported by the Company and parties through the briefing stage of these proceedings.

TABLE 1
Proposed Total Adjustments to Annual Revenue Requirement ($M) Relative to Current Rates (Electric)

	As-Filed	Supplemental	Response	Rebuttal/Cross Answer	Final
PSE	$148,148,000	$153,640,326		$113, 299, 963	$110,303,620
Staff			$5,826,516	$7,238,781	$10,382,994
Public Counsel			($42,541,000)	($42,506,684)	$7,900,880

[10] Exhibit EMM-5T (Markell) at 11-18.

[11] *Id.*

TABLE 2
Proposed Total Adjustments to Annual Revenue Requirement ($M) Relative to Current Rates (Natural Gas)

	As-Filed	Supplemental	Response	Rebuttal/Cross Answer	Final
PSE	$27,199,177	$30,408,378		$28,464,116	$28,464,116
Staff			$7,130,348	$7,926,564	$9,233,330
Public Counsel			($330,000)	($329,525)	$2,105,652

12 On December 16, 2009, the Commission accepted for filing the "Motion to Strike of Puget Sound Energy, Inc., Commission Staff, NW Energy Coalition, and the Energy Project." The moving parties asked the Commission to strike portions of the response testimony and exhibits of Public Counsel and the Kroger Co. that related to the sales of renewable energy credits (RECs) by PSE. The Commission granted the motion, removing the REC issues from these proceedings, in light of the fact they are pending determination in Docket UE-090725, which the Commission expects to bring to conclusion in the near term.[12]

13 We held public comment hearings in Bremerton on December 7, 2009, in Kirkland on December 10, 2009, and in Olympia on January 19, 2010. Twenty-one individuals, all customers of PSE, provided valuable testimony concerning their individual perspectives on the Company's requests for increased rates and related matters (*e.g.*, service quality). In addition, the Commission received into the record written comments from numerous members of the public, principally customers.[13]

14 Much of the public comment focused on the difficult economic times that are an important part of the context in which we consider PSE's request for increased rates. We keep such testimony in mind as we make decisions implementing our responsibility to set rates that stimulate efforts on the Company's part to reduce operating costs and increase efficiencies. In the current economic climate, customers must make difficult decisions concerning their spending. So, too, must PSE's management make the right decisions to aggressively control the Company's earnings

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[12] Order 10, Granting Motion to Strike Testimony (January 8, 2010).

[13] Exhibit B-1 (Public Comments).

expectations and expenses, limit discretionary spending, and ensure that its capital investments reflect current economic conditions.

15 On January 19 – 21, 2010, the Commission held hearings in Olympia to receive evidence from the parties and to allow them an opportunity to conduct cross-examination of witnesses who prefiled testimony. These hearings also gave the Commission an opportunity to conduct inquiry from the bench. The fully developed record, including public comment and detailed evidence concerning PSE's revenue requirements and other issues, was closed on January 25, 2010, subject to submission of several responses to Commission bench requests made during the hearing. The final transcript consists of more than 800 pages and reflects the admission of prefiled testimony and exhibits sponsored by 39 witnesses. The documentary record includes approximately 550 exhibits.

16 Parties interested in the issues of electric and natural gas rate spread and rate design negotiated settlement stipulations resolving these issues. These were made part of the record during the Commission's evidentiary proceedings along with supporting testimony filed with respect to each settlement. The settling parties presented a panel of witnesses at hearing and the Commission inquired of the panel from the bench.

17 On February 19, 2010, the parties filed their Initial Briefs. On March 2, 2010, the parties filed their Reply Briefs.

II. Discussion and Decisions

A. Introduction

18 The Commission's duty under statute in the context of a general rate case proceeding is to determine an appropriate balance between the needs of the public to have safe and reliable electric and natural gas services at reasonable rates and the financial ability of the utility to provide such services on an ongoing basis. Thus, the end results of our orders in proceedings such as this one must be to establish rates that are, in the words of our governing statutes, "fair, just, reasonable and sufficient" [14] – fair to customers and to the Company's owners; just in the sense of being based solely on the record developed in the proceeding following principles of due process of law; reasonable in light of the range of possible outcomes supported by the evidence and;

[14] RCW 80.28.010(1) and 80.28.020.

sufficient to meet the needs of the Company to cover its expenses and attract necessary capital on reasonable terms.[15]

19 As shown above in Tables 1 and 2, the parties in this proceeding advocate widely divergent end results in terms of PSE's revenue requirement. Following long-established principles of utility ratemaking and historic Commission practices, we must determine on the basis of the evidence presented what levels of prudently incurred expenses the Company will experience prospectively, and allow for recovery of those expenses. In addition, we must determine the Company's "rate base" and allow for an appropriate rate of return on that rate base.[16] This is necessary to allow the Company to recover the costs of its investments in infrastructure, repay its lenders, and provide an opportunity for the Company to earn a reasonable return, or profit, some of which may be distributed to its equity investors in the form of stock dividends. The sum of the two figures – expenses and return on rate base – constitutes the company's revenue requirement that we approve for recovery in rates.[17] The Washington Supreme Court explained this rate-making formula as follows:

> In order to control aggregate revenue and set maximum rates, regulatory commissions such as the WUTC commonly use and apply the following equation:
>
> $$R = O + B(r)$$
>
> In this equation,
>
> R is the utility's allowed revenue requirements;
> O is its operating expenses;
> B is its rate base; and
> r is the rate of return allowed on its rate base.

[15] *See Federal Power Comm'n v. Hope Natural Gas Co.,* 320 U.S. 591 (1944); *See also Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679 (1923).

[16] Reduced to a simple definition, rate base is the Commission-approved level of PSE's investment in facilities plus the cash, or "working capital" supplied by investors that is used to fund the Company's day-to-day operations. The Commission follows the original cost less depreciation method when determining the value of a utility's property that is used and useful in providing service to customers. *People's Organization for Washington Energy Resources v. Washington Utilities & Transportation Comm'n*, 104 Wn.2d 798, 828, 711 P.2d 319 (1985)

[17] *See Id.* at 807-09 (describing ratemaking principles and process).

> Although regulatory agencies, courts and text writers may vary these symbols and notations somewhat, this basic equation is the one which has evolved over the past century of public utility regulation in this country and is the one commonly accepted and used.[18]

20 In this case, there are a host of contested issues concerning operating expenses, rate base and rate of return. We discuss and resolve each of these issues below, arriving ultimately at revenue requirements to be recovered prospectively by PSE in its electric and natural gas rates.

21 While the amounts of PSE's revenue requirements for electric and natural gas services are hotly contested in this proceeding, the allocation of the revenue requirements to various customer classes (*e.g.,* residential; large industrial and commercial), and the design of rates to recover the allocated costs, are not contested. As to these questions, the parties achieved settlement agreements that we approve and adopt as part of this Final Order for purposes of establishing rates. We discuss these settlements in more detail below.

B. Revenue, Expense and Rate Base Restating and Pro Forma Adjustments

1. General Principles

22 In its decision in Avista Corporation's most recent general rate case proceeding, the Commission discussed in detail certain well-established general principles of utility ratemaking as applied to Washington jurisdictional utilities.[19] We find it useful to quote a portion of that discussion here:

> The Commission's long-established and well-understood ratemaking practice requires companies filing for revised rates to start with an historical test year. There is a fundamental reason for this starting point: costs, revenues, loads, and all other pertinent factors are known and can be measured with a high degree of certainty because they have, in fact, occurred. The practical value of the historical test year is that the cost, revenue and plant data are available for audit, and the test year

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[18] *Id.* at 809.

[19] *WUTC v. Avista,* Dockets UE-090134 and UG-090135, Order 10 at ¶¶ 40-50 (December 22, 2009). (Avista 2009 GRC Order).

captures the complex relationships among the various aspects of utility costs, revenue, load, and other factors over a uniform period of time.

The Commission recognizes that the test year is a snapshot in time. The typical test year is the twelve month period preceding the rate filing, ended as of the most recent auditable results of operations.[20] A utility, however, continues to operate, incur costs (including capital additions), achieve savings, and receive revenues during the pendency of its rate review subsequent to the test year that would carry over into the year in which the rates would be effective (known as the "rate year") and beyond. The theory, well supported by ratemaking theory and past commission practice,[21] is that once the relationship is set, it will continue to provide appropriate income to the company in the future. If the utility hooks up new customers, the revenues and expenses will increase in the same proportion as existed in the test year. If new facilities are put into service to serve those customers, then the resulting revenues would not only cover the company's added expenses, but also effectively provide a return on that new investment.

However, our past decisions, and our rules, recognize that there are some expenses or investments that do not take place in the test year that, nevertheless, should be included in the rate-making formula. Thus, subject to important conditions, a company's rate filing may include restating and pro forma adjustments.[22] These are allowed to revise or update expenses, revenues, and rate base so long as there is a

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[20] The test year is a period of company operations for which the Commission conducts a careful audit and review prior to authorizing any change in rates. *See* 1 Leonard S. Goodman, *The Process of Ratemaking* 141 (1998).

[21] *See* Charles F. Phillips, Jr., *The Regulation of Public Utilities* 196 (1993).

[22] WAC 480-07-510 (3)(e)(ii) and (iii) provide as follows:

> (ii) "Restating actual adjustments" adjust the booked operating results for any defects or infirmities in actual recorded results that can distort test period earnings. Restating actual adjustments are also used to adjust from an as-recorded basis to a basis that is acceptable for rate making. Examples of restating actual adjustments are adjustments to remove prior period amounts, to eliminate below-the-line items that were recorded as operating expenses in error, to adjust from book estimates to actual amounts, and to eliminate or to normalize extraordinary items recorded during the test period.
>
> (iii) "Pro forma adjustments" give effect for the test period to all known and measurable changes that are not offset by other factors. The work papers must identify dollar values and underlying reasons for each proposed pro forma adjustment.

> mechanism ensuring, and evidence establishing, that these adjustments do not disturb test year relationships.[23]

23 Thus, in Washington, we use a modified historic test year approach. We start with audited results from a recent 12 month period, but we modify those results to reflect changes that substantial evidence, timely presented, shows have occurred during the pendency of a rate case, or will occur in the rate year that begins at the conclusion of the proceeding. We have found this forward looking approach more appropriate when considering both power costs and production related assets. For example, the AURORA power cost model looks to forecasted power costs in the rate year. Those future costs can then be matched to test year loads through the production property adjustment, discussed below. This approach reduces regulatory lag without burdening ratepayers with unnecessary costs determined on the basis of the more speculative future test year approach to ratemaking that is used in some jurisdictions. Our approach strikes a balance that motivates PSE and the other utilities subject to our jurisdiction to carefully manage their costs and revenues going forward and take full advantage of their opportunity to recover fully all fixed and variable costs including a reasonable return on capital investments.

24 In this general rate case, both restating and pro forma adjustments are proposed and contested. The fundamental question posed by a contested restating adjustment – in this instance, a normalizing adjustment – is whether certain expenses recorded during the test period are extraordinary and should be adjusted to levels that are more indicative of ordinary levels for the expenses in question.

25 With respect to each of the numerous contested pro forma adjustments, the fundamental questions are whether the proposed change in expense, revenue or rate base is "known and measurable" and, if so, whether it is "offset by other factors," a concept also known as the "matching principle."

26 The known and measurable test requires that an event that causes a change in revenue, expense or rate base must be *known* to have occurred during, or reasonably soon after, the historical 12 months of actual results of operations,[24] and the effect of that event will be in place during the 12-month period when rates will likely be in

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[23] Avista GRC Order at ¶¶ 41-43 (internal footnotes in original).

[24] This is also known as the "test year," "test period" or "historical test year." In this case, the test year is the 12 month period that ended December 31, 2008.

effect.[25] Furthermore, the actual amount of the change must be *measurable*. This means the amount typically cannot be an estimate, a projection, the product of a budget forecast, or some similar exercise of judgment – even informed judgment – concerning future revenue, expense or rate base. There are exceptions, such as using the forward costs of gas in power cost projections, but these are few and demand a high degree of analytical rigor.

27 The matching principle requires that all factors affecting a proposed pro forma change be considered in determining the pro forma level of expense. This includes consideration of offsetting factors such as efficiency gains that may or may not be associated directly with the proposed pro forma adjustment. Offsetting factors may "cancel out" or at least mitigate the impact of a known and measurable increase in expense. If offsetting factors are not taken into account, the known and measurable change will result in overstated or understated revenue requirements. That is, a mismatch in the relationship of revenues, expenses, and rate base is created.

28 We emphasize that there are two aspects to the consideration of offsetting factors. First, there should be evidence showing consideration of whether a proposed increase in expense directly produces any offsetting benefits. For example, the Company may obtain a new computer program that automates aspects of the billing process, reducing the need for employees responsible for this process. Thus, the costs of the computer program may be partially or fully offset by the savings in wages and benefits. On the other hand, it may turn out that other demands on the Company require additional employees during the same period that exactly replace the costs of the savings in the billing function. This illustrates the other aspect of offsetting factors—contemporaneous changes in revenues or expenses that are not directly related to the proposed pro forma adjustment, but which offset its financial impacts.

29 This second aspect of the offsetting factors evaluation makes the question of remoteness from the test year important when considering proposed pro forma adjustments. The further out the point at which a proposed pro forma adjustment is known and measurable, the less sure the Commission can be that there are no offsetting factors – direct or indirect. Thus, any proposed adjustment that becomes

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[25] This is also known as the "rate year." In this case, based on the statutory suspension date of April 7, 2010, the rate year is the 12 month period that will end April 6, 2011.

known and measurable more than a few months after the test year is inherently suspect and requires a greater showing, if it is to be allowed.[26]

30 Offsetting factors may or may not be present when adjusting for expense items, but there typically will be offsetting factors for any addition to rate base. Thus, focusing on rate base, when a utility replaces an older piece of equipment with a new, more efficient piece of equipment, there should be gains in efficiency or reduced maintenance expense. If the piece of equipment is included in rate base without reflecting these offsetting factors, a mismatch is created. Pro forma rate base adjustments often are not considered to be appropriate because the offsetting factors are extremely difficult to measure. That is, it is not possible to properly match revenues, expenses, and other relationships that constitute the entire business operation.

31 Despite this, Commission practice during recent years has allowed adjustments to rate base to bring power production facilities into rates, even though the acquisition occurred after the test period. The Commission adopted in PSE's case the Power Cost Only Rate Case ("PCORC") mechanism, and has allowed in general rate cases pro forma adjustments for major plant additions in order to match the in-service date with the start of the recovery of those investments.[27] The main reasons for allowing such adjustments were the materiality of the resource acquisition and the fact that offsetting factors were captured through the power supply and production factor adjustments.

32 In this proceeding, we are asked again to allow significant pro forma rate base additions. In addition, we are presented proposed pro forma adjustments to rate base and expense that fall further and further from the end of the test year. Many components of these adjustments are based simply on estimates or forecasts, which may have been updated one or more times during the course of the proceeding. This has placed a burden on Staff and other parties to continuously evaluate updated information, which may impact the quality of the record upon which the Commission

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[26] The farther a proposed adjustment is removed in time from the test year, and the less time that supporting evidence is available for examination, discovery, and auditing by our staff and other parties, the greater is the Company's burden to demonstrate that the requirements guiding our consideration of adjustments to test year data have been met.

[27] In PSE's case, these include Fredrickson 1 (Docket UE-031725); Hopkins Ridge (Docket UE-050870); Wild Horse (Docket UE-060266); Goldendale (Docket UE-070565); and Whitehorn and Sumas (Docket UE-072300).

must base its decisions. It accordingly is reasonable for the Commission to establish in the context of this Order some parameters for future guidance to parties.

33 Increases in rate base and in expense and revenue items ideally are audited before they are approved for recovery in rates. They, at the least, should be auditable by Staff within a reasonable time after a company files a general rate case and well before the date set for Response Testimony. In all but exceptional cases, any rate base addition or pro forma adjustment to expense must satisfy the known and measurable requirement at the time the company makes its filing. This gives Staff and other parties adequate time to evaluate the adjustments and consider whether offsetting factors are appropriately taken into account. Such evaluation promotes a more rigorous record than would otherwise be possible. Supplemental filings can continue to be used for good cause shown, if failure to do so might seriously skew results. However, they should be used sparingly and filed prior to the deadline for Staff and others to file their responsive testimony. Should a supplemental filing not provide parties sufficient time to rigorously evaluate the new evidence and respond to it in their responsive testimony, they can request additional time to make their responsive filing, in whole or in part. Requests to make a supplemental filing later than the deadline should be accompanied by either an agreement to adjust the overall procedural schedule[28] (even if it would extend the original suspension date) or a showing of extraordinary circumstances.

34 With these principles in mind, we turn now to consideration of the contested issues, starting with proposed pro forma adjustments. There are 11 contested pro forma adjustments in this case that are not associated with rate base. Except for Power Costs, these adjustments are contested as to both the electric and the natural gas revenue requirements.

35 An additional 13 contested expense items are associated with rate base.[29] Three of these adjustments, Jackson Prairie, Net Interest Due to the IRS and Corporate Aircraft Expense, are contested as to both the electric and the natural gas revenue requirements. Jackson Prairie, is treated as a separate adjustment on the natural gas side, but is within the Power Cost adjustment on the electric side. The remaining ten adjustments associated with rate base are all on the electric side.

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[28] We remind the parties that the Commission prefers to have six weeks from the date of the final briefs to complete the decision and order writing process.

[29] The parties dispute only expense levels on four of these adjustments, but both expense and rate base are contested on the other nine.

2. Contested Adjustments -Non-Rate Base- Electric and Natural Gas

a. General Revenues and Expenses (Adjustments 10.02 and 9.02-Conservation Phase-in Adjustment)

36 PSE proposes an adjustment to test period revenues and expenses that it calls a "conservation phase-in adjustment." This adjustment restates test period, weather-normalized loads for the Company's retail natural gas and electric customers to mitigate what it describes as "certain ratemaking consequences of the phase-in of Company-sponsored conservation that occurred during the test year."[30] The ostensible effect of the Company's proposed adjustment is to reduce test-year electric and natural gas loads to reflect the conservation achieved by its programs through the end of the test-year. The adjustment reduces test year electric loads by 124 million kWh and test year natural gas loads by 2 million therms.[31] The effect would be to increase unit rates to customers.

37 The parties' final revenue requirement presentations show the conservation phase-in adjustment decreasing electric net operating income by $6,242,791 and natural gas net operating income by $379,566. Using the conversion factors we approve in this proceeding, discussed later in this Order, PSE's proposal would increase the electric revenue requirement by $10,048,564 and the gas revenue requirement by $610,341.

38 Mr. Story and Mr. Piliaris, testifying for PSE, contend the conservation phase-in is a proper pro forma adjustment akin to weather normalization, meeting the known and measurable requirements and satisfying the matching principle.[32]

39 Staff, Public Counsel and others advocate rejection of the conservation phase-in adjustment. They argue it is not a proper pro forma adjustment, being neither known and measurable, nor taking account of offsetting factors.

40 Although the proposed conservation phase-in mechanism has novel attributes relative to what the Commission has considered in the past, it appears to be a means to achieve the ends of mechanisms that are usually referred to as "decoupling mechanisms." That is, it is an adjustment that allows the Company to recover

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[30] Exhibit JAP-1T (Piliaris) at 19:10-12.

[31] Exhibit JAP-1T (Piliaris) at 24:1-3; Exhibit MPP-1T (Parvinen) at 13:7-8.

[32] *See* Exhibit JHS-1T (Story) at 11:11-17 and 60:1-61:1; Exhibit JAP-1T (Piliaris) at 21:1-2; and see *generally* Exhibit JAP-5T (Piliaris) at 19:6-23:3.

marginal revenue lost due to reduced load attributed to the Company's demand-side management (*i.e.,* conservation) programs. PSE's principal witness on this subject, Mr. Piliaris, describes it in exactly these terms.[33] When asked directly, however, Mr. Piliaris flatly denies that the Company's proposal is a form of decoupling.[34]

41 The Company's reasons for denying the conservation phase-in adjustment is a form of decoupling include the fact that PSE committed in connection with its recent transfer of ownership not to propose any form of decoupling mechanism for industrial customers for two years after the sale of the Company.[35] The transfer was consummated during the early part of 2009 following Commission approval of the settlement agreement in which PSE made this commitment. The Company also stated at the time of the transfer that it had no plans to propose decoupling at all for any customer class.[36] Public Counsel, ICNU and NWIGU argue the proposed conservation phase-in adjustment is decoupling and, therefore, PSE is barred from proposing it in its present form, which includes industrial customers.

42 However, we need not decide whether PSE's proposal is decoupling as contemplated by its commitment to make no such proposals for industrial customers. Even accepting PSE's argument that the proposed conservation phase-in adjustment is not a decoupling mechanism,[37] but rather is simply a classic pro forma adjustment, there are two reasons why, on this record, it should not be accepted.

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[33] Tr. 557:8-13 (Piliaris) (I would characterize this [*i.e.,* the conservation phase-in adjustment] as the company has shifted its focus away from incentives per se and more towards cost recovery, and specifically the lost margin recovery, and the phase-in adjustment is a small piece of the overall lost margin recovery in the company's opinion, so the focus now is more on cost recovery.); Tr. 558:14-18 (Piliaris) ("Right now this phase-in adjustment only addresses a small piece of the lost margin recovery, and we fully intend to seek recovery of the entire lost margin due to conservation, company sponsored conservation.").

[34] Tr. 565:8-10 (Piliaris).

[35] *Re Puget Holdings and PSE*, Docket U-072375, Order 8 at ¶ 95 and Appendix A to Stipulation, page 13, Commitment 63 (December 30, 2008).

[36] *Id. and* Appendix A to Stipulation, page 13, Commitments 62 and 63.

[37] Indeed, the parties seem to agree that the proposed adjustment is not the same as a typical decoupling mechanism. The purpose of decoupling is to remove a company disincentive to conserve by "breaking the link" between the company's sales and profits. Avista 2009 GRC Order at ¶ 242 (quoting from *UTC v. PacifiCorp*, Docket UE-050684, Order 04, ¶¶ 108-110 (April 17, 2006). Here, the phase-in adjustment does not break that link. *See* NWEC Reply Brief at ¶¶ 5-6. Tr. 565:18-566:1 (Piliaris)

43 First, as argued by Staff and Public Counsel, PSE's proposal fails to take offsetting factors into account, thus not passing one of the critical tests that define proper pro forma adjustments. Staff argues that "Company-sponsored conservation is only one of many factors that influence electricity and natural gas sales."[38] Staff cites to Mr. Dittmer's testimony for Public Counsel that identifies such factors as the number of customers served, the average use per customer that can be impacted by selected end-uses (such as heat, water heat, air conditioning and other appliance or device choices), home size, building codes, economic conditions, and customer-financed measures that have nothing to do with PSE's conservation programs.[39] Mr. Piliaris acknowledged at hearing that the Company's proposal will allow it to recover lost margins from conservation even when total household use increases or remains unchanged due to new end uses.[40]

44 Mr. Dittmer, for Public Counsel, presented evidence showing overall electric usage on a total company basis has increased while overall electric usage per customer is essentially flat, notwithstanding PSE's conservation programs.[41] Public Counsel argues that "this in itself shows that offsets are occurring."[42] Mr. Dittmer testified that overall sales of gas on a company-wide basis also continue to rise and long term trends in declining use per customer were reversed between 2007 and 2008.[43]

45 PSE argues that "[w]hether or not loads are increasing is irrelevant; PSE would have had greater sales to cover increasing costs if conservation had not reduced load."[44] Public Counsel replies that:

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[38] Staff Initial Brief at ¶ 65.

[39] *Id.* (citing Exhibit JRD-1CT (Dittmer) at 37:7-38:2).

[40] Tr. 560:1-25 and Tr. 561:9-12 (Piliaris).

[41] Mr. Piliaris, on rebuttal, took exception to Mr. Dittmer's five year analysis of usage per customer, suggesting the time period is too short. Exhibit JAP-5T (Piliaris) at 23-24. However, as Public Counsel points out, he does not disagree with Mr. Dittmer's conclusion that per-customer usage is flat over that period, nor does he provide alternative data that might allow for some alternative inference.

[42] Public Counsel Initial Brief at ¶ 133.

[43] Exhibit JRD-1CT (Dittmer) at 43-44.

[44] PSE Brief at ¶ 74 (footnote omitted).

> On the contrary, nothing is more relevant than the fact that overall loads are increasing, and that usage per electric customer remains flat, in spite of conservation efforts. PSE asks the Commission to employ tunnel vision and look at a single element of customer usage (conservation), while disregarding all other factors that are causing loads to increase. Nothing could be more inconsistent with the requirement of WAC 480-07-510(3)(e)(iii) that offsetting factors must be considered.[45]

Indeed, in response to a hypothetical about a customer who received a rebate for a more efficient gas hot water heater purchased under a PSE conservation program, but also acquired a new gas oven, dryer and cook top at the same time to take advantage of the gas re-plumbing, Mr. Piliaris testified that the net increase in load would not be reflected under the PSE proposal, only the estimated reduced usage for the hot water heater.[46] This illustrates plainly that while a conservation program may lead to reduced load on the one hand, it may stimulate customer behavior that actually increases net load. The net increase in load, which would produce additional margins for PSE, would not be recognized under the Company's conservation phase-in adjustment.

46 Second, PSE's proposed adjustment also fails the known and measurable criteria by which pro forma adjustments are evaluated. The Company argues that conservation in 2007 and 2008 was projected to result in lost margins of $34 million and lost revenues of $46 million.[47] However, PSE provided no support for those amounts, which are misleading, at best.[48] Mr. Piliaris states in his rebuttal that the Blue Ridge

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[45] Public Counsel Reply Brief at ¶ 30 (citing Avista 2009 GRC Order at ¶¶ 45-47).

[46] Tr. 560:6-561:12 (Piliaris). In response to Bench Request No. 5, PSE clarified that fuel switching effects are not included in the conservation phase-in adjustment because the fuel switching pilot does not begin until after the test year. In the future, however, this issue could re-emerge if the "phase-in" were approved and PSE did not reflect the offsetting effect of increased gas usage.

[47] Exhibit JAP-5T (Piliaris) at 15:5-12.

[48] Tr. 549:20-22 and 552:19-22 (Piliaris). These numbers reflect Mr. Piliaris's calculation of lost margins over a period of several years, not the single year of the test period. Hence, they seriously exaggerate PSE's claim concerning the impact of lost margin during the periods relevant for ratemaking purposes. Furthermore, PSE's lost margin claim fails to consider the effect of intervening rate cases, in which the Company's forecasted load would be reset taking into consideration the impacts of its conservation program. Without considering the effect of resetting the load forecast, the Company could double (or triple)-count conservation's impact on loads.

report "reviewed" and "validated" PSE's conservation savings estimates.[49] However, it is clear from the Blue Ridge report that Blue Ridge performed no "verification" whatever of the estimates or of the data provided by PSE, as acknowledged at hearing in response to questions from the bench.[50] In fact, Blue Ridge suggested that PSE's lack of awareness concerning conservation-related lost revenues and lost margins may indicate "the lack of impact of these disincentives in terms of harm to the financial health of the Company."[51] Furthermore, as Staff points out, there has been no post-installation measurement and verification of PSE's conservation savings claims.[52] While Mr. Piliaris asserts in his rebuttal testimony that PSE's conservation savings estimates are consistent with the International Performance Measurement and Verification Protocol (IPMVP), he was unable, at hearing, to provide any explanation of what this means or why it might be significant.[53]

47 *Commission Determination:* Having fully examined the record on this issue, we find compelling reasons to reject PSE's conservation phase-in adjustment. Measured against familiar principles of ratemaking, the proposal does not pass muster as a proper pro forma adjustment. It plainly fails to take obvious and indisputable offsetting factors into account, thus violating the matching principle. Moreover, the evidence PSE presented to support the adjustment as being known and measurable is simply inadequate to its intended purpose.

48 Although we reject PSE's proposed adjustment as presented in this general rate case, we would be remiss to not comment generally on the subject of conservation. The Commission discussed this subject in considerable detail in its recent Final Order in an Avista Corporation (Avista) general rate case proceeding.[54] This was in the context of the Commission's decision to allow Avista to continue on a permanent basis, albeit with significant modifications, a decoupling mechanism previously implemented on a pilot basis. While we need not repeat the Commission's discussion

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[49] Mr. Pilaris claim in testimony that no party had questioned the Blue Ridge report was shown at the hearing to be a clear misstatement of fact. Tr. 553:3-536:8; Exhibit JAP-12.

[50] Tr. 550:6-551:13 (Piliaris) (discussing lost margin data calculated by PSE but not confirmed by Blue Ridge); *see also* Exhibit JAP-6 at 3.

[51] Exhibit JAP-6 at 78.

[52] Exhibit MPP-1T (Parvinen) at 16; Exhibit JAP-11.

[53] Exhibit JAP-5T (Piliaris) at 10; Tr. 540:19-542:9.

[54] Avista 2009 GRC Order at ¶289.

here, given that the order was published just three months ago, it is worth reiterating the Commission's conclusion of its general and background discussion, as follows:[55]

> Conservation is one of our cornerstone missions. Consequently, we encourage and support efficiency programs as one of the key objectives in our ratemaking. We have long recognized that conservation is, under almost all circumstances, the least cost energy resource available to a utility and its ratepayers.[56] To further its development, we enable company spending on conservation resources by allowing our utilities to collect all costs associated with their respective conservation programs from ratepayers, subject to an annual reconciliation or "true-up." In addition, we have provided financial incentives for meeting and exceeding conservation targets[57] and have approved pilot programs for the purpose of determining whether mechanisms, such as the one we have before us, would support a "conservation" culture within our regulated utilities.[58] With this in mind, we judge Avista's decoupling mechanism and whether it has effectively increased the utility's efforts to support cost-effective conservation programs for its customers.

49 Accordingly, consistent with our recent *Avista* order, PSE should feel free to propose a mechanism to address possible disincentives to conservation, which would include lost revenues due to reduction in load from implementation of its conservation measures. This could take the form of a decoupling program, an attrition adjustment, or a more traditional pro forma adjustment. If PSE can develop fully, propose, and offer persuasive evidence to support any of the above mechanisms, or an alternative mechanism, to promote conservation, we will carefully consider such a proposal in a future proceeding.[59]

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[55] *Id.* (Internal citations, *infra,* footnotes 56 – 58).

[56] Cost-effective conservation potentials have been clearly identified for decades. The difficulty is achieving them. Hence, the Commission's consideration of decoupling in this [the Avista] docket.

[57] *WUTC v. PSE*, Dockets UE-060266 & UG-060267, Order 08 (January 5, 2007) at ¶¶ 145-158 (PSE 2007 GRC Order).

[58] *WUTC v. Cascade Corporation*, Docket UG-060256, Order 5 (January 12, 2007) at ¶¶ 67-85; *In Re Petition of Avista Corporation d/b/a Avista Utilities For an Order Authorizing Implementation of a Natural Gas Decoupling Mechanism and to Record Accounting Entries Associated With the Mechanism*, Docket UG-060518, Order 04, Final Order Approving Decoupling Pilot Program (February 1, 2007).

[59] The Commission will initiate a review of conservation incentive mechanisms in spring 2010, by filing a Statement of Inquiry under the Administrative Procedure Act, RCW 34.05.310. We

50 Of course, one possible mechanism is a direct incentive mechanism by which the utility is rewarded for exceeding conservation targets. Such a program is authorized by state law.[60] We approved such an Energy Conservation Incentive Mechanism (ECIM) for PSE on a pilot basis in Docket UE-060266 in 2007.[61] The ECIM provided $3.5 million in additional revenue to the Company during 2007, or 146 percent of the lost margin the Blue Ridge report shows PSE attributes to conservation programs for that year.[62] During the test year, the ECIM provided PSE $4.3 million in additional revenue, making a significant contribution to PSE's test year margin losses that are attributed to its conservation programs during 2008.[63] Given these benefits – and positive incentives – we find it surprising that PSE has elected to abandon its existing opportunity to recover via incentives at least a portion of its costs associated with conservation efforts that might arguably be lost through reduced load resulting from that same conservation. This is particularly unfortunate considering that the alternative the Company proposes in this case was put forth without adequate support to permit a meaningful evaluation, which is a necessary precursor to Commission approval.

b. Miscellaneous Operating Expense (Adjustments 10.14 and 9.09)

51 PSE consolidated several small, unrelated items into one larger Miscellaneous Operating Expense adjustment for both its electric and natural gas results of operations.[64] Staff and Public Counsel initially contested PSE's proposed inclusion of increases in service contract baseline charges from Quanta/Potelco, the Company's principal contractor providing construction-related services for both the electric transmission and gas distribution systems. According to Staff witness Mr. Foisy, PSE included increases in service contract baseline charges using estimated contract

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anticipate that this will be a productive, informal forum, in which to discuss the pros and cons of all such mechanisms.

[60] RCW 19.285.060(4).

[61] PSE 2007 GRC Order.

[62] Exhibit JAP-6 at 65 (Table 12).

[63] *Id.;* Exhibit MPP-1T (Parvinen) at 17:9-12.

[64] The adjustments include, for example, the costs of the Wire Zone Vegetation Management Program and contractual rent for the Summit Building. Other components move the following expenses below the line: the Company store which sells items with PSE logos to employees; airport and hotel parking; and athletic events expenses. These components of the adjustment are not contested. Exhibit MDF-1T (Foisy) at 4:17-5:6.

amounts.[65] Mr. Foisy stated that as of the date of his testimony, these contracts were not signed and finalized and, therefore, do not meet the test of being known and measurable. Staff proposed that the unadjusted test year amounts for these contract costs be used, instead of what PSE proposed.

52 PSE's contracts with Quanta/Potelco were finalized and executed in December 2009.[66] Staff, for this reason, accepted PSE's proposed adjustments[67] that, the Company says in its brief, actually understate the final costs that PSE will incur pursuant to the final contracts.[68]

53 Public Counsel contests this adjustment, arguing that it should be rejected because it fails to "recognize offsets."[69] In addition, Public Counsel argues, the adjustment does not satisfy the known and measurable criteria because the actual amount was being negotiated during the pendency of this proceeding.[70]

54 *Commission Determination:* December 2009 is nearly a year after the end of the test period. Much can change in a year in terms of the Company's overall costs of operation and it is unquestionably true that the further out we go from the test year the less sure we can be that there are not offsetting factors. Consistent with our general discussion concerning the propriety of pro forma adjustments we determine that PSE's adjustment should not be allowed despite Staff's acquiescence at the briefing stage of this proceeding.

c. Property Tax (Adjustments 10.15 and 9.10)

55 Staff's adjustments for property taxes are based on "PSE's actual tax liability for all property for the 2008 test year, based on the actual, centrally-assessed valuation of the Department of Revenue ("DOR") and the actual levy rates announced by taxing

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[65] Exhibit MDF-1T (Foisy) at 6:6-12.

[66] PSE Initial Brief at ¶ 106 (citing Tr. 173:12-20 (Valdman)); Staff Initial Brief ¶ 44 (citing Tr. 173:21-174:3 (Valdman)).

[67] Staff Initial Brief at ¶ 44 (citing Exhibit B-3 at Exhibit KHB-2, page 2.21and Exhibit KHB-3, page 3.14).

[68] PSE Initial Brief at ¶ 106.

[69] Public Counsel Initial Brief at ¶ 99.

[70] *Id.* (citing Exhibit JRD-1CT (Dittmer) at 49-50).

districts."[71] Staff contests PSE's proposed adjustments for property taxes because "[t]he Company's adjustments utilize estimated property tax levy rates to be paid in 2009."[72] PSE acknowledges this point, stating:

> Because the levy rate – the third component for calculating property taxes – will not be available until March or April of 2010, PSE used the average of the levy rates for the past four years in its calculation.[73]

56 Although Mr. Marcelia testifies it is appropriate to use this estimated tax rate, his testimony is not persuasive and, in any event, misses the point.[74] As in the case of our recent decision in Avista, it is appropriate here to rely on the most recent available actual tax assessments, rather than the projections used by the Company.[75] While "[i]t is wholly appropriate to pro form new tax rates and assessments *once they become measurable*,"[76] it is equally inappropriate to pro form taxes based on levy rates that will be determined in the future.

57 Staff illustrates by example in its Initial Brief why this is true:

> The 2009 property tax estimates used by PSE for its adjustment have changed and will continue to change until PSE's actual tax liability is finally determined. PSE's initial forecasted change in property taxes for its electric operations was $2,467,222.77 The forecast later decreased 187 percent to ($2,139,835).[78] Similarly, PSE's projection of property taxes for its gas operations changed from $1,308,384 to $1,620,627, a 24 percent increase.[79] It is wholly inappropriate to pro

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[71] Staff Initial Brief ¶ 75 (citing Exhibit B-2 at Exhibit KHB-2, page 2.22 and Exhibit KHB-3, page 3.15, Exhibit MRM-9; Tr. 465:7-466:16 and Tr. 519:10-19 (Marcelia)).

[72] Exhibit MDF-1T (Foisy) at 8:8-9.

[73] PSE Initial Brief at ¶ 107.

[74] Exhibit MRM-4T (Marcelia) at 16:3-14.

[75] Avista 2009 GRC Order at ¶154.

[76] *Id.* (emphasis added).

[77] Exhibit JHS-10 at 21.

[78] Exhibit B-2 at Attachment C, page 2.22.

[79] Exhibit MJS-9 at 9.10; Exhibit B-2 at Attachment D, page 3.15.

> form estimates of property taxes that have so significantly changed and can be expected to change again.[80]

58 PSE included estimates of property taxes for 2009 in the individual plant adjustments for Hopkins Ridge (Adjustment 10.06),[81] Sumas (Adjustment 10.09),[82] and Whitehorn (Adjustment 10.10)[83] As Staff points out in its Initial Brief, the only difference between PSE and Staff concerning these three adjustments is the treatment of property taxes.[84] Staff's single adjustment on property taxes (Adjustment 10.15) using DOR's centrally-assessed valuation of PSE's property, encompasses these adjustments.

59 *Commission Determination:* We find Staff's property tax adjustment, using test year actual tax rates and DOR centrally assessed values, is appropriate. We reject PSE's proposal to use estimated levy rates that will not be known until sometime later this year and may vary significantly from the Company's estimates.[85] Accordingly, we accept Staff's property tax adjustment 10.15 and, in so doing, resolve the disputed property taxes that are the only contested issues between PSE and Staff with respect to Adjustments 10.06, 10.09, 10.10 and 10.33, and one of the contested issues with respect to Adjustments 10.07 and 10.08.[86]

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[80] Staff Initial Brief at ¶ 77.

[81] Adjustment 10.06 involves the August 2008 addition of four turbines at Hopkins Ridge.

[82] Adjustment 10.09 involves the addition of the Sumas Cogeneration facility in July 2008.

[83] Adjustment 10.10 involves the purchase of Whitehorn in February 2009.

[84] Staff Initial Brief at ¶ 111 (Noting that a comparison of Exhibits B-2 and B-3 demonstrates that PSE has otherwise accepted Staff's calculation of these adjustments based on actual August 2009 plant balances).

[85] We note the interplay between this issue and PSE's proposed property tax adjustments in connection with several of its production properties. Staff's approach is consistent with how tax assessors throughout the state actually assess and tax utility property on an aggregate basis, not individual property by individual property.

[86] In section II.B.2.e. of this Order, *infra,* we reject Public Counsel's proposed adjustments to liability insurance associated with these individual plants. Taken with our decision here, the effect is to accept Staff's Adjustments 10.06, 10.07, 10.08 10.09, 10.10 and 10.33, except for the disputed rate base in Adjustments 10.07 (Wild Horse Expansion) and 10.08 (Mint Farm), which we discuss separately below.

d. Directors and Officers Insurance (Adjustments 10.17 and 9.12)

60 Staff, through Ms. LaRue, agrees with PSE's D&O insurance for the total Company including PSE's allocations both to its subsidiaries and to its electric and gas operations, but advocates that the costs of D&O insurance should be shared equally between ratepayers and shareholders. Ms. LaRue testifies that:

> D&O Insurance financially protects corporate directors and officers when legal claims are brought against them while performing their corporate duties. D&O Insurance is a necessary cost of doing business and it provides benefits to both ratepayers and shareholders. Ratepayers should bear some of the cost of this insurance, as they benefit from it, but shareholders also benefit from D&O Insurance and should therefore bear some of the costs, as well.[87]

61 Mr. Dittmer for Public Counsel also recommends an equal sharing of the Company's premiums for D&O insurance. He testifies that both groups benefit from the coverage. Ratepayers benefit, according to Mr. Dittmer, because D&O insurance facilitates the retention of competent management. While shareholders also enjoy this benefit, Mr. Dittmer testifies that in his experience "if payments were to be made by the insurance carrier, such payments would most likely be made to aggrieved shareholders for directors' and officers' actions that have caused them some kind of economic harm."[88] Thus, shareholders receive an additional benefit.

62 PSE argues:

> Directors and Officers ("D&O") Insurance is a necessary cost of doing business, and the majority of the risk that D&O insurance addresses is derived from operations of the Company. The Company's calculation allocates a portion of this insurance to subsidiaries and accomplishes the sharing of risk and cost that the Commission has previously approved.[89] The 50% allocation of premiums to shareholders proposed by Commission Staff and Public Counsel has no foundation and is

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[87] Exhibit AMCL-1T (LaRue) at 4:7-14.

[88] Exhibit JRD-1CT (Dittmer) at 67:11-13.

[89] *See* Exhibit MJS-12T (Stranik) at 21:1-11.

inconsistent with the Commission's established treatment of such costs.[90]

63 Staff and Public Counsel, however, both point out that the Commission's recent decision in the Avista rate case "recognized that shareholders benefit from D&O insurance and it is therefore inappropriate to charge customers the full cost."[91] Both argue that while the Commission found that a 90/10 sharing between customers and shareholders was appropriate under the facts of that case, PSE has offered nothing to justify its position that no sharing of these costs is appropriate. Therefore, Staff and Public Counsel argue, the Commission should consider a different sharing proportion here.

64 *Commission Determination:* The Commission determined on the basis of a limited record in the Avista general rate case that "D&O insurance is a benefit that is part of the compensation package offered to attract and retain qualified officers and directors."[92] The Commission said in that proceeding that it made sense to split the costs of insurance in the same manner required for other elements of the directors' and officers' compensation, hence requiring a 90/10 percent sharing as between ratepayers and shareholders. There is no similar evidence in the record of this case.

65 Absent evidence supporting a particular sharing of these costs other than Ms. LaRue's statement that PSE's allocations both to its subsidiaries and to its electric and gas operations seem appropriate, we have no basis in the record that would support an allocation of a portion of PSE's proposed adjustment to shareholders. We accordingly determine that PSE's adjustments should be approved.

e. Property and Liability Insurance (Adjustments 10.23 and 9.16)

66 PSE's as-filed case included estimates for property and liability insurance premiums. Mr. Story, for PSE, stated the Company's intention to update these premiums, once actual premiums were known. This apparently was done in discovery prior to the

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[90] PSE Initial Brief at ¶ 109.

[91] Public Counsel Initial Brief at ¶ 111; Staff Initial Brief at ¶ 78.

[92] Avista 2009 GRC Order.

date for Response testimony in which Staff proposed alternative adjustments based on actual premiums.[93] PSE agreed to Staff's proposed adjustment in its rebuttal case.[94]

67 Public Counsel, however, opposes the 2010 property insurance increases PSE included in its pro forma electric and gas expense adjustments as not being known and measurable. Public Counsel also objects to PSE's proposal to update the estimates with actual premiums. Mr. Dittmer testifies that he believes "it is inappropriate to reflect increases occurring *so far beyond* the end of the historic test year for which there are probable offsets."[95] Public Counsel does not tell us, however, at what point in time after PSE filed its case the actual premiums became known.[96]

68 PSE argues that Public Counsel's "suggestion that there may be hypothetical but unidentified offsets to the actual, known cost of these insurance premiums" is unsupported and therefore an inadequate reason to reject the adjustment, to which Staff and the Company agree.

69 *Commission Determination:* Although we unfortunately do not know the point in time when the actual insurance premiums became known and measurable it apparently was early enough to give Staff time to review them and accept them in its Response Testimony. Public Counsel raises a valid point of principle, as in the case of other pro forma adjustments, but offers no evidence concerning when the actual data became known during the discovery process, or evidence of offsetting changes. Although it is a close call, we find Staff's use of actual data as of the time it filed its response case offers sufficient support for that result to be sustained. Our decision to accept Staff's insurance adjustments, with which PSE agrees, applies to Adjustments 9.16, 10.23,10.06, 10.07, 10.08 10.09, 10.10 and 10.33.[97]

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[93] Exhibit TES-1T (Schooley) at 6:1-12.

[94] Exhibit JHS-14T (Story) at 23:9-13.

[95] Exhibit JRD-1CT (Dittmer) at 49:17-19; Public Counsel Initial Brief at ¶ 98.

[96] Mr. Schooley refers to PSE's response to Staff Data Request 175 as the source for his adjustment, to which PSE agrees. Exhibit TES-1T (Schooley) at 6:6. That discovery response, however, is not an exhibit in our record.

[97] In section II.B.2.c. of this Order, *supra,* we accept Staff's property tax adjustment 10.15. This, along with our decision here, means that Adjustments 10.06, 10.07, 10.08 10.09, 10.10 and 10.33 are resolved in favor of Staff's adjustments, except for the disputed rate base in Adjustments 10.07 (Wild Horse Expansion) and 10.08 (Mint Farm), which we discuss separately below.

f. Pension Plan (Adjustments 10.24 and 9.17)

70 PSE used a four-year average of pension contributions including projected pension contributions through September 30, 2009, as the basis for its proposed adjustment to pension plan expense. Public Counsel argues that pension expense for PSE's qualified retirement plan should be calculated based upon a four year average of contributions for the four calendar years ending December 2008. FEA advocates using the same period for the determination (*i.e.,* four-year average through December 2008), but recommends using Financial Accounting Standard (FAS) 87 expense levels that are calculated on an actuarial basis, rather than actual contributions. [98]

71 Public Counsel states its approach "is consistent with the methodology employed in PSE's last two rate cases, which included four years of contributions, the last year of which coincided with the end of the then-utilized historic test year."[99] Here, however, Public Counsel argues that:

> PSE departed from its past approach by "reaching" forward to pick up actual/anticipated contributions to be made some nine months following the end of the historic test year being used in this docket. By "reaching" to pick up contributions for the four twelve-month periods ending September 30, 2006, September 30, 2007, September 30, 2008 and September 30, 2009, PSE was effectively able to include in its four-year average one additional "heavy" year of contributions. This is not appropriate. If an average of "contributions" is to be employed to calculate "normalized" pension costs, as in previous PSE rate cases, the methodology and cut-off periods used in the calculation should be applied consistently. PSE should not be allowed to pick and choose the most beneficial annual periods that it desires to include in the normalization calculation.[100]

72 PSE does not dispute that it looked nine months beyond the test year to its planned 2009 contributions when proposing its pension adjustment.

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[98] Exhibit RCS-1CT (Smith) at 24:11-16.

[99] Public Counsel Initial Brief at ¶ 102 (citing Exhibit JRD-1CT (Dittmer) at 55).

[100] *Id.* at ¶ 103. Notably, PSE did not contribute to its pension fund during 2004-2005 because of plan funding levels. PSE states further that while in 2006 and 2007, the Company could have made tax deductible contributions, it chose not to because the plan was fully funded. PSE Initial Brief at ¶ 112 (citing Exhibit TMH-9CT (Hunt) at 12:7-10).

73 Ignoring its own proposal to change methodology and use estimated amounts, PSE argues somewhat ironically that FEA's proposal to use FAS 87 calculated pension expense instead of actual cash contributions is a "retreat from long-established Commission practice of using actual cash payments to determine rate recovery" and that it therefore should be denied.[101] PSE argues:

> Although actual cash payments or SFAS 87 calculated expense equal each other over time and either could be used to fix pension expense for ratemaking purposes, it is improper and unfair rate making policy to move back and forth between these two methodologies, electing whichever methodology provides the lower contribution recovery at any given time.[102]

Such criticism, of course, can equally be leveled at PSE's departure in this case from recent past practice of using a four year average through the end of the test year.

74 Public Counsel and FEA also recommend removing costs for PSE's Supplemental Excess Benefit Retirement Plan (SERP), which provides retirement benefits for certain top executives in excess of the limits placed by IRS regulations on pension plan calculations for salaries in excess of specified amounts. Mr. Dittmer testifies for Public Counsel that highly paid employees who qualify for SERP are already entitled to "normal" retirement benefits pursuant to the "qualified" retirement plan offered. Moreover he says: "the plan is expensive to offer given that it is not tax efficient like the qualified retirement plan."[103] Mr. Dittmer also points out that other Washington utilities are either no longer offering the benefit or do not seek rate recovery of such costs. Mr. Dittmer says "it is reasonable to question 1) whether it is necessary to offer such plans to a select group of already highly compensated employees, and 2) whether it is reasonable to request ratepayers to pay the cost of such "supplemental" retirement plans."[104]

75 PSE argues that SERP is part of the overall compensation package for the Company's executives, not something that should be viewed in isolation.[105] PSE states that the SERP allows executives to replace income at the same proportions in retirement as

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[101] PSE Initial Brief at ¶ 113.

[102] *Id.*

[103] Exhibit JRD-1CT (Dittmer) 60:21-61:15.

[104] *Id.*

[105] PSE Initial Brief at ¶ 114 (citing Exhibit TMH-9CT (Hunt) at 22:1-14).

compared to other employees and allows mid-career employees to come to PSE without suffering a decrease to their retirement benefits."[106]

76 Ignoring Public Counsel's argument that no other jurisdictional utility in Washington seeks to recover SERP expenses from ratepayers, PSE takes aim at Public Counsel's and FEA's argument that other jurisdictions have not allowed SERP expenses in revenue requirements. PSE contends this is "irrelevant and without merit" because the Commission "has historically allowed SERP expenses in revenue requirements." However, the only authority PSE cites for this assertion is both incorrectly cited and misleading in substance. Specifically, PSE quotes from the Commission's Order 04 in PacifiCorp's 2006 general rate case (albeit identified in PSE's brief as a PSE general rate case), and argues:

> The ultimate issue is whether total compensation is reasonable and provides benefits to ratepayers, not whether incentive compensation is pay in stock or whether compensation, particularly for executives, is similar to that of other comparable companies. The Company's SERP meets this test. Taken as part of the overall compensation package, it is reasonable as a common feature of a market competitive pay program in the utility industry. [107]

The referenced so-called test, however, was applied in the context of a dispute over incentive compensation, not retirement benefits.

77 Relevant in this context is Public Counsel's point in its brief that PacifiCorp closed its SERP plan to new participants in 2007.[108] Public Counsel also points out that:

> Cascade Natural Gas has prohibited new participants [in its SERP] since 2003 and has restricted new benefits to existing participants. Avista provides SERP to its senior executives but records the cost below the line and does not seek recovery from ratepayers.[109]

Public Counsel argues that other than "boilerplate recruitment and retention arguments, PSE has not offered a persuasive justification for requiring its customers

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[106] *Id.*

[107] PSE Initial Brief at ¶ 114 (citing *WUTC v. PSE,* Order 04 at ¶ 128 (April 17, 2006) for the quoted language). The quote actually is taken from *WUTC v. PacifiCorp*, Docket 050684, Order 04 (April 17, 2006).

[108] Public Counsel Initial Brief at ¶108.

[109] *Id.* (citing Exhibit JRD-1CT at 64 (regarding Avista 2009 GRC and citing to Tr. 597:10-11 in that proceeding, of which we take administrative notice)).

to pay SERP costs."[110] In addition to its other arguments, Public Counsel closes with the argument that:

> This expense is particularly unjust and unreasonable at a time when many PSE customers face severe economic challenges and many are losing jobs and potentially retirement benefits of their own.[111]

78 In addition to advocating the use of an actuarial basis for determining pension expense and the removal of SERP costs, FEA recommends that the Commission require PSE to:

> Evaluate whether it should continue to provide defined benefit pension plans.[112] As the recent economic turmoil has demonstrated, a defined benefit plan can require radical increases in funding during periods of poor investment performance. Many other companies have discontinued defined benefit pension plans in favor of other alternatives such as Defined Contribution Plans. Basing a ratemaking allowance for pension costs on plan funding contributions, which are up to utility management and can span a range as wide as $60 million or more, could deter the Company from making reforms to its pension plans that would reduce cost.[113]

79 *Commission Determination:* We find that the actual four year average pension expense ending December 31, 2008, provides a reasonable measure of the amount of pension expense that should be allowed for recovery in rates. This approach has been reliably used in recent cases and it provides at least some degree of normalization with respect to contributions that have tended to be highly variable from year to year. PSE's use of projected 2009 contributions is similar in some respects, but does not satisfy the known and measurable standard.

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[110] Public Counsel Initial Brief at ¶109.

[111] *Id.* (noting that in *Re Application of Connecticut Natural Gas Corp. for a Rate Increase,* Docket No. 08-12-06, Decision (June 30, 2009), at 144 (Section entitled "Current Economic Conditions"), 274 PUR 4th 345, the Connecticut Dept. of PUC rejected SERP recovery as inappropriate and excessive given the current economic climate).

[112] Exhibit RCS-1T (Smith) at 18-20.

[113] FEA Initial Brief at 12 (citing Exhibit RCS-1T (Smith) at 18-20).

80 We do not find FEA's case for moving to an actuarial basis for measuring this expense sufficiently developed to apply it in this case, but a more fully developed record could convince us to order such a change in a future proceeding. There also is insufficient record upon which to make any determinations concerning FEA's suggestion that PSE should move away entirely from offering a defined benefit form of retirement in favor of other alternatives. We emphasize, however, that we are not by this observation making any determination of principle.

81 As to SERP, we find persuasive the arguments recommending removal of these costs. PSE has failed to provide an adequate justification for continuing to require ratepayers to fund supplemental retirement benefits for a small number of executives who already are highly compensated and entitled to the same levels of qualified retirement plan benefits as other employees, within the limits of what the IRS allows.

g. Wage Increase (Adjustments 10.25 and 9.18)

82 Staff and Public Counsel both initially advocated rejection of union and non-union estimated wage increases that PSE projected would occur during 2010. Ms. Huang, for Staff, testified:

> Potential wage increases beyond the current employee contract expiration dates are not known and measurable. Therefore, Staff adjusts wage increases to March 31, 2010 for non-union employees. Staff also adjusts wages increases to March 31, 2010 for IBEW members and to September 30, 2010 for UA members according to the Company's current contract[s] with those unions.[114]

Mr. Dittmer testified that the Commission should also reject a contractual increase for UA (United Association of Plumbers and Pipefitters) union workers because "the increase did not become effective until October 2009, nine months beyond the end of the test year and fifteen months beyond the mid-point of the 2008 test year."[115]

83 PSE and Staff resolved their differences concerning union wage increases given the Company's agreement to include increases provided in contracts.[116] Thus, Staff now accepts inclusion of the IBEW contractual increase that will be effective from January

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[114] Exhibit JH-1T (Huang) at 4:19-23.

[115] Exhibit JRD-1CT (Dittmer) at 46:8-22.

[116] Staff Initial Brief at ¶ 80 (citing Exhibit MJS-12T (Stranik) at 26:9-10).

1, 2010 to December 31, 2010. Staff and PSE also agree to include wage increases for UA employees through September 30, 2010, the end of the current UA contract.[117]

84 Staff, however, opposes PSE's adjustment to the extent of amounts included for non-union employee wage increases. Specifically, Staff rejects a three percent increase from March 1, 2010, based on the Company's 2010 budget forecast.[118] Staff argues that such budget estimates are uncertain and, thus, not "known and measurable."[119] Staff points out that the budget was not approved until November 2009, that there are no documents supporting the budgeted wage increase and that the Board has the authority to rescind any budgeted increase. Therefore, Staff argues: "It is inappropriate to pro form budgeted wage increases that the Company is not yet obligated to pay."[120]

85 Mr. Dittmer testified for Public Counsel that he:

> Rejected the IBEW 3.00% wage increase *estimated* to be effective in January 1, 2010, the actual UA wage increase that became effective October 1, 2009, as well as the UA 3.00% wage increase *estimated* to be effective on October 1, 2010. Further, I have rejected all non-union wage increases *estimated* to become effective following the March 1, 2009 actual increase granted.

Public Counsel continues to oppose allowing in this adjustment any of the initially estimated union and non-union wage increases because "estimates are not 'known and measurable' changes."[121] Public Counsel would have us exclude in addition the three percent increase for UA employees that became effective October 2009 because it took effect nine months after the test year and fifteen months beyond the test year's mid-point. Public Counsel argues this is not an appropriate adjustment in that it does not account for offsets "for productivity increases, deflationary trends in materials, or an expectation the PSE should strive to cut costs in this economic environment."[122]

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[117] *Id.* (citing Exhibit JH-3(Huang) at 4:21-23 and Exhibit MJS-20 (Stranik) at 1).

[118] Exhibit TMH-20.

[119] Staff Initial Brief at ¶ 81 (citing Avista 2009 GRC Order at ¶110).

[120] *Id.* at ¶¶ 82 and 83.

[121] Public Counsel Initial Brief at ¶ 95 (citing Exhibit JRD-1CT (Dittmer) at 45-46 (listing PSE pro forma adjustments from testimony of John Story, and describing those rejected by Public Counsel)).

[122] *Id.*

86 PSE argues all its proposed wage increases are known and measurable. PSE states it contractually committed to the IBEW increases in April 2009 and January 2010, but does not mention the UA increase in January 2010.[123] Mr. Hunt testified that PSE contractually agreed to the January 2010 increase in 2007.[124] As to non-union employees:

> The Company's Board approved merit increases of three percent and PSE is now in the process of allocating those monies to managers who will be determining individual merit-based increases for their employees. Those increases will be paid in March 2010.[125]

87 Turning to the question of offsets, PSE argues that "increased productivity does not translate into "offsets" or reduced hours worked as Commission Staff and Public Counsel claim."[126] Instead, PSE argues, the Company reallocates employees to meet new demands such as those placed on the Company by "increased regulations, compliance, and the ongoing work of system replacement."[127]

88 *Commission Determination:* We agree with Public Counsel's proposed adjustments to wages. Although outside the test period, we allow the IBEW April 2009 contractual increase, which does not appear to be in dispute, because it is close enough in time to the end of the test year to limit our concerns about possible offsets. We agree with Public Counsel that the other changes (IBEW and UA in October 2009 and October 2010, and non-union in March 2010) are too remote from the end of the test year to be included without risk of violating the matching principle.

h. Investment Plan (Adjustments 10.26 and 9.19)

89 According to PSE's 401(k) Investment Plan, the Company matches employees' contributions to their individual retirement accounts. In addition, the Company

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[123] PSE Initial Brief at ¶ 115.

[124] Exhibit TMH-9CT (Hunt) at 25:4-6.

[125] *Id.* (citing Tr. 449:24-450:6 (Hunt)).

[126] PSE Initial Brief at ¶ 116.

[127] *Id.* (citing Exhibit TMH-9CT (Hunt) at 26:13-15; Tr. 191:5-7 (Valdman)).

contributes to each employee's retirement account an amount equal to one percent of each employee's base pay. Thus, the Investment Plan adjustments are tied to the Company's portion of the investment plan expense and simply reflect the additional expense associated with wage increases, discussed above.

90 *Commission Determination:* The parties do not disagree on the methodology for this adjustment. The differences in their adjustment amounts simply reflect their different positions on the wage adjustments, previously discussed. Given our determination of the wage adjustments in the preceding section of this Order, we here adopt the recommendation by Public Counsel.

i. Employee Insurance (Adjustments 10.27 and 9.20)

91 PSE's as-filed adjustments to Employee Insurance were estimates based on a budget forecast. Thus, Ms. Huang testified, they do not meet the Commission's criteria for pro forma adjustment which allows for known and measurable adjustments to test year amounts.[128] Staff used the actual, negotiated Flex Credit amount per employee of 4.75 percent for 2010 to adjust Employee Insurance. Ms. Huang testifies this so-called Flex Credit amount is based on known and measurable changes that are not offset by other factors. Mr. Hunt testifies on rebuttal that PSE agrees with Staff's recommendation to use the actual 4.75 percent change.

92 The difference in the level of adjustments proposed respectively by PSE and Staff now result from the use of different employee counts. Mr. Stranick testifies that when calculating the adjustment for rebuttal the Company updated the employee counts from 2,586 to 2,613. He explains that the original employee counts were based on a system report run at the start of each month in 2008 for employees who were active and enrolled in a medical coverage choice at the date the report was run. Because new employees have 30 days to sign up for coverage, new employees electing coverage any time after the beginning of the month were not included in the employee count for that month. These updates were provided to all parties in PSE's Response to Public Council Data Request No. 319 dated August 17, 2009.

93 Staff opposes the use of PSE's updated employee counts because it includes employees hired at the end of the test period, but not eligible until 30 days later.

[128] Exhibit JH-1T (Huang) at 7:8-1.

94 Mr. Dittmer, for Public Counsel, would disallow any increase in PSE's employee benefit flex credits. He argues that the initial 8% increase proposed by PSE was not known and the 4.75 percent rate was negotiated after the filing date of this rate case and will not be a "known" change until January 1, 2010. Mr. Dittmer testifies:

> It is inequitable to reflect an adjustment occurring so far beyond the end of the historic test year when there are expected "offsets" in the form of efficiency gains, deflation for other cost of service components, as well as expected cost containment efforts on behalf of PSE in the current economic environment.[129]

95 *Commission Determination:* PSE's obligation to provide insurance to employees hired in December 2008 matured at the time they accepted employment. Since this was before the end of the test year, we find it appropriate to include these additional 27 hires for purposes of calculating this adjustment. We do not know exactly when the 4.75 percent actual rate became final and, hence, known and measurable, but we do know it was sufficiently in advance of Staff filing its Response Testimony to permit Staff to examine the amount and be satisfied with it. Considering all the evidence, we find it is the best evidence of the rate we should use for making this adjustment.

j. Injuries and Damages

96 Mr. Dittmer testifies for Public Counsel recommending that PSE's injuries and damages expenses be normalized by using a three year average rather than the test year amounts, which he contends are "considerably higher" on the electric side relative to prior years.[130] PSE argues that "Public Counsel has not demonstrated a reasoned basis for changing from the use of historical test year to a three-year average."[131] However, the total Injuries and Damages Expense accruals for claims, and payments of claims in excess of accrual amounts, for electric and gas operations for the last three years were:

[129] Exhibit JRD-1CT (Dittmer) at 48:10-14.

[130] Exhibit JRD-1CT (Dittmer) at 50:20-51:17.

[131] PSE Initial Brief at ¶ 136.

Year	Electric Operations Accruals & Payments in Excess of Accruals	Gas Operations Accruals & Payments in Excess of Accruals
2006	$2,475,968	$465,804
2007	2,205,721	473,145
2008 (test year)	3,847,528	769,674

97 Thus, we see an increase of nearly 75 percent on the electric side and 63 percent on the gas side between 2007 and 2008.

98 PSE also argues that

> To selectively average accounts over a specified period when they are higher than average, while using actual account balances for the test year when they are lower than average, would be arbitrary and unreasonable.[132]

However, we do not perceive that Public Counsel is proposing such an approach. Public Counsel observes that PSE offers no testimony as to why the higher test year amount in 2008 relative to 2006 and 2007 should be considered normal. Public Counsel also makes the point that PSE itself uses multi-year averages for other expenses that exhibit significant differences from year to year, such as bad debt expense and pension costs.

99 *Commission Determination:* A spike in costs in a single year of the magnitudes evident here provides a sufficient basis to consider a normalizing adjustment. Absent any evidence from PSE showing the test year level is representative (*i.e.,* normal), we accept Public Counsel's recommendation to normalize this expense using a three year average.

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[132] *Id.*

3. Contested Adjustments – Non-Rate Base – Electric Only

a. Power Costs (Adjustment 10.03)

100 Disputed power costs are highly significant in this case in terms of dollars. PSE, ICNU and Staff (ICNU/Staff) jointly, and Public Counsel all propose to reduce projected power costs from the test year levels. On a net operating income measurement ICNU/Staff and the Company are more than $18.6 million apart, and Public Counsel and the Company are nearly $3.7 million apart. In terms of revenue requirement, using the conversion factor we approve here, ICNU/Staff would reduce PSE's power costs by approximately $30 million from the level advocated by the Company. Public Counsel would reduce the Company's power costs by approximately $6 million more than PSE. The parties' relative positions are illustrated in Table 3.

TABLE 3

	PSE	Staff	Public Counsel
NOI (net operating income)	50,909,893	69,513,083	54,597,730
Revenue Requirement	(81,945,931)	(111,890,125)	(87,881,973)

The parties present a number of discrete arguments that, considered together, make this a complex issue. ICNU/Staff sponsor a number of adjustments to input data used in the AURORA power cost model, and propose a number of adjustments to be made outside of the model (*i.e.*, adjustments to the modeled results).[133] Public Counsel also sponsors adjustments to both the model and its results. In addition, ICNU/Staff and Public Counsel advocate changes to the ratemaking treatment for the Tenaska regulatory asset, the net cost of mark-to-market gas hedges, and the treatment of gas fuel costs in the Power Cost Adjustment.

[133] AURORA is the power cost model PSE uses to estimate net power costs within the west-wide grid of utilities. The AURORA model includes fuel costs, plant statistics and costs to buy and sell power. EPIS, Inc. developed and owns the model, which it calls the AURORAxmp Electric Market Model. The Company's web page describes it as "a fundamentals-based model that employs a multi-area, transmission-constrained dispatch logic to simulate real market conditions. Its true economic dispatch captures the dynamics and economics of electricity markets – both short-term (hourly, daily, monthly) and long-term."

101 *Overall Commission Determination:* We discuss individually below the parties' arguments concerning the disputed aspects of the power cost adjustment. First, we examine the disputed adjustments within the AURORA model and then the disputed adjustments outside the AURORA model. In the final analysis, considering our determination of each issue and applying the results of our determinations to reject the Company's proposed conservation phase-in adjustment and to adjust accordingly the production factor, we arrive at NOI $48,587,893, resulting in a revenue requirement reduction of ($78,208,377). That said, we recognize that these final numbers will change at the compliance stage as the Tenaska and March Point disallowances are taken into account, as discussed by PSE's witness, Mr. Mills.[134]

AURORA Adjustments

Hydro Filtering

102 ICNU/Staff propose to apply a quasi-statistical filter to exclude from AURORA the water-years that fall outside of one standard deviation above or below the mean water year in the 50-year record on which PSE relies (*i.e.,* 1929 – 1978).[135] Applying this filter to the 50-year record of data, they remove 9 years that are "above the range" and 11 years that are "below the range." They derive their adjustment to the Company's power cost by rerunning AURORA with these years excluded and comparing the resulting modeled power costs to the Company's modeled costs.[136] The ICNU/Staff proposal reduces the rate year power cost projection by approximately $5.7 million, as compared to PSE's 50 water year AURORA run.

103 ICNU/Staff acknowledge that their proposed filter "is not based on a scientific study of any kind," but assert that that it is nonetheless a "reasonable approach" because it is simple and straightforward.[137] They take pains to emphasize that their approach "is based on assumptions regarding the probability of water conditions, not normalized power supply costs" because the filter is carried out on water years, not the resulting annual power supply costs.[138] According to ICNU, the purpose of the ICNU/Staff'

[134] Exhibit DEM-12CT (Mills) at 58:4-60:11.

[135] ICNU/Staff use hydroelectric generation from the Mid-Columbia projects as a proxy for water years. They refer to the Mid-Columbia generation as the "water flow equivalent."

[136]Exhibit JT-1CT (Schoenbeck/Buckley) at 10:25-11:15.

[137] *Id.* at 11:19-12:5.

[138] *Id.* at 9:1-4.

hydro filtering proposal is to eliminate bias in the calculation of projected rate year power costs, saying: "the removal of extreme outlier years from power cost calculations logically *reduces* bias by normalizing the range of water years under consideration."[139]

104 According to ICNU/Staff, the filtering approach they propose is appropriate because it "better aligns the methodology for determining base power costs with a regulatory environment that includes a PCA."[140] They argue that the filter addresses the power supply costs associated with "extreme, or outlier" water years leaving these low probability events to be addressed, should they occur, in the annual PCA review.[141]

105 ICNU/Staff assert that the Commission has favored water filtering adjustments for utilities with PCA mechanisms pointing to several recent rate case settlements and quoting a recent Commission order, as follows:

> If the Company and its customers will share the costs and benefits of unusual power cost extremes, there is no need to include those extreme circumstances in the calculation of normalized power costs, particularly if they are controversial . . . We agree with Staff and PacifiCorp that water filtering is appropriate in the context of a PCAM, but not appropriate if there is no PCAM in place.[142]

ICNU characterizes this statement as a "guiding principle" and argues for the ICNU/Staff that "there should be no question about the propriety of the ICNU/Staff' hydro filtering proposal" since the Commission has approved hydro filtering when some form of PCA mechanism is present and PSE, in fact, has a PCA.[143]

106 The Company disagrees with this characterization arguing that the Commission has endorsed filtering in theory, but never considered it fully in a case where a company has a PCA. The Company argues that the ICNU/Staff have failed to comply with

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[139] ICNU Initial Brief at ¶ 27.

[140] Exhibit JT-1CT (Schoenbeck/Buckley)at 7:26-27.

[141] *Id.* at 7:26-8:5

[142] *WUTC v. PacifiCorp,* Dockets UE-061546, et al, Order 8 at ¶¶ 88-89 (June 21, 2007).

[143] ICNU Initial Brief at ¶¶ 23, 25.

Commission directives regarding how filtering should be considered in the context of a PCA.[144]

107 PSE, through Mr. Mills and Dr. Dubin, objects to the hydro filtering proposed by the ICNU/Staff. Mr. Mills testifies:

> In theory, rate year power costs should be calculated using agreed upon methodologies and regulatory precedents. The existence of a PCA mechanism is irrelevant when setting base rates. If a PCA mechanism is in place and if the PCA mechanism indeed shifts risk from the shareholders to customers, it is the underlying conditions of the PCA mechanism itself (*i.e.,* sharing bands and procedures) that should be adjusted to more appropriately balance risk between shareholders and customers—not the underlying power costs. The proposal of the ICNU/Staff merely biases projected rate year power costs.[145]

108 Mr. Mills offers a detailed critique of the proposed hydro filtering and support for PSE's use of 50 years of data. He says that in an average year nearly 30 percent of the Company's power generation comes from hydropower resources. According to Mr. Mills, market prices for power tend to be low when hydropower is abundant and high when hydropower is limited and consequently the distribution of power costs is skewed across various hydro conditions.[146] Considering the definition of "outlier water years" proposed by ICNU/Staff, he notes that three poor hydro years experienced in the last seven years would fall in this category and that over this period PSE has absorbed 90 percent of the power costs in excess of normalized power costs through operation of the PCA.[147] Mr. Mills argues that the balance between risk and benefits associated with deviations from baseline power costs should properly be considered in the design of the PCA and its sharing bands. He notes that the Company prepared a study of that issue pursuant to a settlement condition in the 2007 rate case, but received no comments from the parties in response to that study.[148] Referring to the record of the 2004 general rate case, Mr. Mill's says that both Company and Staff experts agreed that at least 50 water years should be used in

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[144] PSE Reply Brief at ¶ 7.

[145] Exhibit DEM-12CT (Mills) at 33:18-34:4.

[146] *Id.* at 31:21-32:3.

[147] *Id.* at 33:19-35:9.

[148] *Id.* at 35:11 – 37:3.

AURORA to determine base power costs, in contrast to the filtered record of 30 years proposed by the ICNU/Staff in this case.[149]

109 Mr. Mills also points out an error he asserts the ICNU/Staff made in application of their proposal. Mr. Mills testifies that:

> If the Joint Parties had used only PSE's share of Mid-C hydro generation in its hydro filter calculation, the adjustment would have resulted in a $3.0 million reduction to projected rate year power costs, rather than the $4.6 million reduction calculated using the ICNU/Staff' approach.[150]

110 Dr. Dubin, attacks the hydro filtering adjustment from a statistical and analytical perspective. He presents a detailed discussion to support his conclusions that:

> Commission Staff and ICNU propose a methodology to truncate or trim the hydro data used to set power costs for PSE. There exists no statistical or intuitive reason to filter the hydro-generation in the manner suggested by Commission Staff and ICNU--it is neither appropriate nor statistically sound to eliminate twenty of the fifty data points (40 percent) to force data to be "normal." In short, the proposed hydro filtering methodology is inappropriate, and the Commission should reject this adjustment.[151]

111 Directing fire at Dr. Dubin's testimony, ICNU says:

> What [Dr.] Dubin fails to recognize is that the inherent uncertainty in determining resultant *power costs* during the more extreme water years, good or bad, forms the basis for the ICNU/Staff filtering recommendation-not an extensive analysis of the historical water year data itself.[152]

112 ICNU contends in its brief that considering the "fine points of statistical theory is unhelpful and unnecessary."[153]

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[149] *Id.* at 39:7-15.

[150] Exhibit DEM-12CT (Mills) at 40:15-18.

[151] Exhibit JAD-1T (Dubin) at 3:4-10.

[152] ICNU Brief at ¶ 30.

[153] *Id.*

113 *Commission Determination:* ICNU and Staff are justified in raising the topic of how power cost normalization should be employed in the context of a power cost adjustment mechanism. The Commission examined this issue in some detail in the 2006 PacifiCorp general rate case. Indeed, the Final Order in that case provides some carefully developed direction on the matter. However, Staff and ICNU have overlooked the focus of the Commission's discussion and the key paragraph in that order. The Commission concluded:

> We find that filtering water-years is appropriate in the context of a PCAM, but that such filtering must reflect whether the distribution of variability in power costs is symmetrical or skewed as well as how the deadband and sharing bands are designed to reflect asymmetry in the risks and benefits that may accrue to both customers and the Company.[154]

It is simply not the case that the Commission "favored a water filtering adjustment for utilities with a PCA mechanism." Instead, it found that, if designed correctly, a water filtering mechanism could be appropriate in the context of a PCA mechanism. The Commission did not establish a "guiding principle" that in the presence of a PCA any form of hydro filter would be appropriate. The hydro filter proposed in this case fails to address any of the issues for which the Commission previously gave guidance.[155]

114 Moreover, in the PacifiCorp case cited by ICNU/Staff, the Commission found fault with the specific mechanism proposed here – a simple one-standard-deviation filter. Dr. Dubin's testimony in this case points out persuasively that the filter proposed is not justified on any statistical grounds. ICNU/Staff's assertion that despite its lack of a basis in science, the proposed filter should be adopted because it is simple and

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[154] *WUTC v. PacifiCorp,* Dockets UE-061546, et al, Order 8 at ¶ 101, June 21, 2007.

[155] In contrast, we note that this matter was addressed in the settlement agreement of Avista's 2008 rate case by adoption of an asymmetric sharing band in that company's Energy Recovery Mechanism. *WUTC v. Avista Corporation,* Order 08, Final Order Approving and Adopting Multi-Party Settlement Stipulation and Requiring Compliance Filing, Dockets UE-080416 and UG-080417 (December 29, 2008) at ¶ 52, Appendix A-Multi-Party Settlement Stipulation at 6-7. The issue was also addressed in the settlement of PSE's 2007 general rate case with a provision requiring the company to complete a study and provide it to the parties by December 2008. *WUTC v. Puget Sound Energy,* Order 12, Final Order Approving And Adopting Settlement Stipulations: Authorizing And Requiring Compliance Filing, Dockets UE-072300 and UG-072301(consolidated) (October 8, 2008), Appendix E-Partial Settlement Re: Electric and Natural Gas Revenue Requirements at ¶ 17.

straightforward is untenable. ICNU/Staff's dismissal of "the fine points of statistical theory" is inapt.

115 Judging from their repeated emphasis that the filter is being applied to water records rather than to the power costs that are correlated with water conditions, ICNU/Staff misread the basic point of our analysis in the PacifiCorp order. Specifically, they miss the point that while hydrologic data may be normally distributed, these data are strongly correlated with power costs which were not normally distributed in the case of PacifiCorp and may not be normally distributed in PSE's case either. Indeed, ICNU acknowledges in its brief that the real focus of the ICNU/Staff proposal is "uncertainty in determining resultant power costs." While it is true that removing both high and low values from the normally distributed water record will not significantly bias the average *water year*, it did, in the case of PacifiCorp, bias the average power cost.[156] Since the purpose of calculating a normalized power cost is to estimate the expected value (*i.e.,* the average) of power costs, the Commission found that the one-standard deviation method was flawed and actually favored a different, less biased, statistical method offered by PacifiCorp in that case.

116 Ultimately, no hydro filter was adopted in the PacifiCorp case because, among other reasons, PacifiCorp does not have a PCA mechanism. But the point of the discussion is what is important here. ICNU/Staff have neither offered any analysis of the probability distribution of power costs nor shown how that distribution is related to the probability distribution of hydrologic data. In addition, they have offered no analysis of how those probability distributions affect the sharing of risks and benefits accomplished by the PCA sharing bands. We find this somewhat puzzling in light of the Company having fulfilled its obligation to complete a study and provide it to the parties under the settlement terms of the 2007 rate case.

117 Consistent with our discussion above and for the reasons stated, we reject the ICNU/Staff proposal to apply a quasi-statistical filter to exclude from AURORA the water-years that fall outside of one standard deviation above or below the mean water year in the 50-year record from 1929 – 1978.

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[156] Indeed, if simply filtering water-years were enough to address the concerns raised in our PacifiCorp order, there would be no reason to use multiple water years at all. The average water year would suffice. We find value in the using AURORA with a full distribution of water records because the modeled results capture the way the water conditions interact with other factors affecting power costs.

118 Having made our determination on the issue contested by the parties, our discussion above leads us to determine also that it would be appropriate for the parties to examine in PSE's next general rate case, or in another suitable proceeding, the questions whether there are asymmetrical risks in the distribution of power costs that may affect the sharing of risks and benefits accomplished by the PCA sharing bands. It seems particularly appropriate that the Commission should hear more on this question in the future given the Company's 2007 study concerning the balance between risk and benefits associated with deviations from baseline power costs and how it should properly be considered in the design of the PCA and its sharing bands.

<u>Hydrologic Record</u>

119 Public Counsel contests PSE's use of the 50-year water record from 1929 – 1978. Public Counsel's witness, Mr. Norwood, testifies:

> PSE has used the average hydro generation level for the 50-year period 1929-1978 as the basis for its rate year hydro forecast in this case. The Company indicates that it has used this period rather than a more recent period because this approach was recommended by the WUTC Staff in the Company's 2004 general rate case. However, the average annual hydro generation level for the Mid-C hydro contacts for the most recent 50-year period for which information is available (*i.e.,* 1949-1998) is significantly higher than the level experienced during the 1929-1978 period.[157] Given the significant increase reflected in the more recent 50-year average hydro generation data for the Mid-C hydro contracts, I am concerned that using the 1929-1978 period for forecasting PSE's hydro generation levels will result in the under-forecast of rate year hydro generation levels and therefore lead to significant over-recovery of power supply costs by PSE.[158]

120 Mr. Norwood recommends that PSE's rate year hydro generation forecast be revised to reflect the average hydro generation levels over the 50-year period 1949-1998. This recommendation would serve to increase PSE's rate year hydro generation forecast for the Mid-C hydro contracts.[159] To calculate the reduction in rate year

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[157] Exhibit SN-8C.

[158] Exhibit SN-1HCT (Norwood) at 35:5-17 (internal citation omitted).

[159] Exhibit SN-8C.

energy costs resulting from this adjustment, Mr. Norwood used PSE's forecasted average cost of market energy purchases during the rate year.[160] His recommended adjustment for this issue reduces PSE's originally filed rate year power costs by \$6,180,410.[161]

121 Turning to Public Counsel's proposal to use a more recent 50 years of available data (1949-1998), Dr. Dubin, testifies that Public Counsel's proposal advocating a 50-year rolling average for this adjustment is arbitrary, unscientific and without merit:

> As I said in my testimony in the 2004 GRC, the 60-year record would be better to use than the 50-year record and similarly the full 70-year record is preferred to the 60-year record or the 50-year record. I strongly advocate the use of the available 70-year hydro record to determine likely future levels of hydro generation and recommend strongly against the use of a rolling average whether the motivation is that 50 is somehow special (it is not) or whether earlier periods reflect significantly lower mean hydro flows (properly tested they do not). Mr. Norwood's suggestion is another form of filtering wherein he ignores the data and arbitrarily drops the first 20 years of the historical hydro record with no basis other than his "concern" that it is different.[162]

122 Mr. Mills testifies that "simply using a more recent period of data because it creates results favored by Public Counsel is not a valid reason to change the hydro information used to set rates."[163] He states that the Company would be willing to use the full 70 year data set, but has instead used the 1929-1978 data because the AURORA model data files do not include the most recent 20 years of hydro data. According to Mr. Mills, the Company has this more recent data for its Mid-C and western Washington hydro resources, but not for the other regional hydro resources that contribute to market pricing in AURORA. He offers a method that would use the full set of 70 years, but would not fully reflect variation in hydro conditions associated with the non-PSE resources.[164]

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[160] *Id.*

[161] *Id.*

[162] Exhibit JAD-1T (Dubin) at 32:11-33:1.

[163] Exhibit DEM-12CT (Mills) at 42:6-14.

[164] *Id.* at 42:7-43:21.

123 *Commission Determination:* The Company correctly points to the thorough examination of this matter undertaken in its 2004 rate case. The Commission's discussion in that case examines statistical analyses undertaken by both Company and Staff expert witnesses.[165] Those analyses agree in their conclusion that water-year data are normally distributed and trendless and that the longest period of data was the best to use for purposes of estimating normalized power costs. These analyses also concluded that use of a "rolling average" was statistically flawed. The 50-year record spanning 1929 – 1978 was used in the 2004 rate case because the more recent water-year data was not yet adjusted to reflect actual operation of the hydropower system.

124 In this case we are faced with a similar quandary, the science argues for use of data spanning as long a period as possible, but the most recent 20-years of data available for use in AURORA is apparently incomplete. Inasmuch as the Company has access to at least some of the more recent data, its power cost evidence in future rate proceedings should include consideration of that data. It also should be made available to other parties who may wish to address these issues in future cases.

125 We reject Public Counsel's proposal to eliminate the first 20 years of water records in favor of adding the 1978-1998 data because this data set is not demonstrated to be superior to the earlier records and it is not comprehensive for use in AURORA. However, we have stated above our preference for using the longest span of years possible. We reiterate the direction given by the Commission in PSE's 2004/2005 general rate case encouraging the parties to continue their discussions of this subject and their efforts to develop even more rigorous tools for hydro normalization.

<u>*Regional Load Forecast Adjustment*</u>

126 The Company's September 28, 2009, Supplemental Filing includes significantly reduced loads for PSE, but does not consider any other regional load reductions. The Company's load forecast for the rate year is lower by 3.9 percent than its original filing, ostensibly because of the recent recession and reduced economic growth.

127 The AURORA power supply model uses regional loads throughout the western United States and Canada for determining market electricity prices for purposes of

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[165] *WUTC v. Puget Sound Energy.* Dockets UG-040640, UE-040641, UE-031471, and UE-032043 (consolidated), Order No. 06, ¶¶ 124-131(February 18, 2005).

making balancing sales and purchases. Presumably the economic factors affecting PSE's loads have also affected economic growth and power loads throughout the western United States. ICNU/Staff argue that the Company's failure to adjust all of the load forecasts in AURORA leads to an over-estimate of power costs because the model dispatches higher cost resources to meet the unreduced forecast of western loads.[166]

128 ICNU/Staff recommend an adjustment to the AURORA model inputs assuming no load growth for 2009, 2010 and 2011 for Pacific Northwest loads and the loads of Southern California Edison and Pacific Gas & Electric, which they say taken together represent a significant portion of WECC loads. They characterize their adjustment as conservative considering that PSE's own loads actually declined. According to the ICNU/Staff, this approach still results in a reduction to rate year power costs of approximately $ 1.1 million based on a single average water year AURORA run. When determined in conjunction with the other AURORA related adjustments, the decrease in the rate year power cost projection is $0.83 million.

129 Mr. Mills testifies on rebuttal:

> PSE did not reduce regional loads in the AURORA model. PSE believes that its load reduction would have only a minor impact on the Pacific Northwest aggregate loads because the Pacific Northwest rate year load is about 163,229,598 MWhs, or 18,634 aMWs. Therefore, the reduction in PSE's load is less than 1 percent, or only about 0.57%, of the aggregate regional load. A subsequent run of the AURORA model proved the impact of incorporating the regional load reduction in the AURORA analyses is a reduction of about $0.12 million in projected rate year power costs.[167]

130 Mr. Mills disagrees with the adjustment proposed to AURORA model load inputs because he says "neither PSE nor the ICNU/Staff have developed a methodology to analyze the extent of such impact loads."[168] However, he says that the Company agrees that the same economic trend data that reduced PSE's load forecast may have had an impact on the regional load forecast. Therefore, PSE is willing to accept the $1.1 million reduction to the Company's rate year power costs proposed by the

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[166] Exhibit JT-1CT (Schoenbeck/Buckley) at 4:22-6:17.

[167] Exhibit DEM-12-CT (Mills) at 26:11-18.

[168] *Id.* at 28:7-16.

ICNU/Staff, but only as an adjustment made to the AURORA power cost results, rather than adjustment to the model inputs.[169]

131 *Commission Determination:* ICNU and Staff have identified an error in the Company's calibration of the AURORA model. An adjustment to the rate year power cost is justified to correct this error. The Company is correct to point out that a proper adjustment to the AURORA load would require detailed knowledge of the load forecasts for all of the model's sub-regions. The Company's agreement to adjust the results of the AURORA model by $1.1 million is a reasonable resolution of this issue.

Out of AURORA Adjustments

Jackson Prairie Storage Capacity

132 PSE acquired a three-year assignment of 6,704 MMBtu/day deliverability and 140,622 MMBtu of Jackson Prairie natural gas storage capacity under a three-year, renewable, asset management arrangement with Cabot Oil & Gas Marketing. Under this agreement, PSE will manage these natural gas assets on behalf of Cabot. The Company will pay tariff rates to Cabot for the storage capacity and gas transport capacity and will retain all value obtained from managing the capacity. According to Mr. Mills, PSE's management of the Cabot assets, including the Jackson Prairie storage capacity, will help ensure the reliable provision of gas supply to customers and power generation facilities, enhance the Company's ability to balance load, improve integration of renewable resources, and facilitate PSE's ability to meet peak-load requirements with gas-fired generation facilities.[170]

133 ICNU/Staff assert that while the Company included in its requested revenue requirements the $415,000 cost of the Cabot asset management arrangement, it did not include quantifiable value associated with the benefits it asserts. According to ICNU/Staff, ratepayers should expect to receive benefits that at least partially mitigate the inclusion of the expense in the determination of the rate year power cost projection. According to ICNU/Staff, when the transaction was presented to the Company's Energy Management Committee on March 19, 2009, the presentation showed a cost of $577,000 per year for the arrangement with an associated value of $806,000 per year. The value included a component related to the benefit associated

[169] *Id.* at 27:18-28:7.

[170] Exhibit DEM-12CT (Mills) at 23:6 – 25:5; Exhibit JT-7C.

with the storage capacity. No such benefit is reflected in the Company's filing in this proceeding. ICNU and Staff recommend a storage benefit be included based on the difference in market prices between the low and high gas cost months multiplied by the associated storage volume of the agreement. Based on PSE's Sumas forward prices, this calculation yields a benefit of $338,000 attributable to this arrangement.[171]

134 PSE opposes the proposed adjustment. Mr. Mills testified that if PSE could use this gas storage to capitalize solely on seasonal price differentials, the adjustment proposed by ICNU/Staff would seem appropriate. He asserts, however, that PSE does not have the opportunity to purchase gas at low summer prices and store it to sell during the higher priced winter months. Mr. Mills reiterates on rebuttal that PSE acquired the Cabot asset management agreement storage for reliability and renewable resource integration management. He states that PSE's rate year power costs accordingly should not include any benefit for the seasonal gas price differences.[172]

135 *Commission Determination:* The Company's objection that it did not acquire control of the additional capacity simply to exercise seasonal arbitrage of gas pricing is persuasive. Nonetheless, if the costs of the Cabot arrangement are to be included in rates, any quantifiable benefits also should be taken into account. The best evidence of the appropriate adjustment is found in Exhibit JT-7C, which includes a presentation made to PSE's Board of Directors. The exhibit shows the net benefit of the arrangement on the power side to be $186,000.[173] That, accordingly, is the adjustment we determine should be made here.

<u>*Westcoast Pipeline Capacity*</u>

136 The Company has acquired additional Canadian natural gas pipeline capacity on the Westcoast Energy System to allow it access to gas deliveries at the "Station 2" delivery point. It asserts that this capacity will allow it to diversify its delivery points for Canadian-sourced gas so that is not solely dependent on the Sumas hub.[174] The Company secured a rate year "basis differential" between gas sourced at Sumas and gas delivered at Sumas from a single broker quote to estimate the benefit of the additional capacity. Applying this differential to gas volumes estimated to be

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[171] Exhibit JT-1CT (Schoenbeck/Buckley) at 24:17-25:10.

[172] Exhibit DEM-12CT (Mills) at 26:6-13.

[173] Exhibit JT-7C (ICNU/Staff) at 19.

[174] Exhibit DEM-12CT (Mills) at 28:10 -29:20.

delivered at Station 2, and correcting for a spreadsheet error identified by ICNU, the Company estimates a benefit of $5.7 million reduction in power costs.[175]

137 ICNU/Staff do not question the prudence of the Company's acquisition of the pipeline capacity, but they contend additional "basis price differences" are required to justify the significant annual expense of about $8.7 million.[176] This is because, using PSE's approach to estimating basis gain, there are no estimated basis gains during five months of the rate year. They assert that historical data shows that in every trading day for the last two years, there has been a favorable price differential between Station 2 and Sumas. ICNU/Staff say this makes sense because the cost for transporting gas from Station 2 to Sumas was about 47 cents/MMBTU during the test period. Thus, Staff and ICNU argue, faced with the alternatives of buying gas at Station 2 and transporting it to Sumas versus simply buying the gas at Sumas, PSE needs a savings of at least 47 cents/MMBTU at Station 2 as compared to Sumas. Using this estimation "logic," Staff and ICNU recommend an additional $4.0 million in estimated annual benefits, or a total out-of-AURORA rate year basis gain benefit of $9.7 million, requiring a reduction in that amount to the rate year power cost projection.[177]

138 Mr. Riding disputes that PSE acquired the additional gas pipeline capacity to capture an assumed market price differential between Station 2 and Sumas.[178] In fact, he testifies, "PSE has acquired Westcoast Energy T-South capacity in order to improve the reliability and predictability of supply to its generation portfolio by diversifying supply risks."[179] Mr. Riding testifies that the market price differential between Station 2 and Sumas should be considered for PSE's rate-making purposes, but at the "at the contractable differential, which is best measured by market quotes or actual gas supply contracts, consistent with the pricing for all gas purchases for gas-fired generation."[180] He argues that "historical prices, or price differentials, may or may not have any bearing on future prices; therefore, the appropriate methodology is to

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[175] Exhibit JT-7C (ICNU/Staff) at 15:22-16:7.

[176] *Id.* at 14:11 – 15:18.

[177] *Id.* at 16:12 – 19:11.

[178] Exhibit RCR-6T (Riding) at 7:12-15.

[179] *Id.* at 7:17-19.

[180] *Id.* at 9:14-16.

consistently apply forward price curves and market quotes that are developed primarily by third-party forecasters or market makers."[181]

139 Mr. Riding also contends that recent volatility in the price of gas makes using historical period prices inappropriate.[182]

140 Mr. Mills states that the ICNU/Staff' method produces a basis benefit that exceeds the cost of the pipeline capacity. Mr. Mills testifies that PSE secured four additional broker quotes for the Station 2 to Sumas price differential. Based on these new brokerage quotes, he says, the basis benefit does not exceed the total cost of the new capacity in any month. Mr. Mills accordingly revises his calculation of basis benefit to include an additional \$2.4 million.[183] This increases the benefit to \$8.1 million (*i.e.,* \$5.7 plus \$2.4 million).

141 *Commission Determination:* The ICNU/Staff argument that the Company's reliance on a single broker quote is insufficient to estimate the rate-year basis differential is persuasive. We also find merit in the Company's argument that basis differential should be based on forward market information, as are fuel gas prices. On balance, however, we agree with ICNU/Staff that use of documented price differentials between the two stations is a reliable method to determine the benefit of the basis differential. We acknowledge the Company's observation that the resulting benefit more than offsets the cost of the additional capacity but are puzzled by its assertion that this must represent a flaw in the ICNU/Staff proposal. Indeed, we favor Company actions for which the benefits exceed the costs. Accordingly, we determine that the ICNU/Staff proposal to reflect a basis differential of \$9.7 million is appropriate. Our decision results in a \$1.6 million reduction in power expense from what the Company included in its final case.

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[181] *Id.* at 9:16-20.

[182] *Id.* at 10:3-21.

[183] Exhibit DEM-12CT (Mills) at 30:13-31:14.

Mark-to-Market for Gas Hedges

142 The Commission has approved a gas mark-to-market adjustment in PSE's last several general rate cases and power cost only rate proceedings. This post-AURORA adjustment reflects the cost difference between PSE's actual short-term forward gas purchases, which are primarily financial but also physical, and the current forward gas price for the rate period used in the AURORA model. The adjustments approved in proceedings since 2004 have ranged from $4,296,000 to $(5,166,000). In this filing, however, PSE's short-term mark-to-market adjustment is over $45,000,000. The adjustment is substantial for various reasons, including that PSE has extended the forward time period over which it purchases gas and the Company has additional baseload gas-fired generation in its power portfolio with the acquisition of Goldendale and Mint Farm.[184]

143 ICNU/Staff say that while these two factors may make sense and may be reasonable, the Company's proposed adjustment in this proceeding is unreasonable because it has procured "far more gas for its power supply requirements than is necessary or justifiable and at a much higher cost than the current market."[185] According to ICNU/Staff, the Company has contracted for 105 percent of the natural gas projected by AURORA to be needed in the April 2010 to March 2011 rate year. ICNU argues that the Company has conducted the forward gas purchases for wholesale activity not reflected in AURORA and that this is "a thoroughly preventable result for which customers should not be charged."[186] Staff and ICNU contend that because AURORA cannot capture PSE's substantial wholesale market trading, there is a mismatch between purchases and need as reflected in the AURORA projections.[187]

144 ICNU/Staff propose that the volume of PSE's forward gas purchases for each month be capped at 80 percent of the AURORA-projected baseload need for each month of the forecast rate-year period. ICNU argues that "this recognizes that it is prudent for a utility to acquire a portion (20%) of its gas needs at market prices, while hedging the remainder."[188]

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[184] Exhibit JT-1CT (Schoenbeck/Buckley) at 19:17-20:1.

[185] *Id.* at 20:12-14; ICNU Initial Brief at ¶ 8.

[186] ICNU Initial Brief at ¶ 10.

[187] *Id.* at 20:17-22:7.

[188] ICNU Initial Brief at ¶ 10.

145 PSE argues that the ICNU/Staff proposal to cap purchases at 80 percent of the AURORA-projected baseload need for each month of the forecast rate-year period is arbitrary and would expose PSE and its customers to increased market risk.[189] In contrast, PSE states, "the existing treatment for gas hedges has resulted in a cumulative benefit to customers."[190] PSE states that excluding a certain level of long-term mark-to-market contracts, is not appropriate and ignores approximately $122.1 million in customer benefits over the past decade as these long-term and short-term mark-to-market contracts have been included in the calculation of the power cost baseline rate in each of the recent PSE rate proceedings.[191]

146 PSE points out that no one has objected in several general rate cases, power cost only rate cases, or in response to the Company's PCA compliance reports, to PSE's treatment of these contracts. PSE argues:

> It is only now, when the mark-to-market adjustment reflects a cost rather than a benefit to customers, that parties question the inclusion of the mark-to-market adjustment in determining power costs. Allowing a mark-to-market adjustment in the baseline power cost calculation when the adjustment benefits customers, then removing the mark-to-market adjustment in years when gas prices are declining, creates unbalanced and arbitrary regulatory policy. The baseline rate should continue to reflect the gas hedges that have been executed under PSE's hedging program, rather than relying on AURORA's static power costs forecast.[192]

147 PSE argues that the parties are simply wrong in their assertion that PSE's gas hedges exceed the Company's gas for power needs. The Company cites to evidence introduced by ICNU that shows the Company's actual transacted gas hedges are below its forecast gas needs, as modeled by PSE's risk management system.[193] PSE

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[189] PSE Initial Brief at ¶ 34.

[190] *Id.*

[191] *Id.* at ¶ 36 (citing Tr. 778:19-23 (Mills); Exhibit DEM-12CT (Mills) at 19:7-13).

[192] *Id.* (citing Mills, Tr. 776:6-10; 777:24-778:20; 779:19-23).

[193] Exhibit DEM-23C.

emphasizes that while it hedged in excess of the AURORA-projected gas for power needs, its actual hedging did not exceed its forecast needs.[194] In sum, PSE argues:

> Short-term fixed-price gas for power and power contracts incurred at the price cut-off date for the rate year represent prudent, known and measurable transactions PSE has entered into and is obligated to pay; they are supported by PSE's hedging program, and have been historically included in rates.
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> * * *
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> The Joint Parties' argument to cap mark-to-market transaction at 80% of the AURORA forecast ignores the fact that AURORA is a static modeling tool that provides a snapshot in time.[195] The Joint Parties are well aware that PSE utilizes a comprehensive risk management system—not AURORA—for daily management of the energy portfolio. It makes no sense for PSE to base its hedging on a fixed regulatory model and ignore the actual service requirements of its customers.[196]

148 ICNU/Staff propose an alternative to their recommendation to remove mark-to-market costs from base power rates that the mark-to-market costs be recovered through a separate tariff rider with a sunset date at the end of the rate year on April 1, 2011. Public Counsel also contends that a mark-to-market adjustment of the magnitude present in this case should not be a permanent component of baseline power rates. Mr. Norwood asserts there is no basis for including this adjustment beyond the rate year period. Mr. Norwood recommends that a mark-to-market "credit factor" of $0.00201 per kWh be implemented effective April 1, 2011, which is the date immediately following the end of the rate year in this case. This adjustment would have no impact on the rates proposed in this case, but would affect PSE's power cost charges beyond the rate year period. Mr. Norwood recommends that this mark-to-market credit factor should be implemented only if PSE does not modify its baseline power rate before April 1, 2011.[197]

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[194] These differences are caused by different input assumptions due to regulatory modeling limitations which, in this case, have caused lower heat rates in AURORA. *See* Exhibit DEM-12CT (Mills) at 19:8-14.

[195] *See* Tr. 750:7 – 751:10 (Mills).

[196] PSE Reply Brief at ¶¶ 2, 5.

[197] Exhibit SN-1HCT (Norwood) at 40:19-41:6.

149 Mr. Story and Mr. Mills, for the Company, oppose the ICNU/Staff and Public Counsel proposals to treat the mark-to-market costs in tariffs separate from base rates. Mr. Mills says that they inaccurately portray the mark-to-market as a one-time significant cost that should not be allowed to be included in base rates past the rate year. He contends that, with a $1 billion power portfolio, there are many costs that could potentially be singled out as "significant" and proposed to be recovered separately. He asserts that PSE's hedging program and its attendant costs and benefits is not a one-time event, but an ongoing effort by the Company to mitigate volatility in its power portfolio. He says that there will always be a mark-to-market adjustment because the market cost of gas will vary from the cost of gas negotiated in the hedging contracts. There will be a gain if forward gas prices increase after the date of the hedging transaction, and there will be a cost if forward gas prices decline.[198]

150 Mr. Story testifies that during and beyond the rate year there will be a new relationship of hedges to market gas costs but there is nothing in this record to indicate what that relationship will be. He says that power costs could be much higher and hedging costs lower, yet the net total power cost could be close to what is currently in rates. He contends that, to re-adjust power costs at the end of the rate year as the Joint Parties and Public Counsel recommend would require all costs to be examined. According to Mr. Story, just removing one item in the power cost forecast is not reasonable or justified.[199]

151 *Commission Determination:* This issue is complex. It highlights the difference between the methods used to set the Company's baseline power rate and the methods the Company uses to manage its day-to-day operations. PSE uses the AURORA model only to set the baseline power rate and project normalized power costs. Fundamentally, AURORA results represent a static projection of power system operation in the rate year that cannot serve as a rigid management plan for actual operations. Accordingly, while AURORA is the benchmark used to set normalized power rates, it has been accepted practice to adjust its results to reflect actual costs that are difficult or impossible to include in the model.

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[198] Exhibit DEM 12-CT (Mills) at 51:1-22.

[199] Exhibit JHS 14-T (Story) at 18:12-21.

152 The mark-to-market adjustment for gas contracts and hedges has been a relatively uncontroversial example of such an adjustment for many years. In this case we are presented with an adjustment that encompasses the same category of costs that have been regularly included in approved baseline power costs rate, but that is much larger than in the past. We find that the parties proposing to change the way mark-to-market gas hedges are treated in determining power costs have failed to present any convincing reason to do so.

153 The Company is correct to argue the importance of matching all costs, benefits, and other factors when rates are adjusted. And it is disappointing to hear ICNU/Staff and Public Counsel advocate a single issue rate adjustment when they otherwise so vigorously and correctly defend the matching principle. If hedging is an appropriate tactic to manage fuel cost risk, and we think it is, then it is appropriate for the cost of hedges to be included in power cost rates.

154 While it is true that the intrinsic value of hedges will vary with the actual cost of gas, this does not make hedging costs any less known and measurable than the market cost of gas that is an input to the AURORA model. We don't find ICNU's argument for excluding a mark-to-market adjustment on this basis consistent or persuasive.

155 This adjustment has routinely been an element of the power cost calculation and we can see no principled reason to exclude it from rates simply because of its size in this case. We also reject the proposals by Public Counsel and ICNU/Staff to separately track the mark-to-market costs through either a tariff that sunsets or a tariff with a delayed credit.

<u>*Operations and Maintenance Expense*</u>

156 PSE initially proposed to base its operation and maintenance (O&M) expenses on a five-year forecasted cost analysis.[200] Staff opposes the Company's use of budgeted or forecast figures for plant expenditures and relies instead on historical on normalized expenses over a five-year period for established facilities (*i.e.,* Colstrip 1 and 2, Encogen, Frederickson 1 and 2, Fredonia 1-4, Whitehorn) . For new facilities added during the test year, Staff calculates an annual expense based on January through August 2009 (Mint Farm and Hopkins Ridge Infill), monthly average actual expense from August 2008 through August 2009 (Sumas), or actual construction costs through October 2009 (Wild Horse Expansion). Staff used the monthly average actual

[200] Exhibit JHS-1T (Story) at 15:6-10.

expenditure from March 2007 to August 2009 for Goldendale. Staff included the fixed costs associated with the Baker River Project license and the Vestas turbine maintenance contracts for Hopkins Ridge and Wild Horse.[201]

157 Staff argues that its cost figures are more appropriate for ratemaking than the Company's because forecasts and budgeted costs are "inherently unreliable" and should be rejected in favor of documented historical costs.[202] Based on its review of the maintenance costs and requirements at each individual plant, Staff concludes that the pro forma adjustment for rate year plant operation and maintenance should be $90,026,915 – a reduction of $2,305,723 from the test-year level.[203] In total, this reduction is $506,000 greater than the Company's proposed adjustment which reduces test-year expense by $1,799,720.[204]

158 The Company proposes to treat plant operation and maintenance expenses in three categories:

- O&M costs of less than $2 million would be expensed as they occur.
- Capital costs that are prepaid under maintenance contracts will be capitalized when they occur (and not included in the O&M expense item).
- Maintenance events that are not capital in nature, but are in excess of $2 million would be deferred and included in the next general rate case.

Although PSE does not propose to include any maintenance costs in this third category in this rate case, it proposes that deferred costs that are approved in future rate cases be amortized over five-years with the unamortized balance included in rate base as a regulatory asset.[205] The Company requests that the Commission clarify "that rate recovery for actual major maintenance costs for turbines with and without

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[201] Staff Initial Brief at ¶ 105.

[202] Staff Brief at ¶ 108.

[203] Exhibit B-3 at (revision to KHB-2) at page 2.10 line 18.

[204] Staff Initial Brief at ¶ 96.

[205] Exhibit JHS-1T (Story) at 14:3-15:5.

maintenance contracts be capitalized and amortized to expense over the estimated period until the next planned major maintenance activity."[206]

159 As to O&M expense for projects less than $2 million per occurrence, the Company states it is willing to use historical data rather than forecast data, but it makes the following modifications to Staff's recommended amounts for each plant.

- For Snoqualmie the Company asserts that fixed payment obligations under its FERC license should be included.[207]

- For Colstrip, the Company argues the rate year costs provided by the plant owner, PPL-Montana, should be used. According to the Company, these costs have been reviewed and approved by the majority of owners and such costs have been included in the last six rate cases.[208]

- For Goldendale, the Company argues that test-year costs should be used because the 30-month average used by Staff does not reflect the period of time the plant was owned by PSE.[209]

- For Mint Farm, the Company proposes to use Goldendale as a proxy. It argues that Staff's January to August data fails to reflect fall and winter operational data.[210]

- For Sumas, the Company proposes to use a full year of data ending October 2009, rather than the year of data ending August 2009, proposed by Staff. The Company argues that its proposed period represents the most current and accurate figure.[211]

- For Whitehorn, Fredonia, Frederickson and Encogen, the Company proposes to use test-year data, because it says these data are the most current and accurate.[212]

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[206] PSE Initial Brief at ¶ 87.

[207] *Id.* at ¶ 84.

[208] *Id.* at ¶ 86.

[209] *Id.* at ¶ 89.

[210] *Id.* at ¶ 90.

[211] *Id.* at ¶ 91.

[212] *Id.* at ¶ 92.

- For Wild Horse, Hopkins ridge, and Hopkins Ridge Infill, the Company argues that maintenance contract escalation tied to the Consumer Price Index and the Goss Domestic Product Implicit Price Deflator should be allowed recovery in current rates.[213]

160 Staff opposes the Company's proposal to capitalize major plant maintenance expenses through creation of regulatory assets that are amortized over five-years. Staff argues that this approach would require multiple accounting petitions to determine and track for every facility the appropriate maintenance intervals and resulting expense recovery and would include carrying charges that can become excessive over time.[214] According to Staff, the conventional method of recovering major maintenance costs through the "deferral method" and all other maintenance costs as expense when incurred is superior for ratemaking and does not require capitalization.[215]

161 Public Counsel accepts the levels of plant operation and maintenance expense proposed by the Company on rebuttal.[216] With regard to accounting for the recovery of major plant maintenance, Public Counsel advocates use of the "deferral method" and says that the rate decision in this case should address costs to be deferred and considered in a future rate case.[217]

162 *Commission Determination.* While the Company originally proposed to use forecasts and states that it still supports such an approach in principle, it is willing to accept the use of historical data to determine O&M costs in this proceeding. We have discussed elsewhere in this Order the Commission's longstanding preference for using the best and most representative historical data when making pro forma adjustments. This is the most reliable source of information from which to determine known and measurable changes to test year costs. Accordingly, we will use such data here. The question remains, however, as to what historic data we should use. Staff's figures are based on use of a five-year average that the Company argues do not reflect more current expense trends. Public Counsel accepts the Company's rebuttal amounts. O&M is an ongoing expense and there is no evidence that the more recent historic

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[213] *Id.* at ¶¶ 93-94.

[214] Staff Initial Brief at ¶ 100-101.

[215] *Id.* at ¶ 102.

[216] Public Counsel Initial Brief at ¶ 120.

[217] *Id.* at ¶¶ 121-122.

data upon which the Company would have us rely requires any normalizing adjustments. We accept the Company's proposals and its proposal to reduce overall plant operations and maintenance expense by $1,799,720 from test year levels.

163 All parties advocate that major plaint maintenance should be handled using the "deferral method," though it appears the parties may have some different ideas about what this means in practice. While we accept in principle the use of a deferral methodology for major plant maintenance expenses, we have no need to decide its finer points here. This undoubtedly will be brought before the Commission in some future proceeding when such costs are incurred and it will then be ripe for decision.

Off System Sales

164 Public Counsel witness Norwood recommends that PSE's baseline power cost forecast for the rate year be adjusted outside of AURORA to reflect the average annual volume of off-system power sales (OSS) made by PSE over the last 5 calendar years. He states PSE's level of OSS is much higher than the level projected in the AURORA model.[218] Mr. Norwood testifies that he sees no reasonable explanation for why the modeled level of OSS is so much lower than actual in this case. Moreover, he states, forecast OSS sales have consistently been far below actual sales in recent rate cases. He contends that the actual level of rate year OSS is likely to be even higher than the historical average due to the addition of the Mint Farm and Wild Horse expansion projects.[219] Mr. Norwood argues that if OSS volumes are under-represented in the baseline power rate, that rate may over-recover actual net power costs in the rate.

165 Mr. Norwood recommends that PSE's updated rate year power cost forecast be reduced to reflect a credit of $5,141,295 to account for OSS.[220] In addition, he recommends that in future cases PSE be required to account for actual OSS revenues and margins and present such information to support the reasonableness of forecasted OSS revenues in its power cost forecasts.[221]

[218] Exhibit SN-1HCT (Norwood) at 36:16-37:2.

[219] *Id.* at 37:4-38:3.

[220] Exhibit SN-9C.

[221] Exhibit SN-1HCT (Norwood) at 40:2-4.

166 Public Counsel argues that the Company concedes that the baseline power rate would be lower if OSS revenues were adjusted to be higher than projected in AURORA. Public Counsel also argues that the Company concedes that the baseline power rate would be expected to be lower if power purchases are under-estimated by AURORA because power purchases are only transacted when market power is less expensive the Company's own generation.[222]

167 Staff and ICNU do not take a position on Public Counsel's adjustment, except to say that if their recommended adjustment for mark-to-market gas sales is not adopted, the Commission should adopt Public Counsel's adjustment to reflect increased OSS revenue.[223]

168 Mr. Mill's testifies in opposition to Public Counsel's adjustment. He argues that Mr. Norwood's attack is focused on the reliability of AURORA model that has been used to set the Company's power costs in all recent rate cases. He asserts that the history of the PCA shows power cost under-recoveries of $6.8 million out of $6.9 billion in actual power costs over six and one-half years and that this refutes any contention that the baseline power rate has been set too high. He says that in the first eleven months of the current PCA period, PSE has under-recovered $17 million in power costs.[224]

169 Mr. Mill's says that Public Counsel has focused only on the difference between projected and actual OSS, without considering market purchases. According to Mr. Mills, the Company is "short" more often than it is in a long position and AURORA also tends to under-predict market purchases. He provides data to show that over the past six rate cases actual market purchases exceeded forecast purchases and that in aggregate the dollars spent on increased market purchases exceed the dollars received from increased market sales by $83.1 million.[225] He testifies that the differences between modeled and actual sales and purchases are the consequence of AURORA modeling the resource portfolio available to PSE and that the actual resources that are available always differ from the model's projection due to the Company's "diverse mix of resources with widely differing operating and cost characteristics."[226]

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[222] Public Counsel Initial Brief at ¶ 78.

[223] ICNU Initial Brief at ¶ 12.

[224] Exhibit DEM-12CT (Mills) at 44:21-46:2.

[225] *Id.* at 46:15-48:2.

[226] *Id.* at 48:5-9.

170 Mr. Mills argues that the Commission should reject Public Counsel's adjustment to rate year OSS and Public Counsel's $2.00/MWh sales margin because it is not based on any relevant actual margin information.[227] According to PSE, Public Counsel's proposed adjustment lacks any sound foundation and should be rejected.[228]

171 Mr. Mills also urges the Commission to reject Public Counsel's recommendation that PSE be required to account for OSS revenues and margins. He says that to do so would require each sale to be identified with a specific resource which would require the Company to "significantly upgrade and modify its systems, which would require costs not planned in this proceeding."[229]

172 *Commission Determination.* Revenue from off-system sales have an undeniable impact on PSE's net cost of power, just as power purchases are an important element of overall power costs. Public Counsel's attention to this issue highlights some of the limitations of the AURORA model. On balance, however, the Company has done a good job explaining why it is difficult to compare the model's results with actual operations within any given year. As a first priority, the model's normalized results are intended to capture the expected value of net power costs. The Company's evidence shows that while the model underestimates both power purchases and power sales, over the past half dozen years deviations from the baseline power rate have not been biased toward over-recovery.

173 At this point, we are satisfied that the process used to set the baseline power costs is providing a reasonable and robust result that is not partial to either the Company or its customers. We caution however, that continued examination of how well the estimation of net power costs compares with actual power costs is important. In that light, we expect the Company to continue to provide such comparative information in its rate case filings and to provide clear and concise explanations of unusual circumstances and anomalies. The data regarding off system sales and purchases and mark-to-market costs from this case are good examples.

174 We find Public Counsel's proposed reduction in power costs to account for OSS is unnecessary to ensure a reliable estimate of net power costs and conclude it should be rejected. Nor will we require additional record-keeping and reporting as Public

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[227] *Id.* at 48:19-49:7.

[228] PSE Initial Brief at ¶ 46.

[229] Exhibit DEM-12CT (Mills) at 49:10-19.

Counsel proposes. At this juncture it appears this would cause PSE to incur unnecessary expense because there is no demonstrated need for the data.

Tenaska Amortization

175 The rate year net power cost projection includes an annual $38.3 million expense associated with the buy-down of the Tenaska fuel prices as determined in Dockets UE-971619 and UE-031725. This annual amortization is scheduled to end on December 31, 2011. ICNU/Staff recommend that base rates determined in this proceeding be reduced by the revenue requirement reflecting the expiring balance of the Tenaska amortization. They recommend establishing a tariff rider with a class-specific kWh rate sufficient to recover these costs for the duration of the amortization period, but with a sunset, or ending date, of December 31, 2011. According to ICNU/Staff, this would ensure that the costs are removed from customers' rates in a timely manner with the least amount of administrative burden for the Commission and parties.[230]

176 Mr. Story says that the concept is acceptable to PSE with certain modifications. One deficiency he identifies with the ICNU/Staff proposal is that it fails to address the disallowance associated with the Tenaska buy-down. Mr. Story testifies that the disallowance is implemented as a credit of $2.3 million[231] that is also built into power costs. He contends that this amount should be removed from general tariffs at the same time the amortization of the regulatory asset is removed.

177 Mr. Story also testifies that the ICNU/Staff proposal fails to address the increase in amortization of the regulatory asset that occurs in 2011 and the return on the regulatory asset. He explains that what PSE included in the current proceeding for amortization of, and return on, the regulatory asset for the Tenaska buy down is nine months of 2010 amortization and three months of 2011 amortization. According to Mr. Story, the ICNU/Staff proposal should be corrected to collect the remaining 2011 amortization (*i.e.*, "return of"), and return on, the regulatory asset that occurs after March 2011, the end of the rate year. He testifies that the Company does not oppose implementing a tracker tariff, if the ICNU/Staff proposal is corrected to account for

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[230] *Id.* at 26:16-27:1.

[231] The final amount of the Tenaska buy down disallowance is dependent on the final authorized rate of return. Exhibit DEM-17C shows the methodology used to determine the disallowance.

all of the costs associated with the remaining Tenaska buy down, and if it provides for a true up of the tracker at the end of the rate year.[232]

178 ICNU/Staff agree with the modifications suggested by Mr. Story and recommend that the Commission order all remaining Tenaska amortization costs be excluded from base rates and recovered through a separate tariff scheduled to sunset at the end of 2011.[233]

179 *Commission Determination:* We find the ICNU/Staff proposal has merit and conclude it should be adopted with the modifications suggested by PSE. The ratepayers will benefit from the timely removal of these costs from rates, regardless of the timing of PSE's next general rate case.

180 As a part of its compliance filing, we direct the Company to remove from its revenue requirement used to set base rates all costs and amounts pertaining to amortization of the Tenaska regulatory asset consistent with the method proposed by the Company and agreed to by ICNU/Staff. We direct the Company to file a separate tariff rider for recovery of these costs set to expire once all costs have been recovered.[234]

<u>Gas Trigger Mechanism</u>

181 Public Counsel recommends the Commission consider implementing a mechanism to "trigger" a power cost reduction whenever gas prices drop by 15% or more from the gas prices reflected in the AURORA model.[235] Mr. Norwood states that PSE's gas-fired generation has increased over the past five years, which he says will make fuel costs more volatile and difficult to predict. He contends that a trigger mechanism is appropriate because the Company has little incentive under the PCA to reduce rates when market costs go down.[236] Public Counsel argues that adopting a 15 percent trigger mechanism does not impose an administrative burden on the Company since it

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[232] Exhibit JHS-14T (Story) at 16:18-17:19; Exhibit JHS-32.

[233] ICNU Initial Brief at ¶ 45 (citing Tr. at 589:18-592:5 (Story)).

[234] Removal of all costs associated with amortization of the Tenaska regulatory asset from general revenue requirement will necessarily involve revisions to a number of pro forma adjustments including, but not limited to, Adjustment 10.03 Power Costs, Adjustment 10.31 Regulatory Assets, and Adjustment 10.37 Production Adjustment.

[235] Exhibit SN-1CT (Norwood) at 42:9-13.

[236] *Id.* at 41:10-16.

was willing to adjust its baseline power cost in this proceeding to reflect a change of only 1 percent in gas prices.[237]

182 Mr. Story, for PSE opposes Mr. Norwood's recommendation, saying that the proposed mechanism is neither reasonable nor justified. He contends that, using the 2007 general rate case as an example, the average gas price set in that proceeding was \$8.35. According to Mr. Story, the actual average price of gas through October 2009, which is the end of the rate year from that proceeding, was \$3.97, a 53 percent decrease from what was set in rates. Pointing to the PCA summary report for the period ending October 2009, Mr. Story says that the Company nevertheless under-recovered its power costs by \$25 million over that period. He maintains that adding the additional under recovery of \$8.4 million experienced for the month of November 2009 to the \$25 million, the total under- recovery since the gas prices were set in rates represents an under recovery of \$33.4 million.

183 Mr. Story states that while the arguments to adjust elements of the power cost mechanism may have a certain superficial appeal, the interactions of the resources used to serve the customers are very complex. He says that this is one of the reasons why all the components of power costs are used in setting the PCA baseline rate and are reviewed together in a PCORC or general rate case. He urges that single issue adjustments for one element of the power cost forecast should be denied by the Commission.

184 *Commission Determination:* While Public Counsel's proposal may indeed have superficial appeal, the need for it is not demonstrated by evidence. It is clear from Mr. Story's testimony that an observed decline in natural gas prices between general rate cases, even one of significant magnitude, does not necessarily mean PSE is over recovering its power costs in rates. Moreover, we continue to experience a period during which PSE and other jurisdictional utilities are filing general rate cases on a regular basis. We expect that to continue and see no reason to entertain any mechanisms that might lead to an unnecessary or premature filing. Accordingly, we reject Public Counsel's recommendation.

[237] Public Counsel Initial Brief at ¶ 82.

4. Contested Adjustments—Rate Base—Electric and Natural Gas

a. Net Interest Paid to IRS for SSCM (Adjustments 10.36 and 9.03)

185 These adjustments concern PSE's use of the simplified service cost method (SSCM) of accounting under section 263A of the Internal Revenue Code from 2001 to 2003. The SSCM permits companies to deduct costs related to capitalized labor and overheads that they otherwise would have to capitalize. PSE's use of this method resulted in tax deductions totaling $204 million, for a tax benefit of $71.4 million.

186 After an Internal Revenue Service (IRS) audit disallowed the tax deduction, PSE filed a formal protest. Ultimately, PSE succeeded in retaining approximately 85% of its original tax deductions in a settlement reached with the IRS. The settlement, however, required PSE to make an interest payment to the IRS.[238] PSE proposes in this case to recover net interest it paid to the Internal Revenue Service, including carrying costs.

187 Staff recommends that the Commission reject this adjustment. Staff argues that PSE has already been the net beneficiary of the use and subsequent disallowance of the tax method. Any additional recovery, Staff argues, would be a windfall to PSE.[239]

188 Staff argues that PSE benefited for several years as a result of deductions taken through the simplified service cost method, but ratepayers received no benefits until March 2005 when the $72 million tax benefit was used to reduce rate base in a general rate case.[240] Staff says that Mr. Marcelia's testimony that customers received benefits since September 2002, when the deferred tax was recorded, relies upon "ratemaking principles" that support a "theory" that the tax benefits offset other utility-related costs that customers should bear.[241] However, Staff argues, PSE provides no support for its theory or asserted ratemaking principles.[242]

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[238] *See* Exhibit MRM-1T (Marcelia) at 11:1-13:9; Exhibit MRM-3.

[239] Staff Initial Brief ¶ 89 (citing Exhibit RCM-1T (Martin) at 12:6-16:17; Exhibit RCM-2).

[240] *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-040641 and UG-040640, Order 06 (February 18, 2007) at ¶27.

[241] Staff Initial Brief ¶ 91 (citing Exhibit MRM-4T (Marcelia) at 37:16-38:2 and Tr. 462:12-22 (Marcelia)).

[242] *Id.* (citing Exhibit MRM-8). Indeed, PSE does not explicitly make this argument in its brief.

189 Staff also argues that ratepayers have already given back to PSE the benefits they eventually derived from lower rates.[243] When the IRS disallowed all of the tax deductions that gave rise to the rate base reduction, PSE incurred financing costs associated with repayment of the tax benefit. The Commission recognized in PSE's 2005 general rate case the potential repayment of tax benefits with interest if the deductions associated with PSE's accounting method were disallowed:

> We cannot lawfully prejudge future rates. However, we do find it appropriate to recognize in principle that if the IRS successfully challenges in court the adjustment PSE and other utilities have taken, and requires future repayment of the current benefits taken, presumably with interest, PSE should file an accounting petition asking for appropriate treatment of any back taxes and interest assessed.[244]

PSE apparently did not make a filing specifically in response to this invitation until November 2008, which, according to PSE, has not yet been "brought before the Commission."[245] In other proceedings, however, the Commission allowed PSE to defer and accumulate financing costs necessary to repay the disallowed benefits,[246] and subsequently authorized rate recovery of the deferred financing costs.[247]

190 Staff's final argument is that PSE's proposed adjustment departs from the traditional ratemaking treatment of income taxes in which the Commission sets rates by looking at the whole income of a company, rather than the taxability of a single item.[248] Staff argues that PSE fails to justify the "unique" treatment it proposes in this adjustment.

191 *Commission Determination:* We find PSE's proposed adjustment to be unwarranted. Exhibit RCM-2, which the Company did not contest, shows that PSE already has received net benefits of $2,948,780 that were not passed through to ratepayers and

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[243] Exhibit RCM-2.

[244] *WUTC v. Puget Sound Energy, Inc.,* Dockets UE-040641 and UG-040640, Order No. 06 at ¶159 (February 18, 2005).

[245] PSE Initial Brief ¶ 129. Although PSE does not identify this filing in its Initial Brief, it apparently is Docket U-082012. Exhibit MRM-4T (Marcelia) at 35:1-6.

[246] *In the Matter of the Petition of Puget Sound Energy,* Dockets UE-051527 and UG-051528, Order No. 01 (October 26, 2005).

[247] *WUTC v. Puget Sound Energy, Inc.,* Dockets UE-060266 and UG-060267, Order No. 08 (January 5, 2007).

[248] Tr. 512:9-24 (Marcelia).

$6,905,776 in financing costs paid by ratepayers, for a total of $9,854,557. Subtracting the claimed net interest plus carrying costs paid to the IRS (*i.e.,* 7,741,418) shows the Company benefits exceed by $2,113,139 the amount required to keep it whole in connection with the SSCM. That is, PSE has been more than fully compensated considering all relevant factors, including interest paid to the IRS.

b. Accumulated Deferred Income Tax Adjustment

192 The Federal Executive Agencies (FEA) argue that PSE's electric and natural gas rates should be adjusted to reflect the implementation of an IRS ruling allowing the Company to adjust its tax accounting method for the treatment of repairs.[249] FEA argues that the effect of the ruling is to allow the Company to defer significant additional income taxes that should be reflected by reducing both electric and natural gas rate base.[250]

193 Mr. Smith testifies for FEA that PSE sought approval from the IRS to implement the accounting change at issue by letter dated December 30, 2008.[251] The Company does not dispute that it made this request and it confirms that the IRS granted permission for the accounting method in late 2009. Apparently, the change is reflected in the Company's 2008 tax return.[252] While the IRS has given its consent for the accounting change, it has not yet audited and accepted PSE's figures or methodology.[253] Nonetheless, FEA argues that the increase in accumulated deferred income taxes (ADIT) is known and measurable and should be reflected as a rate base reduction in this case. FEA contends that the expenditures for repairs that are at issue took place during the test year.[254]

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[249] One of FEA's arguments is that the IRS also granted Rocky Mountain Power the authorization for the accounting method at issue and that the Utah Public Service Commission approved a rate base reduction effective for a test-year ending June 30, 2010. FEA Initial Brief at 8 (citing Exhibit MRM-14 at 4-5). However, the Utah Public Service Commission's treatment of Rocky Mountain Power is neither controlling in our jurisdiction nor on point, because that treatment apparently involves a future test-year that will not conclude until June of 2010.

[250] FEA Initial Brief at 9. The actual amounts are classified as confidential under the protective order that governs the use of such information in this proceeding.

[251] Exhibit MRM-15C (Marcelia) at 1; Tr. at 470:6-9, 485:1-12; Exhibit RCS-1T (Smith) at 11.

[252] Tr. at 492 (Marcelia) and Exhibit MRM-14 at 9.

[253] Exhibit RCS-1T (Smith) at 11; Tr. at 487:21-488:5; Exhibit MRM-15C.

[254] FEA Initial Brief at 9.

194 The Company opposes FEA's proposed adjustment. According to PSE, the IRS only granted "limited approval for the Company to adopt the repairs methodology after the close of the test year." The Company points out that the IRS has not yet audited the Company's implementation of the methodology. It asserts that its experience with the IRS disallowance of the simplified service cost method (SSCM) shows why it would be inappropriate for the ADIT adjustment FEA advocates to be implemented in this case.[255] In addition it argues that the adjustment would be one-sided because significant expenditures that occurred after the close of the test-year have not been included in this rate proceeding.

195 *Commission Determination:* The Company has apparently implemented the accounting change allowed by the IRS in its 2008 tax return or an amendment to that return. However, the Company is correct to point out that the lesson of the SSCM issue demonstrates the risks of recognizing IRS-allowed accounting changes before they are audited.

196 Additionally, there is the Company's argument that the permissive tax treatment was not granted until long after the end of the test period. While the Company has definitely sought to include some adjustments in its favor that reflect events as long as 12 months after the close of the test-year, the Commission's principles governing pro forma adjustments, and its decisions in this case, are fashioned to allow such adjustments only in limited circumstances.

197 We accordingly reject FEA's adjustment in this case as an inappropriate pro forma adjustment. The final disposition with the IRS is not known and the tax impact is in any event subsequent to the test-year. Having made this determination for purposes of this proceeding, we note that the Company should implement an increase to ADIT in a future case if the IRS approves its methodology for treatment of repair costs following an audit.

c. Corporate Aircraft

198 Public Counsel argues it is reasonable to examine whether the costs of PSE's corporate aircraft are excessive relative to alternative forms of transportation and to remove costs that are considered excessive, for two principal reasons:

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[255] PSE Initial Brief at ¶ 130.

- PSE's service territory is entirely within Washington State, primarily on the west side of the Cascades in the I-5 corridor, and at most a few hours drive from company headquarters in Bellevue.

- The approximate average cost *per PSE passenger* is $945 per flight leg or $1,890 per round trip for trips that are generally of short duration.[256]

Public Counsel says Mr. Dittmer determined, using conservatively high level of expense for alternative forms of transportation, that PSE's *excess* costs from its aircraft are approximately $550,000.[257]

199 PSE observes that the costs of its corporate aircraft and aircraft operations have been allowed for recovery in rates since it was purchased in 1986.[258] The Company argues that its airplane "provides value to the customers and the Company by allowing quick and safe access to the Company's generating resources in diverse and remote locations."[259] PSE argues further that Public Counsel "ignores other benefits the airplane provides, such as performing snow level survey flights in the Cascades to allow for more efficient management of PSE's hydro operations."[260]

200 PSE also criticizes Public Counsel's analysis of the costs of alternative transportation because:

> It does not factor in such costs as the loss of productivity by employees having to drive long distances or wait for plane flights, or the additional delays that can result when relying on commercial airlines' flight schedules.[261]

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[256] Public Counsel explains in a footnote that Mr. Dittmer's $1,890 estimate for the cost per passenger for round trips was developed by dividing the total company corporate aircraft ownership and operation costs included in the development of the test year cost of service (found in Exhibit JRD-2 and Exhibit JRD-3C) and dividing this total by the number of one-way trips taken by all PSE employees, counsel , agents and other representatives during the test year (found in Dittmer workpaper titled "Aircraft Cost Adjustment") to arrive at an average cost for each "one-way" trip of $945. This amount was doubled based on an assumption that most "one-way trips" during the test year represented one leg of a round trip.

[257] Public Counsel Initial Brief at ¶ 114 (citing Exhibit JRD-1CT (Dittmer) at 74).

[258] PSE Initial Brief at ¶ 135.

[259] PSE Initial Brief at ¶ 135 (citing Exhibit MJS-12T (Stranik) 14:15-11).

[260] *Id.* (citing Exhibit MJS-12T (Stranik) 15:13-18:16).

[261] *Id.* (citing Exhibit MJS-12T (Stranik) 15:13-18:16.

While these may be legitimate criticisms of Mr. Dittmer's analysis, Public Counsel closes its argument with the point that:

> PSE provides no empirical data to show that use of the corporate aircraft is more economical than ordinary commercial travel. While it argues productivity benefits, no study has ever been performed to quantify this factor. . . . PSE officers and senior employees may find it convenient to travel by corporate aircraft, but that is not sufficient justification for asking customers to pay the excess costs of that convenience. This is type of economizing that customers can reasonably expect from PSE in the current economic climate.

Public Counsel argues this is significant because it is, after all, PSE that bears the burden of justifying its costs and the Company's attention should be focused at this time on opportunities to save even relatively small amounts of money to help keep rates reasonable.

201 *Commission Determination:* We find that Mr. Dittmer's analysis challenging PSE's recovery of these costs in rates is not sufficiently rigorous to support a decision to disallow them. His analysis, however, raises a legitimate concern. If PSE continues to seek recovery of the costs of its corporate aircraft in future proceedings, the Commission will require evidence showing the ownership and use of a corporate aircraft is more economical than other forms of travel available to the Company.

5. Contested Adjustments—Rate Base—Electric Only

a. Regulatory Assets and Liabilities (Adjustment 10.31)

202 Staff identifies three components to this adjustment that remain in dispute:

- West Coast Pipeline Capacity Payment
- White River Proceeds
- Colstrip Settlement Payment

West Coast Pipeline Capacity Payment

203 The West Coast Pipeline Capacity Payment relates to a regulatory credit PSE received from FB Energy Canada Corporation. PSE received payment on October 24, 2008,

for assumption of the pipeline capacity on November 1, 2009.[262] The payment offsets the cost of the capacity charge, which is a variable cost under the Power Cost Adjustment ("PCA") mechanism. Staff treated the credit as an offset to power-related regulatory assets as of the date PSE received payment.[263]

204 PSE agreed to Staff's proposal through Mr. Story's rebuttal testimony, subject to not having to restate prior period PCA reports and financial impacts in previous periods. Mr. Story testifies that these impacts, instead, should be reflected at the time an order issues in this proceeding.[264]

205 Staff argues, however, that:

> PSE ignores the fact that adjustments to prior PCA periods are addressed by approved procedures. Adjustments for previous PCA periods of $1 million or less (debit or credit) flow through the current month's calculation. Adjustments above $1 million (debit or credit) flow through the recalculation of the prior PCA period. PSE has provided no justification to diverge from these established procedures.[265]

206 PSE does not address this matter in its brief.

207 *Commission Determination:* We accept Staff's adjustment, treating the regulatory credit as an offset to power-related regulatory assets as of October 24, 2008. We see no reason to disturb the established PCA procedures described by Staff and direct that they be followed in connection with this adjustment.

White River Proceeds

208 Public Counsel and Staff reflect in this adjustment a net reduction in the tax ramifications of the sale of the White River assets and water rights to the Cascade Water Alliance. PSE initially assumed that all of the sales proceeds would be taxable and proposed to reflect taxes payable as an offset to proceeds of the sale and an

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[262] Exhibit RCM-1T (Martin) at 9:15-20.

[263] *Id.* at 10:1-8.

[264] Exhibit JHS-14T (Story) at 48:2-9.

[265] Staff Initial Brief ¶ 126 (citing *In the Matter of the Petition of Puget Sound Energy, Inc.*, Docket UE-031389, Order 04, Attachment A, Exhibit A, Section C (January 14, 2004)).

increase in rate base. Mr. Dittmer's testimony, however, showed that there would be an expected tax loss on the transaction which would act as an offset to other taxable income generated by electric operations.[266] PSE, accordingly, removed the tax amounts associated with the White River sale.[267]

209 PSE, however, has not agreed with Public Counsel's position, now also subscribed to by Staff, that there should be an incremental rate base reduction to recognize the probable tax loss, which would translate to a tax receivable not yet recognized by the Company. In other words, Public Counsel and Staff argue the tax receivable should be used to reverse the rate base addition proposed by PSE in the form of a tax payable amount.[268] Although the record clearly reflects that the sale will result in a tax loss and attendant tax receivable, PSE argues in rebuttal that it is inappropriate to consider such tax losses in this proceeding until all of the transactions have occurred.[269]

210 Public Counsel argues that this argument is not persuasive because:

> If it was appropriate for PSE to reflect taxes payable as an offset to proceeds of the sale and an increase in rate base, as originally proposed, it is likewise appropriate to recognize the rate base reduction reflecting the tax receivable now expected to result from the sale.[270]

Staff agrees.[271] Staff also points out that the adjustment it adopts from Public Counsel is consistent with the Commission's order establishing that proceeds from the sale of White River assets and all related costs would be deferred without amortization.[272]

211 *Commission Determination:* We find it reasonable to require PSE to reduce its rate base to reflect the tax receivable expected to result from the sale the White River assets, as proposed by Public Counsel and Staff. Application of the proceeds can be

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[266] Exhibit JRD-1CT (Dittmer) at 15.

[267] Exhibit MRM-4T (Marcelia) at 3.

[268] Exhibit JRD-1CT (Dittmer) at 15:9-20.

[269] *Id.* PSE Initial Brief at ¶ 118.

[270] Public Counsel Initial Brief at ¶ 128.

[271] Staff Initial Brief at ¶¶ 130 and 131.

[272] *In the Matter of the Petition of Puget Sound Energy, Inc.,* Docket UE-032043, Order 06 at ¶¶251-253 (February 18, 2005).

addressed in the next general rate case after the sale of all assets and surplus property is complete.[273]

Colstrip Settlement Payment

212 PSE proposes to defer and amortize over a five year period the cost incurred from certain Colstrip litigation settled in the 2008 test year. Specifically, PSE included in rate base $5.8 million during the rate year which represents the $10.4 million Colstrip settlement payment less the $2.0 million insurance receivable along with carrying charges to be recovered over five years at $1,967,556 per year.[274]

213 Staff argues that the Commission should approve creation of a regulatory asset, as proposed by PSE, "only in unusual or extraordinary circumstances."[275] Staff, calculating that the $8.4 million settlement payment is relatively immaterial, constituting only 0.42 percent of total test year operating expense, argues the amount should be expensed, in accordance with FERC's Uniform System of Accounts and GAAP. Staff states that its approach "recognizes that costs of this nature do occur from time to time and, therefore, should be considered as a cost of business relative to their contribution to total expense."[276]

214 Public Counsel argues that the Commission should deny PSE's proposal to recover any Colstrip litigation expenses from customers because "[t]his litigation expense is an unusual and non-recurring item."[277] Therefore, Public Counsel contends, this litigation expense should be borne by shareholders.

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[273] *In the Matter* of *the Application of Puget Sound Energy, Inc.,* Docket UE-090399, Order 01 at ¶13 (May 14, 2009).

[274] PSE Initial Brief at ¶ 119 *(citing* Exhibit B-3; PSE's Response to Bench Request No. 3, Adjustment 10.31).

[275] Staff Initial Brief at ¶ 134 (citing *Re Puget Sound Power & Light Co*., Dockets UE-920433, 920499 and 921262, 11th Supp. Order at 53 (September 21, 1993) (rejecting deferred accounting of costs without a Commission order approving same) and *Re Pacific Power & Light Co*., Cause Nos. U-82-12 and U-82-35, 4th Supp. Order at 23-24 (February 1, 1983) (rejecting deferred accounting of expenses into capital accounts to the extent the company failed to achieve its authorized return)).

[276] Staff Initial Brief at ¶ 135.

[277] Public Counsel Initial Brief at ¶ 125.

215 PSE rejoins that Public Counsel fails to take into consideration this settlement payment protects the customers' interest in a low cost production resource and is known and measurable.

216 *Commission Determination:* We are not persuaded that the costs of the Colstrip litigation should be afforded any extraordinary treatment, either as a regulatory asset or as a non-recurring expense. Indeed, these costs are not out of the ordinary and it is appropriate to treat them as a test period expense, as proposed by Staff.

b. Production Property Adjustment (10.37)

217 The Commission recognizes that while it is reasonable to reduce regulatory lag and avoid the under-recovery of the significant costs associated with the acquisition of production assets and power to meet the load expected during the rate year, it is important in doing so to preserve the matching principle. The method by which the Commission has addressed this problem for PSE for many years is by application of a so-called production factor. The production factor is applied so that power and production-related costs are built into rates at the same unit cost when spread over test year loads as they would be using rate year costs spread over rate year load.[278]

218 The production factor is applied separately to power costs and production-related costs. The effect of the production factor on power costs is embedded in Adjustment 10.03, discussed *supra,* in section II.B.3 of our Order.[279] Adjustment 10.37 the production property adjustment, reflects the application of the production factor only to the production-related costs.

219 The production factor is based on the ratio of the test period normalized delivered load to the rate year delivered load. From the time the production factor adjustment was first adopted in the 1970's, PSE has been in a growth mode. Now, however, the Company projects a significant reduction in loads during the rate year relative to the test year. The Company's September 28, 2009, supplemental filing includes a significant reduction in forecasted rate year electric loads of 932,382 MWhs, as

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[278] *See* Exhibit JHS-14T (Story) at 14:20-15:7.

[279] Although we do not develop the point here, or in our discussion of power costs, application of the production factor proposed by PSE increases power costs by approximately $17 million.

compared to PSE's initial filing. This represents an approximate 3.9 percent reduction in rate year loads, as compared to the initial filing.[280]

220 Under these conditions, Mr. Parvinen for Staff recommends that the production factor adjustment be eliminated in developing the Company's electric revenue requirement in this proceeding. He testifies that the adjustment shifts the risk of reduced loads from the Company to its customers. This in turn, removes the incentive and obligation of the Company to control costs and mitigate the impacts of reduced loads on its financial performance, according to Mr. Parvinen. It simply proposes to adjust loads to compensate itself for the financial consequences of projected reduced loads and the effects those reductions may have on revenues.[281]

221 Mr. Parvinen says the adjustment was never contemplated to be an attrition offset for projected load reductions due to reduced economic activity. The adjustment, he testifies, was designed as an offset to the pro forma rate base calculation where new production rate base was added outside of the test year to serve increasing loads. Staff says that if the Company believes that there is attrition mismatch between test period revenue, expenses, and rate base, it should have supported the adjustment with an attrition analysis in its direct case. According to Staff, it is improper to use the production property adjustment as a "backdoor" means to a proper attrition analysis.[282] Staff contends that the Company has not provided a rebuttal regarding the underlying rationale of Staff's position.[283]

222 Mr. Story, for the Company, says that the production adjustment does not become an adjustment for positive attrition now anymore than it was an adjustment for negative attrition when load was growing.[284] The Company argues that, because the same unit cost per kWh is built into rates for the rate year and the test year after the production factor has been applied, there is no positive, or negative, attrition built into the adjustment. PSE asserts the Commission has affirmed the production adjustment,

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[280] Exhibit DEM-9CT (Mills) at 4:11 and Exhibit DEG-9T (Gaines) at 9:3. The Company's proposed conservation phase-in adjustment also affects the originally filed production factor. Our rejection of that adjustment increases *test-period* load by 119,213 MWh. (*See* Exhibit JHS-23 at 2).

[281] Parvinen, MPP-1T 19:16-19.

[282] Exhibit MPP-1T (Parvinen) at 20:5.

[283] Staff Initial Brief at ¶ 160.

[284] Exhibit JHS-14T (Story) at 16:10-16.

noting the Commission described it as a "well established mechanism" for "adjusting rate year cost to match rate year loads."[285] PSE states its approach does no more than allow for the recovery of the production-related costs the Commission approves for recovery in the rate year.[286]

223 Public Counsel proposes an alternative modification to the Company's production property adjustment that removes the effect of the conservation phase-in adjustment and Public Counsel's other rate base adjustments. Public Counsel does not propose a change to the production property methodology or the projected load reduction.

224 The matter of a production property adjustment was at issue in the recent Avista general rate case proceeding. The Commission's Final Order in that proceeding relates Staff's testimony, as follows:[287]

> Staff asserts that the purpose of the adjustment is to "bring the pro formed rate year costs, on a unit basis, back to the historical test year for proper matching and comparability of all costs used in the revenue requirement determination." Staff says that its method allows the Company to recover its test year costs at rate year loads, which is the objective of this type of adjustment.

In this case, Staff apparently believes that the principles guiding the adjustment only apply if loads are growing and that the Company is not entitled to recover its pro formed test-year costs at rate year loads simply because they are lower, rather than higher relative to the test year. Staff's position is logically inconsistent with its position and the Commission's order from only a few months ago. While the factual context here is distinguishable from the Avista facts, this should not engender a new set of principles.

225 *Commission Determination:* While we have some concerns that PSE's revised load forecast is not consistent with other representations the Company has recently made concerning future load,[288] other parties have not challenged it on this record.

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[285] PSE Reply Brief, ¶ 27 (citing *Avista 2009 GRC Order* at ¶ 50 (December 22, 2009).

[286] *Id.*

[287] Avista 2009 GRC Order at ¶ 100.

[288] We take administrative notice of PSE's revised load forecast presented with its 2009 IRP in the Company's briefing to the Commission on September 10, 2009. We are concerned and perplexed about the apparent discrepancy between that load forecast for the near-term period, which appears

Therefore, we accept it for purposes of establishing rates in this proceeding. At the same time, the Company's proposed decrease *in test period loads* considering its conservation phase-in adjustment is contested by several parties. As previously discussed, we reject the Company's conservation phase-in proposal and therefore adjust upward the test period loads.

226 The net effect of these adjustments to rate period and test period loads is to increase power cost and costs associated with production rate base by 1.760 percent rather than to reduce those costs by 2.741 percent as was the case in the Company's original filing. The production adjustment now decreases net operating income by $2,740,945 versus an increase of $4,657,230 in the original filing, and increases rate base by $27,799,765 versus a decrease of $43,893,528 in the original filing.[289]

227 Because several of our decisions affect the production rate base and related costs, we direct the Company to recalculate this adjustment to give effect to all of our decisions that bear on calculation of the production adjustment including but not limited to the following: the conservation phase-in adjustment, adjustments 10.07 and 10.08 related to Mint Farm and Wild Horse, adjustments 10.34 and 10.38 related to Mint Farm and Wild Horse deferred costs, adjustment 10.31 related to regulatory assets and liabilities, and the removal of all costs and other amounts pertaining to amortization of the Tenaska regulatory asset that we direct be removed from base rates and collected through a separate tariff as discussed below.[290]

228 We acknowledge that the effect of rejecting the conservation phase-in adjustment is to increase test year loads relative to the loads PSE used to calculate its production factor. This, in turn, increases the production factor and the Company's revenue

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to indicate positive load growth during the rate year, and the 3.9 percent reduction in load forecast for the rate year in the Company's supplemental filing in this proceeding. We have traditionally placed substantial emphasis on the analysis included in the IRP process, and in particular its load and resource balance, since this provides specific information regarding both the timing and preferred resource mix in the future. In this instance, prior to 2009, we specifically asked the Company to revise its IRP load forecast in light of the economic recession. Since both filings were submitted to us within a short period of time, we would not expect to see such a wide divergence in the load forecasts.

[289] Exhibit JHS-9T (Story) at 8:1-8. We note, as previously discussed, that Adjustment 10.37 only addresses production property rate base and associated costs. It does not address application of the production factor adjustment to net power cost. The effect of the production factor adjustment on net power costs is reflected in the power cost adjustment, number 10.03.

[290] At ¶¶ 177-182.

requirement. There is, however a benefit to customers and to the public interest because PSE's more aggressive 2009 IRP conservation target is supported by recognizing in rates the effect of overall load reduction in the rate year, including conservation, relative to the test year.[291] That is, the production factor adjustment shelters production related costs and power costs, which are a major portion of the Company's costs, from the effects of the decline in sales beyond the test year due to Company sponsored conservation.

c. Wild Horse Expansion Rate Base (Adjustment 10.07)

229 PSE expanded the Wild Horse wind generation facility by adding 22 turbines that went into service on November 9, 2009. The Company initially used its cost analysis of the plant expansion to estimate the impact on rate year costs. PSE updated these estimated costs in its rebuttal filing to reflect different estimates for the final costs of construction and rate year expenses.[292] The Company used forecast capital cost expected by December 2009 to calculate the gross plant values for the Wild Horse Expansion.

230 Staff points out that PSE's revised budget forecasts of plant and rate year costs on rebuttal differed significantly from its original estimates.[293] Specifically, PSE's forecast decreased $5,469,920 (5.3 percent) for plant investment, increased $1,295,256 (5630.1 percent) for wheeling, decreased $82,056 (100.0 percent) for property insurance, and decreased $274,947 (61.4 percent) for property taxes.[294] Staff argues that this "demonstrates that the judgment of management, even if informed through detailed analysis, can result in forecasts that fluctuate, in some cases significantly, in violation of [the] requirements [for pro forma adjustments]."[295]

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[291] *See* Exhibit DEG-9T (Gaines) at 4:3-11; 8:15-18 ("PSE's third and final major change to the [F2008 load] forecast was an increase of the programmatic conservation to reflect the higher energy efficiency acquisition targets that PSE included in the 2009 IRP.").

[292] Exhibit JHS-14T (Story) at 30:2-8.

[293] Staff Initial Brief at ¶ 113 (citing Exhibit JHS-14T (Story) at 30:6-14).

[294] *Id.* (inviting comparison of Exhibit JHS-10 at 13 to Exhibit B-2 at Attachment C, page 2.14). We discuss and resolve issues related to property insurance and property taxes in other sections of this Order.

[295] *Id.* at ¶ 115.

231 Staff's adjustment substitutes all of PSE's rate year projections with actual plant balances through August 2009.[296] Staff's adjustment also reflects the land value of the project included in the test year and the depreciation calculation reflects the actual in-service date of November 9, 2009.[297]

232 *Commission Determination:* Staff's adjustment, based on actual data, meets the requirements of a pro forma adjustment used in historic test year ratemaking in terms of being known and measurable. PSE's approach, using estimates, does not meet these requirements. Although the data on which Staff relies became known and measurable further out from the end of the test year than would ideally be the case, we are less concerned that this might result in a mismatch of costs and revenues because the assets at issue are generation assets, the benefits of which are matched to a significant degree via the power cost and production factor adjustments. We accept Staff's rate base adjustment for the Wild Horse Expansion project.

d. Mint Farm Rate Base (Adjustment 10.08)

233 PSE acquired Mint Farm, a 311 MW natural gas-fired, combined cycle combustion turbine (CCCT) generation facility located in Longview, Washington, and placed it in service in December 2008. PSE's pro forma adjustment relies on the Company's cost analysis of the plant to estimate the impact of the plant on rate year costs. The Company updated these costs on rebuttal to reflect actual plant balances through October 2009 and trued up the estimates of the final costs of construction and rate year expenses.[298]

234 Staff argues, as in the case of the Wild Horse Expansion project, that PSE's adjustment demonstrates again that projections based on management judgment, even when informed, are an improper basis for ratemaking. This is illustrated, Staff argues, by PSE's revised adjustments on rebuttal that include new estimates of plant additions through December 2009.[299] According to Staff, PSE's revised adjustment decreased $3,922,732 (1.6 percent) for plant including acquisition costs, decreased $401,950 (52.1 percent) for property insurance, decreased $475,252 (36.7 percent) for

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[296] Exhibit KHB-1TC (Breda) at 28:14-17.

[297] Exhibit B-3 at Exhibit KHB-2, page 2.14.

[298] *See* Exhibit JHS-14T (Story) at 32:18-33:6.

[299] Exhibit No. JHS-14T (Story) at 33:9-11.

property tax, decreased $2,864,717 (4.6 percent) for fuel expense, and decreased $4,148,029 (44.30 percent) for O&M expense.[300]

235 Staff's adjustment substitutes all rate year projections with verified, actual plant balances and expense through August 2009.[301]

236 *Commission Determination:* Staff's rate base adjustment, as in the case of the Wild Horse Expansion project discussed immediately above, is based on actual data. Thus, it is known and measurable. PSE's estimates do not meet these requirements. Staff again measured actual plant balances through August 2009, but our concerns about matching are allayed for the same reasons as discussed in the preceding section of this Order. We accept Staff's rate base adjustment for Mint Farm.

e. Mint Farm and Wild Horse Deferred Costs (Adjustments 10.34 and 10.38)

237 PSE requests approval under RCW 80.80.060(6) to defer the fixed and variable costs of Mint Farm, beginning on the acquisition date of December 5, 2008, and ending with the effective date of new rates in this proceeding. Given our determination elsewhere in this Order that RCW 80.80 applies to Mint Farm, PSE is entitled to defer these costs beginning on December 5, 2008.

238 On October 27, 2009, PSE filed with respect to the Wild Horse expansion project a notice of intent to defer, as permitted by RCW 80.80.060(6). There is no dispute that RCW 80.80 applies to the Wild Horse Expansion project and deferrals began on November 9, 2009, the same day the expansion became operational.[302]

239 Although Staff and PSE both contend that there are two contested issues in common as between Mint Farm and Wild Horse with respect to the treatment of these deferred costs, it appears that there is, in fact, only one: Whether PSE is entitled to recover carrying costs on the deferred costs.

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[300] Staff Initial Brief at ¶ 117 (inviting comparison of Exhibit B-2 at Attachment C, page 2.15 to Exhibit JHS-10 at 14).

[301] As discussed elsewhere in this Order, Staff included actual premiums for property insurance and actual taxes, removing PSE's estimated property tax. Staff Adjustment 10.15 includes the 2008 actual tax liability for all property. *See* Exhibit KHB-1TC (Breda) at 29:16-22.

[302] Exhibit No. RCM-1T at 17:11-19.

240 PSE argues that it should be allowed to recover carrying costs on the deferral. In support of this contention, PSE relies on an extensive quote from Mr. Story's testimony, as follows:

> When a company does not have revenues coming in to recover its costs of purchasing a new plant that is in-service, it has to finance the funds to cover the lack of revenues. This is true not just for the cash expenditures that are funding interest on the financing used to buy the plant and fund its current operations and maintenance expenses, it is also true for depreciation and the equity return not received. Depreciation and the equity return are certainly the two main contributors of cash generation for a utility. Without this cash available, additional funds must be raised and the cost of financing these new funds are an additional cost associated with operating the plant that is now in-service. This is the interest that is being deferred and the cost is calculated using the rate the Commission has already approved as the appropriate cost of capital in the Company's last general rate case. There is no part of this that is "tantamount to double recovery" – it is simply recovery of all of the costs associated with the resource.[303]

241 The principal weakness of this argument, as Staff points out, is that it tacitly depends on the notion that the right to *defer* costs under RCW 80.80 is tantamount to a right to *recover* instantly the deferred costs. This is belied by the language of the statute itself, which states expressly that the creation of a deferral account "does not by itself determine actual costs of the [resource addition], whether recovery of costs is appropriate, or any other issues decided by the Commission in a general rate case."[304]

242 In addition, as Staff also argues, a portion of Mint Farm fixed costs is return on net rate base consisting of plant balance, accumulated depreciation, and deferred income tax. If carrying costs are allowed, the Company's total return on investment will exceed the allowed net of tax return.

243 Finally, with respect to deferred expenses, we must consider that PSE's rate base includes an allowance for investor-supplied working capital. As Staff says: "This allowance, upon which PSE earns a return, provides the Company with funds to pay

[303] Exhibit JHS-14T (Story) at 53:4-17.

[304] RCW 80.80.060(6).

its current obligations while awaiting payment from customers."[305] The Commission allows PSE to earn a return on investor supplied working capital. Thus, according to Staff, no further allowance for carrying costs is appropriate.

244 PSE and Staff also identify and argue the question whether the operation of PCA Exhibit G should be suspended with respect to the treatment of net variable costs included in the deferral amounts. Staff and PSE, however, now agree on the treatment of these costs.[306] We accordingly have no reason to address what apparently is, in the context of this case, no more than a theoretical question concerning the operation of the PCA.

245 There is an additional contested issue with respect to the treatment of Mint Farm deferred costs. PSE argues for a 10-year amortization period. Staff advocates a 15 year amortization period.

246 PSE's argument is based simply on the point that a "ten year amortization period for the Mint Farm deferral is consistent with recent decisions." The example PSE offers is that "the cost of the Mint Farm deferral are approximately 70% of the storm costs that were deferred over ten years as approved in the settlement of PSE's 2007 general rate case."[307] PSE does not explain how the determination of an appropriate amortization period for storm costs is in any way relevant to the determination of an appropriate amortization period for costs associated with a hard asset that has a remaining life of 25-30 years.[308] Staff argues would be "reasonable to amortize the deferred costs over that period in order to match the depreciation of plant costs." Staff nevertheless proposes to amortize the deferred costs associated with Mint Farm over 15 years, which "accelerates recovery in the Company's favor"[309] relative to what would be the case if costs were recovered over the remaining life of the plant.

247 *Commission Determination:* PSE's deferral accounts for Mint Farm and Wild Horse include the Company's capital costs, return on those capital costs and the operating expenses allowed pursuant to the agreement with Staff concerning the treatment of net variable costs. RCW 80.80 allows the Company to defer these costs but does not

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[305] Staff Initial Brief at ¶ 150.

[306] Staff Initial Brief at ¶ 140; PSE Initial Brief at ¶ 122.

[307] Exhibit JHS-14T (Story) at 54:18 – 55:1.

[308] Exhibit DN-1HCT (Nightingale) at 16:14-19.

[309] Staff Initial Brief at ¶ 153.

authorize recovery and, indeed, expressly reserves the question of recovery for later determination by the Commission in a general rate case proceeding such as this one. Thus, the statute does not disturb the allocation of risks for recovery of deferred costs. It remains just as it would be if PSE were required to file an accounting petition and obtain our approval to defer these costs. It follows from this that there is no reason to allow PSE to recover yet additional revenue in the form of carrying costs.

248 Staff's proposed 15-year amortization for the Mint Farm deferred costs, tied to the expected life of the assets is reasonable. We determine it should be approved.

f. Baker Hydro Relicensing (Adjustment 10.11)

249 This adjustment relates to the cost of obtaining a new license for the Baker River Project. PSE adopted Staff's adjustment for actual plant additions and related amortization expense through August 2009.[310] The only remaining difference is the basis for federal land use fees.[311] Staff excludes what it characterizes as "PSE's rate year estimate of these costs."[312]

250 PSE argues that the fee for 2010 is known and measurable.[313] Mr. Lane testifies for PSE that the Federal Energy Regulatory Commission (FERC) adopted an updated fee schedule on February 24, 2009, for calculating annual charges for use of federal lands.[314] According to Mr. Lane, FERC's regulations[315] double the U.S. Bureau of Land Management's linear right-of-way fees to establish the annual fees for the use of federal lands for project works other than transmission lines, such as these Baker

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310 Exhibit JHS-14T (Story) at 40:3-4.

311 Exhibit B-3 at KHB-2, page 2.18. Staff corrected the amortization rate and accumulated deferred income tax to conform to the Company's adjustment. *See* Exhibit JHS-14T (Story) at 41:3-20.

312 Staff Initial Brief at ¶ 120 (citing Exhibit KHB-1TC (Breda) at 32:17).

313 PSE Initial Brief at ¶ 105 (citing Exhibit KWL-1T (Lane) at 9:6).

314 Exhibit KWL-1T (Lane) at 8:12-17 (citing *Update of the Federal Energy Regulatory Commission's Fees Schedule for Annual Charges for the Use of Government Lands*, 74 Fed. Reg. 8184 (February 24, 2009) FERC Stats. & Regs. ¶ 31,288 (2009); *see also* Order Denying Rehearing, 129 FERC ¶ 61,095 (October 30, 2009)).

315 18 C.F.R. § 11.2(b).

Project federal lands.[316] Mr. Lane testifies further that FERC issued an invoice to PSE for the Baker Project's 2009 annual charges for use of federal lands in the amount of $887,223.64, or 75 percent of the full scheduled rental rate in 2009. He notes that this is a significant increase from the 2008 invoiced amount of $231,252.63. Finally, relying on various government publications, Mr. Lane testifies that while PSE is only required to pay 75 percent of the fee in 2009, the amount in 2010 will be the full 100 percent, or a total fee of $1,109,030.00.[317]

251 *Commission Determination:* We find this a close question because Mr. Lane's testimony for the Company is thorough and well documented. It nevertheless depends on expectations of future events as to which there is no evidence of actual experience. That is, our record does not include an invoice or other evidence finally establishing the fee for PSE's use of federal lands in connection with the Baker River facilities during 2010. Thus, we cannot find the amount is known and measurable. We accept Staff's recommendation resulting in an NOI adjustment of $(855,589).[318]

6. Contested Adjustment—Rate Base—Natural Gas Only

a. Jackson Prairie

252 PSE states that it received a refund of tax and interest previously paid to the Washington State Department of Revenue relating to the expansion of the Jackson Prairie natural gas storage facility. "PSE accounted for the refund in the same manner in which the original assessment was handled, with the sales tax portion of the refund being applied to capital orders associated with the Jackson Prairie project and the interest portion being applied to interest."[319] According to Staff, this means PSE reduced the Jackson Prairie rate base by $246,875.[320]

253 Public Counsel proposes to reduce the plant balance of Jackson Prairie by the amount of PSE's one-third share of the refund, $246,875. Staff states in its Initial Brief that it

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[316] Exhibit KWL-1T (Lane) at 8:17-21 (citing Order Denying Rehearing, 129 FERC ¶ 61,095, at ¶ 8 (October 30, 2009)).

[317] *Id.* at 9:6-21.

[318] Exhibit B-3 (Revision to Exhibit KHB-2, updating Staff's revenue requirements)

[319] PSE Initial Brief at ¶ 141 (citing Exhibit MRM-4T (Marcelia).

[320] Staff Initial Brief at ¶ 161.

adopts Public Counsel's proposal. Mr. Dittmer offered no rationale for this treatment in his testimony and Public Counsel makes no argument of principle on the point in its Initial Brief.

254 *Commission Determination:* Given the testimony and argument presented, it is difficult to understand what, if anything, actually separates the parties on this issue. Public Counsel's recommendation, adopted by Staff, is to reduce PSE's plant balance (*i.e.,* rate base) by $246,875. Staff states that PSE has already reduced the Jackson Prairie rate base by $246,875. PSE, however, does not expressly confirm that the plant balance it included for Jackson Prairie in its initial filing in this case was reduced by this amount.

255 In any event, we find that the plant balance for Jackson Prairie, which we describe for purposes of ratemaking as "rate base," must exclude the $246,875 refund amount that was previously capitalized.

7. Summary of Electric Revenue Requirement Determination

256 Table 4 summarizes the Commission's determinations with respect to the contested electric adjustments (shaded) and the uncontested adjustments, which we accept without the necessity for detailed discussion. Table 5 shows the Electric Revenue Requirement that we approve for recovery in rates, subject to revision to reflect recalculation of the Tenaska and March Point disallowances affecting the power costs adjustment (10.03) and recalculation of the production property adjustment (10.37) made necessary by our decision concerning Mint Farm, Wild Horse and regulatory assets and liabilities.

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TABLE 4
Commission Determinations of Restating and Pro Forma Adjustments – Electric

Adjustment	Adj. #		NOI	Rate Base	Rev Reqm't
Temperature Normalization	10.01		(12,235,767)	0	$19,695,019
Revenues and Expenses	10.02		86,639,195	0	(139,456,775)
Power Costs [a]	10.03		48,587,893	0	(78,208,377)
Federal Income Taxes *	10.04		(19,308,575)	0	31,079,601
Tax Benefit of Pro Forma Interest	10.05		522,225	0	(840,587)
Hopkins Ridge Infill	10.06		(204,970)	4,075,268	861,258
Wild Horse Expansion	10.07		(3,289,703)	65,055,430	13,777,107
Mint Farm	10.08		(46,408,534)	217,579,446	103,068,382
Sumas	10.09		(594,207)	8,753,305	2,097,705
Whitehorn	10.10		(2,025,046)	17,953,824	5,600,384
Baker Hydro Relicensing	10.11		(855,589)	31,784,211	5,521,197
Pass-Through Revenues & Expenses	10.12		(640,213)	0	1,030,504
Bad Debts	10.13		1,021,353	0	(1,643,997)
Misc Operating Exp	10.14		1,578,526	0	(2,540,838)
Property Tax	10.15		(883,953)	0	1,422,834
Excise Tax & Filing Fee	10.16		264,096	0	(425,096)
D&O Insurance	10.17		205,413	0	(330,638)
Montana Electric Tax *	10.18		50,981	0	(82,060)
Interest on Customer Deposits	10.19		(61,479)	0	98,958
SFAS 133	10.20		4,899,699	0	(7,886,687)
Rate Case Expense	10.21		380,361	0	(612,239)
Deferred Gains/Losses on Property Sales	10.22		(247,166)	0	397,845
Property & Liability Ins	10.23		(778,678)	0	1,253,381

Pension Plan	10.24		(486,442)	0	782,990
Wage increase	10.25		(1,823,076)	0	2,934,472
Investment Plan	10.26		(86,983)	0	140,010
Employee Ins	10.27		(935,975)	0	1,506,570
Incentive Pay	10.28		1,137,979	0	(1,831,722)
Merger Storm Savings	10.29		568,233	0	(914,643)
Storm Damage	10.30		(6,176,024)	0	9,941,094
Regulatory Assets & Liabilities	10.31		(4,659,619)	(116,363,511)	(7,671,201)
Depreciation Study	10.32		9,109,591	4,554,795	(14,069,189)
Fredonia Power Plant	10.33		(1,051,142)	41,512,955	7,104,396
Amortization of. Mint Farm Def Cost	10.34		(2,377,216)	27,099,835	7,359,701
Fleet Vehicles	10.35		1,272,207	7,448,028	(1,076,706)
Net Interest Paid to IRS	10.36		0	(3,530,928)	(460,362)
Production Adjustment [b]	10.37		(2,740,945)	27,799,765	8,036,426
Wild Horse Deferred Cost	10.38		(1,824,273)	2,747,493	3,294,616
Wild Horse Solar Removal	10.39		113,791	(3,663,687)	(660,832)
Excess Aircraft Costs			0	0	0
Injuries & damages			652,896	0	(1,050,919)

[a] The Power Cost adjustment will require revision to recalculate Tenaska and March Point disallowances and to remove recovery of the Tenaska regulatory asset from base rates. This can be accomplished during the compliance filing phase of this proceeding.

[b] The Production adjustment will require revision during the compliance filing phase of this proceeding to reflect removal of the Tenaska regulatory asset from base rates and our decisions concerning Mint Farm and Wild Horse (*i.e.,* Adjustments 10.07, 10.08, 10.34 and 10.38), and our decision concerning Regulatory Assets and Liabilities (Adjustment 10.31).

* These are so-called fall-out adjustments as to which the parties do not disagree in principle.

TABLE 5
Electric Revenue Requirement

Rate Base	$3,797,019,369
Rate of Return	8.10
NOI Requirement	$307,558,569
Pro Forma NOI	$272,640,632
Operating Income Deficiency	$34,917,937
Conversion Factor	.621262

Gross Revenue Requirement Increase	$ 56,204,849

8. Summary of Natural Gas Revenue Requirement Determination

257 Table 6 summarizes the Commission's determinations with respect to the contested natural gas adjustments (shaded) and the uncontested adjustments, which we accept without the necessity for detailed discussion. Table 7 shows the Natural Gas Revenue Requirement that we approve for recovery in rates.

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TABLE 6
Commission Determinations -Restating and Pro Forma Adjustments – Natural Gas

Adjustment	Adj. #	NOI	Rate Base	Revenue Requirement
Temperature Normalization	9.01	(8,781,321)	0	14,120,354
Revenues & Expenses	9.02	20,919,189	0	(33,638,031)
Net Interest to IRS for SSCM	9.03	0	(2,443,571)	(318,270)
Federal Income Tax	9.04	1,028,039	0	(1,653,086)
Tax benefit of Pro Forma Interest *	9.05	(8,079,880)	0	12,992,437
Depreciation Study	9.06	(6,218,349)	(3,109,174)	9,594,135
Pass Through Revenue & Expense	9.07	342,920	0	(551,415)
Bad Debts	9.08	454,572	0	(730,951)
Miscellaneous Operating Expense	9.09	894,751	0	(1,438,759)
Property Taxes	9.10	(308,161)	0	495,523
Excise Tax & Filing Fee	9.11	693,130	0	(1,114,552)
D&O Insurance	9.12	142,454	0	(229,066)
Interest on Customer Deposits	9.13	(30,273)	(6,973,756)	(859,638)
Rate Case Expense	9.14	153,958	0	(247,564)
Deferred Gains/Losses on Property Sales	9.15	(313,412)	0	503,966
Property & Liability Insurance	9.16	234,055	0	(376,360)
Pension Plan	9.17	(262,622)	0	422,296
Wage Increase	9.18	(866,475)	0	1,393,291
Investment Plan	9.19	(43,626)	0	70,151
Employee Insurance	9.20	(505,317)	0	812,549
Incentive Pay	9.21	615,785	0	(990,182)
Merger Savings	9.22	311,112	0	(500,268)

Fleet Vehicles	9.23	696,545	4,077,858	(588,911)
Jackson Prairie	9.24	0	(246,875)	(32,155)
Corporate Aircraft Costs		0	0	-
Injuries & Damages		130,086	0	(209,178)

* This is a so-called fall-out adjustments as to which the parties do not disagree in principle.

TABLE 7
Natural Gas Revenue Requirement

Rate Base	$ 1,467,519,444
Rate of Return	8.10%
NOI Requirement	$ 118,869,075
Pro Forma NOI	$ 112,557,361
Operating Income Deficiency	$ 6,311,714
Conversion Factor	0.621891
Gross Revenue Requirement Increase	$ 10,149,229

C. Capital Structure and Cost of Capital

258 PSE's currently authorized rate of return (ROR) is 8.25 percent with a return on equity (ROE) of 10.15 percent and an equity ratio of 46 percent. The Commission set these factors on October 8, 2008, in an order approving and adopting the parties' full settlement in Dockets UE-072300 and UG-072301 (consolidated).[321] In this docket, filed just seven months later, the Company requested an overall ROR of 8.5 percent based on a 10.8 percent ROE and an equity ratio of 48 percent.

259 Table 8 summarizes PSE's currently approved capital structure and cost rates and the recommendations of the Company, Staff and Public Counsel in their respective briefs. Our determinations, discussed in detail below, are shown in Table 9.

[321] *WUTC v. Puget Sound Energy,* Final Order Approving And Adopting Settlement Stipulations: Authorizing And Requiring Compliance Filing, Order 12, Dockets UE-072300 and UG-072301(consolidated) (October 8, 2008) at ¶ 51.

TABLE 8
Capital Structure and Cost of Capital Proposals

	Commission Approved		Company Proposal		Staff Proposal		Public Counsel Proposal	
	Share/Cost		**Share/Cost**		**Share/Cost**		**Share/Cost**	
Equity	46.0	10.15	48.0	10.8	45.0	10.0	43.0	9.50
Long-Term Debt	53.97	6.64	48.05	6.70	51.05	6.48	53.0	6.70
Short-Term Debt[322]	NA	NA	3.95	2.47	3.95	2.47	4.0	2.47
Preferred Stock	.03	8.61	0	0	0	0	0	0
TOTAL ROR	**8.25**		**8.50**		**7.91**		**7.73**	

TABLE 9
Commission Determination of Capital Structure and Cost of Capital

	Share %	Cost %	Weighted Cost %
Equity	46	10 .10	4.65
Long-Term Debt	50.05	6.70	3.35
Short-Term Debt	3.95	2.47	0.10
TOTAL ROR			**8.10**

260 The parties' disputes regarding cost of capital focus on the following three issues:

- Share of Common Equity in the capital structure.
- Cost of long-term debt.
- Cost of Common Equity.

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322 *Id.* The Commission-approved cost of capital in Dockets UE-072300/UG-072301 (consolidated) includes debt costs as an average of long-term and short-term debt.

261 Mr. Gaines presents PSE's overall cost of capital case for electric and natural gas.[323] Relying on Dr. Morin's testimony for analysis of the cost of common equity, Mr. Gaines says his recommended capital structure, debt costs, and overall 8.50 percent ROR are appropriate and necessary to maintain the Company's credit rating.[324] Mr. Gaines testifies that, in contrast to the Company's proposal, the cost of capital recommendations made by Staff and Public Counsel are unsupported, flawed in method, and if adopted, would be insufficient to maintain the Company's credit metrics and would likely lead to a credit rating downgrade.[325]

262 Mr. Parcell presents Staff's cost of capital recommendations. Based on his recommended capital structure, re-pricing of the Company's projections for new debt issues, and application of conventional methods that estimate the cost of common equity capital, Mr. Parcell recommends 7.91 percent as an appropriate overall cost of capital for PSE.[326] He contends that changes in the capital markets since PSE's last general rate case justify a 15 basis point reduction in return from the current level because, "capital opportunity costs, as well as interest rates, have generally declined from the time PSE's last return on equity was established by the Commission."[327] Mr. Parcell testifies that his recommended rate of return would provide credit metrics sufficient to maintain PSE's "BBB" corporate credit rating.[328]

263 Staff argues that PSE's currently authorized ROE should be reduced because capital markets have recovered and stabilized from the recent global financial crisis, and the economic recession has reduced the profits and capital costs of all enterprises. Staff argues that PSE's return should be reduced because opportunity costs, as well as interest rates have declined since its ROE was last set.[329] In addition, Staff states that PSE has not demonstrated that it faces a greater construction-related risk than other utilities or any problem obtaining the capital necessary to fund its capital program. Finally, Staff contends that Dr. Morin's evidence by itself demonstrates that the

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[323] Exhibit DEG-1T (Gaines) at 29:13-30:10.

[324] *Id.* at 30:14 -38:10.

[325] Exhibit DEG-11HCT (Gaines) at 2:1-6, 3:19-20:6.

[326] Exhibit DCP-1T (Parcell) at 3:19 – 4:22.

[327] *Id.* at 7:21-24.

[328] *Id.* at 46:1-5.

[329] Staff Initial Brief at ¶¶ 16-20.

Company's cost of capital is declining, because his estimates of ROE dropped during the pendency of this proceeding.[330]

264 Based on the Company's "per books" rate base, the difference between Staff's recommended ROR and the Company's requested ROR is $32.8 million in annual electric revenue and $14.0 million in annual natural gas revenue.

265 Public Counsel presents its overall cost of capital recommendation for electric and natural gas operations through Mr. Hill. Based on his recommended capital structure and return on equity, Mr. Hill recommends an overall rate of return of 7.73 percent. He says that this rate of return will afford the Company an opportunity to achieve a pre-tax interest coverage ratio of 2.72 percent, "well above the interest coverage achieved by PSE in the past five years and sufficient for the Company to maintain its financial position."[331] Mr. Hill testifies that during the financial crisis of late 2008 and early 2009 corporate bond yields increased dramatically, as did the difference between corporate bond yields and the yield on U.S. Treasury bonds (the yield spread).[332] However, he says that since the first quarter of 2009 the risk-free rate as measured by Treasury bond yields has remained low and even declined from pre-crisis levels and that corporate bond yields have declined to below pre-crisis levels. Mr. Hill testifies that the capital markets stabilized during 2009.[333] With this analysis he implies, but does not specifically state, that the cost of capital for a utility like PSE has declined, too.[334]

266 Public Counsel states that once Dr. Morin corrected his DCF, CAPM and Risk Premium analytic estimates of ROE to remove flotation they averaged 10.21 percent, which is considerably below PSE's requested 10.8 percent.[335] He also argues that the Company's assertions that it requires a higher return on capital in order to attract the investment necessary to support its capital program is not credible given that these are

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[330] *Id.* at ¶¶ 25-26 ("Dr. Morin's original cost of equity was in the upper portion of a range of 11.0 to 11.5 percent. Exhibit No. RAM-1T at 3:11-20. His rebuttal recommendation, however, appeared to be 10.95 percent, but actually had dropped to 10.7 percent. Tr. 654:6-9 (Morin).").

[331] Exhibit SGH-1HCT (Hill) at 5:11-6:3.

[332] *Id.* at 24:6-25:5.

[333] Tr. at 724:15-725:24.

[334] Exhibit SGH-1HCT (Hill) at 25:6-26:3.

[335] Public Counsel Initial Brief at ¶ 24.

the same challenges the Company argued would be addressed by the access to capital provided by the Puget Holdings transaction.[336]

267 Based on the Company's "per books" rate base, the difference between Public Counsel's recommended ROR and the Company's requested ROR is $42.4 million in annual electric revenue and $18.0 million in annual natural gas revenue.

1. Capital Structure

268 No party proposes to base capital structure for purposes of setting rates on the Company's *actual* test-period capital structure or any other measurement of the Company's actual capitalization. PSE, Staff and Public Counsel each propose a different *hypothetical* capital structure. PSE requests a 48 percent equity ratio. Staff recommends 45 percent and Public Counsel proposes 43 percent for the equity ratio.

269 Mr. Gaines testifies that the Company's capital structure during the test year included 44.67 percent equity, but he states this does not reflect the Company's current capital structure because, among other reasons:[337]

- The completion of the transaction to merge Puget Energy with Puget Holdings on February 6, 2009, included investment of funds into PSE used to repay short-term debt and increase PSE equity capitalization.
- PSE defeased and called for redemption of its outstanding preferred stock on March 13, 2009.
- PSE issued $250 million of new 6.75 percent 7-year senior secured notes in January 2009.

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[336] *Id.* at ¶ 26 ("Puget and the Investor Consortium argued that the transaction offered it the opportunity to meet its capital expenditure requirements, very large relative to its size, through access to a significant pool of "patient capital," providing PSE a "more reliable method of obtaining needed capital now and in the future on reasonable terms without being subject to the vagaries of quarterly and annual earnings forecasts and short-term market reactions." *In the Matter of the Joint Application of Puget Holdings LLC and Puget Sound Energy*, Docket U-072375, Order 08 (December 30, 2008) at ¶ 142); *Id.* at ¶¶ 27-30.

[337] Exhibit DEG-1T (Gaines) at 10:3-11:17.

270 Mr. Gaines says that at the end of the first quarter of 2009, PSE's capital structure included 52.9 percent equity. He testifies, however, that this level of equity capitalization fails to represent the capital structure likely to support utility operations during the rate year. He offers several reasons explaining why this is so, including that some of the Company's long-term debt will mature and be refinanced, Puget Energy will make equity investments in PSE, and the level of outstanding short-term debt and retained earnings will vary.[338]

271 Instead of using the test year capital structure or the actual capital structure at the completion of the merger transaction, Mr. Gaines recommends capitalization that includes 48 percent equity, 48.05 percent long-term debt, and 3.95 percent short-term debt. He says such a capital structure "will allow PSE to attract debt capital necessary to fund PSE's infrastructure and new resource construction program" and that it "appropriately balances the risks and costs of funding PSE's utility operations."[339] Mr. Gaines testifies that a 48 percent equity ratio is comparable to, but lower than, the 49 percent average for equity ratios approved by regulatory bodies in the United States during 2008 and the first quarter of 2009, and the 3.95 percentage of short-term debt is the mid-point of the 3 to 5 percent range of short-term debt PSE expects to use during the rate year.[340] Finally, Mr. Gaines testifies that Standard & Poor's and Moody's assign stable credit ratings to PSE in the BBB and Baa3 categories, respectively, and that the Company's proposed capital structure will support these ratings.[341]

272 Staff presents its capital structure recommendation through Mr. Parcell. He recommends a capital structure containing 45 percent equity based on his review of the Company's actual capital structure for the years 2004 through 2008 and his review of average capital structures allowed by regulatory bodies across the nation for the years 2004 through 2008. Mr. Parcell contends that these data justify an equity ratio of 45 percent because this is "the same capital structure ratio requested by PSE in prior cases" and "is similar to recent actual ratios and is consistent with the capital structures of other utilities."[342] He says that the equity ratio requested by PSE exceeds what was requested by the Company or approved by the Commission in

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[338] *Id.* at 11:20-13:1.

[339] *Id.* at 12:2-13:19.

[340] *Id.* at 16:4-13 and 22:16:23:1; Exhibit DEG-4.

[341] *Id.* at 32:2-38:10.

[342] Exhibit DCP-1T (Parcell) at 23:13-26:7.

recent proceedings, including the currently approved 46 percent. Staff argues that, in fact, PSE has advocated for a 45 percent equity ratio in its last 5 rate cases despite actual equity ratios that were below 45 percent. Mr. Parcell asserts that PSE's actual capital structure since the conclusion of the merger "reflects decisions made by the new owners of PSE" and "may not be consistent with the Commission's policy to balance safety and economy."[343]

273 Public Counsel presents its capital structure recommendation through Mr. Hill. Mr. Hill states that PSE was able to maintain a BBB corporate credit rating from December 2004 to December 2008 with an actual equity ratio of only 41.71 percent.[344] He testifies that PSE has actually capitalized its operations over the past several years with lower equity ratios than allowed by the Commission for rate-setting.[345]

274 Mr. Hill says that each percentage point of equity ratio in PSE's capital structure used for rate setting costs customers $4.7 million annually, when income taxes are considered. He also states that the holding company structure in which PSE now resides contains substantially more debt than does PSE and that increases in PSE's equity share and return on equity serve only to service that debt.[346] He claims that third-party debt held by entities in the holding Company structure has increased beyond what was contemplated in the merger proceeding.[347] Considering these factors, he argues it is inappropriate to set rates on a capital structure similar to the regulated utility's capital structure.[348] Indeed, Mr. Hill says that the 46 percent equity ratio agreed to in the settlement of PSE's last rate case was too "equity rich" and that the 43 percent he recommended in that case would be appropriate to use here.[349]

275 Public Counsel argues that it would inappropriate to provide more cash flow to PSE's corporate owners by now increasing the share of equity its regulatory capital structure

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[343] *Id.* at 26:10-27:7.

[344] Exhibit SGH-1HCT (Hill) at 8:16-21. We note that this appears to be an error. PSE's corporate credit rating was BBB- during this period. This is still investment grade, but not as high a quality as Mr. Hill indicates.

[345] *Id.* at 8:22-9.

[346] *Id.* at 9:13 – 17:12.

[347] Exhibit SGH-1HCT (Hill) at 13:2-18.

[348] *Id.* at 17:16 – 18:4

[349] *Id.* at 18:7-22.

because the average equity ratio in the electric industry is 44 percent, because triple-B rated electric utilities have an average equity ratio of 40 percent, because PSE has not proven any increase in operational risk since the last rate case, and because PSE says it has no concerns about funding its capital budget plans. Public Counsel argues that reducing the Company's equity ratio from 46 to 43 percent is appropriate because this level is actually higher than the average level over the last four years during which Public Counsel contends PSE maintained its financial position.[350]

276 Mr. Gaines contends on rebuttal that the equity ratios in the capital structures advocated by Staff and Public Counsel should be rejected because they are:

- Lower than the equity ratio approved in the Company's last general rate case.
- Lower than the common equity ratio currently employed by PSE.
- Lower than the common equity ratio to be employed, on average, during the rate year.
- Lower than the average common equity ratio recently approved by state regulatory commissions.

He argues that the Commission should reject Staff's use of comparative statistics for equity ratios of other utilities because the ratios Staff used are based on "per-books" figures that include unregulated operations.[351] Mr. Gaines urges the Commission to reject Public Counsel's recommended 43 percent equity ratio because he says it is not supported by any rationale other than that it is the recommendation Public Counsel made in the last rate case.[352] Mr. Gaines objects to the suggestion that the Company's equity ratio should be based on the ratio used over the last few years because, he says, this ignores the Company's and Commission's efforts to strengthen the Company's balance sheet and ignores the equity investments made by Puget Holdings. Taking aim at Staff and Public Counsel, Mr. Gaines contends that both parties' recommendations ignore the financial plans explained and approved as part of the

[350] Public Counsel Initial Brief at ¶¶ 8-14.

[351] Exhibit DEG-11HCT (Gaines) at 4:8-6:11.

[352] *Id.* at 7:19-23.

merger transaction.[353] He denies Public Counsel's contention that any entity in the holding company structure issued new third-party debt.[354]

277 Finally, Mr. Gaines contends that the capital structure, cost of equity, and other revenue adjustments proposed by Staff and Public Counsel would cause PSE's credit metrics to fall below Standard & Poor's expectations and would not allow PSE to maintain its current credit rating.[355]

278 *Commission Determination:* The Commission observed in its order setting rates in the Company's most recent fully litigated case that it "has approved hypothetical capital structures when there was a clear and compelling reason to do so."[356] In this case there appear to be two related reasons:

1) The Company argues persuasively that the utility's actual capitalization in the test year and early post-test year period was affected by short-term circumstances and is not representative of how it will capitalize its operations in the rate year.

2) There is no dispute among the parties that the actual capital structure during the test year or shortly after is not a true measurement of how the Company will, or should capitalize its operations.

Thus, we are left to answer the question of which, if any, of the proposed hypothetical structures should be accepted as appropriate for setting prospective rates.

279 The Commission approved the Company's current cost of capital in the fall of 2008 based on an all-party settlement, which included a capital structure with 46 percent common equity. Two major developments affecting the Company and potentially affecting its cost of capital have occurred since the August 2008 settlement: the completion of the sale of Puget Energy to Puget Holdings, and the financial crisis that severely affected all capital markets beginning with the collapse of Lehman Brothers in September 2008.

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353 *Id.* at 6:16-7:15 and 8:18 -11:14.

354 *Id.* at 11:3-20.

355 *Id.* at 26:18-28-12.

356 *WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UE-060266 and UG-060267, Order 08 (January 5, 2007).

280 The Commission approved the Company's execution of the Puget Holdings transaction in December 2008. As Mr. Hill observed at hearing, the terms of the rate case settlement proposed in August 2008 were known and accepted by all parties, including the Company's potential new owners, during the Commission's review and ultimate approval of the sale of Puget Energy to Puget Holdings.[357] In its order approving the transaction, the Commission approved a condition that the equity-share in the utility's capital structure would not be allowed to fall below 44 percent, unless the Commission approved a lower level of equity for ratemaking purposes.[358] In addition, the order prohibited PSE from declaring or making any dividend distributions if its equity capitalization dropped below 44 percent, again subject to exception if the Commission approves a lower level of equity for ratemaking purposes.[359] Finally, the Commission directed that determination of the cost of equity in the Company's allowed rate of return in future rate cases "will include selection and use of one or more proxy group(s) of companies engaged in businesses substantially similar to PSE, without limitation related to PSE's ownership structure."[360]

281 Turning to the financial crisis, our record shows that the capital markets suffered significant distortions beginning in early fall 2008 and extending through much of 2009. Among these distortions was a significant increase in the "yield spread" between debt issued by the U.S. Treasury and corporate bonds, including utility bonds. Our record also shows that the capital markets have substantially recovered from the distortions caused by the financial crisis and now again reflect cost characteristics similar to, if not lower than, those extant before the onset of the crisis.

282 Our determination of an appropriate capital structure must therefore consider the following:

- All parties agreed to a capital structure with 46 percent equity prior to approval of the Puget Holdings transaction and prior to the onset of the financial crisis.

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[357] Tr. at 723:5-724:14 (Hill).

[358] *Re Puget Holdings and PSE*, Docket U-072375, Order 8, Appendix A to Stipulation, Commitment 35 (December 30, 2008).

[359] *Id.* Commitment 36.

[360] *Id.* Commitment 24, as clarified by the Commission's Eighth Condition.

- Disruptions in the capital markets have stabilized at levels similar to pre-crisis conditions.

283 Considering these factors, we determine that the appropriate equity share in the Company's capital structure should remain at the currently allowed 46 percent.

2. Cost of Long-Term Debt

284 In its original filing, the Company included a 6.82 percent average cost of long-term debt using the yield to maturity, maturity date, net proceeds to PSE, and coupon- rate for each existing debt issue as well as for the incremental contribution to debt cost of issuing three new debt issues to replace six debt issues that will mature before the end of the rate year.[361] In testimony filed September 28, 2009, Mr. Gaines revised the average cost of long-term debt downward to 6.70 percent to reflect the effect of $350 million Senior Secured Note issued at 5.75 percent on September 11, 2009.[362] This is the long-term debt cost PSE's recommends in its brief.

285 Mr. Parcell testifies for Staff that the Company's proposed 6.70 percent cost for long-term debt includes the cost of two future debt issues to be sold in 2010. He argues these future issues should carry an imputed price equal to the 5.75 percent rate the Company secured for its most recent debt issue in September 2009. Staff contends that the 5.75 percent rate is the most appropriate to impute to the Company's expected rate year debt issuances because that rate is what the Company actually experienced in the capital markets.[363]

286 Public Counsel accepts the Company's cost of long-term debt.

287 PSE argues that the Commission should reject Staff's proposed cost of long-term debt because Mr. Parcell "arbitrarily uses the interest rate on PSE's most recent senior secured note issue."[364] PSE states that this rate is the lowest coupon that PSE has ever

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[361] Exhibit DEG-1T (Gaines) at 24:3 – 26:10.

[362] Exhibit DEG-9T (Gaines) at 12:4-14:11.

[363] Staff Reply Brief at ¶ 15.

[364] PSE Initial Brief at ¶ 65.

received on a 30-year senior secured note issue. PSE argues that Staff did not produce any evidence that PSE could issue bonds at such a low rate in the future.

288 *Commission Determination:* Ideally, the cost rate for debt in PSE's capitalization is directly measurable as the cost of debt outstanding in the Company's actual capital structure. In this case, however, the Commission is faced with approving a hypothetical, rather than an actual capital structure and it is, to a degree, forward-looking. The Company estimates what its aggregate average cost of long-term debt will be taking into account the replacement of debt issues that will mature before the end of the rate year. While Staff asserts that the estimate of cost for new debt issues should be based on the Company's most recently negotiated bond issue, it is undisputed that the rate the Company achieved is unprecedented. It is significant in this connection that at the time of the recent issue, the Company's actual capital structure included more than 50 percent equity. Thus, the attractive rate on the recently issued debt reflects a capital structure with substantially less leverage than the 46 percent equity share that was approved in PSE's last general rate proceeding and that will remain unchanged as a result of our decisions here.

289 We accordingly find appropriate the Company's proposed average cost rate for long-term debt: 6.70 percent.

3. Cost of Equity

290 The Commission last determined a return on equity capital for PSE based on a fully litigated record in January 2007. In that general rate proceeding, the Commission found an ROE of 10.4 percent, the mid-point of a range from 10.3 to 10.5 percent, to be appropriate for setting rates. The record in that proceeding contained a large volume of expert testimony and a remarkable range in analytic estimates. The Commission observed that little of the evidence focused on circumstances that would justify a change in the Company's cost for equity capital from that previously authorized. Instead, the evidence in that proceeding focused on familiar and rather academic disputes regarding methods, theories and assumptions based on the professional judgment and orientation of the experts.

291 During the intervening three years, the Company and parties again presented substantial evidence on cost of equity in PSE's general rate case filed in late 2007. That case was ultimately resolved by settlement in August 2008 when the parties agreed to, and the Commission approved, a return on equity of 10.15 percent.

292 In this case, we are once again presented with a substantial body of evidence, this time marshaled in support of ROE recommendations that range from 9.5 percent to 10.8 percent. This range continues to be accounted for by disagreements regarding the growth rates to apply in the DCF method and the market risk premiums to apply in the CAPM and Risk Premium methods. It is not unusual for experts to disagree over these key analytic elements and assumptions. The Commission has said in more than one order that it appreciates and values a variety of perspectives and analytic results because these serve to better inform the judgment it must exercise than would a single model, or a single expert's opinion. We reiterate that perspective here. We value and rely on multiple methodologies, models and expert opinions to develop a robust record of evidence to inform our judgment. It is particularly important to take multiple methods and models into account in the present circumstances of financial turmoil that may affect the input values and assumptions used in each method.

293 As is usually the case, much of the dispute among the experts testifying in this case involves "analytic judgment" concerning key data assumptions and model application. These disputes are not resolvable on the basis of objective tests – their resolution requires the application of considerable judgment when we review the expert testimony. In our experience there is no precise or single right answer to these analytic questions.

294 Table 10 presents the range in analytic results calculated by the cost of capital experts, and each party's final ROE recommendation.

TABLE 10
ROE Analytical Estimates

	Dr. Morin[365]	Mr. Parcell[366]	Mr. Hill[367]
DCF	10.3 – 11.3	9.6 – 11.3	9.57 - 9.87
Risk Prem.	10.34	N/A	N/A
CAPM	9.3-9.7	7.9 – 8.2	7.79 – 8.49
MEPR	N/A	N/A	9.19 – 9.33
MTB	N/A	N/A	9.6 – 9.71

[365] Dr. Morin's results are presented as he revised them to remove the effect of flotation. Exhibit B-7.

[366] Exhibit DCP-1T (Parcell) at 44:13-15

[367] Exhibit SGH-1HCT (Hill) at 40:18-19 and 55:15-56:13

Comparable Earnings	N/A	9.5 – 10.5	N/A
Party Recommendation	**10.8**	**10.0**	**9.5**

295 Our record in this proceeding differs in at least two important ways from the evidence we have considered in past proceedings. Here the experts acknowledge openly that the analytic models are difficult to use and interpret in the context of volatile financial markets. And here, the circumstances of the utility have changed with completion of the Puget Holdings transaction.

296 Neither of these factors, however, turns out to be centrally important for setting the ROE in this case. The Commission's order approving the Puget Holdings transaction makes clear that the nature of the utility's ownership is not a limiting factor for determining a fair equity return based on businesses substantially similar to PSE without regard to ownership structure. Our record also shows that while the analytic ROE models may presently be affected by recent market turmoil, it appears that market conditions themselves have recently returned to more normal circumstances.

297 With this background in mind, we turn to the analytic estimates and opinions of the three experts. Despite the rich diversity in their opinions and results, their analyses provide a solid foundation on which we can construct a reasonable range for ROE.

298 All of the experts provide DCF results, supported to one degree or another by each expert's alternative methodologies, which differ from one expert to the next. DCF results, like other analytic models, are subject to bias in perturbed markets because the critical yield component is affected by utility stock prices, which have been somewhat volatile recently.[368] This may lead to a significant divergence of opinion among the experts despite their use of a common approach. Nonetheless, we find the experts' DCF results overlapping in this case – Mr. Parcell's results overlap with Mr. Hill's at the low end and with Dr. Morin's at the high end.

299 In this context, we also find that Mr. Hill's DCF estimates for Public Counsel are persuasively critiqued by Dr. Morin for the Company because they rely on growth estimates that are obscure and not subject to replication. We find, too, that Dr. Morin's DCF results are persuasively critiqued by Mr. Hill because they rely solely

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[368] This is because, for a given dividend, elevated stock prices depress the yield and lower stock prices increase the yield. In like fashion, for a given stock price, increased dividends increase yield and lower dividends decrease yield.

on analysts' forecasts of earnings growth, without benefit of historical rates of growth and other information published by the analysts or other reputable financial sources.

300 In contrast, Mr. Parcell's DCF estimates are derived from a broad set of published growth figures that are transparent and include both forward-looking estimates and historical data. His DCF results span the ground between the 9.87 percent high end of Mr. Hill's DCF range and the 10.3 percent low end of Dr. Morin's DCF range. The mid-point of this range is 10.1 percent. Mr. Parcell's comparable earnings results of 9.5 percent to 10.5 percent also encompass this middle-ground and have a mid-point of 10.0 percent. Considering that the experts' other corroborating analyses, including CAPM results, produce results below 10 percent, we discount the high end of Mr. Parcell's and Dr. Morin's DCF results.[369] Taking all of this into account, we are confident that a reasonable ROE for PSE can be found within the range of 9.9 percent to 10.3 percent. This zone of reasonableness is made somewhat wider than the zones we have determined in past cases because of the circumstances affecting the financial markets and the effect of these circumstances on application of the analytic ROE models.

301 *Commission Determination:* Considering all of the above, we determine that PSE's cost of equity capital should be set at 10.1 percent for purposes of setting rates in this proceeding. Coupled with our decision to set PSE's equity share at 46 percent, the Company's computed weighted average cost of equity is 4.65 percent.

4. Capital Structure and Cost of Capital Summary

302 We summarize our determinations of the issues concerning Capital Structure and Cost of Capital above in Table 9. As shown there, our findings and conclusions concerning the appropriate capital structure and component cost rates produce an overall weighted cost of capital of 8.10 percent.

303 We are mindful of our responsibility to set the allowed return on capital at a level "sufficient to assure confidence in the financial integrity of the enterprise, so as to

[369] The CAPM results in this case fall below, in some cases substantially below, estimates derived from the other analytic approaches. All of the experts note that the CAPM may be less reliable in current circumstances, though Mr. Parcell recommends that CAPM results should be used to corroborate DCF analyses. We agree, but in these unusual financial circumstances we have accorded the CAPM results diminished weight.

maintain its credit and to attract capital."[370] The credit metrics by which the debt rating agencies develop and evaluate utility credit ratings are one measure of this confidence. Standard & Poor's (S&P) publishes a matrix of credit metrics it looks to when rating the quality of utility credit.[371] Mr. Gaines, in his testimony, estimates the credit metric ratios for each of the parties' revenue requirements cases.[372] We have carefully examined this evidence and are satisfied to find that the ratios Mr. Gaines calculates for Staff's case fall within the S&P ranges for a company rated BBB with the excellent business and aggressive financial risk profiles S&P assigns to PSE. Considering that the results of our Order here allow for a higher rate of return and recovery of more revenue than what Staff recommends, we are confident that our decision will allow the Company, with prudent management, to maintain or improve its current credit rating.

D. Electric Rate Spread and Rate Design Settlement

304 Rate spread allocates the revenue requirement to each of PSE's customer classes. Rate design is the pricing mechanism for PSE to recover its costs. Rate design determines the rates that each individual customer actually pays.

305 PSE, Staff, and other parties that took an active interest in the electric rate spread and rate design issues submitted a proposed Multiparty Settlement Agreement on July 25, 2009, which they ask the Commission to approve and adopt to resolve all rate spread and rate design issues. The Settlement Agreement is supported by Joint Testimony addressing why the Agreement will result in rates that are just and reasonable, and consistent with established Commission policies. It is unopposed.

306 The parties agree to use PSE's electric cost-of-service study, rate spread, and rate design. According to the Settlement Agreement, any revenue requirement increase ordered in this proceeding will be allocated among the various customer classes and rate schedules in proportion to the rate spread proposed by PSE. The Settlement

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[370] *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

[371] *Criteria Methodology: Business Risk/Financial Risk Matrix Expanded.* Standard & Poor's. Global Credit Portal. RatingsDirect. May 27, 2009. We take administrative notice of this industry publication.

[372] Exhibit DEG-19 (Gaines) at 2.

Agreement includes an illustrative example or "baseline" that uses a hypothetical final electric revenue requirement increase of $113 million.

307 The Settling Parties state in their Joint Testimony that the rate spread set forth in the Multiparty Settlement, and illustrated on page 1 of its Attachment, represents a reasonable balancing of the factors traditionally used by the Commission to set rates, including cost-of-service, fairness, perceptions of equity, economic conditions in the service territory, gradualism, and rate stability.[373] According to the parties' Joint Testimony, most electric rate classes already are relatively close to parity (*i.e.,* rates recover 97% to 130% of the costs caused by a given customer class). The proposed rate spread is designed to bring each rate class even closer to parity without causing rate shock.

308 The Multiparty Settlement assigns a uniform percentage rate increase to Residential Schedules 5and 7, and Schedules 24, 26, 31, 35, 43, 46, 49, 50-59, 448, and 449.[374] At the illustrative baseline increase, this is a 5.83% percent increase. Mid-sized commercial and industrial customers (*i.e.,* secondary voltage customers with demand between 50 and 350 kW) under Schedules 25 and 29 are assigned 75 percent of the uniform percentage rate increase assigned to the other rate schedules, or 4.37% percent, assuming the illustrative baseline increase. Schedule 40 (*i.e.,* campus rate) rates for power supply (generation and transmission) are set equal to the Schedule 49 (*i.e.,* high voltage) charges (adjusted for power factor and losses). In addition, delivery-related charges are derived based upon customer specific costs of PSE's distribution facilities used to directly provide delivery services to the Schedule 40 customers.

309 In terms of rate design, the proposed settlement produces no major change from current practice. The rate design follows the methods proposed by PSE,[375] except for the one phase basic charge for residential service under Schedule 7 and rates under

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[373] Exhibit JST-2 (Higgins, Phelps, Schoenbeck, Schooley and Watkins) at 6:9-15.

[374] Schedules 24 and 26 are smaller (*i.e.,* demand less than 50 kW) and larger (*i.e.,* demand greater than 350 kW) secondary voltage commercial and industrial customers. Schedules 31, 35 and 43 are primary voltage customers. Schedules 46 and 49 are high voltage customers. Schedules 50 and 59 are lighting customers. Schedules 448 and 449 are "choice" and retail wheeling customers.

[375] *See generally* Prefiled Direct Testimony of Mr. David W. Hoff, Exhibit DWH-1T, the Rebuttal Testimony of Ms. Janet K. Phelps, Exhibit JKP-25T and supporting exhibits. Multiparty Settlement Agreement Re: Electric Rate Spread and Rate Design, Attachment, page 2.

Schedule 26. The parties agreed that the one phase basic charge for residential service under Schedule 7 will increase from \$7.00 to \$7.25. As to Schedule 26, PSE accepted Kroger's proposal to link both the demand and energy charges of Schedules 26 and 31 so that the differential between the demand and energy charges of the two schedules is equalized.[376]

310 There is substantial evidence in the record supporting the electric rate spread and rate design proposals embodied by the Multiparty Settlement Agreement.[377] We determine the electric rate spread and rate design proposals presented in the parties' Settlement Agreement are reasonable and should be approved and adopted. The Settlement Agreement is attached and incorporated into this order as Appendix A.

E. Natural Gas Rate Spread and Rate Design Settlement.

311 PSE, Staff, and other parties interested in natural gas rate spread and rate design also submitted their proposed Multiparty Settlement Agreement on July 25, 2009. As in the case of the electric settlement discussed above, they ask the Commission to approve and adopt their agreement to resolve all rate spread and rate design issues. The Settlement Agreement is supported by Joint Testimony addressing why the Agreement will result in rates that are just and reasonable, and consistent with established Commission policies. No party opposed this Multiparty Settlement.

312 The Multiparty Settlement assigns a share of the PSE revenue requirement to each rate schedule based on a rate spread that is derived using a hypothetical increase of \$28 million as a baseline. These respective shares of the revenue requirement are then used to apportion any rate increase of a differing amount.

313 At the baseline revenue requirement, the Multiparty Settlement assigns a uniform percentage rate increase of 7.4 percent to residential Schedules 16, 23, 53 (propane); smaller volume commercial Schedules 31and 61; and water heater rental Schedules 71, 72, and 74. Schedules 41 and 41T, large volume commercial and industrial Schedules, are assigned increases equal to 75 percent of the uniform percentage rate

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[376] Exhibit JKP-25T (Phelps) at 28:2-10.

[377] Prefiled Direct (Exhibit JKP-1T) and Rebuttal Testimony of Janet K. Phelps (Exhibit JKP-25T), and supporting exhibits; Prefiled Direct Testimony of David W. Hoff (Exhibit DWH-1T), and supporting exhibits; Exhibit JST-2 (Joint Settlement Testimony of Higgins, Phelps, Schoenbeck, Schooley and Watkins: Electric Rate Spread and Rate Design).

increase assigned to the residential, smaller commercial and water heater customers, or 5.5 percent. Finally, the interruptible customers on Schedules 85, 85T, 86, 86T, 87, and 87T are assigned a rate increase equal to 50 percent of the uniform percentage rate increase assigned to residential, smaller commercial and water heater customers, or 3.7 percent.

314 The rate design structure proposed under the Settlement Agreement is similar to the current structure. The rate design follows the methods proposed by PSE,[378] except for residential service under Schedules 23 and 53. Under the agreement, the basic charge for residential service under Schedules 23 and 53 will remain at $10.00 per month, rather than being increased to $10.73, as PSE originally proposed.

315 There is substantial evidence in the record supporting the natural gas rate spread and rate design proposals embodied by the Multiparty Settlement Agreement.[379] We determine the natural gas rate spread and rate design proposals presented in the parties' Settlement Agreement are reasonable and should be approved and adopted. The Settlement Agreement is attached and incorporated into this order as Appendix B.

F. Prudence Issues

1. Mint Farm

316 PSE purchased the Mint Farm Energy Center (Mint Farm), a 311 MW natural gas-fired, combined cycle combustion turbine (CCCT) generation facility located in Longview, Washington on December 5, 2008. Mint Farm is currently part of the PSE's resource portfolio serving customers.[380]

317 PSE requests a Commission determination that it was prudent to acquire Mint Farm. PSE also asks the Commission to determine that Mint Farm complies with the greenhouse gases emissions performance standard (EPS) established by RCW 80.80.

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[378] *See generally,* Exhibit JKP-1T (Phelps) and supporting exhibits. Multiparty Settlement Agreement Re: Natural Gas Rate Spread and Rate Design, Attachment, page 2.

[379] *See generally,* Exhibits JKP-1T and JKP-25T (Phelps), and supporting exhibits; *see also* Exhibit JST-4 (Joint Settlement Testimony of Higgins, Phelps, Schoenbeck, Schooley and Watkins: Natural Gas Rate Spread and Rate Design).

[380] Exhibit DN-1T (Nightingale) at 9:18-19.

Although this question also informs our prudence determination,[381] we discuss it separately below.

318 Staff, through its testimony and in its brief, supports the Company on both questions. Public Counsel, however, disputes the prudence of the Mint Farm acquisition. While not directly addressing the EPS issue, Public Counsel challenges the Company's request that the facility be classified as "baseload" for purposes of RCW 80.80. Were the Commission to determine it is not a baseload facility, the statute simply would not apply, mooting the question whether it meets the EPS.

319 The leading decisions in which the Commission articulates its standard for determining prudence are the Eleventh and Nineteenth Supplemental Orders in PSE's 1992 general rate case and other consolidated dockets.[382] The Commission held, pursuant to RCW 80.04.130, that the utility has the burden of proof on prudence, and "must make an affirmative showing of the reasonableness and prudence of the expenses under review."[383] The Commission reaffirmed the standard it applies in reviewing the prudence of power generation asset acquisitions in 2003:

> The test the Commission applies to measure prudence is what would a reasonable board of directors and company management have decided given what they knew or reasonably should have known to be true at the time they made a decision. This test applies both to the question of need and the appropriateness of the expenditures. The company must establish that it adequately studied the question of whether to purchase these resources and made a reasonable decision, using the data and methods that a reasonable management would have used at the time the decisions were made.[384]

320 The Commission continues to evaluate prudence considering specific factors identified in its earlier decisions. In particular, the Commission requires the Company to show:

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[381] *WUTC v. PacifiCorp, d/b/a, Pacific Power & Light Co.*, Docket UE-090205, Order 09 at ¶67 (December 16, 2009).

[382] *WUTC v. Puget Sound Power & Light,* Docket Nos. UE-920433, UE-920499, UE-921262 (consolidated)(*PSE 1992 GRC)*; Eleventh Supplemental Order, Nineteenth Supplemental Order.

[383] *Id.* Eleventh Supplemental Order at 19.

[384] *WUTC v. Puget Sound Energy, Inc.,* Docket UE-031725, Order 12 at ¶ 19 (April 7, 2004).

- The new resource is needed.
- The new resource fills the need determined in a cost-effective manner, evaluating that resource against the standards of what other purchases are available, and against the standard of what it would cost to build the resource itself.
- Management kept its board of directors informed and involved the board in the decision process.
- The Company has adequate contemporaneous records that will allow the Commission to evaluate its actions with respect to the decision process. [385]

Public Counsel's challenge to the prudence of PSE's Mint Farm acquisition concentrates on the first two factors.

321 On the question of need, PSE documented through its testimony and exhibits its current and projected need for new resources. PSE's 2007 Integrated Resource Plan ("IRP") projected that PSE would need to acquire "nearly 700 aMW of electric resources by 2011, more than 1,600 aMW by 2015, and 2,570 aMW by 2027" to meet the projected baseload demand of PSE's customers.[386] The Company's 2007 IRP indicated that the lowest reasonable cost electric resource strategy to pursue at the time would rely on gas-fired CCCT generating capacity to the extent its energy needs cannot be met through demand-side and renewable resources.[387]

322 PSE updated its 2007 IRP load forecast before issuing a request for proposals (RFP) in 2008. PSE's energy need for supply-side resources for the 2008 RFP was 143 aMW by 2011.[388] The supply-side energy need grew to 700 aMW by 2012 and 977

[385] *PSE 1992 GRC,* Nineteenth Supplemental Order at 5-11.

[386] Exhibit KJH-8T (Harris) at 4:5-9. PSE's 2009 IRP projects that PSE will need to acquire 676 MW of electric resources and energy efficiency by 2012, 1,084 MW by 2015, and 2,453 MW by 2020. These needs include the addition of the Mint Farm Energy Center, the Barclay's 4-year seasonal PPA and reflect the economic downturn and its impact on load. *See* Exhibit WJE-21HCT (Elsea) at 5:9 – 7:4

[387] Exhibit KJH-5 at 218-219 (2007 IRP, pages 8-2 and 8-3).

[388] Exhibit WJE-3.

aMW by 2013.[389] There were also significant capacity needs of 208 MW by 2011, 760 MW by 2012, and 771 MW by 2013.[390]

323 Contesting PSE's asserted need for resources – specifically Mint Farm – Public Counsel cites to a presentation to PSE's Board of Directors dated August 4, 2008, which indicated that Mint Farm would create surplus capacity on PSE's system through 2011.[391] PSE and Staff argue that Public Counsel's position in this regard ignores the reality of resource acquisition. Specifically, Staff points out that CCCTs become available in large blocks of capacity in a timeframe not often matched perfectly to demand.[392] As a result, Staff says, acquiring such "lumpy" resources means the Company's power portfolio may at times be long.[393] Staff argues that "PSE's 2007 IRP showed a need for a CCCT by 2011."[394] It follows, Staff reasons, that the fact "Mint Farm created surplus capacity through 2011 is no reason to find the purchase imprudent."[395]

324 The main thrust of Public Counsel's opposition to the Mint Farm acquisition focuses on the second of the prudence evaluation criteria bulleted above: Whether the new resource fills the need determined in a cost-effective manner, evaluating that resource against the standard of what other purchases are available, and against the standard of what it would cost to build the resource itself.

325 As to the question of the cost of Mint Farm relative to what it would cost PSE to build such a resource, Staff states that "PSE purchased the plant at a 30 percent discount

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389 *Id.*

390 *Id.*

391 Public Counsel Initial Brief at ¶ 33; Exhibit SN-1HCT (Norwood) at 9:4-6.

392 Exhibit DN-1HCT (Nightingale) at 15:19-20.

393 Staff Initial Brief at ¶ 178; *see also* Public Counsel Initial Brief at ¶ 16.

394 Staff Initial Brief at ¶ 178 (citing Exhibit KJH-5 at 79).

395 *Id.* Staff states that it finds Public Counsel's position on Mint Farm in this connection "striking given his position in PacifiCorp's 2009 GRC." Staff Initial Brief at ¶ 177. In that case, Public Counsel agreed that the Chehalis Generating Plant was a prudent acquisition by PacifiCorp, even though the facility was acquired to fill a resource deficit that would not occur until 2012 according to an IRP. The Commission agreed the acquisition was prudent, commenting on the benefit of acquiring a plant that, like Mint Farm, otherwise was a "lost opportunity." *WUTC v. PacifiCorp, d/b/a, Pacific Power & Light Co.*, Docket UE-090205, Order 09 at ¶¶ 50, 66 (December 16, 2009).

from the cost to build a new facility."[396] This does not appear to be in dispute. Certainly, then, Mint Farm is cost-effective when measured against what it would cost to build a comparable resource, and taking into account the construction risk of a self-build option.

326 PSE used a two-phase process to analyze the qualitative and quantitative advantages and disadvantages of each of the 31 proposals it received in response to the 2008 RFP. [397] The qualitative evaluation addressed compatibility with PSE's resource needs, cost minimization, risk management, public benefits, and other strategic, technical and financial factors.[398] The quantitative evaluation examined each proposal using three measures: the Portfolio Benefit, the Portfolio Benefit Ratio, and the 20-Year Levelized Cost.[399]

327 Staff provides a useful summary of the evidence showing why Mint Farm emerged from the evaluation process as a candidate for acquisition, as follows:[400]

- Mint Farm provided a significant contribution to meeting PSE's energy and capacity needs over the mid- to long-term.[401]

- Mint Farm minimized PSE's cost of power relative to new CCCT construction.[402]

- Mint Farm had a low heat rate compared to other CCCTs.[403]

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[396] Staff Initial Brief ¶ 162 (citing Exhibit RG-53HCT (Garratt) at 27:21-22 and 44:15-16).

[397] Exhibit WJE-1HCT (Elsea) at 9:5-10.

[398] Exhibit RG-1HCT (Garratt) at 6:20-7:5 and Exhibit RG-3HC (Garratt) at 13.

[399] Exhibit RG-3HC (Garratt) at 15.

[400] Staff Initial Brief ¶ 169.

[401] *Id.* (citing Exhibit RG-1HCT (Garratt) at 42:7-14).

[402] *Id.* (noting that Mint Farm's "all-in" cost is about 60 percent of the price for new CCCT construction. Citing Exhibit RG-1HCT (Garratt) at 42:15-19 and comparing to Exhibit RG-3HC (Garratt) at 179 and Exhibit WJE-1HCT (Elsea) at 30:10).

[403] *Id.* (citing Exhibit DN-1T (Nightingale) at 5:13-19 and noting that a lower heat rate means that Mint Farm requires less fuel supply than a higher heat rate CCCT to produce the same amount of energy).

- Mint Farm had pre-existing electric transmission rights in Western Washington.[404]

- Mint Farm had sufficient gas transmission and supply.[405]

- Mint Farm was a new plant that, with good maintenance, had an expected service life of 25-30 years.[406]

- Mint Farm posed no risk of construction or counterparty default since it was an existing, operational facility.

- As the last available CCCT in Washington with firm transmission rights, Mint Farm was a unique opportunity not likely to remain available during the Company's next RFP.[407]

- Mint Farm provided flexibility to meet variable loads including integrating wind resources.[408]

In addition, Mint Farm had a positive Portfolio Benefit and Benefit Ratio, although not as high as an alternative PPA (purchase power agreement) that also was under consideration.[409]

328 Public Counsel argues that because the alternative PPA scored higher than Mint Farm in terms of the Portfolio Benefits and Benefit Ratio metrics, Mint Farm should have

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[404] *Id.* Exhibit RG-1HCT (Garratt) at 30:10-17. PSE acquired Mint Farm with a minor deficiency of firm transmission capacity: 3 MW of Mint Farm's baseload capacity of 296 MW. However, PSE identified methods to manage this small deficit. Exhibit RG-53HCT (Garratt) at 42:11-43:12.

[405] *Id.* (citing Exhibit RCR-1CT (Riding) at 2-7 and noting that PSE had a strategy to ensure firm capacity sufficient to deliver the full requirements to Mint Farm. Exhibit RCR-6T (Riding) at 2-7.) Staff notes further that the strategy appears to have worked in that sufficient gas has been delivered whenever plant operations were warranted, including during December 2009 when record demands were recorded due to cold weather. Exhibit RCR-6T (Riding) at 7:3-6).

[406] *Id.* (citing Exhibit DN-1T (Nightingale) at 16:14-19).

[407] *Id.* (citing Exhibit DN-1T (Nightingale) at 17:1-5 and noting that the Grays Harbor CCCT is the only other CCCT not under long-term contract, but it does not have available firm transmission capacity until 2015. Exhibit RG-1HCT (Garratt) at 43:1-8 and Exhibit RG-53HCT (Garratt) at 7:17-20).

[408] *Id.* (citing Exhibit DN-1T (Nightingale) at 15:10).

[409] Exhibit RG-3HC (Garratt) at 119 and Exhibit WJE-11HC (Elsea) at 28.

been rejected in favor of the PPA. Staff and PSE argue, however, that this ignores that Mint Farm's 20-Year Levelized Cost was 30 percent less than the alternative PPA, even with the financial burden of Mint Farm acquisition costs and surplus capacity through 2011.[410] Thus, according to Staff, "the added costs of Mint Farm before 2012 were outweighed by the increased benefits of its lower longer-term operating costs."[411] More significant, perhaps, is PSE's argument that: "Quantitative analyses alone do not, and should not, dictate the resources that PSE acquires. PSE's resource acquisition decisions also reflect a variety of qualitative and commercial analyses."[412]

329 Public Counsel also argues PSE's decision to acquire Mint Farm was imprudent because the Company did not have adequate firm gas transportation capacity to supply the full requirements of the facility, or sufficient firm transmission rights to deliver the full output of Mint Farm to its system.[413] Public Counsel states that PSE also knew that Mint Farm had no back-up fuel capability, which he argues increased the risk that the output of the plant could be restricted if the natural gas supply were to be curtailed for any reason.[414]

330 Characterizing Public Counsel's contentions concerning firm gas transportation capacity and firm transmission rights, PSE states that Public Counsel:

> Ignores the fact that PSE held and still holds (i) sufficient firm transportation capacity on the Northwest Pipeline system to ensure delivery of adequate gas supply to Cascade Natural Gas Corporation's distribution system and (ii) sufficient firm distribution capacity on the Cascade Natural Gas Corporation system, when combined with unused

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[410] *Id.*

[411] Staff Initial Brief at ¶ 182. Staff notes that Public Counsel misses the point in his attempt to show that the 20-Year Levelized Cost need not be evaluated independently because it uses the same cost inputs as the Portfolio Benefit and Benefit Ratio. Tr. 223:13-224:4 (Garratt) and Tr. 290:12-292:21 (Elsea). Staff states that the 20-Year Levelized Cost is the only criteria that measures the expected costs to deliver power for a specific resource over 20 years. Tr. 290:12-22 (Elsea). Thus, Staff argues, even if it shares cost inputs with the Portfolio Benefit and Benefit Ratio, it provides unique analytical results that were evaluated separately and collectively with all other quantitative and qualitative factors. Tr. 225:10-24 (Garratt) and Tr. 289:6-25 (Elsea).

[412] PSE Initial Brief at ¶ 17 (citing Exhibit RG-53HCT (Garratt) at 17:7 – 22:17).

[413] Exhibit RG-1HCT (Garratt) at 30-31.

[414] Exhibit RG-1HCT (Garratt) at 31-32; Exhibit SN-1HCT (Norwood) at 16.

> firm capacity on such system, to adequately serve the gas requirements of the Mint Farm Energy Center.[415]

And, as to transmission rights, PSE says:

> Mint Farm Energy Center's firm transmission deficit of 3 MW is not a risk to owning the plant. PSE has identified methods to manage this minor issue. In the short-term, existing firm transmission can be used to cover instances when the plant is capable of producing in excess of 293 MW. In the long-term, PSE has submitted a transmission request to BPA under BPA's 2009 Network Open Season to acquire an additional 12 MW of firm transmission.[416]

331 On the question of back-up fuel capability, Mr. Garratt testified:

> Public Counsel, however, fails to acknowledge that it would be nearly impossible to permit a baseload combined cycle combustion turbine in Washington for both natural gas and oil due to the high-polluting emissions of oil. Furthermore, Public Counsel is, in effect, questioning the firmness of firm gas transportation. Although it is possible that the fuel supply could be curtailed, it is not likely.[417]

Mr. Garratt's points are well taken. Concerning the prospect of obtaining a permit for a plant with oil as a backup fuel, the Washington Energy Facility Site Evaluation Council expressed its view as early as 2002 that developers should not include such a proposal in their plans if they wished to obtain a positive recommendation from the Council.[418] As to Mr. Garratt's second point, there is no evidence of any curtailment of firm gas transportation by Northwest Pipeline or Cascade in recent years or, indeed, at any time.

332 Staff observes that Mint Farm will run many more years and many more hours in any year due to its longer service life and lower heat rate relative to alternatives. On this

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[415] PSE Initial Brief ¶ 20 (citing Exhibit RCR-6T (Riding) at 2:2 –7:6).

[416] *Id.* ¶ 21 (citing Exhibit RG-53HCT (Garratt) at 43:3-6).

[417] Exhibit RG-53HCT (Garratt) at 43:16-21.

[418] *In the Matter of: Application No. 99-01, Second Revised Application, Sumas Energy 2, Inc., Sumas Energy 2 Generation Facility,* Council Order No. 768, Findings of Fact, Conclusions of Law, and Order Recommending Approval of Site Certification on Condition (May 24, 2002) (discussion of Air Quality at 29 – 34).

basis, Staff argues that if PSE had acquired the alternative PPA that Public Counsel says was a superior resource, PSE would have been exposed more often to variable market pricing because the PPA would have produced less energy to meet load.[419] Even Public Counsel's witness on the Mint Farm issue acknowledges that that "in the long-run ownership of Mint Farm should benefit customers."[420]

333 Mr. Garratt testified that the alternative PPA was not a suitable fit to meet PSE's resource needs in 2011 due to pre-existing contractual requirements.[421] It was placed on the "Continuing Investigation List" for future monitoring.[422] Staff and PSE both point out opportunities to extend the alternative PPA have not been foreclosed. In the context in which PSE considered Mint Farm, the alternative PPA and other options, Mint Farm was the preferred choice but not the only choice that the Commission might find prudent. Each resource acquisition decision is complex and depends on a host of factors, both quantitative and qualitative. Thus, it would not be appropriate to determine on the basis of one alternative being less attractive than another on one or two measures taken in the overall evaluation process that the Company was imprudent in selecting that alternative.

334 An additional matter Public Counsel raises with respect to PSE's acquisition of Mint Farm is the suggestion that the Company may have been motivated, or improperly influenced to purchase Mint Farm because it adds $230 million to rate base, which increases PSE's revenue requirement due to the return allowed on rate base.[423] PSE presented testimony from several witnesses disputing that this was a factor in its decision making process.[424] Public Counsel argues this evidence is belied to some degree by Mr. Garratt's testimony that acknowledged PSE's August 2008 presentation to the Board included an analysis of the financial impact of the acquisition – a "Financial Pro Forma."[425] Public Counsel also cites to Ms. Harris's testimony on

[419] Tr. 216 (Garratt); Exhibit DN-3HCT (Nightingale) at 5:16-6:16.

[420] Exhibit SN-1HCT (Norwood) at 21:15-16 and Tr. 209:24-210:7 (Harris).

[421] Exhibit RG-53-HCT (Garratt) at 7:12-16.

[422] Exhibit RG-3HC (Garratt) at 26 and Exhibit RG-53HCT (Garratt) at 23:6-15; Tr. 211:8-9 (Harris) and Tr. 281:7-14 (Garratt).

[423] Public Counsel Initial Brief at ¶¶ 51, 52.

[424] Exhibit KJH-8CT (Harris) at 11; Exhibit RG-53HCT (Garratt) at 28-29; Exhibit WJE-21HCT (Elsea) at 15.

[425] Public Counsel Initial Brief ¶ 52 (citing Tr. 230:19-22 (referring to Exhibit RG-7C, August 2008 Board Presentation, Financial ProForma, p. 74, *et seq.*)

cross-examination in connection with this argument. In point of fact, however, Ms. Harris's testimony is that:

> I believe as is stated in the testimony of Mr. Garratt, we're always looking at any sort of financial impact on the company, because that would impact our customers in the long term.[426]
>
> * * *
>
> Your previous questions were do we look at a financial impact for the shareholder. My answer would be no, not specifically for a shareholder. Your other question was do we look at the impact, and yes, we have to look at the credit ratings and even all the aspects revolving around the financial stability of the company. So if the question is do we look at financial impact, yes, but not for shareholder or customer, we're looking at it holistically.[427]

PSE's consideration of the financial impact of an acquisition does not suggest any impropriety in the decision making process.[428]

335 Although Staff supports a Commission determination that PSE's acquisition of Mint Farm was prudent, Staff raises a concern about the plants security and requests that we address it in our order. Staff recommends that the Commission order PSE to perform a detailed potential hazard assessment of the dike system protecting Mint Farm and develop a flood contingency plan to protect the site from flooding.[429] Staff says it is ready to work with PSE on the detail of these measures to ensure they are developed in a timely way without undue burden.

336 PSE objects to this proposal, citing a 2007 inspection report of the U.S. Army Corps of Engineers.[430] However, Staff states, this 4-page document merely concludes,

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[426] Tr. 198:3-6 (Harris).

[427] Tr. 199:1-9 (Harris).

[428] We note that it would be highly inappropriate for the Company to not consider this important factor. Indeed we expect it and will expect to see evidence in future cases showing that PSE is being diligent in its ongoing resource acquisition efforts to strike an appropriate balance in terms of relying on a financially sound mix of Company-owned generation and purchased power.

[429] Exhibit DN-1HCT (Nightingale) at 20:21-21:3.

[430] Exhibit RG-53HCT (Garratt) at 22:8-17.

without analysis, that "[t]he levee and pumping plants appear to be in good condition."[431] According to Staff, no evidence was presented that the levee has been evaluated for long-term stability and there is no evidence of actual system performance during floods. Staff argues that flood protection facilities should be assessed routinely for structural integrity. Staff says this is especially important for a plant that will run another 25-30 years and is located near the Columbia River on flat land.

337 *Commission Determination:* We determine that PSE was prudent in deciding to purchase the Mint Farm facility. Such decisions are complex and involve consideration of a host of factors when a number of candidate resources are simultaneously evaluated. While one resource may be superior to others by some measures, an alternative resource may be more favorable considering other, equally important criteria. It is clear from the evidence that PSE undertook a careful, thorough and detailed examination of the leading candidates for acquisition that emerged during the evaluation process pursuant to the RFP. PSE ultimately selected Mint Farm from among several alternatives, any one of which the Commission might find prudent.

338 Although we determine PSE's decision to acquire Mint Farm was prudently made, it is appropriate that we discuss our concerns with regard to two issues raised by Public Counsel. There is no dispute that the acquisition of Mint Farm leaves PSE long in terms of capacity during 2010. This means that customers will bear the total costs of the facility in rates during a period when its benefits are not fully realized. But that short term reality does not detract from the mid- and long-term prudence of the acquisition.[432]

339 As we have noted in earlier decisions,[433] acquisitions such as Mint Farm are rarely, if ever, in precise balance with a company's forecasted near-term load. Instead, opportunities such as Mint Farm are predictably out of balance with a company's short-term resource needs because such purchases are opportune in their inception. The timing of these events is driven by the seller. When the seller decides to market

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[431] Staff Initial Brief at ¶ 186.

[432] At worst, we expect it to result in a modest intergenerational misalignment of costs and benefits, and see no need to fine tune rates to correct for this minor effect. However, if circumstances should change, we may revisit this issue.

[433] *WUTC v. PacifiCorp, d/b/a, Pacific Power & Light Co.*, Docket UE-090205, Order 09 at ¶¶ 50, 66 (December 16, 2009).

its property, potential buyers must act with alacrity or lose their opportunity to acquire the asset. Here, we are convinced that PSE moved to acquire Mint Farm, not because of an immediate need for the resource, but because it offered significant benefits to its generating portfolio at a reasonable price relative to comparable alternatives and the company's longer-term resource needs. There is no evidence that suggests PSE could have waited to act on Mint Farm and achieve the same result.

340 While there is no evidence in the record to support Public Counsel's concerns that PSE's decision to acquire Mint Farm was driven in part by an interest in acquiring a capital asset on which it will earn a return, rather than making a power purchase that would not impact return, the concern is valid as a general proposition. Even in the absence of any evidence of abuse, regulatory authorities in the utility sector must be alert to the potential that a company might make unnecessary or premature capital additions to inflate returns. Utility companies, for their part, should be aware of the regulators' responsibility in this regard. Thus, we expect PSE to continue to evaluate carefully the financial impacts of alternative resource acquisition decisions, both on the Company from a business perspective and on customers in terms of rates. In addition, PSE should continue to evaluate the security of its power supply in terms of its ability to provide safe and reliable service. There should be an appropriate balance in the Company's power portfolio at all times between owned generation and power purchases. Determining the appropriate balance is a matter of informed judgment. We expect PSE to obtain the information necessary to make good judgments in this connection, and to share that information with the Commission on an ongoing basis in the context of IRPs and their updates and general rate cases, and by other means, as appropriate.

341 Turning to Staff's concerns about flood hazard at the Mint Farm site, we do not find it appropriate to require PSE to perform a detailed potential hazard assessment of the dike system protecting Mint Farm and develop a flood contingency plan. It is apparent from our record that PSE is fully aware of its obligation to be prudent when acquiring resources, and we are confident the Company is equally aware of its obligation to prudently manage them on an ongoing basis. Thus, we leave it to the Company, in the first instance, to take appropriate measures considering any environmental hazards that might affect the Mint Farm facility.

2. Uncontested Asset Acquisitions

342 PSE asks the Commission to determine expressly that the Company acted prudently in acquiring the following resources and in executing the following power purchase agreements:

- Purchase of Fredonia Generating Units 3 and 4.
- Expansion of the Wild Horse Wind Facility to add 44 MW of capacity to the facility.
- Execution of a four-year winter power purchase agreement with Barclays Bank PLC.
- Execution of a four-year and three-month power purchase agreement with Credit Suisse.
- Execution of a five-year power purchase agreement with Puget Sound Hydro LLC.
- Execution of a five-year power purchase agreement with Qualco Energy, LLC.[434]
- Execution of a five-year power purchase agreement with Powerex for Point Roberts.[435]

PSE provided evidence concerning, and no party challenges the prudence of, these resource acquisitions.[436]

343 Finally, PSE requests our express determination that the sale of the White River assets to the Cascade Water Alliance was appropriate. PSE provided detailed testimony regarding the sale, the alternatives considered by PSE, and the appropriateness of the consideration received.[437] No party opposed this requested determination.

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[434] *See* Exhibit KJH-8CT (Harris) at 1:17 – 2:4.

[435] *See* Exhibit DEM-9CT (Mills) at 9:10-13; *see also* Exhibit DEM-1CT (Mills) at 38:8-9.

[436] *See* Exhibit KJH-1CT (Harris) at 8:18 – 9:8; *See passim* Exhibit RG-1HCT (Garratt).

[437] *See* Exhibit PKW-1T (Wetherbee) at 2-18.

344 *Commission Determinations:* No one opposes a Commission determination that the resource acquisitions discussed in this section of our Order are prudent and PSE has presented satisfactory evidence that this is so. We accordingly determine each of them to be prudent. In addition, no one opposes a determination that PSE's sale of the White River assets was reasonable. Again, PSE has presented evidence showing the reasonableness of its decision. We accordingly determine the sale was appropriate.

G. Satisfaction of Emissions Performance Standards

345 Washington state law requires that utilities comply with a greenhouse gas emissions performance standard (EPS)[438] and requires the Commission to enforce the standard with respect to electrical companies.[439] The EPS applies to long-term financial commitments that RCW 80.80.010(15) defines as:

> (a) Either a new ownership interest in baseload electric generation or an upgrade to a baseload electric generation facility[440]; or
>
> (b) A new or renewed contract for baseload electric generation with a term of five or more years for the provision of retail power or wholesale power to end-use customers in this state.

346 We turn first to consideration of whether Sumas and Mint Farm satisfy the definition of baseload electric generation.

<u>*Baseload Generation*</u>

347 The Company presents evidence through Mr. Henderson to demonstrate that the Mint Farm Generating Station meets the statutory definition of baseload generation. Mr. Henderson says "Mint Farm was designed and intended to operate as a baseload

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[438] RCW 80.80.040 and WAC 480-107-405.

[439] RCW 80.80.060.

[440] Baseload electric generation is defined as "Electric generation from a power plant that is designed and intended to provide electricity at an annualized plant capacity factor of at least sixty percent." RCW 80.80.010(4).

power plant."[441] He says that it is the Company's intent to operate the plant as a baseload plant in a manner similar to its operation of the Goldendale plant. Turning to the Sumas generating plant, Mr. Henderson says that it too is "currently designed and permitted as a baseload plant."[442] Mr. Henderson provides letters from the Department of Ecology (Ecology) to demonstrate that Ecology has concluded that both the Mint Farm and Sumas generating plants are baseload electric generation facilities subject to the EPS statute.[443]

348 Staff, through Mr. Nightingale, provides a detailed discussion about the operating characteristics of the Mint Farm generating plant and whether it qualifies as baseload generation. According to Mr. Nightingale, the Commission is required by the EPS statute to determine whether a plant qualifies as baseload after looking at:

1) The design of the power plant.

2) Its intended use, based upon:

   a. Permits necessary for the operation of the power plant.

   b. Any other matter the commission determines is relevant under the circumstances.[444]

349 Mr. Nightingale concludes that the key factors for the Commission to consider are "the design and the permits, and any similar operating characteristics such as technical capability limitations or legal operating restrictions."[445] He testifies that while the flexible characteristics of gas-fired generation plants allow modeled and actual operation to vary significantly from plant capability, it is more important to focus on evaluation of permit conditions and actual technical capability.[446]

350 Mr. Nightingale explains that the Mint Farm plant is a combustion turbine matched with a steam turbine that the manufacturer specifies has the capability to routinely

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441 Exhibit JMH-1T (Henderson) at 3:3-9.

442 *Id.* at 4:18-5:6

443 Exhibit JMH-5; Exhibit DN-2.

444 Exhibit DN-1CT (Nightingale) at 39:16-40:2.

445 *Id.* at 40:5-40:7.

446 *Id.* at 41:8-42:6.

meet and exceed a 60 percent annualized capacity factor. He says that the relevant air permit issued by Ecology places no limitations on the number of hours during a year the plant can operate. Finally, he testifies that the Company has sufficient firm gas supply and gas transportation arrangements to operate the Mint Farm plant at or above a 60 percent capacity factor.[447]

351 Mr. Nightingale concludes that the Mint Farm plant qualifies as baseload generation because it is designed and permitted to operate at or above a 60 percent capacity factor.[448]

352 Mr. Norwood, for Public Counsel, does not dispute that the Sumas plant is baseload generation, but he contends that the Mint Farm plant does not appear to meet the definition because the Company's forecasts and models depicting actual use of the plant show capacity factors of 25 to 45 percent, significantly below the 60 percent requirement.[449] Public Counsel argues that the Company's actual operational data for Mint Farm demonstrates that it has not achieved a capacity factor of 60 percent since commencing operations and is not forecast to be operated in the rate year at more than 45 percent. He contends that the Company has admitted that it will operate the plant as baseload only if it is economical to do so.[450]

353 Public Counsel contends that it is not enough to meet the statutory definition of baseload for a power plant to be designed and permitted to operate at capacity factors of 60 percent or more. According to Public Counsel, the use of the term "intended" in the statute requires that actual operation of the facility be considered as a separate factor.[451] He argues that to not do so would violate the principles of statutory construction.

354 Turning to the air permit issued by the Department of Ecology, Public Counsel argues that it is not "determinative of intent." He says that the Commission, not Ecology, is given the authority to determine whether a plant qualifies as baseload.[452] Finally,

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[447] Exhibit DN-1CT (Nightingale) at 42:12-44:17.

[448] *Id.* at 44:21-45:2.

[449] Exhibit SN-1HCT (Norwood) at 28:7-24.

[450] Public Counsel Initial Brief at ¶ 71.

[451] *Id.* at ¶¶ 68-71.

[452] *Id.* at ¶¶ 72-74.

Public Counsel argues that nothing in the air permit issued by Ecology verifies any intent for the plant to be operated at or above a 60 percent capacity factor.[453]

355 Staff disagrees with Public Counsel. Staff argues that the Commission must consider "intended use," but says that the statute directs the Commission to base that consideration on permits and other factors it determines to be relevant under the circumstances. Staff contends that in prior decisions the Commission has held that plant design is the primary focus.[454]

356 The Company argues further that Mr. Norwood's conclusion fails to consider Company testimony that "Mint Farm . . . is designed to run at a baseload capacity factor above 90 percent, and PSE intends to operate it in that matter whenever it is economically feasible to do so"[455] and ". . .Mint Farm, Sumas, and other combined-cycle plants . . . are designed to operate at capacity factors above 90%."[456] The Company argues that Mint Farms design capability and the lack of any limitations under its air permits demonstrate that it qualifies as baseload generation.[457]

357 *Commission Determinations:* No party challenges whether the Sumas facility qualifies as baseload generation and is therefore subject to the EPS requirements. The record contains the Company's assertion that the plant is capable of operating at the required capacity factor as well as evidence that the plant belongs to the class of combined-cycle turbines that were designed to achieve this performance. The record also includes Ecology's determination that the plant is baseload and must meet the EPS. While the latter is not determinative, because the law gives the authority to the Commission to make this judgment, it does add weight to the Company's own assertions. We determine that Sumas is baseload generation and must comply with the EPS.

358 Public Counsel's challenge to the classification of Mint Farm as baseload generation is based on the Company's modeling of plant operations and his interpretation of the EPS statute. Public Counsel acknowledges that the plant is designed to operate at a

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[453] *Id.* at ¶ 25.

[454] Staff Reply Brief at ¶¶36-37.

[455] Exhibit WJE-1HCT (Elsea) at 51:16-19.

[456] Exhibit LEO-1CT (Odum) at 29:1-9.

[457] PSE Initial Brief at ¶¶ 26, 28.

capacity factor of 60 percent or more. However, his argument concerning "intended use" is wide of the mark. The fundamental intent of the RCW 80.80 is to ensure that new, or newly acquired, power generation facilities and long-term contracts do not emit greenhouse gases in excess of the EPS. To achieve this objective, the statute requires consideration of both design and intended use because neither factor by itself is sufficient. It would be inappropriate to allow a utility to circumvent the EPS simply by asserting that it intended to use a plant at less than 60 percent of its capacity, even though the design of the plant would accommodate more intensive operation if the utility's needs changed. It would also be inappropriate for the statute to allow for the special deferral treatment provided in RCW 80.80.060(6) if a utility argued it intended to use a plant at a capacity factor of 60 percent or more if the plant design, or air permits, will not allow such operation.

359 Public Counsel argues that the utility's forecasts and its flexibility in dispatch due to projected economics are determinative factors in judging whether a plant qualifies as baseload. This interpretation would allow utilities, or the Commission, to circumvent the EPS simply based on the strength of forecasts and uncertain conditions relating to economic dispatch. This is not a reasonable interpretation of the intent of the legislature. The more reasonable interpretation is that the design of a plant is the primary consideration, unless operations are specifically constrained by other factors, such as air permits.

360 There is no dispute about whether the Mint Farm combined cycle facilities are designed to operate at a capacity factor of 60 percent or more. There also is no constraint regarding the number of hours the plant is allowed to operate per year included in the air permit issued by the Department of Ecology.[458] We accordingly determine that the Mint Farm plant is baseload generation and is subject to the EPS and other provisions of RCW 80.80.

361 Having found both Sumas and Mint Farm meet the definition of baseload generation under RCW 80.80, we turn next to consideration of whether they comply with the EPS.

Compliance with the Emissions Performance Standard (EPS)

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[458] Exhibit JMH-3.

362 RCW 80.80 establishes a greenhouse gases emission performance standard of no more than 1100 lbs. of carbon dioxide/MWh. The law states: "No electrical company may enter into a long-term financial commitment unless the baseload electric generation supplied under such commitment complies with the greenhouse gases emissions performance standard."[459] Commission rules require in relevant part that: "Electrical companies bear the burden to prove compliance with the greenhouse gases emissions performance standard under the requirements of WAC 480-100-415 as part of a general rate case."[460]

363 Mr. Henderson testifies that the Company provided detailed information to the Department of Ecology concerning the design and operation of both Sumas[461] and Mint Farm.[462] Ecology provided the Company with a letter verifying its determination that the Sumas generating plant is estimated to emit greenhouse gases at a rate of 951 lb/MWh and that Ecology believes the plant "should comply with the greenhouse gas emissions performance standard in WAC 173-407-130."[463] Ecology also provided the Company with a letter verifying its determination that the Mint Farm generating plant "will comply with the greenhouse gas emissions performance standard in WAC 173-407-130."[464]

364 Staff testifies that it has verified the methods and findings of Ecology that the plants will meet the standard.[465]

365 Public Counsel argues that for a power plant to comply with the EPS a utility must also show that it has need for the resource and the resource is appropriate. He points to both RCW 80.80.060(5) and WAC 480-100-415 and argues that the Company has not met these requirements with respect to Mint Farm. Public Counsel asserts that the Company does not need the plant to meet current capacity requirements and that less expensive resources were available that provided greater economic benefits.[466]

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[459] RCW 80.80.060(1).

[460] WAC 480-100-405(1).

[461] *Id.* at 5:9-16 and Exhibit JMH-6.

[462] Exhibit JMH-1T (Henderson) at 3:12-21 and Exhibit JMH-4.

[463] Exhibit JMH-5 at 2 and Exhibit DN-2.

[464] Exhibit JMH-5 at 2.

[465] Exhibit DN-1HCT (Nightingale) at 18:20-20:6.

[466] Public Counsel Initial Brief at ¶¶ 59-60.

366 The Company counters that no provision in RCW 80.80.060 requires or mentions the need or appropriateness of a resource as criteria for determining EPS compliance.[467] Indeed, as Staff points out, RCW 80.80.060(5) no longer references the issues of resource need and appropriateness and even the prior version of the statute referenced those considerations only in the context of a Company application outside of a general rate case.[468]

367 Public Counsel acknowledges that the RCW 80.80.060 was amended effective July 2009 to remove the consideration of need and appropriateness from matters the Commission must consider, but he argues that the original accounting petition and the agreement among the parties to defer the matter to this general rate case predated the amendment to the statute. He also notes that the WAC 48-100-415 has not been amended to remover reference to resource need and appropriateness.[469]

368 *Commission Determination:* The Company has provided significant technical detail regarding plant emissions from both the Sumas and the Mint Farm facilities to the Commission and Ecology. After reviewing this information, Ecology concluded that both facilities meet the standard and Staff indicates that it has reviewed and verified Ecology's methods and findings. We are satisfied that both Sumas and Mint Farm will not exceed the statutory EPS.

369 Public Counsel's reference to the "need" and "appropriateness" criteria is to a version of the statute that is no longer current. Even if Public Counsel's references to these criteria were relevant, they are not applicable because the prior statute only required consideration of these factors in the case of a company's application for determination of compliance with the EPS outside of a general rate case. WAC 480-100-405 only requires that the information included in an application made as part of a general rate case include the same categories of information required for an application outside of a general rate case. In any event, we determine elsewhere in this Order that PSE's acquisitions of Sumas and Mint Farm were prudent, thus establishing them as resources that were both needed and appropriate.

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[467] PSE Initial Brief at ¶ 24.

[468] Staff Reply Brief at ¶ 33.

[469] Public Counsel Initial Brief at ¶ 23.

FINDINGS OF FACT

370 Having discussed above in detail the evidence received in this proceeding concerning all material matters, and having stated findings and conclusions upon issues in dispute among the parties and the reasons therefore, the Commission now makes and enters the following summary of those facts, incorporating by reference pertinent portions of the preceding detailed findings:

371 (1) The Washington Utilities and Transportation Commission is an agency of the State of Washington, vested by statute with authority to regulate rates, rules, regulations, practices, and accounts of public service companies, including electrical and gas companies.

372 (2) Puget Sound Energy, Inc., (PSE) is a "public service company," an "electrical company" and a "gas company," as those terms are defined in RCW 80.04.010 and as those terms otherwise are used in Title 80 RCW. PSE is engaged in Washington State in the business of supplying utility services and commodities to the public for compensation.

373 (3) The following investments by PSE were prudent and were made at reasonable costs:

- Acquisition of the Mint Farm Energy Center.
- Purchase of Fredonia Generating Units 3 and 4.
- Expansion of the Wild Horse Wind Facility to add 44 MW of capacity to the facility.
- Execution of a four-year winter power purchase agreement with Barclays Bank PLC.
- Execution of a four-year and three-month power purchase agreement with Credit Suisse.
- Execution of a five-year power purchase agreement with Puget Sound Hydro LLC.
- Execution of a five-year power purchase agreement with Qualco Energy, LLC.

- Execution of a five-year power purchase agreement with Powerex for Point Roberts.

PSE's sale of the White River Assets to the Cascade Water Alliance was reasonable and appropriate.

374 (4) The Mint Farm and Sumas CCCT plants are baseload generation within the meaning of RCW 80.80. They are subject to, and satisfy, the Emissions Performance Standard established by RCW 80.80.040.

375 (5) PSE, having revised its initial proposal for increased rates during the course of this proceeding, did not show the rates proposed by tariff revisions filed on May 8, 2009, and suspended by prior Commission order, to be fair, just, or reasonable.

376 (6) PSE has demonstrated by substantial competent evidence that its current rates are insufficient to yield reasonable compensation for the electric and gas services it provides in Washington.

377 (7) The record in this proceeding supports a capital structure and costs of capital, which together produce an overall rate of return of 8.10 percent, as set forth in the body of this Order in Table 11.

378 (8) The Commission's resolution of the disputed issues in this proceeding, coupled with its determination that certain uncontested adjustments are reasonable, result in finding that PSE's natural gas revenue deficiency is \$10,149,229 and its electric revenue deficiency is \$56,204,849, subject to adjustment to reflect recalculation of the Tenaska and March Point disallowances and the production factor adjustment, as discussed in the body of this Order.

379 (9) PSE requires relief with respect to the rates it charges for electric service and gas service provided in Washington State so that it can recover its natural gas service and electric service revenue deficiencies.

380 (10) The terms of the multiparty settlements concerning electric and natural gas rate spread and rate design, respectively attached to this Order as Appendices

A and B, and incorporated by this reference, are consistent with the public interest.

381 (11) The rates, terms, and conditions of service that result from this Order are fair, just, reasonable, and sufficient.

382 (12) The rates, terms, and conditions of service that result from this Order are neither unduly preferential nor discriminatory.

CONCLUSIONS OF LAW

383 Having discussed above all matters material to this decision, and having stated detailed findings, conclusions, and the reasons therefore, the Commission now makes the following summary conclusions of law, incorporating by reference pertinent portions of the preceding detailed conclusions:

384 (1) The Washington Utilities and Transportation Commission has jurisdiction over the subject matter of, and parties to, these proceedings.

385 (2) The rates proposed by tariff revisions filed by PSE on May 8, 2009, and suspended by prior Commission order, were not shown to be fair, just or reasonable and should be rejected.

386 (3) PSE's existing rates for electric service and natural gas service provided in Washington State are insufficient to yield reasonable compensation for the service rendered.

387 (4) PSE requires relief with respect to the rates it charges for electric service and natural gas service provided in Washington State.

388 (5) The Commission must determine the fair, just, reasonable, and sufficient rates to be observed and in force under PSE's tariffs that govern its rates, terms, and conditions of service for providing natural gas and electricity to customers in Washington State.

389 (6) The costs of PSE's investments found on the record in this proceeding to have been prudently made and reasonable should be allowed for recovery in rates.

390 (7) PSE should have the opportunity to earn an overall rate of return of 8.10 percent based on the capital structure and costs of capital set forth in the body of this Order, including a return on equity of 10.10 percent on an equity share of 46.00 percent.

391 (8) PSE should be authorized and required to make a compliance filing to recover its revenue deficiency of $10,149,229 for natural gas service. PSE should be authorized, subject to Staff review and Commission approval, to adjust the $56,204,849 revenue deficiency found under the determinations in this Order to be its approximate revenue requirement for electricity to account for recalculation of the Tenaska and March Point 2 disallowances and the production factor adjustment and should be authorized and required to make a compliance filing to recover the adjusted revenue deficiency for electric service.

392 (9) PSE should be authorized and required to recover the portion of its electric revenue requirement that is associated with the Tenaska regulatory asset via a separate tariff rider with a class-specific kWh rate sufficient to recover these costs for the duration of the amortization period, but with a sunset, or ending date, of December 31, 2011. Base rates determined in this proceeding should be reduced by the revenue requirement amount reflecting the separate treatment of the Tenaska-related costs.

393 (10) The multiparty settlements concerning electric and natural gas rate spread and rate design, respectively attached to this Order as Appendices A and B, and incorporated by prior reference, should be approved and adopted.

394 (11) The rates, terms, and conditions of service that will result from this Order are fair, just, reasonable, and sufficient.

395 (12) The rates, terms, and conditions of service that will result from this Order are neither unduly preferential nor discriminatory.

396 (13) The Commission Secretary should be authorized to accept by letter, with copies to all parties to this proceeding, a filing that complies with the requirements of this Order.

397 (14) The Commission should retain jurisdiction over the subject matters and the parties to this proceeding to effectuate the terms of this Order.

ORDER

THE COMMISSION ORDERS THAT:

398 (1) The proposed tariff revisions PSE filed on May 8, 2009, which were suspended by prior Commission order, are rejected.

399 (2) The multiparty settlements concerning electric and natural gas rate spread and rate design, respectively attached to this Order as Appendices A and B, and incorporated into this Order by prior reference, are approved and adopted.

400 (3) PSE is authorized and required to file tariff sheets following the effective date of this Order that are necessary and sufficient to effectuate its terms. The required tariff sheets must be filed at least two business days prior to their stated effective date, which shall be no sooner than April 7, 2010.

401 (4) The Commission Secretary is authorized to accept by letter, with copies to all parties to this proceeding, a filing that complies with the requirements of this Final Order.

402 (5) The Commission retains jurisdiction to effectuate the terms of this Final Order.

Dated at Olympia, Washington, and effective April 2, 2010.

WASHINGTON STATE UTILITIES AND TRANSPORTATION COMMISSION

JEFFREY D. GOLTZ, Chairman

PATRICK J. OSHIE, Commissioner

PHILIP B. JONES, Commissioner

NOTICE TO PARTIES: This is a Commission Final Order. In addition to judicial review, administrative relief may be available through a petition for reconsideration, filed within 10 days of the service of this order pursuant to RCW 34.05.470 and WAC 480-07-850, or a petition for rehearing pursuant to RCW 80.04.200 and WAC 480-07-870.

APPENDIX A

MultiParty Settlement Agreement - Electric Rate Spread, Rate Design

APPENDIX B

MultiParty Settlement Agreement - Natural Gas Rate Spread, Rate Design

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
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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.

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Attachment: SCHEDULES

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

---

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.

---

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

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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]

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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

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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.

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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 on-going 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]

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]

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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]

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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]

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

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.

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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;

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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

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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.

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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]

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[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]

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.

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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

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

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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

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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

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

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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 N[illegible] ting AMI initiatives.[393]

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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[illegible] *Id.* at 14.

388 *See* [illegible] *d Metering Infrastructure Implementation and Cost Recovery Authorization Emergency Act of 2009,* (Bill 18-[illegible] 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

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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

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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. <u>DEPRECIATION RATES</u> (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]

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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

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]

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

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

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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]

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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

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

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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

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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]

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 [illegible] allocator is also appropriate because the maximum [illegible] the subtransmission and distribution system are non-coincid[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

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

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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

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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.

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

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

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

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

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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:

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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]

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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

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

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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

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

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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-

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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

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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.

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

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

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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]

<u>DECISION</u>

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

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]

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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."

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

[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

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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."

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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.

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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 (A)	PEPCO-DC Adjusted (D)	Adjustments (C)	Adjusted Totals (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

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Schedule 2
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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
Page 2 of 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

4. Does Mr. Smith agree or disagree that including (non-cash) AFUDC above the line as going level revenue offsets any revenue requirement related to CWIP? If Mr. Smith disagrees, please provide detailed reasoning supporting that disagreement.

RESPONSE:

Object to form of the question because the word "any" is ambiguous.

The revenue requirement related to KAWC's proposed inclusion of CWIP in rate base has not been fully offset by including AFUDC above the line as revenue. ~~No~~. See OAG response to PSC-1-3 for the approximate revenue requirement impact of CWIP and AFUDC in the current KAWC rate case.

21. Please list all Commission cases you rely upon for Mr. Smith's proposal to normalize rate case expenses.

RESPONSE:

The recommendation to normalize rate case expense is not necessarily based on Commission cases and is explained in the direct testimony as being preferable to a deferral and amortization approach for several reasons including the following. The purpose of a forecasted test period is to match rates with the expected revenue requirements for a specific future 12-month operating period. In this case, the 12-month period is October 2010 through September 2011. KAWC used construction and operating expense budgets to forecast its cost of operations for that 12-month period. The rate case costs for the two previous rate cases were incurred in periods prior to the test period. Under a normalization approach, rate case cost is recorded as an expense in the period incurred. A utility, pursuant to Statement of Financial Accounting Standards No. 71 (FAS 71) can record a "regulatory asset" (an expense carried on its 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 for similar future costs. It is questionable whether the costs for two prior rate cases ~~continue to~~ warrant deferred treatment ~~under FAS 71~~ in the context of the current KAWC rate case due to their relative immateriality and the lack of a Commission order in those prior KAWC dockets that singled out rate case expense for specific and special single issue ratemaking treatment or deferral. KAWC has requested a total rate base of over \$362 million (with CWIP). The balance of costs remaining from those two prior rate cases (per KAWC's response to data request AG-1-122) total to \$256,499. The deferral balance thus represents only 0.071 percent in relation to KAWC's proposed rate base.[3] Additionally, the total expense for those prior rate cases being requested by KAWC is only 0.157 percent of KAWC's total revenue requirement request.[4] This could also be viewed as insufficiently material to warrant special single-issue regulatory asset treatment. By selecting this individual expense to record as an asset to be subsequent recovered, KAWC has, in effect, isolated rate case expense as a single issue.

Prospectively, beginning with the cost for KAWC's current rate case, Mr. Smith ~~I~~ recommends that the Commission commence treating the annual allowance for rate case expense as a normalized operating expense amount, rather than an amortization, for several reasons, including the following: Although the amortization treatment afforded rate case expense previously effectively treats the rate case expense as an asset, where this was addressed in a rate case order other than one involving approval of a "black box" settlement, rate case costs do not meet the criteria for a regulatory asset and should not be afforded regulatory asset treatment. The ratemaking treatment of such costs should therefore provide for a normalized expense allowance (similar to other O&M expenses), rather than the establishment of a regulatory asset that is amortized prospectively.

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[3] \$256,499 / \$362,672,028 = 0.071%. It is noted that KAWC is not requesting inclusion of its unamortized rate case expense balance from those two prior rate cases in rate base (other than as a component of cash working capital). Comparing an asset amount with rate base is a framework for evaluating materiality.
[4] \$148,128 / \$94,371,912 = 0.157%.

24. Please list all Commission cases you rely upon for Mr. Smith's proposal to normalize capitalization rates.

RESPONSE:

Object to form of question. Notwithstanding the objection:

The recommendation to normalize the capitalization rate for the current KAWC rate case future test year is not necessarily based on Commission cases and is explained in the direct testimony as being necessary based on the facts and circumstances of the current KAWC rate case, in which KAWC has used a capitalization rate that is **much lower** than any recent year, or any average of recent years, as shown in the following table:

KAWC Capitalization Rates			
Year	Actual	Budget	Difference
2005	15.54%	12.98%	2.56%
2006	18.84%	19.00%	-0.16%
2007	21.34%	18.06%	3.28%
2008	23.35%	18.12%	5.23%
2009	19.64%	19.96%	-0.32%
Averages:			
2007-2009	21.443%	18.713%	2.730%
2006-2009	20.793%	18.785%	2.008%
2005-2009	19.742%	17.624%	2.118%

1076-E-615 AH

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
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DISTRICT OF COLUMBIA
PUBLIC SERVICE COMMISSION

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

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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

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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

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 4[th] 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 4[th] 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

[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).