ATTACHMENT

1-4c

BEFORE
THE TENNESSEE REGULATORY AUTHORITY

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Atmos Energy Corporation General Rate Case and Petition to Adopt Annual Review Mechanism and ARM Tariff	)	Docket No. 14-00146

DIRECT TESTIMONY
of
WILLIAM H. NOVAK

ON BEHALF OF

THE CONSUMER ADVOCATE AND PROTECTION DIVISION
OF THE
TENNESSEE ATTORNEY GENERAL'S OFFICE

April 7, 2014

IN THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:	)	
	)	
ATMOS ENERGY CORPORATION GENERAL RATE CASE AND PETITION TO ADOPT ANNUAL REVIEW MECHANISM AND ARM TARIFF	)))))	DOCKET NO. 14-00146

AFFIDAVIT

I, William H. Novak, CPA, on behalf of the Consumer Advocate Division of the Attorney General's Office, hereby certify that the attached Direct Testimony represents my opinion in the above-referenced case and the opinion of the Consumer Advocate Division.

WILLIAM H. NOVAK

EMILY KNIGHT STATE OF TENNESSEE NOTARY PUBLIC

Sworn to and subscribed before me
this 30th day of March 2015.

Emily Knight
NOTARY PUBLIC

My commission expires: July 6, 2015

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Q1. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION FOR THE RECORD.

A1. My name is William H. Novak. My business address is 19 Morning Arbor Place, The Woodlands, TX, 77381. I am the President of WHN Consulting, a utility consulting and expert witness services company.[1]

Q2. PLEASE PROVIDE A SUMMARY OF YOUR BACKGROUND AND PROFESSIONAL EXPERIENCE.

A2. A detailed description of my educational and professional background is provided in Attachment WHN-1 to my testimony. Briefly, I have both a Bachelors degree in Business Administration with a major in Accounting, and a Masters degree in Business Administration from Middle Tennessee State University. I am a Certified Management Accountant, and am also licensed to practice as a Certified Public Accountant.

My work experience has centered on regulated utilities for over 30 years. Before establishing WHN Consulting, I was Chief of the Energy & Water Division of the Tennessee Regulatory Authority where I had either presented testimony or advised the Authority on a host of regulatory issues for over 19 years. In addition, I was previously the Director of Rates & Regulatory Analysis for two years with Atlanta Gas Light Company, a natural gas distribution utility with operations in Georgia and Tennessee. I also served for two years as the Vice President of Regulatory Compliance for Sequent Energy Management, a natural

[1] State of Tennessee, Registered Accounting Firm ID 3682.

gas trading and optimization entity in Texas, where I was responsible for ensuring the firm's compliance with state and federal regulatory requirements.

In 2004, I established WHN Consulting as a utility consulting and expert witness services company. Since 2004 WHN Consulting has provided testimony or consulting services to state public utility commissions and state consumer advocates in at least ten state jurisdictions as shown in Attachment WHN-1.

Q3. ON WHOSE BEHALF ARE YOU TESTIFYING?

A3. I am testifying on behalf of the Consumer Advocate & Protection Division ("CAPD" or "the Consumer Advocate") of the Tennessee Attorney General's Office.

Q4. HAVE YOU PRESENTED TESTIMONY IN ANY PREVIOUS ATMOS ENERGY CORPORATION RATE CASES?

A4. Yes. I've presented testimony in TRA Dockets U-82-7211, U-83-7277, U-84-7333, U-86-7442, 89-10017, 92-02987, 05-00258, 07-00105 and 12-00064 concerning rate cases involving either Atmos Energy Corporation ("Atmos" or "the Company") or its predecessor companies as well as dockets for other generic tariff and rulemaking matters. In addition, I previously advised the TRA on issues in other Atmos dockets in cases where I did not present testimony.

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A5. My testimony will support and address the CAPD's positions and concerns with respect to the Company's Petition. Specifically, I will address the following:

i. CAPD's proposed attrition period revenue calculations;

ii. CAPD's proposed attrition period operation & maintenance expense calculations;

iii. CAPD's proposed attrition period taxes other than income tax expense calculations;

iv. CAPD's proposed attrition period rate base calculations; and

v. CAPD's proposed rate design structure.

I will also be presenting testimony related to the Company's proposal to recover its cumulative net operating losses for tax purposes within accumulated deferred income taxes. In addition, I will present testimony on the CAPD's position of the Company's proposed tariff for an annual review mechanism. Finally, I will present testimony on other procedural issues for the TRA to consider in this case.

Q6. WHAT DOCUMENTS HAVE YOU REVIEWED IN PREPARATION OF YOUR TESTIMONY?

A6. I have reviewed the Company's Rate Case Application as filed on November 25, 2014, along with the testimony and exhibits presented with their filing. In addition, I have reviewed the Company's workpapers supporting their attrition period revenues and rate base. I have also reviewed the Company's responses to the relevant data requests submitted by the TRA as well the Company's responses to CAPD's discovery requests (and documents filed in connection with those requests and responses) in these same areas.

Q7. WHAT TEST PERIOD AND ATTRITION PERIOD HAVE YOU ADOPTED FOR THIS CASE?

A7. The Company has proposed the twelve months ended June 30, 2014 as its test period with attrition adjustments through the 12 months ending May 31, 2016. Both of these review periods appear reasonable. Therefore, I have adopted both the Company's proposed test period and attrition period for this case.

Q8. WHAT IS THE YOUR REVENUE DEFICIENCY CALCULATION FOR THIS CASE?

A8. As shown on CAPD Exhibit, Schedule 1, the revenue deficiency/surplus calculation required to produce the 7.55% overall return recommended by Dr. Klein results in a revenue decrease of approximately $3.0 million.

Q9. ARE YOU SURPRISED THAT YOUR REVIEW OF THE COMPANY'S PETITION RESULTS IN A RATE DECREASE?

A9. No. The Company's December 2014 monthly report to the TRA shows that their earned rate of return for all of 2014 was 7.74% which is 19 basis points greater than the overall return recommended by Dr. Klein in this case. Therefore, any cost of capital recommendation below the Company's achieved return would result in a revenue decrease for ratepayers.

[Testimony continues on next page]

I. ATTRITION PERIOD REVENUES

Q10. MR. NOVAK, PLEASE DESCRIBE THE MAJOR AREAS OF DIFFERENCE BETWEEN THE COMPANY'S AND YOUR CALCULATION OF ATTRITION PERIOD BILLING DETERMINANTS.

A10. Because the Company adopted the CAPD's spreadsheet models for their revenue calculations, the differences between the two revenue calculations are relatively minor in total when compared to previous rate cases. As shown in detail on Attachment WHN-2, Schedule 1 and summarized below in Table 1, both the Company and I began with the test period sales and transportation volumes of 23,895,057 Mcf, 1,615,991 bills and 16,126 billing demand units.[2] Both the Company and I then adjusted these test period determinants for the impacts of normal weather, annualized customer usage and customer growth to arrive at attrition billing determinants as shown below.

Table 1 – Summary of Attrition Period Billing Determinants

	Test Period	Weather Adjustment	Customer Growth	Attrition Period
Bills	1,615,991	0	47,898	1,663,889
Billing Demand	16,126	0	0	16,126
Mcf Volumes	23,895,057	-995,686	2,042,836	24,942,207

I have also included a detailed comparison with the Company's attrition period billing determinants on Attachment WHN-2, Schedule 2. This comparison is summarized below on Table 2.

[2] Billing Demand Units refers to peak day capacity subscribed to by the Company's firm industrial customers on Rate Schedules 240 and 260/240.

Table 2 – Comparison of Company and CAPD Attrition Period Billing Determinants			
	Company	**CAPD**	**Difference**
Bills	1,663,887	1,663,889	2
Billing Demand	16,126	16,126	0
Mcf Volumes	24,942,622	24,942,208	-415

Q11. HOW WAS THE WEATHER ADJUSTMENT COMPUTED?

A11. Both the Company and I have used weather data from the Bristol, Knoxville, Nashville and Paducah weather stations to normalize sales data, and we have both used the daily normal weather for the 30-year period ended June 30, 2014 in order to coincide with the test period.

Separate weather normalization calculations were carried out for the Company's residential and commercial customers. A summary of the results from the residential and commercial weather normalization is included on Attachment WHN-3 for WNA tracking purposes.

Q12. HOW HAVE YOU ADJUSTED THE ATTRITION PERIOD BILLING DETERMINANTS FOR EXISTING CUSTOMER USAGE?

A12. I adjusted industrial customer usage by individually analyzing the sales volumes of the Company's 25 largest customers. Where I felt that it was necessary, such as a large swing in gas usage or a material tariff transfer, I adjusted the test period usage to take these changes into account. I then compared my own adjustments with those proposed by the Company. For the most part, I felt in this case that the Company had properly adjusted for any test period anomalies and tariff transfers within the industrial customer group.

Q13. HOW WERE SALES VOLUMES FOR ADDED CUSTOMERS COMPUTED?

A13. A historical average of added customers was first calculated. These forecasted customer additions were then multiplied by an average normalized usage volume per customer giving additional attrition period sales volumes for the residential and commercial rate classes.

Q14. HOW WERE THE ATTRITION PERIOD BILLING DETERMINANTS TRANSLATED INTO REVENUES?

A14. The attrition period billing determinants as shown on Attachment WHN-2 were multiplied by the existing base tariff rates and the PGA rate based upon the Company's demand and commodity gas costs at June 2014. This gives total attrition period gas sales and transportation margin of $63,990,308 as shown on Attachment WHN-4 and summarized below in Table 3.

Table 3 – Comparison of Company and CAPD Attrition Period Gross Margin under Current Rates

	Company	**CAPD**	**Difference**
Residential (210)	$32,479,644	$32,500,610	$20,966
Heating & Cooling (211)	675	689	14
Small Commercial & Industrial (220)	20,408,112	20,351,848	-56,264
Experimental School (221)	82,218	90,041	7,823
Public Housing (225)	180,816	166,166	-14,650
Large Commercial & Industrial (230)	235,443	279,452	44,009
Demand/Commodity (240)	0	0	0
Interruptible (250)	632,584	632,584	0
Transportation (260)	9,010,419	9,009,539	-880
Economic Development (280)	125,293	125,255	-38
Special Contract/Negotiated (291)	811,988	811,988	0
Cogeneration (292)	3,785	3,785	0
Large Tonnage A/C (293)	18,351	18,351	0
Total	**$63,989,328**	**$63,990,308**	**$980**

Q15. HOW DID YOU COMPUTE OTHER REVENUES?

A15. Other revenues primarily consist of forfeited discounts and miscellaneous service charges. To compute these amounts, I took a historical average of these amounts over the last four years. This produced $1,216,690 in Other Revenues as shown on Attachment WHN-4.

Q16. HOW DID YOU COMPUTE THE COST OF GAS?

A16. I began with the attrition period throughput volumes and billing demand discussed above. These determinants were then priced out at the June 2014 PGA rates. This produced $78,138,740 in gas cost as shown on Attachment WHN-5.

[Testimony continues on next page]

II. ATTRITION PERIOD OPERATION & MAINTENANCE EXPENSE

Q17. MR. NOVAK, PLEASE DESCRIBE THE COMPONENTS OF O&M EXPENSES.

A17. O&M Expenses generally represent the regular and recurring costs to operate and maintain the utility plant. Among other things, O&M Expense includes internal labor costs and associated benefits. In addition, O&M Expense also includes external costs relating to gas supply expense, gas storage expense, distribution expense, customer accounts expense, sales expense, and administrative & general expense.

Q18. HOW DID YOU CALCULATE O&M LABOR EXPENSE?

A18. I began by analyzing labor costs for the Tennessee division and the other three shared service divisions providing labor services to Tennessee for the last five years. I then increased the net allowable expense amounts by the average labor growth factor over the last three years of 18.02%[3] to get the attrition period labor expense for each division. The three year growth factor was used because I felt that this rate was most representative of what was likely to occur through the attrition year. Finally, I allocated the attrition period expense for each division to Tennessee using the Company's proposed allocation factors. A summary of this calculation is presented below in Table 4.

[3] Annual rate of 9.03% compounded for 23 months (June 2014 to May 2016).

Table 4 – Attrition Period Labor Expense				
	Division 02	**Division 12**	**Division 91**	**Division 93**
Test Period	$36,319,304	$30,858,772	$2,010,614	$3,833,106
Growth Factor	18.02%	18.02%	18.02%	18.02%
Allocation Factor	4.36%	4.41%	40.68%	100.00%
Attrition Period	**$1,868,941**	**$1,606,160**	**$965,342**	**$4,523,999**
			Total Attrition Period Labor Expense	**$8,964,442**

Q19. HOW DOES YOUR CALCULATION OF O&M LABOR EXPENSE COMPARE WITH THE COMPANY'S CALCULATION?

A19. My total attrition period O&M labor expense of $8,964,442 as shown above is $1,701,444 **<u>less</u>** than the Company's projection of $10,665,486 as shown on CAPD Exhibit, Schedule 7.

Q20. HOW DID YOU CALCULATE O&M NON-LABOR EXPENSE?

A20. I calculated non-labor O&M expense in much the same way that labor expense was calculated with two exceptions. I began by analyzing non-labor costs for the Tennessee division and the other three shared service divisions providing non-labor services to Tennessee for the last five years. Next, I reduced these historical costs for amounts that the TRA has traditionally disallowed from rate recovery which I discuss later in my testimony to get the net test period non-labor expense. We then increased the net test period non-labor expense by the average non-labor growth factor over the last three years of 7.50%.[4] The three year growth factor was used because I felt that this rate was most representative of what was likely to occur through the attrition year. Next, I allocated the attrition period expense for each division to Tennessee using the Company's proposed allocation factors.

[4] Annual rate of 3.85% compounded for 23 months (June 2014 to May 2016).

Finally, I made adjustments to exclude expenses associated with intercompany leased property and included expenses associated with the Company's gas storage facility.[5] A summary of this calculation is presented below in Table 5.

Table 5 – Attrition Period Non-Labor Expense				
	Division 02	**Division 12**	**Division 91**	**Division 93**
Test Period	$48,998,106	$26,322,060	$7,304,472	$6,605,472
Disallowable Costs	-46,715,049	-3,414,383	-2,099,010	-435,853
Net Test Period	**$2,283,058**	**$22,907,678**	**$5,205,462**	**$6,169,618**
Growth Factor	7.5%	7.5%	7.5%	7.5%
Allocation Factor	4.36%	4.41%	40.68%	100.00%
Attrition Period	**$107,007**	**$1,085,992**	**$2,276,393**	**$6,632,319**
Gross Attrition Period Non-Labor Expense				**$10,101,712**
Less Intercompany Leased Property Expenses				-532,000
Plus Gas Storage Expenses				476,081
Net Attrition Period Non-Labor Expense				**$10,045,793**

Q21. HOW DOES YOUR CALCULATION OF O&M NON-LABOR EXPENSE COMPARE WITH THE COMPANY'S CALCULATION?

A21. My total attrition period O&M non-labor expense of $10,045,793 as shown above is $694,775 **more** than the Company's projection of $9,351,018 as shown on CAPD Exhibit, Schedule 7.

Q22. WHAT EXPENSES WERE DISALLOWED AND EXCLUDED FROM YOUR CALCULATION OF NON-LABOR O&M EXPENSE?

A22. As shown below in Table 6, the primary expenses disallowed were FAS 87 pension expense and certain management incentive pay plans.

[5] See rate base testimony below for a further discussion of these items.

Atmos records pension expense in accordance with Financial Accounting Standard No. 87 ("FAS 87"). Tennessee's allocated portions of the FAS 87 pension expense for the attrition year were excluded for rate-setting purposes in Tennessee. This treatment of pension expense is consistent with the Consumer Advocate's forecasting methodology in prior cases and, significantly, the TRA's own precedent relating to pension costs.

The Company has several management incentive pay plans that are designed to encourage its employees to improve its financial performance. The Consumer Advocate certainly would not object if the Company wants to reward its employees for increasing its earnings from regulated operations. However, it would be inappropriate to provide funding for the incentive through increased rates rather than from incrementally efficient operations. This treatment of management incentive plans is also consistent with the Consumer Advocate's forecasting methodology in prior cases.

Table 6 – Disallowed Expenses

	Division 02	**Division 12**	**Division 91**	**Division 93**
Club Dues, Spouse Travel & Donations	$54,431	$10,403	$1,724	$8,124
FAS 87 Expense	16,564,200	2,745,418	454,904	427,730
Management Incentive Expense	30,096,418	658,561	1,642,382	0
Total Disallowed	**$46,715,049**	**$3,414,382**	**$2,099,010**	**$435,854**

III. ATTRITION PERIOD TAXES OTHER THAT INCOME TAXES

Q23. MR. NOVAK, PLEASE DESCRIBE THE COMPONENTS OF TAXES OTHER THAN INCOME TAXES.

A23. Taxes other than income taxes ("Other Taxes") generally represent the regulatory fees and duties imposed by the federal, state, municipal and county taxing authorities in jurisdictions where the Company operates that are not based on the income of the utility. Among other things, these Other Taxes generally include property taxes, payroll taxes, franchise taxes, gross receipts taxes, TRA Inspection Fees, and various other local and allocated taxes.

Q24. HOW DID YOU CALCULATE OTHER TAXES?

A24. I calculated Other Taxes in the same manner that O&M expenses were calculated as described above. I began by analyzing Other Taxes for the Tennessee division and the other three shared service divisions providing services to Tennessee for the last five years. I then increased the net allowable expense amounts by the average Other Tax growth factor over the last three years of -0.43%[6] to get the attrition period Other Tax expense for each division. The three year growth factor was used to be consistent with our O&M calculation methodology and because I felt that this rate was most representative of what was likely to occur through the attrition year. Finally, I allocated the attrition period expense for each division to Tennessee using the Company's proposed allocation factors. A summary of this calculation is presented below in Table 7.

[6] Annual rate of -0.22% compounded for 23 months (June 2014 to May 2016).

Table 7 – Attrition Period Other Taxes Expense				
	Division 02	**Division 12**	**Division 91**	**Division 93**
Test Period	$2,921,595	$2,527,587	$61,636	$5,881,144
Growth Factor	-0.43%	-0.43%	-0.43%	-0.43%
Allocation Factor	4.36%	4.41%	40.68%	100.00%
Attrition Period	**$126,840**	**$110,992**	**$24,967**	**$5,856,144**
Total Attrition Period Other Taxes Expense				**$6,118,944**

Q25. HOW DOES YOUR CALCULATION OF OTHER TAXES COMPARE WITH THE COMPANY'S CALCULATION?

A25. My total attrition period Other Taxes expense of $6,118,944 as shown above is $760,440 **less** than the Company's projection of $6,879,384 as shown on CAPD Exhibit, Schedule 9.

[Testimony continues on next page]

IV. ATTRITION PERIOD RATE BASE

Q26. MR. NOVAK, PLEASE EXPLAIN THE COMPONENTS THAT MAKE UP THE TEST PERIOD AND ATTRITION PERIOD RATE BASE

A26. The development of my proposed Rate Base is shown on CAPD Exhibit, Schedules 2 and 3. This Rate Base represents the net investment upon which the Company should be allowed the opportunity to earn a fair rate of return.

Line 1, Utility Plant in Service $471,880,637. Utility Plant in Service is the largest component of rate base and represents the average amount of utility assets for the attrition year upon which I feel that the Company should be allowed the opportunity to earn a return. To compute attrition year Utility Plant in Service, I began with the test period balance for each of the Company's Tennessee allocated divisions[7] and then increased this amount by the four year average of historical normal plant additions. I then added the CAPD adjusted attrition year special projects to this amount to get our forecast of the attrition year Utility Plant in Service.[8]

In contrast, the Company has calculated attrition year Utility Plant in Service by taking the test period balance and then adding their budgeted capital expenditures for 2014, 2015 and 2016. I feel that Atmos' budget-based approach to forecasting Utility Plant in Service is incorrect because it relies solely upon the Company's anticipated budget expenditures as opposed to the actual experience that has historically taken place.

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[7] Divisions 2, 12, 91 and 93.

[8] This review of the Company's attrition year Special Projects does attest to their prudency.

Q27. HOW DID YOU DETERMINE YOUR PROJECTION FOR ATTRITION YEAR SPECIAL PROJECT ADDITIONS TO UTILITY PLANT IN SERVICE?

A27. I began with the Company's identification of attrition year Special Projects of $2,318,693 for 2015 and $3,805,138 for 2015.[9] I then reduced the 2015 Special Projects amount by $1,274,107 to $1,044,586 and reduced the 2016 Special Projects amount by $3,523,007 to $282,131 in order to exclude the construction related to the Company's proposed office building in Franklin which has since been cancelled.[10]

Q28 WHAT ALLOCATION FACTORS DID YOU USE TO PROJECT THE COMPANY'S CORPORATE AND REGIONAL UTILITY PLANT IN SERVICE?

A28. I have reviewed the Company's proposed attrition year allocation factors for Divisions 2, 12 and 91 as well as the Greeneville and CKV Office Structures and incorporated these same factors into our calculation of Rate Base.

Q29 PLEASE CONTINUE WITH YOUR EXPLANATION OF THE REMAINING COMPONENTS OF THE RATE BASE CALCULATION.

A29. **Line 2, Construction Work in Progress $7,577,821.** This item represents plant currently under construction that will soon become used and useful in providing

[9] Company response to TRA Minimum Filing Requirement #52.
[10] See Company response to CAPD Data Request 1-58 and TRA Data Request 1-6.

utility service to the Company's customers. To project Construction Work in Progress, I used a historical average of the annual balances in this account for all Company divisions allocating costs to Tennessee. In contrast, the Company has calculated their attrition year Construction Work in Progress from their projected capital expenditures for 2015 and 2016. As with Utility Plant in Service, I feel that Atmos' budget-based approach to forecasting Construction Work in Progress is incorrect because it relies solely upon the Company's anticipated budget expenditures as opposed to the actual experience that has historically taken place.

Line 3, Gas Inventory $6,224,579. This item represents the carrying value of gas in storage to serve the Company's customers. As this gas is consumed, it is charged to the customer through the Purchased Gas Adjustment. However, the carrying value of gas in storage represents an investment on which the Company should be allowed to earn a reasonable return. To compute the attrition year gas in storage, the Company has taken their anticipated withdrawals and injections from storage.[11] I reviewed the Company's calculations and modified them to normalize the amount of gas allocated to Tennessee.

Line 4, Materials & Supplies $5,893. This item represents the carrying value of miscellaneous materials and inventories in the Company's regional office and represents an investment on which the Company should be allowed to earn a reasonable return. To compute the attrition year Materials & Supplies, the Company has taken a 13-month average of the anticipated balance in this account

[11] Company Response to TRA Minimum Filing Requirement #12, Attachment 6. Company Response to TRA Minimum Filing Requirement #10. Company Response to CAPD Data Request, Item 1.

during the attrition year. I reviewed the Company's calculations for this item and find them to be reasonable for this case.

Line 5, Regulatory Asset $0. The Company has included $973,868 as a regulatory asset related to the normalization of its Pension Expense. As support for this item, the Company refers to the TRA decision in its 2008 and 2012 rate cases.[12] However, no regulatory asset was ever recognized by the TRA in these cases and no corresponding adjustment was made to rate base. Therefore I excluded this item from the rate base calculation.

Line 6, Intercompany Leased Property $5,322,811. This item represents the original asset cost of certain Tennessee offices and storage plant that are recorded on the books of the Company's affiliates and then leased to the utility. The CAPD has long held the position that these leases represent utility property that should be kept on the utility books. I have therefore removed the lease payments from the cost of service and instead substituted the net book value for the property. The amount included here represents the average net value of this property during the attrition year.

Line 7, Working Capital $1,339,864. This item represents the results from applying the Company's lead/lag study to the CAPD's Cost of Service as shown on CAPD Exhibit, Schedules 4 and 5. The lead/lag study represents the average amount of capital provided by investors in the Company that is over and above the investment in plant and other specifically identified rate base items, to bridge the gap between the time expenditures are required to provide service and the time that collections are received for that service. I reviewed the individual lead

[12] Testimony of Company Witness Waller, Pages 7-8.

and lag days contained within the Company's proposed lead/lag study[13] and find it to be reasonable for this case.

Line 9, Accumulated Depreciation $194,632,301. This item represents the amount of depreciation which has accrued over the life of the various capital assets included within Utility Plant in Service as described above. The difference between the Company and my attrition year Accumulated Depreciation relates to solely to the different projections of Utility Plant in Service as described above.

Line 10, Accumulated Deferred Income Taxes ("ADIT") $57,104,291. This item represents the net amount of income tax (federal and state) that the Company has deferred payment on primarily due to the use of accelerated depreciation methods to compute tax depreciation expense. I have included the impact of accelerated depreciation of its proposed additions to Utility Plant in Service within its calculation of Accumulated Deferred Income Taxes.

However, in addition to increases in Accumulated Deferred Income Taxes for increased utility plant, the Company has also included an amount for Net Operating Loss Carryovers ("NOL Carryovers" or "NOLC" or NOLCs"). According to the Company, these NOL Carryovers are the result of "…tax deductions that can produce a tax net operating loss."[14] The Company has recorded the regulated portion of the NOL Carryovers on its books as an ADIT asset that the Company then offsets against the Company's ADIT liabilities. These NOL Carryovers will then allow the Company to reduce or eliminate its

[13] Company Exhibit, Schedules 7-6 and 7-7.
[14] Direct Testimony of Company Witness Waller, Page 16.

income tax expense in future years. This same treatment of NOL Carryovers was first presented in the Company's 2012 Rate Case.

I reviewed the Company's documentation concerning these NOL Carryovers. While I do agree with the Company's accounting for the NOL Carryovers, I disagree with their inclusion in Rate Base as a basis for setting utility rates. Since the TRA already includes income tax expense in the Cost of Service at the current statutory rates,[15] recognition of the NOL Carryover for rate making purposes is not necessary and not appropriate. Unlike the ADIT liability that the Company attempts to match with it, the NOL Carryovers do not necessarily represent a difference on the corporate books between the utility's book and tax income that will eventually turn around. The NOL Carryover will eventually either expire or be used to offset the Company's tax liability.[16] I therefore recommend that the TRA exclude the Company's NOL Carryover as a component of Accumulated Deferred Income Tax as further discussed below in Section V of my testimony.

Line 11, Operating Reserves $676,061. This item represents the accumulation of prior period expenses recorded for Injuries & Damages and Worker's Compensation as a reserve for significant future expenditures that can be anticipated to occur but for which actual future amounts can only be estimated. The Company omitted Operating Reserves in its calculation of Rate Base. I have included a four-year average of Operating Reserves for each Company division allocating costs to Tennessee.[17]

[15] CAPD Exhibit, Schedule 10.
[16] The Company states that its NOLCs will begin to expire in 2029 in its Form 10-K filed with the Securities Exchange Commission on November 6, 2014, at page 87.
[17] Divisions 02, 12, 91 and 93.

Line 12, Customer Advances $75,078. This item represents non-investor supplied funds from customers for extending utility service that the Company has used to finance a portion of its utility investment and should therefore be included as a deduction in computing Rate Base. I reviewed the Company's calculations for this item and find them to be reasonable for this case.

Line 13, Customer Deposits $3,671,279. This item represents amounts advanced by customers to the Company for the privilege of obtaining utility service. These deposits therefore represent a source of non-investor supplied funds which the Company has available to finance a portion of its utility investment and should therefore be included as a deduction in computing Rate Base.

Line 14, Accumulated Interest on Customer Deposits $67,616. This item represents the interest accrued on Customer Deposits and owed to the customer when the deposit is refunded. Since this accumulated interest is owed to the customer, it represents a source of non-investor supplied funds which the Company has available to finance a portion of its utility investment and should therefore be included as a deduction in computing Rate Base.

After considering all of the above components, I computed Rate Base as shown on CAPD Exhibit, Schedules 2 and 3 to be $236,124,979.

[Testimony continues on next page]

V. NET OPERATING LOSS CARRYOVERS

Q30. MR. NOVAK, WHAT IS THE IMPACT OF THE COMPANY'S PROPOSAL TO NET THEIR NOLC WITH ADIT?

A30. As shown in Table 8 below, the test period impact of netting NOLC with ADIT would be to reduce ADIT, and increase rate base, by $9,103,653.

Table 8 – Impact of Combining Test Period Net Operating Loss Carryforwards with Accumulated Deferred Income Tax[18]			
Division	**Total Amount**	**Tennessee Allocation**	**Tennessee Amount**
ADIT:			
Division 02	$176,587,898	4.36%	$7,699,232
Division 12	-29,007,017	4.41%	-1,279,209
Division 91	14,868,287	40.68%	6,048,419
Division 93	-62,831,884	100.00%	-62,831,884
Total ADIT			**$-50,363,442**
NOLC:			
Division 02	$208,799,390	4.36%	**$9,103,653**
Net ADIT and NOLC			**$-41,259,789**

Q31. MR. NOVAK, WHEN WERE THE OFFSETS OF NOLCS AGAINST ADIT FIRST PROPOSED BY THE COMPANY?

A31. The offset of NOLCs were first proposed in the Company's 2012 rate in case in TRA Docket 12-00064. In that docket, the Company proposed offsetting ADIT in the amount of $-64,322,474 with an NOLC of $8,463,109. The CAPD opposed this offset of ADIT with NOLC in Docket 12-00064. The parties then reached a settlement in TRA Docket 12-00064.

[18] CAPD Rate Base Workpaper RB-60-1.00 and Company Workpaper 7-2.

Q32. DOES THE COMPANY EXPLAIN ITS POSITION THAT NOLCS MUST OFFSET ADIT?

A32. Yes. Specifically, Company witness Waller's direct testimony on pages 15 – 16 reads as follows:

> The Company's rate base has been reduced by its accumulated deferred income tax (ADIT) liability balance. Embedded within the ADIT liability balance is an asset for net operating loss carryforwards (NOLCs). ADIT liabilities are realized because the Company's tax filings reflect tax deductions in excess of book deductions, for example, accelerated tax depreciation. These excess tax deductions offset the Company's current tax liability which allows the Company to retain cash that would have otherwise been paid to the government. The benefit of this excess cash is reflected as a reduction to the Company's required rate base until that time it is repaid to the government. These funds are repaid to the government over time as the Company's book deductions exceed its tax deductions and are appropriately reflected as a reduction to rate base until the funds are repaid to the government.
>
> In certain situations, the Company's tax deductions can produce a tax net operating loss. A tax net operating loss is realized when the Company's tax deductions exceed its taxable income and all tax has been offset. These unused tax deductions are reflected on the Company's tax returns as a net operating loss which is available to be carried back or carried forward to offset taxable income. The Company has fully utilized its ability to carryback tax net operating losses and may only carry forward its remaining tax net operating losses. These carryforwards have not yet offset tax and are reflected on the Company's books and records as an ADIT asset for NOLCs. These NOLCs will be used in future periods to offset tax. Just as ADIT liabilities represent cash received by the Company, the NOLC represents funds the Company has not yet received from the government.
>
> To fully account for the net cash realized from the government in the form of tax savings, all of the ADIT balances, both assets and liabilities, must be included in the calculation of the ADIT rate base reduction.

Q33. DOES COMPANY WITNESS WALLER CITE ANY AUTHORITY UNDER GENERALLY ACCEPTED RATEMAKING PRINCIPLES FOR THE COMPANY'S POSITION?

A33. No, he does not. The Company offers no authority as to ratemaking principles, other than that expressed in its own opinion as to why NOLCs should be offset against ADIT. However, the Company has stated in proceedings before the Kentucky Public Service Commission that normalization rules under the Internal Revenue Code require that the TRA offset NOLCs against ADIT.[19] I would note that the Company's Ruling Request, that resulted from the Kentucky proceedings does not make the same unequivocal statements made by the Company's witness in that proceeding and, further, implies through its analysis and the use of terms such as "implicated" and "suggests" that the offset issue is not free from doubt.[20] In fact, the Kentucky Commission noted the "ambiguity in the governing regulations and the significantly different interpretations of those regulations" by two of the parties on the offset issue.[21]

Q34. DOES THE COMPANY TAKE A POSITION ON WHETHER THE LAW CONCERNING THE ISSUES RAISED IN ITS RULING REQUEST – WHETHER THE COMPANY'S ADIT ACCOUNT MUST BE REDUCED BY ITS NOLCS AND WHETHER THE "LAST DOLLARS DEDUCTED"

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[19] Exhibit E, at pages 5-7, to the Attachments to Informal Discovery Request of the Consumer Advocate, filed March 23, 2015, in this TRA Docket 14-00146.

[20] Exhibit A, at pages 14-15, to the Attachments to Informal Discovery Request of the Consumer Advocate, filed March 23, 2015, in this TRA Docket 14-00146.

[21] Exhibit A, at page 8, to the Attachments to Informal Discovery Request of the Consumer Advocate, filed March 23, 2015, in this TRA Docket 14-00146 (quoting Kentucky Public Service Commission, Case No. 2013-00148, Final Order, dated April 22, 2014, page 7).

METHOD THAT IS USED BY THE COMPANY MUST BE USED TO AVOID A NORMALIZATION VIOLATION – IS UNCERTAIN AND THE ISSUES ARE NOT ADDRESSED BY ADEQUATE AUTHORITY?

A34. Yes. The Company admits that the law with respect to its application of normalization violations is uncertain. Specifically, in its Ruling Request, the Company states that "[t]he law in connection with this request is uncertain and the issue is not adequately addressed by relevant authorities."[22]

Q35. PLEASE OUTLINE YOUR VIEW OF COMPANY WITNESS WALLER'S TESTIMONY PROVIDED IN THIS DOCKET.

A35. First, it is important to note that the context for the ADIT calculation is for a component of rate base under generally accepted ratemaking principles. It is not a cash flow statement or balance sheet that attempts to match cherry-picked inflows with outflow or cherry-picked assets with liabilities.

Second, it is well established under generally accepted ratemaking principles that rate base is reduced by ADIT – so I do agree with Mr. Waller on this point.

Third, it is similarly well established under generally accepted rate making principles over the last century, that the U.S. Supreme Court and other authorities have overwhelmingly rejected the concept of including prior period losses in rate base.[23]

[22] Exhibit A to the Attachments to Informal Discovery Request of the Consumer Advocate, filed March 23, 2015, in this TRA Docket 14-00146, at page 30 of 32 of the Ruling Request, Item 6.

[23] Communications Satellite Corp. v. F.C.C., 611 F.2d 883 (D.C. Cir. 1977), citing, among other cases, F.P.C. v. Nat. Gas Pipeline Co., 315 U.S. 575 (1942). A similar rule disallows past losses as an operating expense. Galveston Electric Co. v. Galveston, 258 U.S. 388 (1922).

Fourth, if a utility proposes to establish a regulatory asset, as Atmos has done here, then the appropriate mechanism for establishing that regulatory asset would be to file a separate petition requesting the TRA open a docket where such a proposal could be thoroughly vetted.

Q36. PLEASE EXPLAIN YOUR VIEW OF COMPANY WITNESS WALLER'S PROPOSAL TO LINK THE ADIT LIABILITY WITH THE NOLC ASSET IN THE CALCULATION OF RATE BASE.

A36. As I mentioned above, it is important to note that the context for the ADIT calculation is as a component of rate base under generally accepted ratemaking principles, and within this context the ADIT liability has significantly different characteristics than the NOLC asset. While the ADIT liability arises from timing differences between tax and book depreciation, this ADIT liability will reverse over time – that is, the same amount of depreciation will be recognized eventually for both tax and ratemaking purposes. In contrast, the NOLC asset does not reverse – it is either used to offset taxable income or it expires after 20 years. In other words, if the Company continues to add plant and the tax code remains essentially unchanged, the Company could continue to generate tax losses and the losses created in year 1 may never be used as long as the Company continued to add plant and failed to generate taxable income. Meanwhile, the ADIT liability generated in year 1 would eventually reverse – that is, the tax deferred due to the use of accelerated depreciation would eventually become zero as the amounts of depreciation under the tax and ratemaking methods reduce the depreciable base to zero. So, on its face, the Company's proposal to offset ADIT with NOLCs would implement a mismatch of rate book items with tax return items.

Another mismatch involves the rationales underlying ADIT and NOLCs. ADIT essentially reflects a cost-free source of capital that can be readily measured and which should reduce rate base because ratepayers should not be required to fund a return on investment on rate base that is already funded through accelerated depreciation and reflected in the ADIT account. In contrast, NOLCs may or may not have value, either because they may expire or may not be used, and should not be an addition to rate base because they add no investment capital that would benefit ratepayers. Rather than providing a benefit to ratepayers, NOLCs instead provide a potential benefit to shareholders, who should more properly bear the risk of NOLCs being realized. In other words, ADIT represents a cost-free source of financing in the ratemaking context, and NOLCs represent a potentially risky financing alternative (through the capitalization of a tax loss carryforward) for the benefit of shareholders in an investment context.

Q37. PLEASE EXPLAIN YOUR POSITION CONCERNING WHETHER PRIOR PERIOD TAX LOSSES MAY BE CAPITALIZED AS NOLCS AND RECOVERED IN RATE BASE.

A37. As described in the Company's testimony presented above, the NOLCs clearly represent prior period losses for tax purposes. The Company is essentially proposing to capitalize the tax benefit associated with the NOLCs resulting from current and prior period net operating losses for tax purposes, and then to charge ratepayers for a rate of return on these capitalized losses. It is well recognized under generally accepted rate making principles that the U.S. Supreme Court and other authorities have rejected the capitalization of prior period losses into rate base.[24] These regulatory principles clearly require that NOLCs be excluded from ADIT and therefore be excluded from rate base.

Q38. PLEASE EXPLAIN YOUR POSITION ON WHETHER THE COMPANY HAS ESTABLISHED A REGULATORY ASSET WITH RESPECT TO THE NOLCS.

A38. If Atmos is proposing to establish its NOLCs as a regulatory asset, then the proper forum would be a separate docket outside of a rate case where this proposal can be thoroughly vetted. There is no evidence that Atmos has attempted to establish such a regulatory asset in contrast with other utilities under the TRA's jurisdiction.[25] Here there has been no clear request for the establishment of a regulatory asset, with the appropriate vetting that would go along with that. In view of that, I believe that the more appropriate course would be to exclude NOLCs as a regulatory asset and consequently deny the addition of NOLCs to rate base.

[24] Communications Satellite Corp. v. F.C.C., 611 F.2d 883 (D.C. Cir. 1977), citing, among other cases, F.P.C. v. Nat. Gas Pipeline Co., 315 U.S. 575 (1942). A similar rule disallows past losses as an operating expense. Galveston Electric Co. v. Galveston, 258 U.S. 388 (1922).

[25] For example, note the Petition of Piedmont Natural Gas Company, Inc. for Authorization to Amortize and Refund to Customers Excess Accumulated Deferred Income Taxes in TRA Docket 14-00017 (company requested regulatory asset for excess ADIT).

Q39. DOES THE COMPANY PROVIDE ANY TESTIMONY IN THIS DOCKET CONCERNING TAX NORMALIZATION RULES?

A39. No. The Company offers no description, and provides no authoritative citation for its position concerning normalization rues. This would seem to be unusual in view of the apparent importance to its argument that the NOLCs must offset ADIT in order to avoid a tax normalization violation.

Q40. HOW DID YOU IDENTIFY TAX NORMALIZATION AS A POTENTIAL ISSUE?

A40. In my review of the discovery responses provided by the Company, I found a proceeding before the Kentucky PSC that had apparently been strongly contested.[26] In that proceeding, there was extensive testimony on the NOLC issue. While the Kentucky Commission did ultimately allow NOLC in rate base, they required the utility to seek an IRS private letter ruling on the tax normalization issue. The specific content of the private letter ruling request continues to be the source of strong disagreement between the parties due to the particular manner in which the Company posed the NOLC questions to the IRS.[27]

Q41. ARE THERE OTHER REGULATED COMPANIES IN TENNESSEE THAT OFFSET NOLCS AGAINST ADIT IN DETERMINING RATE BASE?

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[26] Atmos Energy Corporation's Response to MFR Set No. 1, Question No. 1-06.

[27] See Exhibits B and C to the Attachments to Informal Discovery Request of the Consumer Advocate, filed March 23, 2015, in this TRA Docket 14-00146.

A41. Not to my knowledge. I am not aware of any other regulated utility in Tennessee that has even sought to offset NOLCs against ADIT in determining rate base.

Q42. ARE THERE JURISDICTIONS THAT HAVE SPECIFICALLY DENIED THE OFFSET OF NOLCS TO ADIT?

A42. Yes. Specifically, West Virginia denied the offset of NOLCs to Mountaineer Gas.[28] In that proceeding, Mountaineer Gas took a position similar to that being taken by Atmos in this TRA Docket 14-00146.[29] The West Virginia Consumer Advocate Division and the West Virginia PSC Staff opposed Mountaineer Gas's ADIT position as a "…complete departure from established Commission precedent and the normal treatment for plant related ADIT across the country. Essentially, [Mountaineer Gas] is proposing to simply 'disappear' a large part of its ADIT rate base offset related to accelerated depreciation."[30]

Q43. WHAT IS YOUR VIEW OF THE MOUNTAINEER GAS PROCEEDING?

A43. Mountaineer Gas was a well-contested and argued case, as even a brief review of Attachments WHN-7 and WHN-8 demonstrate, and I agree with the basic arguments and analyses put forward by the West Virginia Consumer Advocate and the result reached by the West Virginia PSC. However, Atmos' response to

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[28] Public Service Commission of West Virginia at Charleston, Case No. 11-1627-G-42T, Commission Order on Rule 42T Tariff Filing To Increase Rates and Charges, dated October 31, 2012, at pages 14-17 (included here as Attachment WHN-6); also see other filings in that docket that may be found at http://www.psc.state.wv.us/webdocket/ and by searching for Case No. 11-1627-G-42T.

[29] See Mountaineer Gas Company's Initial Brief in Public Service Commission of West Virginia at Charleston, Case No. 11-1627-G-42T, Commission Order on Rule 42T Tariff Filing To Increase Rates and Charges, filed August 31, 2012, at page 8 (included here as Attachment WHN-7).

[30] Initial Brief of the Consumer Advocate Division in Public Service Commission of West Virginia at Charleston, Case No. 11-1627-G-42T, Commission Order on Rule 42T Tariff Filing to Increase Rates and Charges, filed August 31, 2012, at page 9 and generally pages 4-17 (included here as Attachment WHN-8).

that West Virginia proceeding appears confused and contradictory. Responding to the Mountaineer Gas proceeding, an Atmos' witness in proceedings in Kentucky stated that:

> The West Virginia commission's recent [Mountaineer Gas] ruling stands alone in its position despite historical precedent at numerous other commissions to the contrary. [The West Virginia Commission] was incorrect in determining that a normalization violation will not occur by its actions. In fact, the commission opined on a subject over which it has no jurisdiction. A commission cannot rule whether a normalization violation has or has not occurred. That determination rests solely with the IRS. A commission can only implement rates. If, in setting rates, a commission violates the normalization provisions, the IRS would be the authority to rule as such and apply the consequences of said violation. The West Virginia commission most certainly set rates that are in violation of the normalization provisions and overstepped its bounds in ruling that no violation has occurred.[31]

From that testimony it would be reasonable to conclude that the only appropriate course for a commission and company to take would be to seek a ruling request from the IRS on the issue. Unfortunately, even that course of action appears controversial, as demonstrated in the context of Atmos' recent proceeding in Kentucky.[32] And the view of the Company's witness in the proceeding in Kentucky is that "[s]eeking a private letter ruling from the IRS is a costly and timely undertaking. It seems a waste of time to seek a ruling on an issue [as to whether to include an NOLC asset in rate base] that is so completely clear."[33]

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[31] Exhibit E to the Attachments to Informal Discovery Request of the Consumer Advocate, filed March 23, 2015, in this TRA Docket 14-00146, at page 29, line 20 through page 30, line 8. The "other commissions" referred to above are addressed in a later question and answer.

[32] See Exhibits B and C to the Attachments to Informal Discovery Request of the Consumer Advocate, filed March 23, 2015, in this TRA Docket 14-00146.

[33] Exhibit E to the Attachments to Informal Discovery Request of the Consumer Advocate, filed March 23, 2015, in this TRA Docket 14-00146, at page 28, lines 17-23.

Q44. ARE YOU AWARE OF ANY SUBSEQUENT DEVELOPMENTS IN THE MOUNTAINEER GAS PROCEEDING WITH RESPECT TO THE WEST VIRGINIA PSC'S DENIAL OF AN OFFSET OF NOLCS AGAINST ADIT?

A44. Yes. The IRS, in PLR 201419804, ruled that the decision of the West Virginia Public Service Commission ("WVPSC") to deny the offset of NOLCs against ADIT **did not** create a normalization violation. As stated in Mountaineer Gas's 2013 financial statements:

> In the October 31, 2012 Rate Order, the WVPSC rejected the Company's position that the thirteen-month average federal net operating loss and alternative minimum tax credit carryforward, resulting from the Company's election of accelerated depreciation, should be added back to rate base. The WVPSC did not believe that this created a potential tax normalization violation. However, the Company believed this action may have created a potential tax normalization violation. On November 21, 2012, the Company filed a Limited Petition for Reconsideration with the WVPSC, asking it to reconsider its decision on this issue. This Limited Petition for Reconsideration was denied on February 11, 2013. On February 13, 2013, the Company filed a Second Petition for Reconsideration. On April 9, 2013, the WVPSC issued its Order once again denying the Company's request. Thus, on July 30, 2013, the Company requested a private letter ruling from the Internal Revenue Service (IRS). **The IRS has since issued its private letter ruling, PLR-133813.13, concluding that such action by the WVPSC did not create a tax normalization violation.** The IRS concluded that because the WVPSC had taken the federal net operating loss and alternative minimum tax credit carryforward into account when setting the Company's rates, the WVPSC's decision to reduce the Company's rate base does not violate normalization requirements.[34] (Emphasis added.)

[34] Mountaineer Gas Company Notes to Financial Statement for the period ended December 31, 2013 and December 31, 2012, at page 17 of 33 of those financial statements, as filed on January 15, 2015, and included here as Attachment WHN-9, as a part of the public workpapers and supporting documents in connection with Mountaineer Gas's 2015 General Rate Case, PSC Case No. 15-0003-G-42T, which may be found at http://www.psc.state.wv.us/webdocket/ and by searching for Case No. 15-0003-G-42T. Also attached is Private Letter Ruling 201418024 (referenced in the quoted citation as PLR-133813.13) as Attachment WHN-10.

Q45. WHAT IS YOUR VIEW OF THE IRS RULING WITH RESPECT TO MOUNTAINEER GAS?

A45. The IRS ruling shows that the West Virginia PSC had the authority to make a reasoned decision to reject Mountaineer Gas's proposed offset of NOLCs against ADIT and, further, that such rejection was not a normalization violation.

Q46. ARE THERE JURISDICTIONS THAT HAVE SPECIFICALLY ALLOWED THE OFFSET OF NOLCS TO ADIT?

A46. Yes. In the Kentucky proceeding, the Company cites a number of jurisdictions that have allowed the offset of NOLCs.[35] However, the Company's witness in that proceeding offers little in the way of supporting facts, authority, or analyses as to how those decisions were reached, and how the facts in those proceedings may have been different from those presented in this TRA Docket 14-00146.

Q47. DO YOU HAVE AN OPINION ON WHETHER THE TRA, WITHIN THE CONTEXT OF A RATE CASE, MAY MAKE A DETERMINATION CONCERNING WHETHER THE IRS TAX NORMALIZATION REQUIREMENTS WOULD BE MET?

A47. Yes. Based upon the Mountaineer Gas proceeding, the apparent agreement of the IRS with that decision, and the result as shown in the referenced private letter ruling, along with the plenary authority of the TRA with respect to setting rates,[36] my view is that the TRA does have the authority to make a decision concerning

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[35] Exhibit E to the Attachments to Informal Discovery Request of the Consumer Advocate, filed March 23, 2015, in this TRA Docket 14-00146, at page 16, line 20 through page 19, line 19.
[36] Tenn. Code Ann. § 65-5-103.

the NOLC offset against ADIT issue and whether the IRS normalization rules would be violated.

Q48. WOULD YOU PROVIDE YOUR PERSPECTIVE ON THE RULING REQUEST FILED BY THE COMPANY AS A RESULT OF THE KENTUCKY PROCEEDING?

A48. Yes. The Company's Ruling Request, which focuses on the narrow tax issues of whether NOLCs should be offset against ADIT and, if they were to be offset, what methodology would be appropriate, reflects the potential complexity of attempting to overlay a tax issue with a regulatory issue. In its Ruling Request, the Company analyzes its tax books and then compares those books with its financial books. The Ruling Request ignores the Company's rate books – and consequently ignores the tax expense that is charged to customers through rates. In other words, the Ruling Request ignores the charge for the deferral of tax that ratepayers are paying every time they pay their gas bill. While ratepayers are paying a charge that takes into account the deferral of tax, the Company is not currently paying any tax, and the Company is receiving cost free capital based on the use of accelerated depreciation for tax purposes. These are essentially the same facts that were presented to the West Virginia PSC that resulted in their determination that NOLCs should not be offset against ADIT – a determination that was followed by an IRS ruling that the West Virginia PSC's decision would not be a normalization violation.

Q49. DO YOU HAVE AN OPINION ON WHETHER THE IRS TAX NORMALIZATION REQUIREMENT WOULD BE MET IF THE NOLCS ARE NOT OFFSET AGAINST ADIT OR OTHERWISE ADDED TO RATE BASE IN TRA DOCKET 14-00146?

A49. Yes. In this Docket, the Company's accounting mechanics, other than the offset of NOLCs against ADIT, reflect the normalization policies and practices that are in accordance with generally accepted ratemaking principles. The Company's ratepayers, through rates, are paying a charge for taxes that take into account the normalized tax for the relevant period. However, the Company is currently not paying any income taxes and has established an accumulated deferred income tax account that reflects timing differences related to the use of different accounting methodologies for tax and ratemaking purposes.

These tax and ratemaking accounting methodologies ultimately reverse over time. However, as a result of these differences, the Company essentially receives cost free capital which is deducted from rate base as ADIT. Also, it should be noted that ratepayers will continue to pay the same normalized tax through rates regardless of whether the Company is profitable from a tax perspective or not. If the Company is not profitable from a tax perspective, then the benefit of any NOLC is passed directly to Company's shareholders. On that basis, my view is that the normalization requirement would be met if the NOLCs are not offset against ADIT or otherwise added to rate base.

Q50. WOULD YOU SUMMARIZE YOUR RECOMMENDATIONS CONCERNING THE COMPANY'S OFFSET OF NOLC AGAINST ADIT IN THIS TRA DOCKET 14-00146?

A50. Based on the foregoing, my recommendation is that the Authority reject the request by the Company to offset NOLCs against ADIT. With that said, if the Authority were to be inclined to consider the offset in a light that is contrary to my analysis and recommendation, or otherwise were to be inclined to consider the normalization aspects of the Company's requests, I would recommend that the Authority require the Company to seek a private letter ruling from the IRS with the full involvement of the Authority and Consumer Advocate in the preparation, approval, and filing of that private letter ruling request. As to the specifics of any such private letter ruling request, I would recommend that the Authority require disclosure in that request of the rate books aspects of such request including the tax expense recorded and collected from ratepayers through rates in accordance with my analysis above.

I would also recommend that any such request within the context of this TRA Docket 14-00146 and with the involvement of the Authority and Consumer Advocate in any such request, involve the thorough consideration of the three methods described as the "last dollars deducted", "first dollars deducted", and "ratable allocations"[37] in the Company's Ruling Request that resulted from the Kentucky proceeding. While such a private letter ruling request would obviously not be necessary if the Authority adopts my recommendation that NOLCs not be

[37] These methods generally are described in the Ruling Request submitted as a result of the Kentucky proceeding. See Exhibit A to the Attachment to Informal Discovery Request of the Consumer Advocate, filed March 23, 2015, in this TRA Docket 14-00146, at pages 19-29.

offset against ADIT, such a ruling request would seemingly be necessary and appropriate if the Authority were to be inclined not to adopt my recommendation.

[Testimony continues on next page]

VI. RATE DESIGN

Q51. HOW DO YOU PROPOSE THAT THE TRA ALLOCATE THE COMPANY'S REVENUE REQUIREMENTS TO EACH CUSTOMER CLASS?

A51. As shown on CAPD Exhibit, Schedule 1, my revenue deficiency/surplus calculation required to produce the 7.55% overall return recommended by Dr. Klein results in a revenue **decrease** of approximately $3.0 million. I recommend that the proposed revenue surplus be allocated evenly across-the-board to all customer classes, including special contract customers, based upon the ratio of each customer class' attrition period margin to total attrition period margin. As shown on CAPD Exhibit, Schedule 14, this allocation results in a rate decrease of -4.59% to all customer classes.

Q52. WHAT RATE DESIGN DO YOU PROPOSE?

A52. I am proposing that the revenue deficiency in this case be recovered through decreased commodity charges. In other words, under the deficiency presented here, I am proposing that the existing base rate customer charges remain at their current levels. At this time, I do not have a specific dollar value rate design proposal to recommend to the TRA, but fully expect to have this completed prior to the hearing.

VII. ANNUAL RATE MECHANISM

Q53. MR. NOVAK, HAVE YOU REVIEWED THE ANNUAL REVIEW MECHANISM ("ARM") TARIFF PROPOSED BY THE COMPANY?

A53. Yes. The Company has elected to implement its proposed ARM tariff as part of an annual review of its rates in accordance with Tenn. Code Ann. § 65-5-103(d)(6).

Q54. DO YOU AGREE WITH THE COMPANY'S PROPOSED ARM?

A54. No, I do not. Unlike the alternative regulation proposal approved by the TRA for Tennessee-American Water Company in Docket 13-00130, the ARM currently proposed by Atmos contains no true-up to actual experience. In other words, under the ARM, Atmos intends to implement its capital and operating budgets without any true-up whatsoever to the actual amounts expended. Without a true-up to actual costs, I would recommend denial of the ARM tariff proposed by the Company.

Q55. ARE THERE ANY SITUATIONS WHERE ATMOS WOULD NOT COMPLETE ITS BUDGETED CAPITAL EXPENDITURES?

A55. Certainly. The budget only represents the anticipated expenditures at a single point in time. As such it is constantly being modified for various external factors. By way of example in the current docket, Atmos originally included amounts in its 2015 and 2016 capital budgeted for the construction of an office building in

Franklin. During the course of this rate case, this project was deferred and the budget was revised. Without a true-up provision in an alternative regulatory mechanism, there would not be a way for the ratepayers to recapture charges already paid for this budget revision.

Q56. ARE THERE ANY OTHER COMPONENTS OF AN ALTERNATIVE REGULATORY MECHANISM THAT YOU FEEL SHOULD BE INCLUDED IN THE COMPANY'S PROPOSAL?

A56. Yes. First, the TRA should consider the need for a management audit in conjunction with the Company's proposed ARM. Unlike the alternative regulatory mechanism that the TRA approved for Tennessee-American Water Company which included only a subset of the total capital and operating expenses, the ARM proposed by Atmos includes the Company's entire cost of service. Such a radical shift in rate setting will likely result in cultural changes since all costs would automatically be recovered. Therefore, the TRA should consider the appropriateness of a management audit that accomplishes two goals. One goal would be to provide a means for highlighting the variances in accounts that could occur each year in the annual review performed by the TRA staff and Consumer Advocate with respect to revisions to rates that would occur annually. The second goal would be to implement a management audit that examines the processes carried out by the Company to ensure that they are both efficient and effective instead of just the going-level rate recovery in an annual filing.[38]

[38] It also is worth noting that it has been an extended period of time since Atmos last had a management audit.

Secondly, the TRA needs to set a finite life for approval of an alternative rate mechanism like the ARM presented here before the Company is required to file a traditional rate case to reset base rates. The enabling legislation of Tenn. Code Ann. § 65-5-103(d)(6) requires a utility to have had a rate case within the last five years. With that time period in mind, I would propose to the TRA that an alternative regulatory mechanism like the ARM presented here should be terminated after five years.

Third, if the TRA does elect to approve an ARM based on the Company's entire capital and operating budget, I would recommend that the TRA consider terminating the Company's existing WNA mechanism. The WNA trues up the sales and transportation volumes approved in the last rate case to the actual weather experienced, while the ARM would true up the rate of return to the Company's actual results of operations. Since the ARM would true-up the Company's entire cost of service, it seems that a WNA mechanism would be redundant and unneeded.

Finally, I would recommend the TRA insure that any alternative regulatory mechanism captures the policy decisions of the TRA that are enumerated in the Company's rate case. For example, the TRA has traditionally recognized only amounts actually paid as pension expense instead of FAS 87 amounts. Therefore any alternative regulatory mechanism should contain a provision for adjustments to the TRA's policy decisions on pension expense.

Q57. EXPLAIN ANY THOUGHTS OR RECOMMENDATIONS THAT YOU MAY HAVE WITH RESPECT TO THE METHODOLOGIES IN THE COMPANY'S PROPOSED ARM TARIFF?

A57. Because the Company has provided its schedules and workpapers that it believes constitute its methodologies, I also have submitted the schedules and workpapers filed today with my testimony as proposed methodologies to be used in calculating rates in this TRA Docket 14-00146 and for purposes of adopting methodologies under Tenn. Code Ann. Section 65-5-103(d)(6) and, as and if applicable, Tenn. Code Ann. Section 103(d)(7).

[Testimony continues on next page]

VIII. <u>OTHER CONSIDERATIONS</u>

Q58. DO YOU HAVE ANY COMMENTS ABOUT THE MANNER IN THE WAY THIS CASE WAS FILED BY THE COMPANY?

A58. Yes. The Company's case was filed with a bare minimum amount of supporting detail and a complete lack of documentation or audit trail as to the source of that supporting information, which causes delays for all parties in analyzing the case. This same lack of support also occurred in the Company's 2012 rate case, as well as the 2014 filing that was later dismissed. As a result, it is apparent that the Company does not take the minimum filing guidelines of the TRA into serious consideration. While the Company did cooperate in providing this information after the filing, it would be better for all parties if the MFRs and other information that is usually requested in discovery were provided at the time of the initial rate case filing. To prevent this problem from recurring in the future, I am recommending that the TRA adopt a minimum filing <u>**requirement**</u> specifically for Atmos Energy Corporation for future rate cases. This minimum filing <u>**requirement**</u> should also contain a provision that requires a determination by the TRA's hearing officer that the Company has materially complied with this requirement before the procedural schedule can begin.[39]

Q59. DOES THIS COMPLETE YOUR TESTIMONY?

[39] My view is that this same requirement should apply to all utilities applying for alternative regulation.

A59. Yes it does. However, I reserve the right to incorporate any new information that may subsequently become available.

ATTACHMENT WHN-1
William H. Novak Vitae

213 pg document
not printed for
Docket office
scanned email
attachments

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Areas of Specialization

Over twenty-five years of experience in regulatory affairs and forecasting of financial information in the rate setting process for electric, gas, water and wastewater utilities. Presented testimony and analysis for state commissions on regulatory issues in four states and has presented testimony before the FERC on electric issues.

Relevant Experience

WHN Consulting – September 2004 to Present
In 2004, established WHN Consulting to provide utility consulting and expert testimony for energy and water utilities. Complete needs consultant to provide the regulatory and financial expertise that enabled a number of small gas and water utilities to obtain their Certificate of Public Convenience and Necessity (CCN) that included forecasting the utility investment and income. Also provided the complete analysis and testimony for utility rate cases including revenues, operating expenses, taxes, rate base, rate of return and rate design for utilities in Tennessee. Assisted American Water Works Company in preparing rate cases in Ohio and Iowa. Provided commercial and industrial tariff analysis and testimony for an industrial intervenor group in a large gas utility rate case. Industry spokesman for water utilities dealing with utility commission rulemaking. Consultant for the North Carolina and Illinois Public Utility Commissions in carrying out their oversight functions of Duke Energy and Peoples Gas Light and Coke Company through focused management audits. Also provide continual utility accounting services and preparation of utility commission annual reports for water and gas utilities.

Sequent Energy Management – February 2001 to July 2003
Vice-President of Regulatory Compliance for approximately two years with Sequent Energy Management, a gas trading and optimization affiliate of AGL Resources. In that capacity, directed the duties of the regulatory compliance department, and reviewed and analyzed all regulatory filings and controls to ensure compliance with federal and state regulatory guidelines. Engaged and oversaw the work of a number of regulatory consultants and attorneys in various states where Sequent has operations. Identified asset management opportunities and regulatory issues for Sequent in various states. Presented regulatory proposals and testimony to eliminate wholesale gas rate fluctuations through hedging of all wholesale gas purchases for utilities. Also prepared testimony to allow gas marketers to compete with utilities for the transportation of wholesale gas to industrial users.

Atlanta Gas Light Company – April 1999 to February 2001

Director of Rates and Regulatory Analysis for approximately two years with AGL Resources, a public utility holding company serving approximately 1.9 million customers in Georgia, Tennessee, and Virginia. In that capacity, was instrumental in leading Atlanta Gas Light Company through the most complete and comprehensive gas deregulation process in the country that involved terminating the utility's traditional gas recovery mechanism and instead allowing all 1.5 million AGL Resources customers in Georgia to choose their own gas marketer. Also responsible for all gas deregulation filings, as well as preparing and defending gas cost recovery and rate filings. Initiated a weather normalization adjustment in Virginia to track adjustments to company's revenues based on departures from normal weather. Analyzed the regulatory impacts of potential acquisition targets.

Tennessee Regulatory Authority – Aug. 1982 to Apr 1999; Jul 2003 to Sep 2004

Employed by the Tennessee Regulatory Authority (formerly the Tennessee Public Service Commission) for approximately 19 years, culminating as Chief of the Energy and Water Division. Responsible for directing the division's compliance and rate setting process for all gas, electric, and water utilities. Either presented analysis and testimony or advised the Commissioners/Directors on policy setting issues, including utility rate cases, electric and gas deregulation, gas cost recovery, weather normalization recovery, and various accounting related issues. Responsible for leading and supervising the purchased gas adjustment (PGA) and gas cost recovery calculation for all gas utilities. Responsible for overseeing the work of all energy and water consultants hired by the TRA for management audits of gas, electric and water utilities. Implemented a weather normalization process for water utilities that was adopted by the Commission and adopted by American Water Works Company in regulatory proceedings outside of Tennessee.

Education

B.A, Accounting, Middle Tennessee State University, 1981
MBA, Middle Tennessee State University, 1997

Professional

Certified Public Accountant (CPA), Tennessee Certificate # 7388
Certified Management Accountant (CMA), Certificate # 7880
Former Vice-Chairman of National Association of Regulatory Utility Commission's Subcommittee on Natural Gas

WHN CONSULTING

Witness & Advisory History for William H. Novak, CPA

Selected Cases

State	Company/Sponsor	Year	Assignment	Docket
Louisiana	CenterPoint Energy/Louisiana PSC	2011	Audit of PGA Filings from 2002 - 2008 of CenterPoint Arkla	S-32534
	CenterPoint Energy/Louisiana PSC	2011	Audit of PGA Filings from 2002 - 2008 of CenterPoint Entex	S-32537
	Louisiana Electric Utilities/Louisiana PSC	2012	Technical Consultant for Impact of Net Meter Subsidy on other Electric Customers	R-31417
Tennessee	Aqua Utilities	2006	Rate Case Audit - Revenue, Expenses, Rate Base and Rate Design	06-00187
	Atmos Energy Corporation/Atmos Intervention Group	2006	Rate design for Industrial Intervenor Group	05-00258
	Atmos Energy Corporation/Atmos Intervention Group	2007	Rate design for Industrial Intervenor Group	07-00105
	Bristol TN Essential Services	2009	Audit of Cost Allocation Manual	05-00251
	Chattanooga Manufacturers Association	2009	Spokesperson for Industrial Natural Gas Users before the Tennessee State Legislature	HB-1349
	Tennessee-American Water Company/Tennessee AG	2011	Rate Case Audit - Weather Normalization Adjustments	10-00189
	Piedmont Natural Gas Company/Tennessee AG	2011	Rate Case Audit - Revenue, Class Cost of Service Study & Rate Design	11-00144
	Lynwood Wastewater Utility/Tennessee AG	2012	Rate Case Audit - Revenue, Class Cost of Service Study & Rate Design	11-00198
	Tennessee-American Water Company/Tennessee AG	2012	Rate Case Audit - Revenues, Rate Base, Class Cost of Service Study and Rate Design	12-00049
	Atmos Energy Corporation/Tennessee AG	2012	Rate Case Audit - Revenues, Rate Base and Rate Design	12-00064
Alabama	Jefferson County (Birmingham) Wastewater/Alabama AG	In Process	Bankruptcy Filing - Allowable Costs and Rate Design	2009-2318
Illinois	Peoples & North Shore Gas Cos./Illinois Commerce Comm.	2007	Management Audit of Gas Purchasing Practices	06-0556
New Mexico	Southwestern Public Service Co./New Mexico PRC	2010	Financial Audit of Fuel Costs for 2009 and 2010	09-00351-UT
New York	National Grid/New York PSC	2011	Audit of Affiliate Relationships and Transactions	10-M-0451
Ohio	Ohio-American Water Company/Ohio Consumers' Counsel	2010	Rate Case Audit - Class Cost of Service and Rate Design	09-0391-WS-AIR
	Vectren Energy Delivery of Ohio/Ohio Consumers' Counsel	2008	Rate Case Audit - Class Cost of Service and Rate Design	07-1080-GA-AIR
	Duke Energy-Ohio/Public Utilities Commission of Ohio	2009	Focused Management Audit of Fuel & Purchased Power (FPP Riders)	07-0723-EL-UNC
Texas	Center Point Energy/Texas AG	2009	Rate Case Audit - Class Cost of Service and Rate Design	GUD 9902
Virginia	Aqua Utilities/PSS Legal Fund	2011	Rate Case Audit - Class Cost of Service and Rate Design	W-218, Sub-319
Washington DC	Washington Gas Light Co./Public Service Comm of DC	2011	Audit of Tariff Rider for Infrastructure Replacement Costs	1027

NOTE: *Click on Docket Number to view testimony/report for each case where available.*

ATTACHMENT WHN-2

CAPD Pro Forma Billing Determinants

WHN Consulting

Atmos Energy Corporation

Comparison of CAPD & Company Volume Adjustments (MCF)

Attachment WHN-2

Schedule 1

Line No.		Test Period	Weather Normalization	Customer Changes	Customer Growth	Attrition Year
	CAPD Volumes (Mcf):					
1	Residential (210)	8,380,632	-657,573	0	241,242	7,964,301
2	Heating & Cooling (211)	486	-38	0	84	532
3	Small Commercial & Industrial (220)	6,002,327	-327,898	0	84,172	5,758,601
4	Experimental School (221)	73,267	-4,002	0	7,927	77,192
5	Public Housing (225)	56,820	-4,458	0	608	52,970
6	Large Commercial & Industrial (230)	321,622	-1,716	-225,328	17,924	112,502
7	Demand/Commodity (240)	0	0	0	0	0
8	Interruptible (250)	578,801	0	-59,120	0	519,681
9	Transportation (260)	7,177,426	0	578,847	0	7,756,273
10	Economic Development (280)	0	0	199,992	0	199,992
11	Negotiated (291)	1,284,296	0	1,196,488	0	2,480,784
12	Cogeneration (292)	2,949	0	0	0	2,949
13	Large Tonnage Air Conditioning (293)	16,429	0	0	0	16,429
14	**Total**	**23,895,055**	**-995,685**	**1,690,879**	**351,957**	**24,942,206**
	Company Volumes (Mcf):					
15	Residential (210)	8,380,632	-657,216	0	240,395	7,963,811
16	Heating & Cooling (211)	487	-38	0	13	462
17	Small Commercial & Industrial (220)	6,002,328	-327,474	0	107,665	5,782,519
18	Experimental School (221)	73,267	-3,997	0	1,314	70,584
19	Public Housing (225)	56,820	-4,456	0	1,629	53,993
20	Large Commercial & Industrial (230)	321,621	-1,714	-225,328	564	95,143
21	Demand/Commodity (240)	0	0	0	0	0
22	Interruptible (250)	578,801	0	-59,119	0	519,682
23	Transportation (260)	7,177,427	0	578,847	0	7,756,274
24	Economic Development (280)	0	0	199,992	0	199,992
25	Negotiated (291)	1,284,296	0	1,196,488	0	2,480,784
26	Cogeneration (292)	2,949	0	0	0	2,949
27	Large Tonnage Air Conditioning (293)	16,429	0	0	0	16,429
28	**Total**	**23,895,057**	**-994,895**	**1,690,880**	**351,580**	**24,942,622**
	Difference (Mcf):					
29	Residential (210)	0	-357	0	847	490
30	Heating & Cooling (211)	-1	0	0	71	70
31	Small Commercial & Industrial (220)	-1	-424	0	-23,493	-23,918
32	Experimental School (221)	0	-5	0	6,613	6,608
33	Public Housing (225)	0	-2	0	-1,021	-1,023
34	Large Commercial & Industrial (230)	1	-2	0	17,360	17,359
35	Demand/Commodity (240)	0	0	0	0	0
36	Interruptible (250)	0	0	-1	0	-1
37	Transportation (260)	-1	0	0	0	-1
38	Economic Development (280)	0	0	0	0	0
39	Negotiated (291)	0	0	0	0	0
40	Cogeneration (292)	0	0	0	0	0
41	Large Tonnage Air Conditioning (293)	0	0	0	0	0
42	**Total**	**-2**	**-790**	**-1**	**377**	**-416**

SOURCE: CAPD Revenue Workpaper R-1.01.

WHN Consulting
Attachment WHN-2
Schedule 2

Atmos Energy Corporation
Comparison of CAPD & Company Bill Adjustments

Line No.		Test Period	Customer Changes	Customer Growth	Attrition Year
	CAPD Bills:				
1	Residential (210)	1,412,850	0	44,829	1,457,679
2	Heating & Cooling (211)	24	0	-2	22
3	Small Commercial & Industrial (220)	194,125	0	3,669	197,794
4	Experimental School (221)	61	0	11	72
5	Public Housing (225)	7,125	0	-644	6,481
6	Large Commercial & Industrial (230)	123	-12	23	134
7	Demand/Commodity (240)	0	0	0	0
8	Interruptible (250)	295	0	0	295
9	Transportation (260)	1,321	7	0	1,328
10	Economic Development (280)	0	12	0	12
11	Negotiated (291)	43	-7	12	48
12	Cogeneration (292)	12	0	0	12
13	Large Tonnage Air Conditioning (293)	12	0	0	12
14	**Total**	**1,615,991**	**0**	**47,898**	**1,663,889**
	Company Bills:				
15	Residential (210)	1,412,850	0	43,976	1,456,826
16	Heating & Cooling (211)	24	0	0	24
17	Small Commercial & Industrial (220)	194,125	0	3,683	197,808
18	Experimental School (221)	61	0	1	62
19	Public Housing (225)	7,125	0	222	7,347
20	Large Commercial & Industrial (230)	123	-12	0	111
21	Demand/Commodity (240)	0	0	0	0
22	Interruptible (250)	295	0	0	295
23	Transportation (260)	1,323	7	0	1,330
24	Economic Development (280)	0	12	0	12
25	Negotiated (291)	43	-7	12	48
26	Cogeneration (292)	12	0	0	12
27	Large Tonnage Air Conditioning (293)	12	0	0	12
28	**Total**	**1,615,993**	**0**	**47,894**	**1,663,887**
	Difference:				
29	Residential (210)	0	0	853	853
30	Heating & Cooling (211)	0	0	-2	-2
31	Small Commercial & Industrial (220)	0	0	-14	-14
32	Experimental School (221)	0	0	10	10
33	Public Housing (225)	0	0	-866	-866
34	Large Commercial & Industrial (230)	0	0	23	23
35	Demand/Commodity (240)	0	0	0	0
36	Interruptible (250)	0	0	0	0
37	Transportation (260)	-2	0	0	-2
38	Economic Development (280)	0	0	0	0
39	Negotiated (291)	0	0	0	0
40	Cogeneration (292)	0	0	0	0
41	Large Tonnage Air Conditioning (293)	0	0	0	0
42	**Total**	**-2**	**0**	**4**	**2**

SOURCE: CAPD Revenue Workpaper R-1.02.

ATTACHMENT WHN-3

WNA Factors

WHN Consulting

Atmos Energy Corporation

SUMMARY OF WNA FACTORS

Attachment WHN-3

Schedule 1

Tariff	"R" Value ($/Mcf)	Heat Factor (Mcf/DDD)	Base Factor (Mcf/Month)
Residential (Rate Schedules 210, 211, 225)			
Bristol Area	**TBD**	0.01266855	0.68355869
Knoxville Area	**TBD**	0.01301322	0.73696229
Nashville Area	**TBD**	0.01638934	0.99565439
Paducah Area	**TBD**	0.01503365	0.71099431
Commercial (Rate Schedules 220C/230C, 221, 220I)			
Bristol Area	**TBD**	0.06253179	9.70872738
Knoxville Area	**TBD**	0.06877299	9.76506880
Nashville Area	**TBD**	0.05904454	10.68969789
Paducah Area	**TBD**	0.05229395	6.46343066

WHN Consulting
Atmos-Res Combined (210, 211, 225) Bristol Area
Cycle Weather Normalization
Bristol Heating Degree Days

Attachment WHN-3
Schedule 2

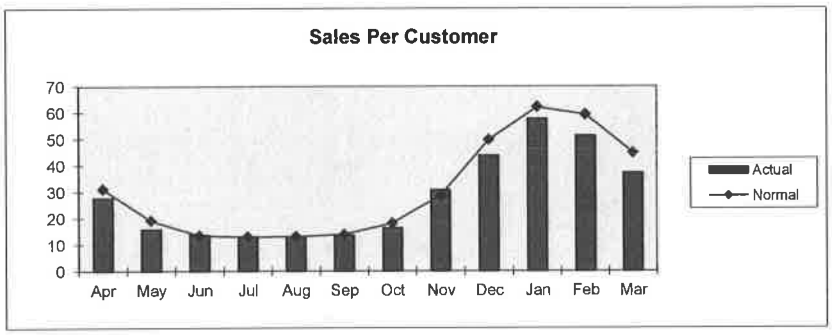
For the 12 Months Ended June 30, 2014

MONTH	SALES	CUSTOMERS	SALES PER CUSTOMER	ACTUAL WEATHER	NORMAL WEATHER
July	23,060	22,575	1.0215	0	1
August	23,161	22,542	1.0275	0	0
September	23,341	22,444	1.0399	4	6
October	27,770	22,612	1.2281	47	128
November	104,320	22,731	4.5893	492	418
December	211,858	22,964	9.2256	682	665
January	304,791	23,174	13.1523	887	858
February	329,771	23,128	14.2585	1,088	879
March	212,808	23,164	9.1870	597	600
April	130,183	23,092	5.6376	429	413
May	53,542	23,155	2.3123	136	167
June	31,760	22,827	1.3913	48	39
TOTAL	1,476,363	274,408	64.0710	4,410	4,174

MONTH	WEATHER DEVIATION	PER CUST ADJUSTMENT	NORMAL SALE/CUST	NORMAL SALES	WEATHER ADJUSTMENT
July	0.8600	0.0109	1.0324	23,306	246
August	0.4300	0.0054	1.0329	23,283	122
September	1.6900	0.0214	1.0613	23,821	480
October	81.0300	1.0265	2.2546	50,982	23,212
November	-74.0400	-0.9380	3.6513	82,998	-21,322
December	-17.2500	-0.2185	9.0071	206,840	-5,018
January	-28.8200	-0.3651	12.7872	296,330	-8,461
February	-208.9100	-2.6466	11.6119	268,561	-61,210
March	3.3600	0.0426	9.2296	213,795	987
April	-16.3000	-0.2065	5.4311	125,414	-4,769
May	31.2400	0.3958	2.7081	62,707	9,165
June	-8.9000	-0.1128	1.2785	29,185	-2,575
TOTAL	-235.6100	-2.9849	61.0861	1,407,222	-69,141

Regression Output:

Constant	0.68355869
Std Err of Y Est	0.91916054
R Squared	0.96853728
X Coefficient	0.01266855
Std Err of Coef.	0.00072205



WHN Consulting

Atmos-Res Combined (210, 211, 225) Knoxville Area
Cycle Weather Normalization
Knoxville Heating Degree Days

Attachment WHN-3
Schedule 3

For the 12 Months Ended June 30, 2014

MONTH	SALES	CUSTOMERS	SALES PER CUSTOMER	ACTUAL WEATHER	NORMAL WEATHER
July	19,587	19,789	0.9898	0	0
August	20,208	19,756	1.0229	0	0
September	18,941	19,813	0.9560	1	1
October	21,397	19,747	1.0835	11	79
November	80,469	19,887	4.0463	372	337
December	173,334	20,065	8.6386	606	592
January	261,076	20,179	12.9380	824	782
February	260,075	20,174	12.8916	985	793
March	157,070	20,173	7.7861	498	516
April	94,488	20,134	4.6930	363	327
May	39,795	20,185	1.9715	105	113
June	24,719	19,975	1.2375	32	19
TOTAL	1,171,157	239,877	58.2547	3,797	3,559

MONTH	WEATHER DEVIATION	PER CUST ADJUSTMENT	NORMAL SALE/CUST	NORMAL SALES	WEATHER ADJUSTMENT
July	0.0600	0.0008	0.9906	19,603	16
August	0.0300	0.0004	1.0233	20,216	8
September	0.3900	0.0051	0.9611	19,042	101
October	67.8700	0.8832	1.9667	38,837	17,441
November	-34.7400	-0.4521	3.5942	71,478	-8,990
December	-13.5900	-0.1768	8.4618	169,786	-3,548
January	-42.5000	-0.5531	12.3849	249,915	-11,161
February	-192.3000	-2.5024	10.3892	209,591	-50,484
March	18.2300	0.2372	8.0233	161,855	4,785
April	-36.2900	-0.4722	4.2208	84,981	-9,507
May	7.8800	0.1025	2.0740	41,864	2,069
June	-13.0000	-0.1692	1.0683	21,339	-3,380
TOTAL	-237.9600	-3.0966	55.1581	1,108,507	-62,650

Regression Output:

Constant	0.73696229
Std Err of Y Est	0.78343958
R Squared	0.97376586
X Coefficient	0.01301322
Std Err of Coef.	0.00067545

WHN Consulting
Atmos-Res Combined (210, 211, 225) Nashville Area
Cycle Weather Normalization
Nashville Heating Degree Days

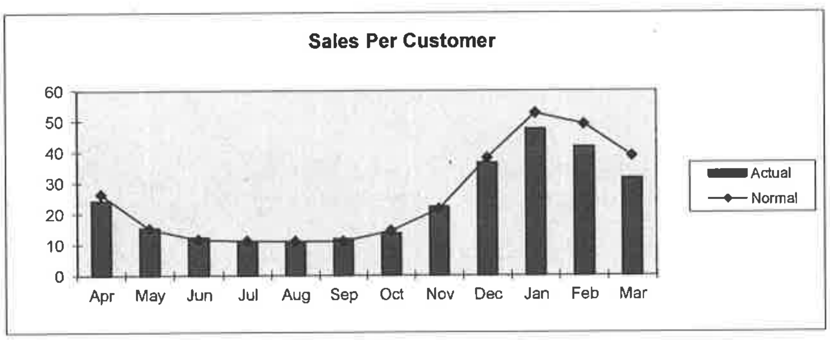
For the 12 Months Ended June 30, 2014

MONTH	SALES	CUSTOMERS	SALES PER CUSTOMER	ACTUAL WEATHER	NORMAL WEATHER
July	84,575	70,944	1.1921	0	0
August	82,935	70,765	1.1720	0	0
September	85,675	70,961	1.2074	1	1
October	94,750	71,129	1.3321	13	76
November	355,281	71,602	4.9619	397	314
December	790,661	72,059	10.9724	687	583
January	1,160,984	72,569	15.9983	817	780
February	1,258,990	72,674	17.3238	1,013	796
March	843,011	72,886	11.5662	536	518
April	471,635	72,737	6.4841	357	316
May	182,226	73,046	2.4947	78	102
June	109,362	72,642	1.5055	22	15
TOTAL	5,520,086	864,014	76.2105	3,921	3,499

MONTH	WEATHER DEVIATION	PER CUST ADJUSTMENT	NORMAL SALE/CUST	NORMAL SALES	WEATHER ADJUSTMENT
July	0.0600	0.0010	1.1931	84,646	71
August	0.1000	0.0016	1.1736	83,049	114
September	0.3000	0.0049	1.2123	86,023	348
October	62.6900	1.0274	2.3595	167,828	73,078
November	-83.0400	-1.3610	3.6009	257,831	-97,450
December	-104.4900	-1.7125	9.2599	667,260	-123,401
January	-36.8900	-0.6046	15.3937	1,117,109	-43,875
February	-217.3300	-3.5619	13.7619	1,000,132	-258,858
March	-18.2200	-0.2986	11.2676	821,247	-21,764
April	-41.4200	-0.6788	5.8053	422,261	-49,374
May	24.0900	0.3948	2.8895	211,065	28,839
June	-7.4500	-0.1221	1.3834	100,493	-8,869
TOTAL	-421.6000	-6.9098	69.3007	5,018,944	-501,142

Regression Output:

Constant	0.99565439
Std Err of Y Est	1.19536427
R Squared	0.96492725
X Coefficient	0.01638934
Std Err of Coef.	0.00098810



WHN Consulting

Attachment WHN-3
Schedule 5

Atmos-Res Combined (210, 211, 225) Paducah Area
Cycle Weather Normalization
Paducah Heating Degree Days

For the 12 Months Ended June 30, 2014

MONTH	SALES	CUSTOMERS	SALES PER CUSTOMER	ACTUAL WEATHER	NORMAL WEATHER
July	3,259	3,429	0.9503	0	0
August	3,197	3,412	0.9371	0	0
September	3,307	3,412	0.9693	2	4
October	3,760	3,418	1.1000	28	104
November	16,738	3,465	4.8305	434	367
December	39,832	3,500	11.3807	775	659
January	57,771	3,544	16.3011	913	880
February	62,275	3,538	17.6018	1,180	892
March	45,051	3,536	12.7406	674	590
April	22,869	3,544	6.4530	413	360
May	8,384	3,509	2.3894	101	119
June	3,888	3,393	1.1460	21	18
TOTAL	**270,332**	**41,700**	**76.7997**	**4,541**	**3,993**

MONTH	WEATHER DEVIATION	PER CUST ADJUSTMENT	NORMAL SALE/CUST	NORMAL SALES	WEATHER ADJUSTMENT
July	0.1700	0.0026	0.9529	3,267	8
August	0.4300	0.0065	0.9436	3,220	23
September	1.5000	0.0226	0.9919	3,384	77
October	76.2700	1.1466	2.2466	7,679	3,919
November	-67.1700	-1.0098	3.8207	13,239	-3,499
December	-115.8400	-1.7415	9.6392	33,737	-6,095
January	-33.4500	-0.5029	15.7982	55,989	-1,782
February	-288.0200	-4.3300	13.2718	46,956	-15,319
March	-83.7300	-1.2588	11.4818	40,600	-4,451
April	-53.1500	-0.7990	5.6540	20,038	-2,831
May	18.3200	0.2754	2.6648	9,351	967
June	-2.9900	-0.0450	1.1010	3,736	-152
TOTAL	**-547.6600**	**-8.2333**	**68.5664**	**241,196**	**-29,136**

Regression Output:

Constant	0.71099431
Std Err of Y Est	1.22319950
R Squared	0.96688346
X Coefficient	0.01503365
Std Err of Coef.	0.00087983

WHN Consulting
Atmos-Com Combined-2 (220C/230C, 221, 220I) Bristol Area
Cycle Weather Normalization
Bristol Heating Degree Days

Attachment WHN-3
Schedule 6

For the 12 Months Ended June 30, 2014

MONTH	SALES	CUSTOMERS	SALES PER CUSTOMER	ACTUAL WEATHER	NORMAL WEATHER
July	64,684	5,366	12.0544	0	1
August	65,528	5,323	12.3103	0	0
September	67,793	5,314	12.7575	4	6
October	70,184	5,326	13.1776	47	128
November	157,532	5,441	28.9528	492	418
December	296,738	5,512	53.8350	682	665
January	414,873	5,657	73.3380	887	858
February	431,751	5,656	76.3350	1,088	879
March	279,013	5,626	49.5935	597	600
April	172,962	5,601	30.8805	429	413
May	96,461	5,624	17.1516	136	167
June	63,993	5,385	11.8836	48	39
TOTAL	**2,181,512**	**65,831**	**392.2699**	**4,410**	**4,174**

MONTH	WEATHER DEVIATION	PER CUST ADJUSTMENT	NORMAL SALE/CUST	NORMAL SALES	WEATHER ADJUSTMENT
July	0.8600	0.0538	12.1082	64,973	289
August	0.4300	0.0269	12.3372	65,671	143
September	1.6900	0.1057	12.8632	68,355	562
October	81.0300	5.0670	18.2446	97,171	26,987
November	-74.0400	-4.6299	24.3229	132,341	-25,191
December	-17.2500	-1.0787	52.7563	290,793	-5,945
January	-28.8200	-1.8022	71.5358	404,678	-10,195
February	-208.9100	-13.0635	63.2715	357,863	-73,888
March	3.3600	0.2101	49.8036	280,195	1,182
April	-16.3000	-1.0193	29.8612	167,253	-5,709
May	31.2400	1.9535	19.1051	107,447	10,986
June	-8.9000	-0.5565	11.3271	60,997	-2,996
TOTAL	**-235.6100**	**-14.7331**	**377.5368**	**2,097,737**	**-83,775**

Regression Output:

Constant	9.70872738
Std Err of Y Est	5.14049286
R Squared	0.95996729
X Coefficient	0.06253179
Std Err of Coef.	0.00403813

WHN Consulting

Atmos-Com Combined-2 (220C/230C, 221, 220I) Knoxville Area
Cycle Weather Normalization
Knoxville Heating Degree Days

Attachment WHN-3
Schedule 7

For the 12 Months Ended June 30, 2014

MONTH	SALES	CUSTOMERS	SALES PER CUSTOMER	ACTUAL WEATHER	NORMAL WEATHER
July	31,306	2,850	10.9847	0	0
August	33,257	2,815	11.8142	0	0
September	34,679	2,818	12.3062	1	1
October	33,853	2,803	12.0774	11	79
November	70,195	2,872	24.4410	372	337
December	142,041	2,912	48.7778	606	592
January	219,841	2,963	74.1953	824	782
February	224,253	2,954	75.9151	985	793
March	144,194	2,949	48.8960	498	516
April	89,365	2,930	30.4999	363	327
May	48,145	2,963	16.2488	105	113
June	34,814	2,864	12.1556	32	19
TOTAL	1,105,942	34,693	378.3119	3,797	3,559

MONTH	WEATHER DEVIATION	PER CUST ADJUSTMENT	NORMAL SALE/CUST	NORMAL SALES	WEATHER ADJUSTMENT
July	0.0600	0.0041	10.9888	31,318	12
August	0.0300	0.0021	11.8163	33,263	6
September	0.3900	0.0268	12.3330	34,754	75
October	67.8700	4.6676	16.7450	46,936	13,083
November	-34.7400	-2.3892	22.0518	63,333	-6,862
December	-13.5900	-0.9346	47.8432	139,319	-2,722
January	-42.5000	-2.9229	71.2724	211,180	-8,661
February	-192.3000	-13.2250	62.6901	185,187	-39,066
March	18.2300	1.2537	50.1497	147,891	3,697
April	-36.2900	-2.4958	28.0041	82,052	-7,313
May	7.8800	0.5419	16.7907	49,751	1,606
June	-13.0000	-0.8940	11.2616	32,253	-2,561
TOTAL	-237.9600	-16.3653	361.9466	1,057,237	-48,705

Regression Output:

Constant	9.76506880
Std Err of Y Est	4.95344145
R Squared	0.96287067
X Coefficient	0.06877299
Std Err of Coef.	0.00427064

WHN Consulting
Atmos-Com Combined-2 (220C/230C, 221, 220I) Nashville Area
Cycle Weather Normalization
Nashville Heating Degree Days

Attachment WHN-3
Schedule 8

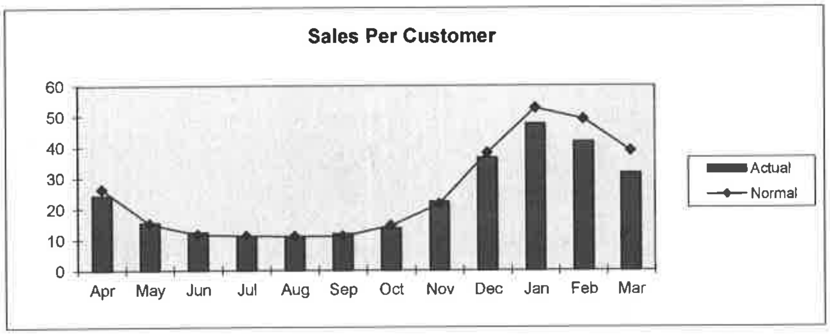
For the 12 Months Ended June 30, 2014

MONTH	SALES	CUSTOMERS	SALES PER CUSTOMER	ACTUAL WEATHER	NORMAL WEATHER
July	80,877	7,062	11.4525	0	0
August	82,510	6,991	11.8023	0	0
September	86,431	6,991	12.3631	1	1
October	84,565	6,960	12.1501	13	76
November	165,944	7,135	23.2578	397	314
December	334,295	7,296	45.8190	687	583
January	507,136	7,424	68.3103	817	780
February	508,075	7,438	68.3080	1,013	796
March	366,726	7,431	49.3508	536	518
April	208,037	7,376	28.2046	357	316
May	124,290	7,451	16.6810	78	102
June	87,439	7,232	12.0906	22	15
TOTAL	2,636,325	86,787	359.7900	3,921	3,499

MONTH	WEATHER DEVIATION	PER CUST ADJUSTMENT	NORMAL SALE/CUST	NORMAL SALES	WEATHER ADJUSTMENT
July	0.0600	0.0035	11.4560	80,902	25
August	0.1000	0.0059	11.8082	82,551	41
September	0.3000	0.0177	12.3808	86,554	123
October	62.6900	3.7015	15.8516	110,327	25,762
November	-83.0400	-4.9031	18.3547	130,960	-34,984
December	-104.4900	-6.1696	39.6494	289,282	-45,013
January	-36.8900	-2.1782	66.1321	490,965	-16,171
February	-217.3300	-12.8322	55.4758	412,629	-95,446
March	-18.2200	-1.0758	48.2750	358,731	-7,995
April	-41.4200	-2.4456	25.7590	189,998	-18,039
May	24.0900	1.4224	18.1034	134,888	10,598
June	-7.4500	-0.4399	11.6507	84,258	-3,181
TOTAL	-421.6000	-24.8934	334.8966	2,452,045	-184,280

Regression Output:

Constant	10.68969789
Std Err of Y Est	5.56138867
R Squared	0.94284615
X Coefficient	0.05904454
Std Err of Coef.	0.00459708



WHN Consulting
Atmos-Com Combined-2 (220C/230C, 221, 220I) Paducah Area
Cycle Weather Normalization
Paducah Heating Degree Days

Attachment WHN-3
Schedule 9

For the 12 Months Ended June 30, 2014

MONTH	SALES	CUSTOMERS	SALES PER CUSTOMER	ACTUAL WEATHER	NORMAL WEATHER
July	3,693	562	6.5713	0	0
August	3,826	569	6.7248	0	0
September	4,432	555	7.9862	2	4
October	7,988	554	14.4186	28	104
November	13,164	572	23.0140	434	367
December	22,153	582	38.0632	775	659
January	35,168	590	59.6063	913	880
February	41,699	585	71.2804	1,180	892
March	26,976	587	45.9564	674	590
April	13,788	591	23.3306	413	360
May	6,178	575	10.7443	101	119
June	4,165	568	7.3319	21	18
TOTAL	183,231	6,890	315.0280	4,541	3,993

MONTH	WEATHER DEVIATION	PER CUST ADJUSTMENT	NORMAL SALE/CUST	NORMAL SALES	WEATHER ADJUSTMENT
July	0.1700	0.0089	6.5802	3,698	5
August	0.4300	0.0225	6.7473	3,839	13
September	1.5000	0.0784	8.0646	4,476	44
October	76.2700	3.9885	18.4071	10,198	2,210
November	-67.1700	-3.5126	19.5014	11,155	-2,009
December	-115.8400	-6.0577	32.0055	18,627	-3,526
January	-33.4500	-1.7492	57.8571	34,136	-1,032
February	-288.0200	-15.0617	56.2187	32,888	-8,811
March	-83.7300	-4.3786	41.5778	24,406	-2,570
April	-53.1500	-2.7794	20.5512	12,146	-1,642
May	18.3200	0.9580	11.7023	6,729	551
June	-2.9900	-0.1564	7.1755	4,076	-89
TOTAL	-547.6600	-28.6393	286.3887	166,374	-16,857

Regression Output:

Constant	6.46343066
Std Err of Y Est	4.91911728
R Squared	0.95622398
X Coefficient	0.05229395
Std Err of Coef.	0.00353826

WHN Consulting
Atmos Energy Corporation
BRISTOL 30 YEAR DAILY NORMAL HEATING DEGREE DAYS

DAY	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1	25.50	26.40	22.10	13.03	4.20	0.93	0.00	0.00	0.00	5.60	10.83	23.63
2	26.80	26.77	20.53	13.13	4.40	0.57	0.00	0.00	0.00	5.03	12.83	23.87
3	27.37	25.77	22.07	11.57	5.13	0.17	0.00	0.00	0.00	5.13	15.27	22.87
4	27.10	27.43	21.50	11.43	5.87	0.37	0.00	0.00	0.30	4.90	15.80	25.00
5	27.90	28.73	19.90	12.27	4.83	0.50	0.00	0.00	0.60	4.90	16.13	25.37
6	28.30	27.93	19.53	12.93	4.30	0.50	0.00	0.13	0.30	5.63	17.63	27.00
7	28.83	26.73	19.27	13.13	4.43	0.60	0.00	0.10	0.23	7.60	16.40	26.77
8	29.50	27.90	19.20	11.30	3.27	0.30	0.00	0.13	0.20	7.77	17.37	25.47
9	29.17	27.83	18.87	12.07	3.13	0.33	0.00	0.07	0.43	5.90	16.80	23.53
10	28.60	27.07	20.40	11.27	2.87	0.30	0.00	0.00	0.20	5.90	16.77	23.93
11	28.40	26.37	20.00	9.10	3.27	0.23	0.00	0.00	0.27	5.57	18.30	25.73
12	27.07	28.10	18.97	9.87	3.57	0.27	0.03	0.00	0.20	6.93	18.00	25.93
13	27.30	28.90	18.03	10.90	3.87	0.37	0.00	0.00	0.30	6.60	18.77	24.93
14	29.23	26.33	17.83	8.17	3.10	0.30	0.00	0.00	0.70	7.57	17.93	25.07
15	29.37	24.80	17.50	7.90	2.70	0.00	0.00	0.00	1.03	8.50	17.23	24.00
16	29.53	25.53	17.20	8.97	3.30	0.07	0.00	0.00	1.50	9.03	17.13	25.33
17	28.07	26.97	17.73	9.77	3.67	0.00	0.00	0.00	1.57	8.70	19.13	24.97
18	29.00	24.93	16.33	8.20	3.47	0.13	0.00	0.00	1.57	9.40	18.90	26.93
19	29.83	23.27	16.17	7.03	3.63	0.07	0.00	0.00	0.90	10.77	18.30	27.20
20	30.83	21.70	16.97	6.10	2.90	0.10	0.00	0.00	1.13	11.20	17.43	28.30
21	31.60	19.60	17.87	6.83	2.23	0.23	0.00	0.00	1.10	10.90	19.30	27.50
22	30.77	20.57	17.83	7.60	2.53	0.20	0.00	0.07	1.33	10.63	20.43	26.40
23	29.67	20.70	16.00	8.17	2.03	0.03	0.00	0.10	2.43	11.00	20.93	26.43
24	29.83	23.63	15.27	7.77	1.67	0.00	0.00	0.03	2.67	10.33	20.37	28.63
25	31.47	23.77	14.33	6.50	1.70	0.00	0.00	0.00	2.47	10.63	19.70	30.83
26	30.93	23.13	14.57	6.63	1.33	0.00	0.00	0.00	2.13	10.20	18.93	30.87
27	31.23	23.23	14.20	6.63	1.30	0.00	0.00	0.00	2.43	10.87	18.23	28.23
28	28.70	22.53	12.30	7.33	1.43	0.00	0.00	0.23	3.63	12.17	19.47	27.03
29	27.20	5.10	12.40	6.37	1.27	0.00	0.00	0.30	4.67	13.50	21.57	27.03
30	25.50		12.13	4.40	0.53	0.00	0.00	0.20	4.97	11.57	21.83	26.63
31	27.87		13.33		0.37		0.00	0.00		11.00		25.43
Calendar Total	892	712	540	276	92	7	0	1	39	265	538	811
Cycle Total	858	879	600	413	167	39	1	0	6	128	418	665

NON-LEAP YEAR TOTAL	4,174
LEAP YEAR TOTAL	4,190

Note: Degree Days for February 29 must be multiplied by 4 to arrive at the true DDD for this day.
NOTE: AVERAGE IS FOR THE 30 YEAR PERIOD ENDED: June, 2014.

WHN Consulting

Atmos Energy Corporation

KNOXVILLE 30 YEAR DAILY NORMAL HEATING DEGREE DAYS

DAY	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1	23.97	23.27	18.97	10.17	2.73	0.30	0.00	0.00	0.00	3.20	8.10	20.97
2	24.87	23.23	18.20	10.43	3.17	0.17	0.00	0.00	0.00	2.87	10.30	21.27
3	25.03	22.87	19.70	9.43	3.80	0.00	0.00	0.00	0.00	2.93	12.20	20.87
4	24.73	24.63	19.30	8.90	4.43	0.07	0.00	0.00	0.00	2.77	12.97	22.23
5	25.13	25.93	17.03	10.23	3.60	0.10	0.00	0.00	0.03	3.10	13.33	22.57
6	25.70	25.63	16.97	10.07	3.10	0.30	0.00	0.00	0.20	3.87	14.83	24.40
7	25.20	24.60	16.63	9.67	2.87	0.33	0.00	0.00	0.07	5.40	14.13	24.13
8	27.13	24.90	15.63	8.53	2.03	0.07	0.00	0.03	0.10	5.50	14.20	22.90
9	26.53	24.67	16.00	9.67	1.67	0.13	0.00	0.00	0.07	4.47	13.43	21.37
10	25.10	24.27	17.10	8.43	1.47	0.10	0.00	0.00	0.00	4.03	14.43	21.47
11	25.63	24.30	16.90	6.77	2.13	0.10	0.00	0.00	0.10	3.93	15.10	22.83
12	24.80	25.47	15.90	6.87	1.77	0.07	0.00	0.00	0.00	4.87	15.67	23.53
13	24.93	25.83	14.80	7.70	2.20	0.23	0.00	0.00	0.13	4.03	16.07	22.37
14	26.73	22.20	14.93	6.23	1.63	0.13	0.00	0.00	0.33	4.77	15.67	23.07
15	26.73	22.30	14.37	5.90	1.43	0.00	0.00	0.00	0.30	5.80	15.23	22.10
16	27.70	21.53	13.77	7.33	2.20	0.03	0.00	0.00	0.53	6.30	15.60	22.67
17	26.63	23.30	14.53	7.27	2.30	0.00	0.00	0.00	0.30	6.47	16.83	22.23
18	26.50	22.17	12.83	5.67	2.00	0.00	0.00	0.00	0.27	6.57	15.90	24.53
19	27.27	20.23	12.97	4.73	2.03	0.00	0.00	0.00	0.40	8.10	15.63	24.40
20	28.03	18.30	13.70	4.33	1.20	0.00	0.00	0.00	0.57	8.80	14.90	25.50
21	28.43	17.00	14.17	4.33	1.43	0.00	0.00	0.00	0.43	7.50	16.40	24.50
22	28.23	18.37	14.33	4.60	1.37	0.03	0.00	0.00	0.47	7.70	17.63	23.87
23	27.63	18.40	13.20	5.57	0.77	0.00	0.00	0.00	1.53	8.63	18.30	24.40
24	26.40	20.27	12.20	5.73	0.53	0.00	0.00	0.00	1.63	7.93	18.30	27.00
25	28.30	20.47	11.50	4.13	0.67	0.00	0.00	0.00	1.30	8.67	17.43	29.10
26	27.97	19.80	11.97	4.60	0.50	0.00	0.00	0.00	1.17	7.53	16.77	28.60
27	28.17	20.00	11.27	4.50	0.47	0.00	0.00	0.00	1.60	9.20	16.07	25.83
28	25.20	19.53	9.87	5.13	0.60	0.00	0.00	0.03	1.93	10.37	16.63	24.80
29	23.97	4.43	10.33	4.40	0.57	0.00	0.00	0.03	2.47	10.90	19.97	24.40
30	23.70		9.80	2.53	0.13	0.00	0.00	0.00	2.73	9.13	19.97	24.33
31	24.47		11.27		0.13		0.00	0.00		7.80		23.13
Calendar Total	811	628	450	204	55	2	0	0	19	193	462	735
Cycle Total	782	793	516	327	113	19	0	0	1	79	337	592

NON-LEAP YEAR TOTAL	3,559
LEAP YEAR TOTAL	3,572

Note: Degree Days for February 29 must be multiplied by 4 to arrive at the true DDD for this day.

NOTE: AVERAGE IS FOR THE 30 YEAR PERIOD ENDED: June, 2014.

WHN Consulting
Atmos Energy Corporation
NASHVILLE 30 YEAR DAILY NORMAL HEATING DEGREE DAYS

DAY	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1	25.07	22.27	19.07	10.57	2.77	0.47	0.00	0.00	0.00	2.73	8.70	21.40
2	25.20	22.63	17.93	8.27	2.83	0.20	0.00	0.00	0.00	2.90	10.77	20.90
3	25.63	24.20	20.87	8.10	4.20	0.13	0.00	0.00	0.00	3.13	12.37	19.87
4	24.93	25.40	18.30	9.73	4.53	0.13	0.00	0.00	0.00	2.73	12.23	20.53
5	26.07	25.93	17.50	10.53	2.93	0.07	0.00	0.00	0.10	3.07	12.17	23.10
6	26.13	25.50	17.07	10.30	2.50	0.10	0.00	0.00	0.37	3.83	14.03	24.67
7	26.57	25.10	16.70	8.23	1.87	0.10	0.00	0.00	0.03	5.20	13.23	24.00
8	27.30	24.80	15.53	7.97	1.17	0.00	0.00	0.00	0.10	4.70	13.03	21.77
9	25.87	25.33	16.23	9.37	0.83	0.00	0.00	0.00	0.00	4.00	12.13	20.97
10	24.67	25.27	17.13	7.97	1.53	0.07	0.00	0.00	0.00	4.07	13.30	22.83
11	24.87	25.27	16.03	5.90	1.63	0.00	0.00	0.00	0.00	4.70	13.73	23.47
12	23.10	26.43	14.73	6.97	1.60	0.03	0.00	0.00	0.00	4.10	15.50	23.97
13	24.50	25.17	14.70	7.30	2.03	0.17	0.00	0.10	0.10	3.90	14.80	22.77
14	26.93	21.87	15.07	5.47	1.60	0.00	0.00	0.00	0.27	4.70	13.90	21.90
15	28.10	22.13	13.70	6.93	1.73	0.00	0.00	0.00	0.23	4.80	13.97	21.57
16	27.00	22.73	14.20	6.97	1.90	0.00	0.00	0.00	0.43	5.73	15.20	22.53
17	26.03	23.23	13.37	6.73	1.63	0.00	0.00	0.00	0.27	5.63	16.60	22.13
18	27.37	21.20	11.73	4.87	1.57	0.00	0.00	0.00	0.10	6.13	15.93	24.07
19	28.10	20.67	13.03	4.20	1.40	0.00	0.00	0.00	0.43	8.40	14.07	24.07
20	27.23	18.00	12.83	3.87	1.07	0.00	0.00	0.00	0.43	8.27	14.00	24.50
21	28.37	16.87	14.47	4.83	1.30	0.03	0.00	0.00	0.60	6.50	15.93	23.93
22	27.27	19.20	13.80	4.30	1.20	0.03	0.00	0.00	0.90	6.60	17.33	24.57
23	26.83	19.50	11.90	4.50	0.43	0.00	0.00	0.00	1.50	6.87	17.63	25.93
24	26.47	20.90	12.37	4.67	0.27	0.00	0.00	0.00	1.57	7.80	17.97	27.70
25	27.90	20.53	11.67	4.03	0.63	0.00	0.00	0.00	1.10	7.63	16.13	31.07
26	27.83	20.40	11.40	4.23	0.27	0.00	0.00	0.00	1.57	7.63	15.23	28.77
27	27.63	19.63	10.77	4.77	0.37	0.00	0.00	0.00	2.03	8.77	15.77	24.10
28	26.27	20.53	8.87	4.37	0.47	0.00	0.00	0.03	1.77	10.07	18.57	23.63
29	24.27	3.83	10.10	3.50	0.23	0.00	0.00	0.07	2.03	9.37	18.93	23.23
30	24.90		10.93	2.50	0.17	0.00	0.00	0.00	2.40	7.93	19.50	22.97
31	24.90		10.53		0.17		0.00	0.00		6.77		21.97
Calendar Total	813	635	443	192	47	2	0	0	18	179	443	729
Cycle Total	780	796	518	316	102	15	0	0	1	76	314	583

NON-LEAP YEAR TOTAL	3,499
LEAP YEAR TOTAL	3,511

Note: Degree Days for February 29 must be multiplied by 4 to arrive at the true DDD for this day.
NOTE: AVERAGE IS FOR THE 30 YEAR PERIOD ENDED: June, 2014.

WHN Consulting
Atmos Energy Corporation
PADUCAH 30 YEAR DAILY NORMAL HEATING DEGREE DAYS

DAY	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1	28.40	25.53	21.40	11.27	4.07	0.60	0.00	0.00	0.10	3.10	10.37	23.33
2	28.63	27.00	21.10	9.47	4.53	0.20	0.00	0.00	0.00	3.77	13.37	21.93
3	28.07	27.87	24.47	9.00	4.50	0.33	0.00	0.00	0.00	3.57	14.93	21.80
4	27.90	28.30	21.77	11.30	4.07	0.47	0.00	0.00	0.13	3.57	15.00	22.37
5	30.17	29.13	19.33	12.20	2.80	0.20	0.00	0.00	0.13	4.43	14.73	25.17
6	29.70	28.53	19.00	11.67	2.63	0.33	0.00	0.00	0.27	6.00	15.97	26.57
7	30.27	28.20	18.73	9.13	1.63	0.13	0.00	0.03	0.27	5.80	14.87	26.20
8	30.80	28.60	17.67	9.27	1.53	0.00	0.00	0.00	0.00	5.40	14.17	25.40
9	29.00	29.40	18.83	10.77	1.13	0.07	0.00	0.00	0.10	4.73	13.23	26.10
10	28.60	27.63	19.57	8.63	1.93	0.03	0.00	0.00	0.07	5.80	13.87	26.23
11	27.33	28.33	18.17	7.23	2.23	0.00	0.00	0.07	0.13	5.93	15.77	26.87
12	24.67	29.73	16.10	8.70	2.20	0.07	0.00	0.10	0.00	4.83	16.87	27.37
13	28.40	27.57	16.07	8.13	2.47	0.03	0.00	0.13	0.33	5.70	17.33	26.47
14	30.37	24.53	16.83	7.33	1.90	0.00	0.00	0.10	0.47	6.53	15.87	24.00
15	31.83	25.80	15.93	8.10	2.23	0.00	0.00	0.00	1.27	5.77	16.87	24.33
16	29.07	27.07	16.47	7.77	1.93	0.00	0.00	0.00	0.77	6.33	18.47	26.23
17	28.63	26.27	14.83	7.00	1.80	0.00	0.00	0.00	0.57	6.63	18.23	25.93
18	31.10	23.73	13.37	6.07	1.80	0.00	0.00	0.00	0.47	7.80	17.57	27.03
19	31.37	23.57	14.70	4.40	1.30	0.00	0.00	0.00	1.00	9.43	15.70	27.60
20	30.60	20.70	14.63	4.80	1.43	0.00	0.00	0.00	0.83	9.10	15.87	27.23
21	31.10	21.23	15.60	5.93	1.20	0.07	0.00	0.00	1.13	7.40	17.97	26.43
22	29.97	21.73	14.77	5.47	1.17	0.10	0.00	0.00	1.17	8.73	19.00	27.00
23	28.77	22.90	13.47	5.53	0.50	0.00	0.00	0.00	2.93	9.03	19.80	28.30
24	30.37	23.83	12.97	5.13	0.87	0.00	0.00	0.00	3.23	9.47	21.17	32.23
25	31.33	23.37	13.67	4.67	1.27	0.00	0.00	0.00	2.47	9.33	19.83	33.90
26	31.03	22.10	13.80	5.03	0.57	0.00	0.00	0.00	2.60	9.23	18.07	31.37
27	29.70	22.00	12.07	5.77	0.77	0.00	0.00	0.00	2.73	10.63	19.07	27.90
28	28.73	22.90	10.37	4.83	0.37	0.00	0.00	0.13	2.27	11.23	22.00	26.60
29	26.33	3.90	11.93	3.87	0.37	0.00	0.00	0.10	3.67	10.87	20.70	26.13
30	29.53		12.93	3.20	0.00	0.00	0.00	0.00	3.50	9.53	21.57	26.10
31	28.20		12.07		0.20		0.00	0.00		8.87		25.43
Calendar Total	910	721	503	222	55	3	0	1	33	219	508	820
Cycle Total	880	892	590	360	119	18	0	0	4	104	367	659

NON-LEAP YEAR TOTAL	3,993
LEAP YEAR TOTAL	4,005

Note: Degree Days for February 29 must be multiplied by 4 to arrive at the true DDD for this day.
NOTE: AVERAGE IS FOR THE 30 YEAR PERIOD ENDED: June, 2014.

ATTACHMENT WHN-4

Margin Comparison

WHN Consulting

Attachment WHN-4

Schedule 1

Atmos Energy Corporation
Attrition Period Margin & Revenue Summary

Line No.		Bills	MCF Volumes	Billing Demand	Margin
	CAPD:				
1	Residential (210)	1,457,679	7,964,302		$32,500,610
2	Heating & Cooling (211)	22	532		689
3	Small Commercial & Industrial (220)	197,794	5,758,601		20,351,848
4	Experimental School (221)	72	77,192		90,041
5	Public Housing (225)	6,481	52,970		166,166
6	Large Commercial & Industrial (230)	134	112,502		279,452
7	Demand/Commodity (240)	0	0		0
8	Interruptible (250)	295	519,681		632,584
9	Transportation (260)	1,328	7,756,273	16,126	9,009,539
10	Economic Development (280)	12	199,992		125,255
11	Negotiated (291)	48	2,480,784		811,988
12	Cogeneration (292)	12	2,949		3,785
13	Large Tonnage Air Conditioning (293)	12	16,429		18,351
14	**Total Sales & Transportation**	1,663,889	24,942,207	16,126	$63,990,308
	Company:				
15	Residential (210)	1,456,826	7,963,811		$32,479,644
16	Heating & Cooling (211)	24	462		675
17	Small Commercial & Industrial (220)	197,808	5,782,519		20,408,112
18	Experimental School (221)	62	70,584		82,218
19	Public Housing (225)	7,347	53,993		180,816
20	Large Commercial & Industrial (230)	111	95,143		235,443
21	Demand/Commodity (240)	0	0		0
22	Interruptible (250)	295	519,682		632,584
23	Transportation (260)	1,330	7,756,274	16,126	9,010,419
24	Economic Development (280)	12	199,992		125,293
25	Negotiated (291)	48	2,480,784		811,988
26	Cogeneration (292)	12	2,949		3,785
27	Large Tonnage Air Conditioning (293)	12	16,429		18,351
28	**Total Sales & Transportation**	1,663,887	24,942,622	16,126	$63,989,328
	Difference:				
29	Residential (210)	853	491		$20,966
30	Heating & Cooling (211)	-2	70		14
31	Small Commercial & Industrial (220)	-14	-23,918		-56,264
32	Experimental School (221)	10	6,608		7,823
33	Public Housing (225)	-866	-1,023		-14,650
34	Large Commercial & Industrial (230)	23	17,359		44,009
35	Demand/Commodity (240)	0	0		0
36	Interruptible (250)	0	-1		0
37	Transportation (260)	-2	-1	0	-880
38	Economic Development (280)	0	0		-38
39	Negotiated (291)	0	0		0
40	Cogeneration (292)	0	0		0
41	Large Tonnage Air Conditioning (293)	0	0		0
42	**Total Sales & Transportation**	2	-415	0	$980

SOURCE: CAPD Revenue Workpaper R-1.00.

ATTACHMENT WHN-5

Gas Cost Calculation

WHN Consulting

Attachment WHN-5
Schedule 1

Atmos Energy Corporation
ATTRITION PERIOD REVENUE & GAS COST SUMMARY

Tariff	Revenues	Margin	Gas Cost
Residential (210)	$82,499,066	$32,500,610	$49,998,456
Heating & Cooling (211)	3,397	689	2,708
Small Commercial & Industrial (220)	56,507,002	20,351,848	36,155,154
Experimental School (221)	477,453	90,041	387,412
Public Housing (225)	498,703	166,166	332,537
Large Commercial & Industrial (230)	986,348	279,452	706,896
Demand/Commodity (240)	0	0	0
Interruptible (250)	0	632,584	-632,584
Transportation (260)	0	9,009,539	-9,009,539
Economic Development (280)	1,157,078	125,255	1,031,823
Negotiated (291)	0	811,988	-811,988
Cogeneration (292)	0	3,785	-3,785
Large Tonnage Air Conditioning (293)	0	18,351	-18,351
Total Gas Sales & Transportation	**$142,129,047**	**$63,990,308**	**$78,138,739**
Other Revenues	1,216,690	1,216,690	0
Total Revenues	**$143,345,737**	**$65,206,998**	**$78,138,739**

SOURCE: CAPD Revenue Workpaper R-100-1.00.

ATTACHMENT WHN-6

West Virginia Commission Order in Mountaineer Gas Company Rate Case

ATTACHMENT WHN-7

Mountaineer Gas Company Initial Brief in Mountaineer Gas Company Rate Case

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04:01 PM AUG 31 2012 PSC EXEC SEC DIV

August 31, 2012

VIA HAND DELIVERY

Ms. Sandra Squire
Executive Secretary
West Virginia Public Service Commission
201 Brooks Street
P. O. Box 812
Charleston, West Virginia 25323

Re: Mountaineer Gas Company; Case No. 11-1627-G-42T

Dear Ms. Squire:

We enclose an original and twelve copies of the Company's (i) proposed order and (ii) initial brief. Each reflects a reduction in the Company's request; the increase in annual revenues has been reduced to $ 9,364,381, as shown in Appendices A through C to the initial brief.

Please file this letter, the proposed order, and the initial brief and circulate the additional copies of both to the appropriate parties at the Commission. We also ask that you date stamp the extra copies provided and return them with our messenger. As always, we appreciate your assistance in this matter.

Sincerely,

Christopher L. Callas

CLC/mrv

Enclosures

c: Tom White, Esq. (w/enc.)
George A. Patterson, Esq. (w/enc.)
L.R. Sammons, Esq. (w/enc.)

 Charleston, WV • Clarksburg, WV • Martinsburg, WV • Morgantown, WV • Wheeling, WV
Denver, CO • Indianapolis, IN • Lexington, KY • Pittsburgh, PA • Washington, DC

04:01 PM AUG 31 2012 PSC EXEC SEC DIV

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

CASE NO. 11-1627-G-42T

MOUNTAINEER GAS COMPANY

Rule 42T Tariff Filing to Increase
Rates and Charges

MOUNTAINEER GAS COMPANY'S INITIAL BRIEF

Mountaineer Gas Company appreciates the Commission's invitation to submit a proposed order in this important proceeding. While the Company's Proposed Order is comprehensive, this accompanying brief will allow the Company to speak in its own voice on selected issues.

Section I of this brief provides the Company's revenue requirement recommendation, based on the evidence presented and the Commission's expected approach to address a variety of cost of service issues. This recommendation reflects the resolution of those issues detailed in the Company's proposed order. The Company believes that this revenue increase proposal, which is substantially less than the Company's filed position, offers a reasonable, practical basis for the Commission's resolution of this case.

Section II of the brief addresses some important insights developed at hearing: the reasons for the Company's past and present financial under-performance, the related ratemaking issues, and how the parties' respective recommendations are likely to affect the Company's financial condition in the rate year. In Section III, we address several cost of service issues that present distinct choices to the Commission; for each issue, the Company encourages the Commission to consider and determine whether its resolution will provide the Company with a realistic opportunity to earn its authorized return. Section IV requests that the Commission modify the current rate suspension date of November 6, 2012 to align with the purchased gas adjustment decrease expected to go into effect on November 1, 2012.

I. THE COMPANY'S PROPOSED REVENUE REQUIREMENT

The Company recommends to the Commission a rate increase of $9,364,548 after harmonization of the rates of former East Resources customers. This recommendation is based on a rate base of $180,423,213, a return on rate base of 9.24%, and a return on equity of 10.50%.

In addition to the Company's concession to a lower ROE than its 11.25% request, this increase removes deferred Clay County receivership costs and deferred rate case expenses from rate base, and decreases expense by $13,708 to reflect the actual IGS management fee of $1.4 million. (Appendix A to this Initial Brief provides a cost of service breakdown, and the Company's rate base and capital structure calculations are shown in Appendices B and C, respectively.) The Company proposes that this increase be recovered entirely through an increase in the service charge, as specified in the Rate Design section of the proposed order.

II. OBSERVATIONS ON THE COMPANY'S RATE FILING

A. Same Old Story – The Company's Financial Performance

Once again, the Company is before the Commission in the midst of a protracted period of under-earning on a GAAP basis. No one denies that the Company lost money each year from 2006 through 2009 and, even with a healthy rate increase to which the parties stipulated in 2009, the Company's calendar year ROEs for 2010 and 2011 were 1.3% and 3.8%, with the warm 2011-2012 heating season pushing these already-low earnings into losses for the twelve month period ended March 31, 2012 (negative 0.7%). Co. Ex. TMT-R at 4-5. The test year, even though colder than normal, generated an ROE of only 6.3%. These returns would have been substantially worse had the Commission adopted either the Staff or CAD recommendations in the 2009 rate case; as the CAD's Mr. Smith acknowledged, the CAD recommendation of a $8.4 million increase at a 10% ROE would have generated approximately $10 million less revenue in 2011 than the Commission-approved stipulation did. Tr. II at 109-110 (Smith) (accepting CAD 2009 position, subject to check).

While the $19 million rate increase from the 2009 rate case offered relief from the serial losses during 2006-2009, the Company still had an inadequate return during the test year, despite colder than normal weather, and its more recent results (albeit weather-affected) have again fallen into the remarkable hole of a ***negative*** ROE. No one has suggested any imprudence, mismanagement, or other circumstance within the Company's control that caused its achieved ROE to be so much lower than its authorized return. Instead, the Company submits that the ratemaking process itself has failed not only the Company, but the Commission as well, which is charged by law with establishing rates that will allow for the full recovery of the Company's cost of service. The Company can identify with near certainty what has caused these insufficiencies, and what ratemaking approaches would perpetuate those insufficiencies in the future. In other words, allowing the Company a reasonable opportunity to achieve its authorized ROE is not a matter of knowing what to do – respectfully, it is a matter of choosing to do it.

B. Making Rates Better, or Making Excuses?

The Staff and CAD have not cast doubt on the Company's financial reporting or its earnings projections. Nor, in many instances, have they questioned the erosive impacts of their recommendations on the Company's ability to earn whatever return the Commission authorizes.

Mr. Smith offered some candid, yet dismissive, thoughts on the subject during his time on the stand. Like other Staff and CAD witnesses before him, Mr. Smith stressed the "apples and oranges" comparison between reported financial results under GAAP – how the financial community evaluates financial performance, investing and lending decisions, and the like – and regulatory earnings. These ideas are "completely different," he said (Tr. II at 110-111 (Smith)), and sophisticated investors know this (id. at 117). He admitted that, as an investor in the Company, he would be more interested in the Company's GAAP financial results, but at the same time he stressed that as an owner, he would "hold management accountable" for differences between GAAP results and regulatory results (id. at 116). Mr. Smith couldn't speculate as to what is or should be important to the Commission, other than the requirement that it must "apply this Rule 42T process" to set the utility's revenue requirement, notwithstanding the differences between regulatory and GAAP outcomes. "I think that's what they're required to do." Id. at 119. "[A]s long as the rates are established using the 42T process . . . that produces the correct result as far as ratemaking is concerned." Id. at 120-121.

Although Mr. Smith's approach to ratemaking sounds much like what the Staff has offered in the past, he did concede that the Commission might have legitimate concern about the impacts its ratemaking has had on the Company's financial performance. Mr. Smith was unwilling to question his recommendations from a prior case, no matter how dismal the utility's subsequent financial performance may have proved to be, but he did think such outcomes could result in "generic inquiries into the whole regulatory framework" if poor financial performance is "happening consistently" (Tr. II at 113 (Smith)) and, he hastened to add, if the Commission actually believes this is "a problem" (id. at 120). While he would not suggest that the Commission initiate such a generic proceeding, Mr. Smith readily identified some issues that Commission might investigate if it did: (i) differences between rate base and capital levels; (ii) differences between actual and allowed O&M expenses; and (iii) the impact of using an "historic test year versus [a] rate effective period" on which to calculate revenue requirements. Id. at 123-124.

Of course, the Commission has processed enough major rate cases to know that these problem areas surface at most every hearing – disconnects between a utility's actual invested capital and its regulatory rate base; disregarded O&M expenses; and the regulatory lag inherent in Rule 42's use of an historical test year and the statutory suspension period. Hiding behind what Rule 42 "requires" and the purported insignificance of GAAP earnings, the Staff and CAD recommend ratemaking approaches that will virtually guarantee the same insufficient returns that have plagued the Company since 2005. In contrast, the Company has identified exactly which issues have the potential to make achieving its authorized ROE impossible, and what can be done to protect against that outcome. Thus, in this case, the Commission must choose between an approach that will give the Company a realistic opportunity to earn its authorized rate of return, and a rigid "Rule 42" outcome that we know will only perpetuate the Company's poor financial performance.

C. Mountaineer is a Good Company, and Now is a Good Time

Throughout this case, no one has had a bad word to say about Mountaineer. Despite its past financial difficulties, and notwithstanding the CAD's rather predictable opposition to full recovery of management fees, the evidence shows Mountaineer to be a responsible, West Virginia-centered gas utility that provides good service, renews its infrastructure, and takes on the public service responsibilities when troubled utilities have failed customers and the Commission. This is not to say merely that the Company is deserving of fair ratemaking; strong earnings are essential to secure reasonably-priced debt, to make infrastructure investments, to pay reasonable dividends, and as Mr. Taylor testified, to be able to forward purchase gas for extended periods and take advantage of current low commodity rates. Tr. I at 75-76 (Taylor).

Furthermore, there could not be a better time to cure the ills of standard, Rule 42-constrained ratemaking that we all ***know*** will produce insufficient results. The Company's recent 30-C filing proposed a November 1, 2012 PGA decrease of $1.13 per Mcf, or approximately $7.00 per month for the average residential bill. Even if the Commission were to grant the entirety of the Company's revised rate request of $9.4 million (including the East Resources rate harmonization), the same customer would still see a net rate reduction of over $4.00 per month.

As Mr. Taylor and Mr. Klemm emphasized, the Company is not trying to get back the millions of dollars lost during the last six years. The Company merely wants to ensure that its past financial performance does not taint its opportunity to achieve the return on equity the Commission authorizes. This rate case provides the opportunity to give the Company a fighting chance, without a material impact on its customers.

III. SELECTED COST OF SERVICE ELEMENTS

In its decisions reviewing Commission orders in investor-owned utility rate cases, the Supreme Court of Appeals of West Virginia has acknowledged that the "basic approach to rate-making" involves a detailed consideration of numerous distinct elements of a utility's cost of service. In C&P Telephone Company v. Public Service Commission, 171 W.Va. 708, 301 S.E.2d 798 (1983), the Court explained this process in some detail:

> The basic approach to rate-making is to take a test year and determine revenues, expenses and investments for that year. Test year data is then adjusted for reasonably anticipated, known and measurable changes. These are called going-level adjustments.

> Going-level adjustments are "used to annualize the effective significant changes that occurred during the test year but which were not reflected for the full 12 month period, and to reflect the effect of known and measurable changes in revenue and expense levels following the end of the test year. Consideration of items treated differently for rate-making purposes than for bookkeeping purposes should also be reflected as going level adjustments.

C&P Telephone, 301 S.E.2d at 801 n.2 (citation omitted).

This analysis requires painstaking detail and, to that extent, conducting it is a rather exhaustive process. Yet C&P Telephone tells us that the Commission's individual determination on each of these items is central to public utility ratemaking. The Company has provided significant evidentiary support and analysis in its Proposed Order to justify its proposed rate base, revenues, and expenses; for that reason, not all of those issues are addressed here. Instead, this Section focuses on key ratemaking issues – rate base, ROE, pension expense, management fees, and income tax expense – on which a fuller exposition will benefit the Commission.

A. Rate Base

Mr. Smith was correct to observe that a common cause of inadequate utility earnings is the difference between a utility's regulatory rate base and the capital it has deployed to finance its operations. Tr. II at 123 (Smith). Yet he devoted much of his testimony to persuading the Commission to create just such a disconnect. The Commission will observe that the significant variance separating the Company's recommended rate base from the Staff and CAD recommendations is not comprised of utility plant in service. Instead, the Staff and CAD rate base recommendations related primarily to accumulated deferred income taxes (ADITs) – particularly an $11.4 million plant-related ADIT liability balance that they insist be used to reduce rate base, and as a consequence, to increase the gap between the Company's proven capitalization and its regulatory rate base. The Staff and CAD positions are not only unwise and unjustified; if adopted, they would make it impossible for the Company to earn its authorized return.

The Company's premise is simple: federal ADIT liabilities on the Company's books should be used to reduce rate base ***only to the extent*** they have provided a cash benefit to the Company – this is the only reason, after all, that ADITs are used to reduce rate base in the first place. To the extent the Company can demonstrate circumstances that prevented it from realizing that cash benefit, there is no justification for reducing rate base, because the Company has not received any interest-free capital that should be accounted for in rates. This rationale is ***exactly*** what Mr. Smith offered to explain his support for the Company's $2.6 million reduction to the ADITs rate base offset to account for the Company's NOL carryforwards. As Mr. Klemm recounted in his rebuttal:

> Mr. Smith contended that "ratepayers should pay deferred income taxes ***only to the extent that the utility is receiving the benefit*** of the tax depreciation deduction net of NOL," and that a "deferred tax asset" should be created to the extent that the utility is reasonably assured of using the NOL. In this connection, Mr. Smith indicated that for NOL carryforward ADIT amounts on the Company's books that ***have yet to produce a tax benefit*** should be reflected in rate base.

Co. Ex. SFK-R at 22, quoting from CAD Ex. RCS-D at 17, 21-22 (emphasis added; citation references omitted).

This rationale is also what motivated regulators in states such as Connecticut, Washington, Illinois, New Mexico, and Texas to exclude NOL deferred tax assets from ADIT liabilities that otherwise would reduce rate base. For example, in <u>Yankee Gas Services Co.</u>, Docket No. 10-12-02RE01 (Conn. D.P.U.C., September 28, 2011), 2011 WL 4609336, the Connecticut Commission reversed itself on reconsideration and recognized an NOL tax asset, in part in response to the utility's contention that it would be unable to fully recognize the cash benefits of the additional tax depreciation deductions until the NOL was used in future years. The Washington Commission applied the same rationale in reducing an ADIT liability by the amount of Puget Sound Energy's $41.7 million NOL carryforward, effectively increasing the utility's rate base for ratemaking purposes. Interestingly, Mr. Smith, as an expert for the Commission staff in that case, supported this outcome. Washington Util. and Transp. Comm'n v. Puget Sound Energy, Inc., Dockets UE-111048 and UG-111049, Order 8 (May 7, 2012), at 65.[1]

The underpinnings of these commissions' adjustments are clearly present in the circumstances necessitating the $11.4 million adjustment – circumstances that no Staff or CAD witness contested:

- To recognize the cash benefit of ADITs, there must be taxable income;
- The Company did not make any money in 2006, 2007, 2008, or 2009, and had negative federal income tax liability during that period; and
- Consequently, the Company did not recognize the cash benefit of plant-related ADITs recorded in those years.

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[1] Excerpts of the relevant portions of the Connecticut and Washington decisions, as well as those identified in this footnote, are collectively provided as Attachment 1. *See also* Pub. Serv. Co. of Co., Docket No. 10AL-963G, 2011 WL 4825894 (Colo. P.U.C. Order dated September 1, 2011) at 30-31 (approving stipulated settlement in which parties agreed to offset ADIT for NOL carryforwards); In re Commonwealth Edison Co., Docket 94-0065, 158 P.U.R.4th 458, 1995 WL 45969 (Ill. C.C. Order dated January 9, 1995) at 467-468 (utility's rate base should include deferred tax asset to offset deduction for deferred taxes, so that deferred tax accounting items are treated consistently, and utility does not forfeit federal deferred income tax benefits); Application of Gulf States Utils. Co., et al., Texas Pub. Util. Comm'n, Docket Nos. 8702, 8922, 8939, 8940, 8946, 8233, 8944, 8945, 8947, 8948, and 8949, 17 Tex. P.U.C. Bull. 703, 1991 WL 790287 (Examiner's Report dated May 2, 1991) at 55 (NOLs represent deductions to utility tax liability that utility has not yet realized, and should be used as an offset in the calculation of deferred income tax balance in rate base); Pub. Serv. of New Mexico, New Mexico Case No. 10-00086-UT, 2011 N.M. PUC Lexis 35 (NM P.U.C. Final Order dated July 28, 2011) at 64-65 (rate base increased by amount of NOL-related ADIT asset). *See also* Kern River Gas Transmission Co., Order No. 486, Docket No. RP04-274-000, 117 FERC ¶ 61,077 (FERC Opinion and Order dated October 19, 2006) at 89-93 (NOL-created ADIT asset used to increase rate base, because utility had not yet achieved tax savings associated with bonus depreciation).

Neither Mr. Smith nor Mr. Oxley explained how the Company would have benefited from the ADITs in the absence of taxable income, or how the principle supporting the $2.6 million ADIT reduction does not also support the $11.4 million component.

Moreover, neither witness proved Mr. Smith's main arguments against the $11.4 million adjustment: (i) that the plant-related ADITs, if reduced as the Company proposes, would be eliminated or lost to customers (CAD Ex. RCS-D at 20); and (ii) that the Company collected customer rates intended for the payment of income taxes, withheld them from the federal government, and now "holds" those funds for its own account (id. at 19). There is no regulatory, factual, or accounting basis for either of these arguments. The plant-related ADITs will stay squarely on the Company's books until they are used and then retired; the Company has not retained a pot of cash relating to income taxes that it has kept from the government, because revenues from customers were never sufficient to generate taxable income (or even to pay the Company's cost of providing service) during the 2006-2009 period. Co. Ex. SFK-R at 23; Tr. I at 160-61, 166, and Tr. II at 60-62, 93-94 (Klemm). Likewise, no party contested Mr. Klemm's explanation that when the Company generates sufficient cash to realize a cash benefit from timing differences, the ADITs will still be on the Company's books, and at that point will be available to reduce rate base. Co. Ex. SFK-R at 24; Tr. II at 93-95 (Klemm). In other words, the customer benefits of the ADITs do not disappear if the Commission recognizes the $11.4 million adjustment.

Mr. Smith repeatedly suggested that the Company's difficulty in earning its authorized return stemmed from the fact that "book equity amounts may be financing assets on the asset side of the balance sheet that are not reflected at all [in] the ratemaking process." *See, e.g.*, Tr. II at 127 (Smith). At the same time, not once did he explain why the Company's actual capitalization is as it is, or why that actual capitalization should be so much greater than the CAD's recommended rate base. After all, what was the Company "capitalizing" with its invested capital (Mr. Smith agreed with the Company's filed capital structure), if not plant and other assets supported by invested debt or equity capital? Mr. Smith does not say. What Mr. Smith failed to admit is this: except for the capital-supported items Mr. Klemm and Mr. Taylor said were properly excluded from rate base,[2] it is ***the CAD's own recommendations*** that, if adopted, would itself create capital-supported assets "not reflected" in ratemaking – not any decision the Company made or failed to make. If the Commission rejects the CAD and Staff rate base reductions as it should, the disconnect between the Company's capitalization and its regulatory rate base will be narrowed sharply, and the Company will have a much better chance of achieving whatever return on equity the Commission may authorize.

The same rationale and analysis applies to the ADITs associated with unamortized debt costs and the Company's customer information system regulatory asset, and the Company will experience the same erosion of its ability to earn its authorized return if those ADITs balances are included in (that is, as a deduction to) rate base. *See* Co. Ex. SFK-R at 33-35. Together,

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2 The Company asserted that the Company's filed variance between capital structure and rate base of approximately $4.1 million related to assets the Company conceded are properly excluded or disallowed in rate base. These included certain assets identified in Case No. 06-1838-G-PC, in particular the Commission's disallowance of construction work in process in rate base. Co. Ex. SFK-R at 14; Tr. I at 87-88 (Taylor). Mr. Klemm also explained that no other aspects of the Company's operations would cause one to expect a difference between deployed capital and rate base:

> The Company is strictly a West Virginia utility, it does not conduct any non-utility business (*i.e.*, appliance sales or repairs), it has not paid any premiums for the utility assets it has acquired, it does not have a consolidated corporate income tax issue, it is efficiently managed, and the Commission has not deemed any of its plant expenditures to be imprudent.

Thus, the Company's capital structure and rate base should approximate each other, except for the effect of CWIP and the production assets excluded in Case No. Case No. 06-1838-G-PC. Co. Ex. SFK-R at 14.

these two items have a rate base impact of nearly $2.3 million and a revenue requirement impact of over $300,000.

Two other earnings-eroding rate base items present serious concerns for the Company. The CAD proposed to reduce rate base by nearly $4.2 million related to state plant ADIT on accelerated depreciation, which would result in a revenue requirement impact of approximately $550,000. Much of this state ADIT liability occurred in years when the Company used the flow-through approach and no state income tax expense was included in the cost of service in determining rates – a fact not considered in Mr. Smith's recommendation. Co. Ex. SFK-R at 32-33. Finally, both the Staff and the CAD have proposed a rate base reduction for prepayments (a $3.6 million rate base item). On this issue, each party hid behind a Rule 42 requirement that supposedly requires a lead-lag study in each and every rate case if prepayments are sought in working capital – something the Commission knows is often not the case. In any event, neither party disproved that the Company did in fact fund its prepayments with short-term debt through much of the test year after consideration of the Company's gas cost over-recovery situation. Id. at 35-36. Excluding prepayments from rate base would have a revenue requirement impact of over $481,000 – yet another hurdle the Company would have to overcome to achieve its authorized return. Like the $11.4 million ADITs issue, these proposed rate base reductions would unquestionably harm the Company.

B. Return on Equity

One of the most common culprits in the difference between the rate recommendations of utilities and Staff in general rate cases is the cost of equity capital. The Staff ROE analysis is deeply flawed, in this case producing a ridiculously low 7.70% cost of equity capital. Even the lower of the CAD's two ROE figures was more than 100 basis points above the Staff recommendation. Respectfully, the time has come for the Commission to redirect its Staff to a more credible approach, not to one without a shred of support in any peer-reviewed literature or regulatory decision throughout the United States.

To his credit, Mr. Dworsky was perfectly candid when asked at the hearing about the sheer aberrance of Staff's hoary, "unbiased" method of mechanically applying (flawed) DCF and CAPM methodologies to a sample group, calculating the arithmetic average, and then "testing" the result for "reasonableness" with a debt coverage ratio. No one else in the United States calculates ROE like Staff – no one. Thus, it should come as no surprise that Staff's proposed ROE falls far below the findings of the several commissions where the firms in Mr. Dworsky's sample group are regulated.

The Company's Proposed Order addresses these and, to some extent, the more technical issues involved in determining the cost of equity capital. The entire record on this issue – particularly the evidence sponsored by Dr. Avera – is voluminous and, to some extent, even arcane, but it amply demonstrates a cost of equity capital several hundreds of basis points higher than Staff's 7.70%. The Company commends Dr. Avera's analyses, which are both theoretically sound and appropriately applied to the Company's particular circumstances, to the Commission's careful consideration. The Company respectfully suggests that the Commission should pay particular attention to some of Dr. Avera's criticisms of the flawed Staff analyses which, when recognized and accounted for, produce a recommendation of 10.61%. (In contrast, and tellingly, Mr. Dworsky's only criticism of Dr. Avera's work arose from his confusion of Dr. Avera's CAPM size adjustment with the entirely different "adders" that have been rejected by the Commission.)

Nor is this flawed Staff approach to ROE repaired by its "end results" test. "In evaluating the end results of a recommendation for return on equity, the Commission is not using the end result to determine the investor required return on equity." Monongahela Power Company and The Potomac Edison Company, Case No. 06-0960-E-42T (Commission Order dated May 22, 2007) at 47. The Commission clearly understands (as Mr. Dworsky acknowledged) that the failure of such tests may prompt further analysis, but that they serve only as a check, a determination that the number arrived at is not ***in***adequate as measured by the "financial integrity" test of Bluefield and Hope. ("End result" as used in Hope, Bluefield, and Permian Basin describes the nature and extent of judicial review of ratemaking, not some distinct ratemaking tool in and of itself that could subvert the comparable earnings, capital attraction, and financial integrity tests.) In over a year, not one word about debt coverage has appeared in the Commission's discussions of ROE in contested general rate cases for investor-owned utilities. *See* West Virginia-American Water Company, Case No. 10-0920-W-42T (Commission Order dated April 18, 2011) at 15-21, Megan Oil & Gas Company, Case No. 11-0532-G-42T (Commission Order dated October 27, 2011)at 15-16, Bluefield Gas Company, Case No. 11-0410-G-42T (Commission Order dated January 17, 2012) at 8-10, Black Diamond Power Company, Case No. 12-0064-E-42T (Commission Order dated August 10, 2012) at 4-6.[3] Yet, Staff clings to a "test" that the Commission apparently has determined to forego.

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3 In Blacksville Oil & Gas Company, Inc., Case No. 11-1321-G-42T (Commission Order dated March 16, 2012) at 7-8, the utility had no debt, and thus no debt coverage ratio could have been calculated.

C. <u>IGS Management Fees</u>

IGS Utilities has been involved in the management of the Company since Monongahela Power Company's sale of the Company in 2005. The Commission and the other parties know full well that Mr. Taylor and Mr. Michael Trusty have been integral to the Company's leadership, management, and stakeholder relationships for the entire time. And, just as in the 2009 rate case, the Company's evidence detailed not only the services IGS provides (Tr. II at 76-77 (Klemm)), but what the test year expense level actually purchased: in addition to the five IGS employees, it covers office space, expenses, travel, health care, and benefits (Co. Ex. TMT-R at 20). Mr. Taylor even explained that as management capacity in Charleston has grown over the years, the $2.3 million annual fee in 2005 has been reduced to $1.4 million, where it stands today. Id.

Despite this evidence, and the long-standing involvement of IGS, both the Staff and the CAD argued for reductions to the Company's recovery of the actual test year amount. Although Mr. Oxley's adjustment focused on a temporary reduction to the fee to support his recommendation, Mr. Smith's proposal to cut management fee recovery by 50 percent – a reduction of $788,000 – appears to have been entirely arbitrary, and apparently based in large part on a general suspicion of affiliate contracts and the possibility (not the fact, or even the allegation) of "abuse" or "mischief." Tr. II at 133-34 (Smith).

Both the Staff and the CAD know that if their recommendations were adopted, the Company's ability to earn its authorized return would be compromised. There is no justification for a routinely recognized cost of service component to be reduced in this way. The Commission should reject both recommendations.

D. Pension Expense

Pension expense is another area in which regulatory accounting and GAAP financial reporting converge, creating the potential for adverse impacts on a utility's financial performance under GAAP. The Commission knows that the Company is required to record pension expense at the contribution level required by ASC 715-30 (formerly FAS 87), but that the Company and other utilities sometimes fund their pensions at the minimum level permitted by ERISA, which at times is lower than the amount expensed on the books. This has been the Company's situation, and is expected to continue in the near term due to recent federal legislation. Tr. II at p. 72 (Klemm). Nevertheless, the Staff recommended that the Company's rate recovery for pensions be limited to the ERISA minimum amount. At hearing, Mr. Oxley conceded that the difference between FAS 87 expense recording and a lower rate recovery would automatically erode the Company's ability to achieve its authorized return. Tr. II at 217-18 (Oxley).

As with the ADITs and management fee issues, establishing rates with an insufficient recovery of pension expense does nothing but (i) exacerbate the Company's GAAP earnings concerns and (ii) encourage utilities to fund at no more than the minimum ERISA level, requiring future customers to make up a pension funding shortfall made worse by having missed the opportunity to generate higher investment earnings over time. The Company's recommended approach resolves both of these concerns. Mr. Klemm represented that if the Commission authorized pension expense recovery at the FAS 87 level, then the Company would pledge to fund its pension expense at that level. This is a sensible approach that is fair to the Company and benefits future customers, and the Commission should endorse it.

E. Income Tax Expense

The Staff and CAD income tax recommendations would also harm the Company's financial viability, and offer the Commission no legitimate benefit to customers, either. The Commission should not "flow through" deferred state income tax related to accelerated tax depreciation, as both Staff and CAD suggest. Furthermore, the Commission should definitively reject the Staff proposal to use the Company's NOL carryforward as a basis to disallow recovery of any state income tax. These two recommendations have only one purpose: to reduce rates today, without the least regard for the impact on customers tomorrow or the Company's financial health.

Flowing through the benefits of accelerated tax depreciation only to today's customers, and depriving future customers of the benefits of ADIT rate base reductions, is a short-sighted, unwise approach. Mr. Klemm demonstrated that flow-through of the impact of book/tax timing differences on state income tax expense is utterly inferior to full normalization. Normalization reduces the fluctuations in income tax expense that the flow through approach can cause, avoiding inconsistent and possibly unfair results between rate cases and minimizing intergenerational inequities. Co. Ex. SFK-R at 71-79. Mr. Smith's sole argument for the flow through method – that normalization need not be used because IRS normalization rules do not require it – misses the point, and as the Commission recognized in Appalachian Power's last rate case, the Commission is not precluded from normalizing timing differences where appropriate.[4] Normalization makes sense, benefits customers over the long run, and is the approach reflected in the settlement of the Company's 2009 rate case. Co. Ex. SFK-R at 73-74.

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4 *See* Co. Ex. SFK-R at 74, citing to Appalachian Power Company's 2010 rate case, Appalachian Power Company and Wheeling Power Company, Case No. 10-0699-E-42T (Commission Order dated March 30, 2011) at 58.

The Staff's proposed elimination of any state income tax expense in rates is even more unfair – if adopted, it effectively would continue to punish the Company with lower rates primarily because of its poor financial performance in the past. This is obviously a perverse outcome, and does nothing to help the Company achieve whatever ROE the Commission establishes in this case. Moreover, the Commission should not adopt ratemaking methods that discourage the use of all available tax deductions to reduce current tax expense, which is exactly what the Staff recommendation on state tax expense would do.

IV. REQUEST TO SHORTEN SUSPENSION PERIOD

The Company also proposes that the Commission shorten slightly the suspension period for the implementation of new rates by six days, to November 1, 2012 from November 6, 2012, to coincide with an expected change in the Company's purchased gas rate, the interim rate for which is expected to go into effect on November 1, 2012.[5] Shortening the suspension period will significantly reduce customer confusion that might arise from two rate changes within one week in November. It would also assist the Company in the implementation of the two rate changes, especially as it relates to programming, billing, and preparing an appropriate bill insert. To give the Company sufficient time to plan for the implementation of the two rate changes, the Company requests that the Commission enter an order addressing this request not later than October 17, 2012.

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[5] The Commission established the November 6, 2012 date in its order of April 20, 2012 in this docket. That order granted the Company's request to toll the statutory suspension period by 67 days. Consequently, shortening the suspension period by six days would effectively provide for a suspension period of 361 days in total (300 + 67 – 6).

V. CONCLUSION

The Company's proposed rates are fair and reasonable. It has presented this case in good faith, applying sound and justifiable ratemaking principles to derive rates that will meet its cost of service. The Company urges the Commission to focus on the individual elements of its cost of service – particularly the rate of return on equity – in establishing the appropriate rates for 2013. When the Commission does so, it will be clear that the Staff and CAD's adjustments are unreasonable and lack evidentiary support. Accordingly, the Company respectfully requests that the Commission adopt the Company's Proposed Order submitted with this Initial Brief, increasing the Company's rates and charges by not less than $9,364,548.

Respectfully submitted this 31st day of August, 2012.

MOUNTAINEER GAS COMPANY

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CERTIFICATE OF SERVICE

I certify service of MOUNTAINEER GAS COMPANY'S INITIAL BRIEF on August 31, 2012 by United States First Class Mail, postage prepaid upon:

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Christopher L. Callas

MOUNTAINEER GAS COMPANY
Cost of Service
Case No. 11-1627-G-42T

Rate Base	$ 180,421,947
Rate of Return	9.242%
Return on Rate Base	$ 16,674,596
Gas Cost	135,992,174
O&M Expense	66,736,280
Depreciation	12,028,933
Other Taxes	19,563,285
Income Taxes	5,877,122
Revenue Required	$ 256,872,390
Going Level Revenue	249,769,553
Revenue Increase	$ 7,102,837
Additional Bad Debt Expense	106,846
Additional B&O Tax	318,370
Increase	$ 7,528,053
Harmonization of East Resources Rates	1,836,328
Total Increase	**$ 9,364,381**

MOUNTAINEER GAS COMPANY
Rate Base
Case No. 11-1627-G-42T

Utility Plant in Service	$ 416,179,997
Accumulated Depreciation	(229,841,186)
Customer Advances	(1,252,165)
Net Utility Plant in Service	$ 185,086,646
Working Capital Allowance:	
Materials and Supplies	2,401,930
Prepayments	3,640,444
Working Cash Allowance	-
Other:	
Regulatory Assets	2,673,052
Customer Deposits	(5,000,987)
Federal Plant ADIT Liability	(4,217,806)
Other Deferred Credits	(90,116)
OPEB, net of Deferred Income Taxes	(4,071,216)
Total Average Rate Base	$ 180,421,947

NOTE: Unamortized Debt Costs have been removed from Rate Base.

NOTE: Regulatory Assets only consist of Deferred Customer Information System Costs.

MOUNTAINEER GAS COMPANY
Capital Structure
Case No. 11-1627-G-42T

	Amount	% of Total	Rate	Weighted Cost
Long-term Debt	$ 84,359,577	45.572%	8.4475%	3.850%
Short-term Debt	15,217,687	8.221%	6.5723%	0.540%
Total Debt	$ 99,577,264	53.793%		4.390%
Common Equity	85,533,709	46.207%	10.5000%	4.852%
Revenue Required	$ 185,110,973	100.000%		9.242%

APPLICATION OF YANKEE GAS SERVICES COMPANY FOR AMENDED RATE SCHEDULES - ADIT RECONSIDERATION

DOCKET NO. 10-12-02RE01

Connecticut Department of Public Utility Control

2011 Conn. PUC LEXIS 189

September 28, 2011

PANEL: [*1] By the following Directors: John W. Betkoski, III; Anna M. Ficeto; Kevin M. DelGobbo

OPINION: DECISION

I. INTRODUCTION

A. BACKGROUND OF THE PROCEEDING

By letter dated July 14, 2011, pursuant to §§ 16-9, as amended by Public Act 11-80, and 4-181a(a) n1 of the General Statutes of Connecticut (Conn. Gen. Stat.), Yankee Gas Services Company (Yankee or Company) petitioned the Public Utilities Regulatory Authority (Authority), formerly the Department of Public Utility Control, to reconsider its June 29, 2011 Decision in Docket No. 10-12-02, Application of Yankee Gas Services Company for Amended Rate Schedules (Rate Case). Specifically, Yankee requested that the Authority reconsider three issues: (1) the denial of Yankee's request to reduce accumulated deferred income taxes (ADIT) by the tax effect of the Company's net operating loss (NOL) created through bonus depreciation (ADIT Issue); (2) the denial of offsetting merger-related costs necessary to achieve customer savings; and (3) the denial of non-union merit pay increases in each rate year.

n1 Conn. Gen. Stat. § 4-181a(a) provides in relevant parts:

> (1) Unless otherwise provided by law, a party in a contested case may, within fifteen days after the personal delivery or mailing of the final decision, file with the agency a petition for reconsideration of the decision on the ground that: (A) An error of fact or law should be corrected; (B) new evidence has been discovered which materially affects the merits of the case and which for good reasons was not presented in the agency proceeding, or (C) other good cause for reconsideration has been shown...
>
> (3) If the agency decides to reconsider a final decision, pursuant to subdivision (1) or (2) of this subsection, the agency shall proceed in a reasonable time to conduct such additional proceedings as may be necessary to render a decision modifying, affirming or reversing the final decision, provided such decision made after reconsideration shall be rendered not later than ninety days following the date on which the agency decides to reconsider the final decision....

[*2]

By letter dated August 2, 2011, the Authority granted Yankee's request to reconsider the ADIT Issue because the Authority found that an error of fact or law may have existed regarding its ruling on the matter. The Authority declined to reconsider the merger-related savings issue and the non-union merit pay increase issue because the Authority found that Yankee did not meet its burden of demonstrating that any of the grounds enumerated in Conn. Gen. Stat. § 4-181a(a) existed relating to these issues. By Decision dated August 3, 2011, the Authority reopened the Rate Case Decision for the limited purpose of reconsidering its ruling on the ADIT Issue.

B. CONDUCT OF THE PROCEEDING

By Notice of Reopened Hearing dated August 5, 2011, the Authority held a public hearing on this matter on August 16, 2011 at its offices, Ten Franklin Square, New Britain, Connecticut. The hearing was continued to August 30, 2011, but was subsequently cancelled as the Authority determined it was not needed. By Notice of Close of Hearing dated September 2, 2011, the hearing on this matter was closed.

By Notice of Taking Administrative Notice dated August 23, 2011, the [*3] Authority noted and incorporated into the record of this proceeding, the following documents submitted in Docket No. 10-12-02:

> Yankee's responses to Interrogatories GA-484, 485, 486, 487, 488, 489, 490 and 491, submitted on July 27, 2011.

In addition, by Notice of Taking Administrative Notice dated September 14, 2011, the Authority noted and incorporated into the record of this proceeding, the following documents submitted in Docket No. 10-12-02:

> Yankee's responses to Interrogatories GA-2SP02, Schedules B-1.0A, B-1.0B, and B-7.0, submitted on April 1, 2011; and GA-57, Part C, Bulk submitted on January 24, 2011; and Yankee's Request for Reconsideration (Motion No. 48), submitted on July 14, 2011.

By Draft Decision issued September 21, 2011 (Draft) the Authority offered Parties and Intervenors an opportunity to provide Written Comments and Oral Argument on the Draft.

C. PARTIES AND INTERVENORS TO THE PROCEEDING

The Authority recognized the following as Parties to this proceeding: Yankee Gas Services Company, 107 Selden Street, Berlin, CT, 06037 and the Office of Consumer Counsel (OCC), Ten Franklin Square, New Britain, CT, 06051. The Authority granted Intervenor status [*4] to the Office of the Attorney General (AG); Environment Northeast; and Connecticut Industrial Energy Consumer (CIEC).

II. AUTHORITY ANALYSIS

A. ADIT ISSUE

In the Rate Case Decision, the Authority added $ 6.741 million to the Company's June 30, 2012 ADIT balance in order to negate a $ 6.741 million NOL tax asset from rate base. Yankee argued that the NOL tax asset must be included in rate base to partially offset the increases to the ADIT that resulted from additional bonus tax depreciation deductions allowed under the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010. Rate Case Motion No. 48, pp. 1-3. According to the Company, it cannot fully recognize the cash benefits of additional tax depreciation deductions, as the NOL generated is to be carried forward to future periods. Id., p. 6.

Additionally, Yankee argued that the Authority's determination to remove the $ 6.741 million in NOL tax asset from the calculation of average ADIT violated the tax normalization rule under internal revenue code (IRC) 168 and would create inconsistency between income tax expense and the recorded deferred tax liability. Id., pp. 9 and 10. Yankee provided [*5] the Internal Revenue Service (IRS) Private Letter Ruling No. 8818040 dated May 6, 1988. In that ruling, the IRS indicated that the taxpayer who requested the ruling should record the tax effect of the NOL in the period the NOL is used. Rate Case Response to Interrogatory GA-485, pp. 3 and 4. An inconsistent treatment between tax expense and deferred tax liability would ensue if ratepayers were allowed to realize the tax benefit of the bonus depreciation deductions before the Company could accrue and record the related deferred income tax liability when it utilized the NOL. Tr. 08/16/11, p. 2916. Yankee also provided an opinion and order issued by the Federal Energy Regulatory

Commission (FERC) dated October 19, 2006, in Docket No. RP04-274-000, Kern River Gas Transmission Company (Opinion No. 486). At paragraph 230 of Opinion No. 486, the FERC stated that Kern River was not able to fully use the available bonus depreciation deductions because the resulting 2003 NOL is carried forward to future years. The tax savings and additional cash flow of the bonus depreciation deductions would accrue to Kern River in the future when the NOL is used. Rate Case Motion [*6] No. 48, pp. 7 and 8; Rate Case Response to Interrogatory GA-485 Bulk, pp. 92 and 93.

The records of this proceeding show, that for tax reporting purposes, Yankee is a member of a consolidated group that files its tax returns on a calendar year basis. For calendar years ended 2008 and 2009, Yankee's consolidated filing group reported federal taxable income (FTI) of $ 42,556,165 and $ 180,170,043, respectively. Yankee's stand alone actual FTI was $ 23,540,600, $ 981,824 and negative $ 13,134,523 for calendar years ended 2008, 2009 and 2010, respectively. Rate Case Response to Interrogatory GA-57 Bulk, pp. 1 and 21; Late Filed Exhibit No. 1, p. 2. The Company testified that the NOL generated in 2011 would be fully absorbed by the FTI by 2013. Yankee stated that the nature of operations of significant members of its consolidated filing group is capital intensive and that most members would similarly generate losses in 2011. The other members of the consolidated filing group would not generate taxable income to absorb the Company's NOL. Generally, the NOL carry back period is two years. The Company indicated that taxable income that is available during carry back years cannot fully absorb [*7] the projected 2011 NOL and that the balance would have to be carried forward to 2013. See, Tr. 08/16/11, pp. 2898, 2899 and 2944.

In the instant proceeding, the Authority finds that the NOL generated during rate year 1 ending June 30, 2012 (RY1) diminished the cash flow available to Yankee as a result of the tax effect of the timing differences between straight line book depreciation and accelerated tax depreciation deductions. In the Rate Case Decision, the Authority had mistakenly assumed that Yankee's adjustment ignored the potential to carry back the losses and recognize the tax benefit immediately. Specifically, that the add back of the NOL tax asset to rate base meant that ratepayers would be permanently denied the tax benefit of bonus depreciation. As this is not the case, the Authority reverses its previous determination and hereby allows the inclusion of the $ 6.741 million of NOL tax asset in the calculations of the average ADIT for RY1 and rate year 2 ending June 30, 2013 (RY2) and ultimately for calculations of average rate base for each of the proposed rate years. Yankee will be required to explain if its consolidated filing group plans to carry back any NOL to be generated [*8] in 2010 and 2011 and to thereof provide the Authority with copies of documents the group will file with the IRS. The rate base and revenue requirements impacts of the Authority's determination in this proceeding to allow the NOL tax asset to be given rate base treatment are discussed in more detail in the following sections.

B. AMENDED RATE BASE

The total amounts of rate base allowed in the Rate Case Decision are $ 699,064,877 and $ 753,640,703 for RY1 and RY2, respectively. Yankee stated that rate base should be increased by $ 6.741 million and $ 10.112 million in RY1 and RY2, respectively. Rate Case Motion No. 48, Exhibit 4; Tr. 08/16/11, pp. 2900-2907. Yankee reiterated this assertion in Written Exceptions to the Draft dated September 26, 2011. Written Exception, p. 3 and Attachment 2. Yankee's assertion is based on the mistaken notion that the Authority, in its Rate Case Decision NOL tax asset adjustment, both added $ 6.741 million to the ADIT balance at June 30, 2012 and eliminated the Company's NOL tax asset; in effect, adjusting for the NOL tax asset twice. Written Exceptions, p.2. However, the Authority's Rate Case Decision NOL tax asset adjustment only added $ 6.741 [*9] million to the ADIT balance at June 30, 2012 while retaining the Company's NOL tax asset and its use in 2013. This is shown on page 21 of the Rate Case Decision where the Authority adds $ 6.741 million to the June 30, 2012 balance and compares the revised balance to the Company's proposed ADIT balances gross of the Company's NOL tax asset. If the Authority had additionally eliminated Yankee's NOL tax asset and its subsequent use the comparison would have had to have been made to the Company's proposed ADIT balance net of the Company's NOL tax asset.

In deed, in the Rate Case Decision and relative to the NOL tax asset, the Authority only made rate base adjustments of $ 4.005 million in RY1 and $ 4.003 million in RY2; adjustments that included, at least in RY1, additional, incremental adjustments to the NOL tax asset adjustment. Rate Case Decision, p. 21. As such, Yankee's claim, i.e., that the rate base adjustments made by the Authority exclusively related to the NOL tax asset were somehow $ 6.741 million in RY1 and $ 10.112 million in RY2, defies logic. Given the $ 6.741 million addition to the June 30, 2012 ADIT balance that the Authority did make exclusively for the NOL [*10] tax asset in its Rate Case Decision, and which the Authority is now reversing as part of this reconsideration, the average ADIT balance should be reduced by $ 3,370,500 [(0 + $ 6,741,000)/2] in RY1 and $ 6,741,000 [($ 6,741,000 + 6,741,000)/2] in RY2.

The Authority's determination in this proceeding is limited to the adjustments made to plant related ADIT as it pertains to the tax effect of the NOL generated and subsequently used, and any resulting impacts on rate base and revenue requirements. The increases to rate base as a result of the Authority's determination in this proceeding are summarized below.

Summary of Adjustments to Rate Base in RY1

	Rate Case Decision	Instant Proceeding	Rate Base Adjustments
Total ADIT	($ 183,736,365)	($ 180,365,865)	$ 3,370,500
Total Working Capital	($ 4,810,363)	($ 4,850,252)	($ 39,889)
Total Rate Base Adjustment			$ 3,330,611

Summary of Adjustments to Rate Base in RY2

	Rate Case Decision	Instant Proceeding	Rate Base Adjustments
Total ADIT	($ 205,081,168)	($ 198,340,168)	$ 6,741,000
Total Working Capital	($ 5,094,735)	($ 5,174,597)	($ 79,932)
Total Rate Base Adjustment			$ 6,661,138

As [*11] depicted in the tables above, the Authority hereby reduces plant related ADIT and consequently increases the rate base amounts allowed in the Rate Case Decision by net amounts $ 3,330,611 and $ 6,661,138 for RY1 and RY2, respectively. The total allowed rate base as amended herein is $ 702,395,488 (699,064,877 + $ 3,330,611) for RY1 and $ 760,301,841 ($ 753,640,703 + $ 6,661,138) for RY2.

C. AMENDED REVENUE REQUIREMENT

Based on its proposed increases to rate base, Yankee stated that revenue requirements should be increased by $ 751,000 and $ 1.122 million in RY1 and RY2 respectively. Rate Case Motion No. 48, p. 12; Exhibit 4.

The revenue requirements approved in the Rate Case Decision were $ 455,503,344 and $ 481,350,330 for RY1 and RY2, respectively. See, Rate Case Decision, Appendix B, pp. 5 and 6. As a result of the Authority's determination to increase the allowed rate base amounts as discussed above, the Authority increases the revenue requirements by $ 370,730 and $ 739,347 for RY1 and RY2, respectively. The calculation of these additional revenue requirements is summarized in the table below.

Summary of Increases to Revenue Requirements

	RY1	RY2
Additional Rate Base Allowed	$ 3,330,611	$ 6,661,138
Allowed Return on Rate Base	7.48%	7.48%
Additional Operating Income	$ 249,130	$ 498,253
Additional O&M - Uncollectible	$ 5,909	$ 11,785
Additional GET	$ 13,370	$ 26,664
Additional Income Taxes	$ 102,321	$ 202,645
Total Additional Revenue Requirements	$ 370,730	$ 739,347

[*12]
Therefore, the amended revenue requirements approved herein are $ 455,874,074 ($ 455,503,344 + $ 370,730) and $ 482,089,677 ($ 481,350,330 + $ 739,347) for RY1 and RY2, respectively.

D. AMENDED RATE SCHEDULES

In the Rate Case Decision, the Authority gave the Company specific directives with regard to the rate design for RY1. Subsequently, the Authority approved the Company's proposed RY1 rates submitted in its compliance filing. These rates became effective July 20, 2011. Regarding the rates for RY2, the Authority ordered the Company to perform a new cost of service study (COSS) and file new rates reflecting the billing determinants and financial profile approved in the Rate Case Decision. The Company has been given an extension of time until November 1, 2011 to file the RY2 compliance filing. As such, RY2 rate schedules have not yet been approved by the Authority, and thus, do not require amendments.

As a result of the $ 370,730 increase to the RY1 revenue requirement, the previously approved RY1 rates must be amended to recover this additional revenue. The Authority directs the Company to recover the additional $ 370,730 from the delivery charges within the commercial and [*13] industrial classes in a manner proposed by the Company during the period October 14, 2011 through June 30, 2012. Yankee will be directed to file a RY1 compliance filing reflecting the revenue requirement approved herein and will include the following exhibits: (1) proposed rate schedules for the affected rate classes (scored and unscored), including index page; (2) Revenue Proof Exhibits CRG-9, CRG-10 and CRG-13; and (3) Schedules E-3.5 and E-3.6.

For RY2, the Company will be directed to reflect in its Rate Case Decision compliance filing to Order No. 11 the amendments for RY2 approved herein.

III. FINDINGS OF FACT

1. Yankee is a member of a consolidated group that files its tax returns on a calendar year basis.

2. Yankee's carry back years cannot fully absorb the projected 2011 NOL and the balance needs to be carried forward to 2013.

3. For calendar years ended 2008 and 2009, Yankee's consolidated filing group, reported FTIs of $ 42,556,165 and $ 180,170,043, respectively.

4. Yankee's stand alone actual FTIs were $ 23,540,600, $ 981,824 and negative $ 13,134,523 for calendar years ended 2008, 2009 and 2010, respectively.

5. Yankee calculated the Authority's Rate Case [*14] Decision adjustment for the NOL tax asset assuming the Authority adjusted for the NOL tax asset twice.

6. Yankee's calculation of the Authority's NOL tax asset related adjustment is greater than the Authority's actual adjustment, which, in RY1, includes additional, incremental adjustments.

7. The revenue requirements approved in the 2010 Rate Case were $ 455,503,344 and $ 481,350,330 for RY1 and RY2, respectively.

8. RY1 rates have been approved by the Authority.

9. RY1 rates became effective July 20, 2011.

10. The Company has been given an extension of time until November 1, 2011 to file the RY2 compliance filing.

11. RY2 rates have not yet been approved by the Authority.

IV. CONCLUSION AND ORDERS

A. CONCLUSION

The Authority determined that it had made an error of fact in the Rate Case Decision in that the Authority assumed that the Company's NOL tax asset ignored the potential to carry back the losses and recognize the tax benefits immediately. Based on the evidence in the record and pursuant to Conn. Gen. Stat. § 4-181a(a)(1)(A), the Authority reverses its ruling on the ADIT issue and hereby allows the inclusion of [*15] the $ 6.741 million of NOL tax asset in the calculations of the average ADIT for RY1 and RY2 and ultimately for the calculations of the average rate base for each rate year. As a result, the Authority reduces plant related ADIT and consequently increases the rate base amounts allowed in the Rate Case Decision by $ 3,330,611 and $ 6,661,138 for RY1 and RY2, respectively, which resulted in total allowed rate base of $ 702,395,488 for RY1 and $ 760,301,841 for RY2. Correspondingly, these adjustments to rate base resulted in increases of $ 370,730 and $ 739,347 to the revenue requirements for RY1 and RY2, respectively. Consequently, the total revenue requirements allowed for RY1 and RY2 are $ 455,874,074 and $ 482,089,677, respectively. Yankee shall amend the rate schedules accordingly. New rates for RY1 will become effective for usage on or after October 14, 2011.

B. ORDERS

For the following Orders, submit one original copy of the required documentation to the Executive Secretary, 10 Franklin Square, New Britain, CT 06051, and file an electronic version through the Authority's website at www.ct.gov/dpuc. Submissions filed in compliance with Authority Orders must be identified by [*16] all three of the following: Docket Number, Title and Order Number.

1. No later than October 5, 2011, Yankee shall submit for review and approval two (2) copies of the RY1 compliance filing as described in Section II.D. Amended Rate Schedules. CW

2. No later than November 1, 2011, Yankee shall notify the Authority if its consolidated filing group generated NOL in 2010 and planned to file Form 1139 with the IRS to carry back such NOL. If so, the Company shall file a copy of Form 1139 filed as well as copies of the unredacted consolidated Federal income tax returns for 2010 and the carry back year. SB

3. No later than August 31, 2012, Yankee shall notify the Authority if its consolidated filing group generated NOL in 2011 and planned to file Form 1139 with the IRS to carry back such NOL. If so, the Company shall file a copy of Form 1139 filed as well as copies of the unredacted consolidated Federal income tax returns for 2011 and the carry back year. SB

4. The Company's Rate Case Decision compliance filing to Order No. 11 shall reflect the RY2 amendments to the Rate Case Decision approved herein. CW

This Decision is adopted by the following Directors:

John W. Betkoski, [*17] III

Anna M. Ficeto

Kevin M. DelGobbo

Legal Topics:

For related research and practice materials, see the following legal topics:
Energy & Utilities LawAdministrative ProceedingsU.S. Federal Energy Regulatory CommissionGeneral OverviewEnergy & Utilities LawUtility CompaniesRatesGeneral Overview

2012 WL 1655380 (Wash.U.T.C.)
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WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant,
v.
PUGET SOUND ENERGY, INC., Respondent.

Dockets UE-111048 and UG-111049 (consolidated)
Order 08

Washington Utilities and Transportation Commission

May ☐2012
REJECTING TARIFF SHEETS; AUTHORIZING AND REQUIRING COMPLIANCE FILING

BEFORE: Jeffrey D. Goltz, Chairman, Patrick J. Oshie and Philip B. Jones, Commissioners.

BY THE COMMISSION.

Synopsis: *The Commission rejects previously suspended tariff sheets Puget Sound Energy, Inc. (PSE or the Company) filed on June 13, 2011, by which the Company proposed to increase electric rates by 8.1 percent and natural gas rates by 3.0 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 rates that will increase electric rates by approximately 3.2 percent and natural gas rates by approximately1.3 percent.*

The Commission reduces PSE's overall rate of return but increases the percent of equity in the Company's capital structure. This gives ratepayers the benefit of lower debt costs that reflect the Company's financial strength while providing support to PSE's ability to earn its authorized return during a period of heightened capital investment.

The Commission recognizes PSE's current need to replace aging transmission and distribution infrastructure and to add cost-effective renewable resources to its portfolio of power production assets to meet Renewable Portfolio Standards mandated by the Energy Independence Act. This is exemplified in this case by the approval of PSE's acquisition and construction of the first phase of the Lower Snake River wind power project as a prudent investment.

This Order requires PSE to update its power costs to a point contemporaneous in time with its effectiveness. This gives the Company's customers the full benefit of declining natural gas prices that are a key driver of these costs. At the same time, this protects the Company by authorizing for recovery in rates a level of power costs that best reflect what its power cost model forecasts for the rate year. The Commission also authorizes and requires PSE to update and use its most recent actual property tax liability when calculating rates that comply with the requirements of this Order.

The Commission considered generally in this case the possibility of full decoupling for PSE and specifically considered such a proposal presented by the Northwest Energy Coalition. Full decoupling would separate PSE's recovery of its fixed costs from the level of its energy sales, thus insulating the Company from the effects of load reductions due to conservation and other factors. PSE, however, made clear its opposition to full decoupling as discussed in the Commission's 2010 Interpretive and Policy Statement. The Commission agrees with PSE in this Order that it should not impose on the Company a decoupling mechanism that it not only did not request, but affirmatively opposed.

case. "The normalized methodology reduces volatility, accommodates for differing rate case schedules and filing frequencies, and provides a more levelized, representative expense."[194]

Commission Determination: Rate case expense was last a fully contested issue in PSE's 2004 rate case.[195] PSE argued then that it should be allowed to defer and recover through amortization over three years its full rate case expense, as it had done in previous cases over the prior 20 years. Ultimately, the Commission approved in that case an amount agreed between PSE and Staff using a normalized expense methodology similar to what PSE uses in this case and identical to the method it adopted in its 2007/2008 general rate case in Dockets UE-072300 and UG-07230.

Testimony from both the Company and Staff shows that rate case expenses vary significantly from one year to the next. It is generally appropriate to normalize such expenses. This tends to come closer to satisfying the matching principle, or at least the principles underlying it, than simply using the costs from a single year, which may be quite high or low relative to the normalized amount.[196] Using average annual costs over several years is one means to normalize such expenses, but it is not the only valid approach. We see no reason, given the present record, to change the normalization method to which Staff and PSE previously agreed, and the Commission approved, for determining rate case expenses.

While it is true that PSE's electric costs represent a larger share of the Company's overall costs relative to natural gas operations, it is unclear from Staff's testimony how this fact relates to the costs of regulation. Many, even most, of the issues litigated in a general rate case proceeding, for example, are common to electric and natural gas operations. PSE separately calculates average expenses of PCORC proceedings and allocates those costs to electric. Moreover, the record includes no evidence that shows us what alternative allocation might be appropriate. Thus, we accept PSE's equal allocation of these costs between electric and natural gas operations.

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

This category of adjustments again includes expenses that PSE incurs in connection with both electric and natural gas service. These adjustments, however, also involve changes to rate base. PSE earns a *return on* its rate base (*i.e.*, its overall rate of return, 7.80 percent, as authorized in this Order), and a *return of* its rate base, via depreciation. Hence, PSE's revenue requirements are affected by our determinations concerning PSE's rate of return, depreciation expense[197] and operating expenses, as reflected throughout this Order. There are two contested adjustments in this category, federal income tax and working capital. We also address in this section of our Order the respective natural gas and electric adjustments for the Tax Benefit of Pro Forma Interest, which is uncontested as to method. It is a straightforward calculation, as discussed below.

a. Federal Income Tax

This adjustment changes PSE's federal income tax expense to regulatory levels based on the pro forma results of operations. There are a number of separate, underlying adjustments, most of which are not contested.[198] Staff, Public Counsel[199] and ICNU, however, raise several points that require discussion and our decisions.

I. ACCOUNTING TREATMENT FOR REPAIRS AND RETIREMENTS

The key Federal Income Tax adjustment issue in this proceeding, in terms of rate base and revenue requirement, concerns PSE's current accounting treatment for repairs and retirements expense. PSE changed its accounting method for repairs in its 2008 tax return, which the Company filed in September 2009.[200] PSE adopted the same method for retirements in March 2010, and used it in PSE's 2010 federal income tax return. This tax method change allows PSE to use different units of property (UOP) for tax purposes than the UOPs used for book purposes. In general, the UOPs for tax purposes are larger than those for book purposes. By using larger UOPs for tax, more of PSE's expenditures qualify for an immediate tax deduction.[201]

The effect of PSE changing its tax accounting method for repairs has resulted in a significant increase in the Company's ADIT (accumulated deferred income taxes) while the corresponding change for retirements resulted in a small offset against the increased ADIT for repairs. The net impacts, according to Staff witness Ralph C. Smith, are increases to ADIT of $41,414,322 for PSE's electric utility operations and $24,564,298 for PSE's gas utility operations.[202]

Considering both repairs and retirements, Staff argues that PSE's 2010 rate base should be decreased by these net amounts. Mr. Smith testifies that:

> By normalizing the tax savings, similar to what has traditionally been done for book-tax timing differences related to accelerated tax depreciation, ratepayers can benefit from the source of funds provided by such tax savings. The normalization treatment helps assure that all tax savings realized by the method change will benefit ratepayers by reducing rate base. However, there is no benefit in the current PSE general rate case under the Company's proposed treatment, which is to totally exclude all impacts from the repairs deduction on ADIT.[203]

PSE removed the tax impact of the new method from this filing based on its interpretation of a single sentence in the Commission's Final Order in Dockets UE-090704 and UG-090705:[204]

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 [Internal Revenue Service] approves its methodology for treatment of repair costs following an audit.[205]

Mr. Marcelia describes this sentence as being "the Commission's instructions on the ratemaking treatment for this accounting method" and says they "are clear and unambiguous."[206] He interprets this as the Commission imposing an audit requirement as a prerequisite to recognition of the increased ADIT in rates. At the time PSE filed this case, the IRS has not yet audited the new method. For this reason, "PSE has not implemented an increase to ADIT."[207]

Mr. Smith quotes the Commission's entire discussion of this subject in its Final Order in Dockets UE-090704 and UG-090705.[208] In the "Commission Determination" section of the discussion the Commission acknowledged the" risks of recognizing IRS-allowed accounting changes before they are audited." The Commission decision however, turned on a different point, discussed as follows:

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.

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 testyear. 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.[209]

Mr. Smith points out that the Commission later considered this same issue in the context of a PacifiCorp general rates case. In that case, despite the absence of an IRS audit, the Commission required PacifiCorp to reflect the full amount of increased ADIT for the test year.[210] The Commission emphasized in its PacifiCorp order that the known and measurable quality of the proposed pro forma adjustment is determinative and explained that this is consistent with its determination in the prior PSE case: "In the PSE case, we rejected the argument that *no* adjustment could be made to rate base until after an IRS audit because the amount was not known and measurable."[211] Observing in PacifiCorp's case that the ADIT adjustment amount "is both known and measurable," the Commission said further that: "The IRS allowed the tax treatment in the PSE case long after the end of the test year. Here, in sharp contrast, the IRS allowed the tax treatment *during* the test year."[212]

A recent amendment to the American Recovery and Reinvestment Act of 2009 (ARRA) eliminated the requirement to normalize Section 1603 Treasury grants.[219] The amendment is not relevant directly to LSR because it occurred after the decision to build. However, it now allows ratepayers to benefit not only from the amortization of the grant as a credit to operating expense, but also from the return on the unamortized balance of the grant regulatory liability.

Staff recommends that the Commission consider alternatives to the current Schedule 95A credit for returning the benefits of the LSR Treasury grant to ratepayers, and asks the Commission to order PSE to defer the grant, when received, with interest as a regulatory liability.[220] Staff argues that this will allow parties to propose alternative treatments when PSE files to update the Schedule 95A credit for the Treasury grants.[221] Schedule 95A requires that filing within 60 days after PSE receives the grant.

PSE states that although Treasury Grants are not an issue in this proceeding the Company does not object to deferring the LSR Treasury Grant and reflecting the appropriate ratemaking treatment, with any associated impact on the Wild Horse Treasury grant, in its November 2012 Schedule 95A filing.[222] PSE says that "in this short interim period, PSE would deposit the funds into an interest bearing account and defer the interest."[223]

Commission Determination: We agree with the parties that elimination of the requirement to normalize Section 1603 Treasury grants, which allows ratepayers to benefit not only from the amortization of the grants as a credit to operating expense, but also from the return on the unamortized balance of the grant liability, is reason enough to revisit the treatment of these federal benefits in rates. PSE's anticipated Schedule 95A filing in November 2012, or a separate filing required by Schedule 95A, will provide a forum in which this question can be addressed.

iii. ***Net Operating Loss***

Since the beginning of the current recession Congress has tried different approaches to revitalize the economy. One approach has been the use of "bonus depreciation" to allow rapid recovery of investment that it is assumed will be reinvested. Bonus depreciation allows companies, including PSE, to deduct from taxable income 50 percent to 100 percent of the cost of a new asset in the year the asset is acquired. The bonus depreciation greatly reduces the taxable income of the company and the amount of income taxes the Company must actually pay. For regulatory purposes the rapid recovery creates: (1) a Net Operating Loss (NOL) resulting in zero income taxes payable and (2) large deferred taxes caused by the bonus depreciation maximizing cash flow.[224] Cash flow is maximized because the related deferred income tax expense created by the timing differences is still recovered in rates.

In the Company's case, the tax basis NOL created by bonus depreciation must be carried forward to future years. NOLs act as additional tax deduction on future tax returns, reducing future taxes payable to zero until the carryforward no longer is large enough to reduce operating income to zero.[225]

The Company observes that as a practical matter, any tax benefits associated with the NOL will be delayed until a future tax year. According to the Company, PSE has claimed bonus depreciation on its taxes but has not received a cash benefit. The cash benefit is the amount of income taxes the Company would have paid had it not been for the accelerated recovery reflected in the bonus depreciation. The Company observes that "[a] NOL carryforward is similar to a tax receivable from the IRS except that it can only be used on future tax returns...."[226]

Since the NOL carryforward cannot be used by the Company to reduce a current liability, the Company argues that the deferred taxes associated with the assets that created the NOL should also be offset by a NOL carryforward deferred tax asset.[227] The reduction in the net deferred tax amount increases rate base by the amount of the tax-affected NOL.

While Staff agrees with the Company and recommends that rate base be increased by the NOL reflecting the impact of the deferred tax asset, Staff also recommends that the current income tax expense be reduced to zero and that all income tax expense be recognized as deferred.[228] Total proposed income tax expense remains the same but the terms of presentation are altered under Staff's response.[229] The Company responds that the tax impact of its adjustments to taxable income is appropriately recorded as current, since PSE's future tax position in the rate year is unknown. More to the point, Mr. Marcelia testifies, the Company is required to follow the FERC Uniform System of Accounts.[230]

Ms. Crane testifying on behalf of Public Counsel and The Energy Project argues that the Company's rate base should not be increased by offsetting accumulated deferred tax by its NOL. She maintains that the Company should make an offsetting adjustment to income tax expense in order to include the impact of the NOL in regulated rates.[231] In addition she proposes that if the Commission accepts the Company's adjustment then the Commission should review other tax issues including whether the Company is subject to a consolidated income tax adjustment.[232]

The Company, responding to Ms. Crane, says she fails to understand how tax expense is actually recorded and because of this her testimony is contrary to PSE's and Commission Staff's testimony on the net operating loss regulatory treatment. Mr. Marcelia testifies that the adjustment Public Counsel seeks has already been reflected on the Company's books.[233] If PSE were to account for the NOL in a different manner than proposed, it would "run afoul" of normalization requirements in IRC §1.167(l)-1(h). The Company says that Ms. Crane's adjustment is "...illogical and contrary to the normalization provisions of the IRC [Internal Revenue Code]".[234]

Commission Determination: We agree with the treatment of PSE's current NOL proposed by PSE and agreed to by Staff. By using the NOL carryforward of $41.7 to reduce ADIT, the effect is to increase electric rate base by $23.2 million and natural gas rate base by $18.5 million.[235]

We have no reason to question Mr. Marcelia's representation that what Ms. Crane proposes has been reflected already on the Company's books following standard accounting practices. Moreover, it appears that it would, in all likelihood, be a violation of normalization requirements if deferred taxes were not reduced by the tax effect of the NOL.

With respect to Staff's proposal that we reclassify all of PSE's current tax expense to deferred tax expense, Staff has not demonstrated that the Commission should involve itself in the detail of specifying how tax-related journal entries should be recorded on the Company's books.[236] PSE, in this regard, is required to follow the FERC Uniform System of Accounts. Therefore the Commission will not order the Company to reclassify current taxes to deferred taxes.

iv. Consolidated Tax Savings

The Internal Revenue Service permits an affiliated group of companies (*e.g.*, Puget Holdings, Puget Energy, Inc., PSE, and various other subsidiaries and affiliates) to file a consolidated federal income tax return. A key benefit of filing such a return is that losses associated with any affiliate can be used to offset taxable income of the other affiliates in the group. ICNU argues PSE's revenue requirement should be reduced by $8.8 million on the electric side and $3 million on the natural gas side to account for ratepayers' fair share of the value of PSE's taxable income that is used to lower PSE's parent company's (*i.e.*, Puget Holdings) overall federal income taxes.[237]

ICNU proposes a novel approach, imputing hypothetical loans from group members with income, including PSE, to those with continuing tax losses.[238] ICNU starts with the actual taxable incomes and losses reported by each member of the consolidated group using "the sum of each company's reported taxable income and/or loss for the most recent ten years."[239] The continuing taxable incomes and continuing tax losses are segregated so that each company has the opportunity to offset its own losses before it is deemed to require a loan from its affiliates.[240]

ICNU says that its consolidated tax adjustment recognizes that the companies with continuing taxable incomes have made loans to those companies with tax losses and the result is a lower consolidated tax liability.[241] The total tax savings realized by the parent company equal the total losses multiplied by the federal income tax rate.[242] According to ICNU: "PSE's fair share of

2011 WL 4825894 (Colo.P.U.C.)
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Re Public Service Company of Colorado

Docket No. 10AL-963G
Decision No C11-0946

Colorado Public Utilities Commission

September 1, 2011

Before Dean, director, and Epel, Tarpey, and Baker, commissioners.

BY THE COMMISSION:

*1 *ORDER ON EXCEPTIONS AND REQUEST FOR CLARIFICATION*

Mailed Date: September 1, 2011 Mailed Date: August 24, 2011

I. BY THE COMMISSION

A. Statement and Background

1. On December 17, 2010, Public Service Company of Colorado (Public Service or Company) filed Advice Letter No. 791-Gas. The advice letter sought a Phase I Revenue Requirement increase of $27.5 million in base rates.

2. By Decision No. C11-0040, issued January 13, 2011, the advice letter was set for hearing and suspended for 120 days.

3. By Decision No. R11-0240-I, issued March 7, 2011, interventions of the following parties were granted: Climax Molybdenum Company (Climax); Energy Outreach Colorado (EOC); Seminole Energy Services, LLC (Seminole); Atmos Energy Corporation (Atmos); Colorado Natural Gas Inc. (CNG); SourceGas Distribution LLC (SourceGas); the Colorado Office of Consumer Counsel (OCC); and Trial Staff of the Commission (Staff).

4. On March 1, 2011, Public Service filed Advice Letter No. 791-Gas Amended, which advice letter asked for an effective date of February 7, 2011.

5. By Decision No. R11-0403-I, issued April 15, 2011, the Hearing Commissioner reset the 120-day suspension period.

6. By Decision No. R11-0412-I, issued April 19, 2011, the Hearing Commissioner extended the suspension period by an additional 90 days or through September 5, 2011.

7. By its rebuttal testimony filed on May 9, 2011, Public Service updated its 2010 historic test year and 2011 future test year to reflect corrections, additional information, and concessions in response to issues raised during the pre-hearing phase of this proceeding. Based on these corrections, Public Service, on rebuttal, calculated a revenue deficiency of $20.7 million based on a 2010 historic test year and $20.3 million based on a 2011 future test year.

8. Subsequently, Public Service, Staff, and the OCC entered into a Settlement Agreement.[1] The Settlement Agreement was filed on May 25, 2011. Atmos, Seminole, CNG, SourceGas, and EOC did not oppose the Settlement Agreement. On the other hand, Climax did oppose the Settlement Agreement.

The Settling Parties agree that the Company shall include in rate base an estimate of the 13 month average Construction Work In Progress ('CWIP') balance for the period June 30, 2010 through June 30, 2011 and Plant Held for Future Use ('PHFU') as of June 30, 2011. The Company shall also include in the test year COS an offset to earnings equal to the estimate of the Allowance for Funds Used During Construction ('AFUDC') for the twelve months ending June 30, 2011.

E. Tax Normalization and Allowance for Net Operating Losses

The Settling Parties agree that the Company shall calculate the revenue deficiency using full tax normalization, allowing the Company to provide for deferred taxes on all book/tax timing differences, including the Company's proposed offset to accumulated deferred income taxes ('ADIT') for the net operating loss carry forward applicable to the Company's gas department for income tax purposes for calendar year 2010. The Company agrees to file on each April 30, as necessary, a GRSA (or to modify its then-current GRSA, if applicable) to reflect the revenue requirement effect of any reduction or elimination of the NOL carry forward offset to ADIT included in the test year COS. This change in rates shall be made in a manner that is consistent with the income tax normalization requirements for public utilities under the Internal Revenue Code. The NOL carry forward offset to ADIT included in the test year COS is equal to $9,007,058 and the revenue requirement associated with this offset is equal to $1,059,099.

F. Rate Case Expenses

The Settling Parties agree that the Company shall be permitted to amortize $1,207,316 million in rate case expenses over a three-year period beginning September 5, 2011. The level of rate case expenses has been reduced by $75,000 from the level initially requested by the Company, which is equal to the Company's estimate of its expenses associated with hiring one of its outside consultants. The Company further agrees that the rolling balance method of treating amortizations of rate case expenses as described in the Company's Rebuttal Testimony shall not apply with respect to the rate case expenses being amortized pursuant to this Settlement Agreement. In the event the Company files a rate proceeding prior to the time that these rate case expenses are fully amortized, the unamortized balance shall not be rolled in to the revenue requirements calculation in the next rate case.

G. Treatment of Gain on Sale of the Technical Services Building.

The Settling Parties agree that the gain on sale of the Technical Services Building shall be amortized over two years as set forth in the Company's Rebuttal Testimony. The Company shall be permitted to increase its GRSA or implement an alternative positive rider to reverse the effect of this amortization effective September 5, 2013.

H. Other Cost of Service Adjustments.

*8 Staff's 2010 HTY COS included a number of adjustments to expenses included in the Company's 2010 HTY COS that have been accepted by the Company in arriving at this Settlement Agreement. These include Staff's recommended adjustments to incentive compensation, alcohol expense, and aviation costs, and the shift in regulatory and resource planning labor. The Company has also accepted the OCC's recommendation to revise the revenue lag associated with residential late payment revenues to thirty-three days for purposes of calculating cash working capital to reflect the change in the billing of late payment fees to non-residential customers beginning June 2010.

In addition to these adjustments, the Company has corrected the common plant allocator used in its HTY COS as filed on February 28, 2011 and has updated the out-of period adjustment it made initially to reflect the known and measurable 2011 increases in pension and benefits cost. The Company also accepted Staff's recommended change to remove the unamortized TIMP balance from rate base. Lastly, the Company has made a minor reduction in the test year COS to incorporate recently received IRS guidance regarding the 2010 tax law changes on bonus depreciation.

The Settling Parties agree that the settlement as to all adjustments to the test year COS discussed in this Section 2.H. shall have no precedential effect going forward and shall not limit or affect the positions that the Settling Parties may take on such issues in any subsequent Phase I rate proceeding.

158 P.U.R.4th 458, 1995 WL 45969 (Ill.C.C.)

Re Commonwealth Edison Company

94-0065

Illinois Commerce Commission

January 9, 1995

<<Deletions are indicated by <<- Text ->>

ORDER authorizing an electric utility to increase its base rates by $303.223 million, exclusive of add-on revenue taxes. The increase reflects an authorized rate of return on equity of 12.28% and a 9.87% rate of return on used and useful jurisdictional rate base. Class revenue allocations are based on a constrained equal percentage of marginal cost approach which balances cost concerns with the need to avoid unacceptable rate shock.

As of May 1, 1995, base rates will be reduced by $93.647 million to reflect the removal of franchise fees from base rates. For prior order requiring the utility to 'remove all franchise and franchise-type costs from base rates for all customer classes on an equal-percentage, revenue neutral basis' and to file a rider to recover such costs from customers in the specific communities which impose the costs, see *Illinois Commerce Commission v. Commonwealth Edison Co.*, 155 PUR4th 17 (Ill.C.C.1994).

The Byron 2 and Braidwood 1 and 2 nuclear generating units are found fully used and useful for rate-making purposes, based upon the application of a 'needs and economic benefits test'. The 'needs' portion of the test considered whether the units would be necessary to meet customer demand over a three-year period centering on the year new rates will take effect, assuming a 22% reserve margin, which provided an 800 MW cushion for 'lumpiness', and excluding 200 MW of interruptible load.

The 'economic benefits' part of the test was used to determine whether portions of the units found not needed would be nonetheless used and useful because they would provide 'net economic benefits' to ratepayers.

Commission rejects a proposal to change its used and useful standard so that a unit would have to be found both needed and economically beneficial in order to be deemed used and useful.

The utility is authorized to recover its annual decommissioning cost of service in base rates and to establish a rate rider to reflect future increases or decreases in that cost. Commission rules that allowing rate recovery based on updated decommissioning cost estimates does not implicate the rule against retroactive rate making.

Commission rejects a proposal to include a 25% contingency factor in the rate-making expense allowance for nuclear plant decommissioning. It finds that the use of site-specific studies for estimating decommissioning costs already accounts for costs included in the proposed contingency factor. Commission also rejects a proposal to shift to an escalating payment methodology for collecting decommissioning funds from ratepayers, finding that the methodology would result in a funding shortfall in the event of premature shutdown.

P.U.R. Headnote and Classification
1. RATES
s120.1

Il.C.C. 1995
[ILL.] Reasonableness - Test period - Electric rate proceeding.
Re Commonwealth Edison Company

P.U.R. Headnote and Classification
2. VALUATION

Edison submitted evidence to show that its capital additions were both 'prudent' and 'used and useful' as required by Section 9-211 of the Act. *See* 220 ILCS 5/9-211. The Company submitted the testimony of Messrs. LaRock, Wallace, Lacey, and Maiman who described the fourteen larger capital projects and explained how and why they were undertaken. That testimony showed that the projects are prudent and used and useful.

Staff witness Kluck requested that Edison provide additional evidence regarding certain specified projects. (Staff Ex. 7 at 7-19). Edison responded with additional testimony, engineering studies, present value revenue requirements ('PVRR') analyses, and other documents explaining the projects in exhaustive detail. Staff reviewed the projects contained in four Edison budgets having costs that exceeded the $35 million standard adopted by the Commission in Edison's last rate case, Docket 90-0169, and concluded that none of those projects exceeded the updated, $40 million standard adopted in this case. Therefore, none of Edison's capital additions projects is 'significant' within the meaning of Section 9-213, and none is subject to audit. In addition, Mr. Kluck reviewed several of the largest capital additions budgets and determined that the projects in those budgets were both prudent and used and useful.

B. Significant Additions Audit Costs

[5] Edison included $347,700 in test-year operating expenses for the audits of three 'significant plant additions' in Docket 90-0169. The total audit expense was $1,043,100 and the Company seeks to amortize that expense over three years.

*467 Staff proposes to amortize this expense over the useful life of the additions, 17.7 years, thereby reducing the recovery of this expense to $59,000 in the test year. Staff witness Jenkins contends that this adjustment is necessary to avoid intergenerational inequity and is similar to the situation in Docket 90-0169, wherein the Commission amortized construction audit consultant costs over the average lives of the nuclear units audited. (Staff Ex. 3 at 6).

The Company contends that significant additions audits are substantially less expensive than generating unit audits. Edison further contends that where, as here, the audit costs are relatively small and the Company must pay these costs currently, a shorter amortization period than the remaining life of the plant is appropriate.

The Commission agrees with Edison's position. While the Commission is concerned about intergenerational equity, the expense is small and there is no reason to treat this expense like a capital item. Moreover, because the audit expenses are small, any intergenerational benefit of Staff's method would be negligible (especially where later generations would have to pay carrying costs on the unamortized balance), further justifying the treatment of these expenses more like ordinary maintenance expenses than as capital costs. Section 9-213 of the Act provides that audit costs for significant additions be recovered as an expense. Since Edison had to pay this expense on a current basis, it should authorize its recovery on a current basis. Accordingly, the Commission will allow the Company to amortize the cost of the significant additions audits over three years.

C. Net Operating Loss ('NOL') Adjustment

[6] AG/City witness Effron proposed the elimination of the deferred tax debit balance related to the NOL adjustment from the balance of accumulated deferred income taxes that is deducted from Edison's rate base. (AG/City Ex. 1.0 at 6). This proposal would reduce the Company's rate base by $103,863,000. The AG/City contend that this NOL deferred tax debit balance does not appear to be of a continuing nature that will exist during the full period since the Company shows a zero balance for the NOL adjustment as of December 1994, on a pro forma basis. In effect, they contend that the inclusion of this ADIT balance in rate base would result in ratepayers paying higher rates as a result of a rate base item that will not exist at any time during the period customers will pay these rates.

While Edison acknowledges that the factual situation posited by Mr. Effron is correct, Edison witness Houtsma gave three reasons for rejection of the adjustment. First, the Company points out that when accelerated tax deductions exceed the Company's taxable income, they produce an NOL. There is a deferral to the future of the cash benefit that Edison would have realized currently and unless a deferred tax asset related to the NOL is recognized, a greater benefit than the Company actually received would be deducted from rate base. (Edison Ex. 22 at 4-5). The Company contends that Mr. Effron, in effect, is proposing to increase net ADIT for tax benefits which have not yet been received. Second, Edison points out that a utility's rate base represents its balance sheet frozen at a point in time, *i.e.*, the test year. The Company objects to Mr. Effron's inconsistent adjustment of a single rate base component because it will not be the same after the test year, while all other rate base components, virtually none of which will be the same after the test year, are stated at test year values, as a violation of test year principles. Third, Edison is concerned that his adjustment might violate Internal Revenue Service 'normalization' rules for deferred tax accounting. The Company contends that under I.R.S. Reg. Sec. 1.167(1)-(1)(h), for ratemaking purposes, deferred taxes must be treated consistently with all other components of rate base and expenses. Edison opines that his adjustment would have the 1994 test year reflect deductions for accelerated depreciation which the Company will not receive until 1995.

The Commission is of the opinion that Mr. Effron's proposed adjustment is inappropriate. We believe, in this instance, Edison's rate base should include a deferred tax asset offsetting the deduction for deferred taxes, so that *468 deferred tax accounting items will be treated consistently. If we were to make this rate base adjustment, the Company well might forfeit its federal deferred income tax benefits. This would be inequitable.

D. Zion Crystallizer Accumulated Deferred Tax Balance

[7] Mr. Effron proposed to reduce rate base by $4.3 million through elimination of the ADIT debit balance related to the Zion Crystallizer because the Crystallizer was written off by Edison for book purposes in 1989 and is not presently providing any service to ratepayers. The Company has not written off the Crystallizer for income tax purposes. Staff supports his adjustment because the Company failed to take the steps between 1989 and the present to qualify the Crystallizer for tax-deductible status, and Staff contends that ratepayers should not be expected to pay a return on the unused tax benefits. (*See* Staff Ex. 13 at 32-33, Sch. 13.09).

In response, Edison contends that the taxes associated with this project are negative ADIT and consistent ratemaking treatment requires that they be offset against positive ADIT that are subtracted from rate base. (Edison Ex. 22 at 10-11; Tr. 1578). The Company points out that in this situation customers have not supplied any funds with respect to a future tax liability. It maintains that the deferred income tax effect here is not a liability, but an asset for which an offset to the rate base deduction for deferred taxes is necessary to preserve ratemaking consistency. (*Id.*). The Company also points out that Edison would incur a cost for the removal and disposition of the Crystallizer which could be charged to ratepayers.

The issue presented to the Commission is whether Edison reasonably sought tax-deductible status for the Crystallizer prior to the test year. The Company has given no reason for its failure to seek tax-deductible status. Accordingly, the Commission will adopt the $4.3 million adjustment to rate base.

E. Byron 1 Deferred Recovery of Depreciation and Decommissioning Expense

[8, 9] CUB recommends that recoveries for Byron 1 deferred decommissioning and deferred depreciation expense should be removed from rate base and test year expenses. The proposed rate base exclusions are $28,261,000 for deferred depreciation and $5,057,900 for deferred decommissioning. The basis for these adjustments is the Illinois Supreme Court ruling in *BPI II*, 146 Ill. 2d 175 (1991) that recovery of deferred depreciation and deferred decommissioning expenses violated the Commission's test year rules and resulted in retroactive ratemaking.

Edison contends that the Commission rejected this argument earlier in the Byron 1 Remand Order (Second Order on Remand, Dockets 83-0537/84-0555 cons. at 13, dated June 2, 1993). Moreover, this issue was settled by Edison, CUB and others in the Rate Matters Settlement Agreement dated September 16, 1993. Among other cases settled was the Byron 1 Remand Order. The Company properly asserts that the voluntary dismissal of these appeals pursuant to the Settlement Agreement, which was affirmed by the Appellate Court, is preclusive to all issues that were subject to appeal and bars future proceedings. (Citations omitted).

F. Working Capital - Unreimbursed Operating Expenses

17 Tex. P.U.C. Bull. 703, 1991 WL 790287 (Tex.P.U.C.)

Application of Gulf States Utilities Company for Authority to Change Rates
Application of Sam Rayburn G&T Electric Coop., Inc. for Sale Transfer or Merger
Appeal of Gulf States Utilities Company from Rate Proceedings of Various Municipalities

Docket Nos. 8702, 8922, 8939, 8940, 8946, 8233, 8944, 8945, 8947, 8948 and 8949
Texas Public Utility Commission

May 2, 1991

*1 EXAMINERS' REPORT

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Tarrant Utility Company, Docket No. 2914, 5 P.U.C. BULL. 627, 686 (Tex. P.U.C. - June 13, 1980.) Normalization requires both a cost of service and a rate base effect.

Consistent with the policy of previous cases, in Docket No. 7195, GSU's cost of service was reduced by approximately $13.9 million, which represented the fact that the NOLs were still being generated. Tr. at 717(15)-718(3) (Kirby Cross). The Commission also reduced the Company's ADFIT balances by approximately $72 million, on a Total Electric basis, which represented the fact that NOLs had been generated previously. Tr. at 1714 (Beekman Redirect). In this case, GSU argues that the Commission should follow its past practice and recognize the Company's NOL as a reduction to the ADFIT balance in determining rate base.

The Company contends that even if the Commission decided that GSU should change its accounting methods, the ruling should be applied only prospectively. It would be improper retroactive ratemaking for the Commission to restate the Company's ADFIT reserve by failing to recognize the NOLs. The situation would be similar to changing prospectively the Company's depreciation rate and retroactively restating its accumulated provision for depreciation based on the new rate. Tr. at 1685, 1686, Tr. 1701, 1702.

*55 GSU argues that in this case, the public interest will not be advanced by removing retroactively the Company's recognition of its NOLs in rate base. The public interest requires only that the Company's rate base is stated properly. The Company has recorded in its ADFIT reserves only those deferred income taxes that the Company received as cost-free capital. Tr. at 1794, 1795 (Warren Cross). Hence, the Company's rate base is stated properly, and the public interest is advanced.

d. Allocation of the Company's NOL

The Company has allocated the entire tax benefit of its NOL "above the line" and claims that consistency required that none of the debit be allocated to the abeyed portion of the River Bend plant. GSU contends its proposed treatment of NOLs complies with the normalization rules. Tr. at 1796(1-6) (Warren Cross). Mr. Warren suggested in his rebuttal testimony, an alternative allocation methodology, which is consistent with the normalization rules, if the Commission determines that some of the NOL should be allocated "below-the-line." GSU Ex. No. 37 at 9(1)-11(23) (Warren Rebuttal). Mr. Beekman calculated the effect of that allocation on the Company's NOL. GSU Ex. No. 32 at 16(4-9), Att. DNB-K (Beekman Rebuttal).

4. Examiners' Recommendation

NSS asserts in its Phase I B brief that GSU is requesting a return on unutilized tax benefits through the inclusion of the NOLs in rate base. NSS' characterization of GSU's request is not completely accurate. GSU's request is more properly characterized as a request to have the amount of cost free capital associated with federal income taxes more accurately stated. This requires that deferred income taxes be included in rate base net of NOLs.

Deferred accumulated federal income taxes are properly included as a credit to GSU's rate base because deferred federal income taxes represent cost free capital to the Company. However, this cost free capital is appropriately reduced to the extent that GSU has NOL carry forwards, which the utility is currently unable to use. Just as deferred income taxes represent future taxes which the utility has not yet been required to pay, NOLs represent deductions to the utility's tax liability which the Company has not yet realized. To the extent that a utility has unutilized NOL carry forwards, its tax liability will be reduced in the future. Therefore, if the Commission is going to include deferred income taxes as a reduction to rate base, which it should, the Commission should likewise include known reductions to those deferred taxes. Consequently, NOLs should be included as an offset in the calculation of the deferred income tax balance included in rate base.

The examiners agree with General Counsel's proposed treatment of GSU's NOLs. Because the Commission is precluded from considering costs held in abeyance, it would be appropriate to adjust the deferred taxes related to NOLs associated with costs held in abeyance to ensure consistent treatment among all FERC accounts related to deferred taxes reflected in rate base.

*56 GSU has requested that the entire NOL related deferred taxes be allocated to "above-the-line" expenses and included as an increase to rate base. This treatment fails to allocate any of the NOLs to the costs held in abeyance as "below-the-line" expenses. Such treatment assumes that the costs held in abeyance have not caused a portion of GSU's net operating losses. The examiners recommend that the more appropriate treatment is to allocate a portion of the NOLs to the costs held in abeyance. The deferred taxes related to the NOL allocated to the abeyance should then be reflected as a "below-the-line" adjustment.

GSU in rebuttal to Mr. Kirby calculated the portion of the NOLs which can be allocated to costs held in abeyance. GSU witness Beekman testified that the deferred taxes related to NOL carry forwards for the proposed inventoried portion of River Bend, which approximately equals the costs held in abeyance, is equal to $48,753,000 on a Texas retail basis. GSU Ex. No. 33, Attachment DNB-K. Because the inventoried plant, approximately equal to $1.4 billion, and the costs held in abeyance, approximately equal to $1.39 billion, are not materially different, it is appropriate to use the inventoried plant as a proxy for the costs held in abeyance. Mr. Beekman also testified that the deferred taxes related to NOL carry forwards associated with disallowed plant are equal to $2,225,000 on a Texas retail basis. Ibid. This results in a total reduction of $50,978,000 to the NOL carry forward related deferred taxes reflected in rate base on a Texas retail basis. The examiners adopt this abeyance adjustment and staff's NOL treatment as reasonable for the reasons stated above.

P. Pre 1971 Investment Tax Credits

See Section VI P of this Report.

Q. Customer Deposits

Test-year customer deposits total $16,210,614. This is not a contested issue in this case. The examiners recommend adoption of this amount as reasonable.

R. Property Insurance Reserve

This is not a contested issue. The examiners recommend adoption of GSU's proposed amount as reflected in the Appendix schedules as reasonable.

S. Injuries and Damages Reserve

This is not a contested issue. The examiners recommend adoption of GSU's proposed amount as reflected in the Appendix schedules as reasonable.

T. Post 1970 Investment Tax Credits (ITC)

This is not a contested issue. The examiners recommend adoption of GSU's proposed amount as reflected in the Appendix schedules as reasonable.

U. Unamortized Contra-AFUDC Relating to Accounting Order Deferrals and Contra-AFUDC Associated with Nuclear Fuel

The examiners recommend that GSU's proposed $17,753,000 adjustment to contra-AFUDC be rejected, and that unamortized contra-AFUDC be calculated as of test-year-end. The examiners also recommend a $643,848 adjustment to nuclear fuel contra-AFUDC.

1. *GSU*

The Company proposed certain post test-year adjustments to rate base to adjust certain River Bend-related items to a December 31, 1989, balance such as contra-AFUDC related to CWIP in rate base and contra-AFUDC related to nuclear fuel in process in rate base.

*57 The amount of unamortized contra-AFUDC GSU proposes to include as a reduction to rate base is $121,561,188. This amount remains unchanged if abeyed River Bend investment is removed.

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF NEW MEXICO FOR A REVISION OF ITS RETAIL ELECTRIC RATES PURSUANT TO ADVICE NOTICE NOS. 397 AND 32 (FORMER TNMP SERVICES), PUBLIC SERVICE COMPANY OF NEW MEXICO, Applicant

Case No. 10-00086-UT

New Mexico Public Regulation Commission

2011 N.M. PUC LEXIS 35

July 28, 2011, Issued

PANEL: [*1] JEROME D. BLOCK, VICE CHAIRMAN; JASON A. MARKS, COMMISSIONER; THERESA BECENTI-AGUILAR, COMMISSIONER

OPINION: FINAL ORDER PARTIALLY APPROVING CERTIFICATION OF STIPULATION

THIS MATTER comes before the New Mexico Public Regulation Commission ("Commission") upon the Certification of Stipulation ("Certification") issued June 21, 2011, by Carolyn R. Glick, the Hearing Examiner in this case, and upon the Stipulation ("Stipulation") filed on February 3, 2011, by Public Service Company of New Mexico ("PNM") and entered into by PNM and the Utility Division Staff of the New Mexico Public Regulation Commission ("Staff"), Gary King the New Mexico Attorney General ("AG"), Albuquerque Bernalillo County Water Utility Authority ("AB-CWUA"), New Mexico Industrial Energy Consumers, Inc. ("NMIEC"), Buckman Direct Diversion Board ("Buckman"), and the City Of Alamogordo ("Alamogordo").

Having considered the Certification (attached hereto as Exhibit 1) and the record in this case and being fully informed in the premises,

THE COMMISSION FINDS AND CONCLUDES:

1. Except as expressly modified herein, the Statement of the Case, Discussion, and all findings and conclusions contained in the Certification [*2] are hereby incorporated by reference as if fully set forth in this Final Order, and are ADOPTED, APPROVED, and ACCEPTED as Findings and Conclusions of the Commission.

I. UPDATED STATEMENT OF THE CASE

2. On July 1, 2011, the following parties filed Exceptions or Joint Exceptions to the Certification: Staff of the Commission's Utility Division ("Staff"), Office of the Attorney General, New Mexico Industrial Energy Consumers, City of Alamogordo, and Public Service Company of New Mexico ("PNM") (collectively, "Excepting Signatories" or "ES") filed Joint Exceptions; n1 Western Resource Advocates, Coalition for Clean Affordable Energy, and Southwest Energy Efficiency Project ("SWEEP") (collectively "WCS") jointly filed Exceptions; Interstate Renewable Energy Council ("IREC") filed its Exceptions; New Energy Economy ("NEE") filed its Exceptions; and the Commercial Energy User Coalition ("CEUC") filed its Exceptions.

n1 The ES (ES) include all of the signatories to the Stipulation, except for Albuquerque Bernalillo County Water Authority and the Buckman Direct Diversion Board. To avoid confusion, the signatories to the Stipulation are referred to collectively as the "Stipulating Parties."

Afton Facility-related rate base items allocable to the wholesale jurisdiction; (iv) the amount in column B, line 24 was multiplied by $ 12.08% and then by 44.19% to reach $ 137,697, which represents the return on the Afton transmission-associated rate base allocable to the wholesale jurisdiction; (v) amounts in column B, lines 312, 348, 370, 407 and 300 were totaled and multiplied by 7.51%, representing the wholesale allocation of Afton Facility-related expenses; and (v) amounts in column B, lines 326, 385, 267 and 268 were totaled and multiplied by 44.19%, representing the wholesale allocation of Afton transmission-associated expenses.

[*249]

c) Bernalillo Service Center

At the hearing, Commissioner Jason Marks, in his examination of Thomas Sategna, referred to a letter that he had received in July 2010 from PNM indicating that PNM was selling the Bernalillo Service Center because it was no longer needed to provide service to PNM customers. In response, Mr. Sategna testified that PNM had not sold the Bernalillo Service Center and that it is included in plant in service in the Illustrative Cost of Service. Tr. 5-12-11 at 976-77.

CEUC argues that the Bernalillo Service Center is not used and useful and should be excluded from the Illustrative Cost of Service. CEUC's Initial Post-Hearing Brief at 39.

While PNM does not admit that the Bernalillo Service Center is no longer used and useful, it did exclude the cost of the building ($ 528,000), and associated depreciation expense ($ 27,000), from a calendar year 2010 cost of service that it prepared in response to a bench request. PNM's Post-Hearing Response Brief at 33-34; PNM Exh. 27. Moreover, PNM does not defend including the Bernalillo Service Center in the Illustrative Cost of Service, but argues that removing it would not significantly impact the revenue requirement. [*250] PNM's Post-Hearing Response Brief at 34.

The Illustrative Cost of Service should be adjusted to remove the Bernalillo Service Center from plant in service along with the associated depreciation expense. The result is to decrease the revenue requirement by $ 90,782. n5

n5 ($ 528,000 x 12.08%) + $ 27,000.

d) Bonus Depreciation

Bonus depreciation refers to a greatly accelerated tax deduction for depreciation that has been permitted pursuant to several statutes signed into law in recent years to stimulate the economy. Bonus depreciation was authorized in 2008 and 2009 pursuant to the Economic Stimulus Act of 2008 and the American Recovery and Reinvestment Act of 2009. Generally, these Acts permitted a first-year depreciation tax deduction equal to 50% of the cost of qualified property. Under the American Recovery and Reinvestment Act of 2009, bonus depreciation was available for property placed in service through December 31, 2009. The Small Business Jobs Act, enacted on September 27, 2010, retroactively extended the [*251] 50% bonus depreciation to property placed in service through December 31, 2010. The Tax Relief Act, enacted on December 17, 2010, increased bonus depreciation from 50% to 100% for qualified property acquired and placed into service on or after September 9, 2010, and through December 31, 2011. In addition, it extended 50% bonus depreciation for plant placed in service after December 31, 2011, and through December 31, 2012. Higgins in Opposition to Stip. at 4; Dittmer Rebuttal at 11; Harland Rebuttal at 11-12.

The availability of accelerated tax depreciation results in a disconnect between cash taxes paid and recoverable income tax expense for financial statement reporting and ratemaking purposes ("book purposes"). The problem of properly matching income tax expense with accounting income is resolved through an accounting process known as tax normalization. Tax normalization is based on the premise that taxes recorded in the income statement for a given accounting period should be matched to the revenues and expenses recorded in the books for the same period. The term "normalization" evolved because income taxes computed on the normalization basis cause reported net income to appear [*252] "normal," in contrast to an approach based on the cash liability reported on the tax return. Robert Hahne & Gregory Aliff, Accounting for Public Utilities, § 17.01(1] (2008). The Internal Revenue Code requires regulated utilities, in determining rates using a cost of service methodology, to use the normalization method to calculate federal income tax expense related to all utility plant-related temporary differences. PNM proposed full tax normalization, for state as well as federal tax purposes, in Utility Case No. 2567. The Commission approved this methodology, which PNM has used in every subsequent rate proceeding. Harland Rebuttal at 9. In contrast to tax normalization is flow-through accounting. Under the latter method, differences between book and taxable income are ignored. It presumes that the income tax expense for the period is the same as the actual tax payable for the period. Hahne & Aliff, *supra*, § 17.01[2].

The use of accelerated depreciation gives rise to a "temporary difference," which is a difference between book income and taxable income that arises in one year and reverses in later years. A temporary difference results in no change in total tax expense payable [*253] over the life of an asset. In contrast, a "permanent difference" is a difference between book income and taxable income that never reverses. A permanent difference affects total income taxes paid, not just the timing of the payments. For example, use of the Domestic Production Activities Deduction ("DPAD") gives rise to a permanent difference. Businesses with "qualified production activities" are eligible for the DPAD. It is purely a creation of the Internal Revenue Code. For book purposes, no such deduction exists. Therefore, tax expense must be decreased by the tax savings resulting from the deduction because the expense permanently reduces taxes payable. Harland Rebuttal at 4-5. If PNM experiences a Net Operating Loss, it loses the ability to take the DPAD because the DPAD is only available to reduce current taxable income and cannot be carried forward. *Id.* at 14.

In the early years of an asset, accelerated depreciation creates larger tax deductions than book expenses. For book purposes, the tax savings are deferred, not saved. The tax savings are credited to an account called Accumulated Deferred Income Tax ("ADIT"), which is a liability account that reduces rate base. The [*254] cash savings is viewed as a cost-free source of capital to a utility. Hahne & Aliff, *supra*, § 17.01(1]. Use of accelerated depreciation can create not only an ADIT liability, but also an ADIT asset if a utility has negative taxable income as a result of taking large tax deductions created by accelerated depreciation. In this situation, the utility experiences a Net Operating Loss ("NOL"), which may be carried forward to reduce taxable income in future periods. A utility records the NOL as an ADIT asset, which increases rate base. Harland Rebuttal at 12-13.

The Illustrative Cost of Service includes the impact of bonus depreciation for qualified property placed in service between January 1, 2008 and December 31, 2009 per the American Recovery and Reinvestment Act of 2009. It does not reflect the extension of 50% bonus depreciation for property placed in service through June 30, 2010. Mr. Sategna testified that the Illustrative Cost of Service does not reflect the extension because it is based on PNM's books and records as of June 30, 2010, before enactment of the Small Business Jobs Act and the Tax Relief Act. Sategna in Support of Stip. at 31, 36.

In response to a bench request, [*255] PNM calculated that adjusting the Illustrative Cost of Service to reflect the extension of bonus depreciation to property placed in service through June 30, 2010, would create an ADIT liability in the amount of $ 9,717,100. PNM Exhibit 1, Exh. HE 6-b (PNM North plus PNM South amounts). It would also create an ADIT asset, in the form of a NOL, of $ 4,609,446. *Id.* (PNM North plus PNM South amounts). Thus, extension of bonus depreciation to property placed in service through June 30, 2010, results in a net decrease of $ 5,107,654 to retail rate base, which results in a $ 616,807 decrease to the revenue requirement. *Id.* (PNM North plus PNM South amounts). But the revenue requirement impact of extending bonus depreciation to property placed in service through June 30, 2010, does not end there. The NOL eliminates DPAD from the income tax calculation, which results in a $ 2,767,497 increase to the revenue requirement. *Id.* (PNM North plus PNM South amounts). The net impact, therefore, of adjusting the Illustrative Cost of Service to extend bonus depreciation to property placed in service through June 30, 2010, is to increase the revenue requirement by $ 2,150,689. *Id.* (PNM [*256] North plus PNM South amounts).

Kroger argues that because of the NOL, the full tax savings from bonus depreciation is not passed on to ratepayers. Tr. 5-12-11 at 814. Kroger recommends that the Commission require PNM to create a regulatory liability for the tax savings realized in 2011, 2012 and 2013 from bonus tax depreciation associated with plant included in rate base. Higgins in Opposition to Stip. at 11. Kroger witness Higgins testified that "it makes sense to calculate annually the revenue requirement reduction associated with the increase in accumulated deferred income tax associated with bonus tax depreciation as this benefit is realized by the Company." *Id.* Mr. Higgins recommends that the regulatory liability accrue a carrying charge equal to PNM's approved rate of return and be credited to customers at a future date. *Id.* at 12. He states that the regulatory liability would capture benefits in the intervening period between rate cases that would otherwise be lost to ratepayers. Tr. 5-12-11 at 815-16.

Kroger's recommendation should be rejected. Generally, events occurring between test periods in rate cases are ignored. Mr. Higgins acknowledged himself that "there are [*257] things that happen in intervening periods all the time that do not get captured going forward unless there is a special deferred accounting mechanism that gets established." Tr. 5-12-11 at 817. Moreover, Kroger's proposal is flawed because it ignores the impact of the loss of the DPAD resulting from tax savings from accelerated depreciation. Mr. Higgins recognized that PNM's calculation shows a net increase in the revenue requirement from extending bonus depreciation to property placed in service through June 30, 2010. *Id.*

at 827. However, he stated that his proposal does not incorporate a DPAD impact because no evidence shows that tax savings would eliminate the DPAD in 2011 and later years. He suggested that elimination of the DPAD in future years is an unknown, but acknowledged that PNM has experienced NOLs in 2008 through 2010. *Id.* at 829-35.

CEUC recommends incorporating the effects of bonus depreciation resulting from the Small Business Jobs Act and the Tax Relief Act in the Illustrative Cost of Service. Mr. Kumar testified that "there is no reason not to include this known and measurable change which became effective in 2010." Kumar in Opposition to Stip. at 20. However, [*258] CEUC objects to offsetting the ADIT liability arising from bonus depreciation by an ADIT asset. Mr. Kumar testified that the NOL claimed by PNM is based on the consolidated income tax return of PNM Resources, a holding company, while the income tax allowance in the Illustrative Cost of Service is derived from PNM-only data. Mr. Kumar alleges that PNM has sufficient income to take full advantage of bonus depreciation in 2010. *Id.* at 21.

The revenue requirement in the Illustrative Cost of Service should be adjusted to incorporate the effects of bonus depreciation for property placed in service through June 30, 2010. The adjustment should reflect not only the ADIT liability created through using bonus depreciation but the ADIT asset created as a result of the NOL and the loss of the DPAD. Mr. Kumar's objection to recognizing the NOL is based on his erroneous reliance on book taxable income as the appropriate taxable income, PNM's Post-Hearing Response Brief at 26, and is contrary to evidence that PNM, on a stand-alone basis, incurred NOLs in 2008 through 2010, PNM Exh. 1, Exh. HE 6-b at 4. The net impact is to increase the revenue requirement by $ 2,150,689.

e) ADIT Assets

ADIT [*259] can be an addition to rate base as well as a reduction. An ADIT addition occurs when the cash tax payable exceeds the tax expense recorded for book purposes. In such a case, an ADIT asset, rather than a liability, is created. Harland Rebuttal at 8.

CEUC objects to PNM's inclusion in rate base of the following ADIT assets: LXP Policy-Related ADIT ($ 957,131); Capitalized Interest-Related ADIT ($ 19,832,262); CIAC-Related ADIT ($ 42,615,557); Afton Write-down-Related ADIT ($ 7,914,712); and EIP Refinancing Costs-Related ADIT ($ 32,415). Kumar in Opposition to Stip. at 14-19. n6 In general, Mr. Kumar asserts that Internal Revenue Service regulations require reduction of rate base by an ADIT liability, but that he is not aware of any regulation that requires addition to rate base by an ADIT asset. *Id.* at 15. Mr. Kumar also makes specific arguments for excluding specific ADIT assets. *Id.* at 16-19.

n6 Amounts for each ADIT asset are from Exh. TGS-2-Stip. to Sategna in Support of Stip. (PNM North and South amounts, combined).

[*260]

Contrary to Mr. Kumar's belief, the Internal Revenue Code and Internal Revenue Service regulations do require rate base to be increased by ADIT assets. The requirement arises from the requirements of the Code that regulated utilities use, for purposes of determining rates using a cost of service methodology, the normalization method to calculate federal income tax expense related to all utility plant-related temporary differences. Higgins Rebuttal at 25. Thus, Mr. Kumar's general argument supporting his exclusion of ADIT assets should be rejected. Mr. Kumar's specific arguments are addressed below.

(1) CIAC-Related ADIT

Contributions in aid of construction ("CIAC") are funds advanced by a customer for construction to serve the customer in a project that is not economically feasible. Case No. 07-00394-UT, Recommended Decision at 53 (7-16-08). For book purposes, when PNM receives CIAC from a customer, it reduces the basis of the asset by the amount of CIAC received. The Internal Revenue Service requires PNM to record the receipt of CIAC as taxable income and pay tax on the CIAC when received. Because PNM pays tax up front on receipt of the CIAC and receives reversing deductions in future [*261] periods, an ADIT asset is recorded. PNM does not collect income tax from customers who pay CIAC. Harland Rebuttal at 29-30.

CEUC recommends excluding CIAC-Related ADIT from rate base because it alleges that customers other than the customer paying the CIAC do not benefit from the facility and should not be required to "pay for the taxes associated with CIAC." Kumar in Opposition to Stip. at 17.

117 FERC ¶ 61, 077

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

OPINION NO. 486

Kern River Gas Transmission Company **Docket No. RP04-274-000**

OPINION AND ORDER ON INITIAL DECISION

(Issued October 19, 2006)

tax allowance of $7,184,644.[327] The ALJ rejected Kern River's request for all income taxes without distinguishing between Federal income taxes and state income taxes.[328] Kern River argues that the ALJ erred by rejecting Kern River's request for state income tax allowances for the same reasons involved in federal income tax allowances.

223. The Commission concludes that Kern River is entitled to a state income tax allowance consistent with Commission policy. The Commission's policy is that it is appropriate to provide an income tax allowance for partnerships or similar pass-through entities that hold interests in a regulated public utility. Kern River presented evidence that it has paid state income taxes.[329] No specific evidence was offered by any party to show why Kern River should be denied a state income tax allowance. Accordingly, that portion of the ALJ's decision recommending denial of state income taxes in Kern River's cost of service is reversed.

B. Tax Net Operating Loss

224. Kern River claims it is entitled to reflect a $329 million tax net operating loss in its rate base, which produces an increased return and income tax allowances. Based on Kern River's claimed NOL, Kern River included a $112 million tax loss in Account No. 190, which it applied as an offset to accumulated deferred income taxes (ADIT) recorded in Account No. 282, [330] which results in a lower decrease in the rate base due to ADIT than would otherwise be the case. A tax NOL occurs when the allowable tax deductions exceed taxable income for a taxable year.[331] In 2003, Kern River's depreciation for tax

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[327] Kern River Statement A, page 1, 45 day update filing, Item A by Reference.

[328] Initial Decision, at P 445-46.

[329] Ex. KR-71.

[330] ADIT accounts reflect the timing differences between a company's revenue and expense and booked for income tax purposes. Timing differences, multiplied by appropriate Federal and state tax rates, represent ADIT and a rate base reduction. Ex. S-1 at 6.

[331] Kern River's witness Jeffery Valentine testified that Commission regulation at 18 C.F.R. § 154.305 requires tax normalization, which is calculating the total income tax provision as though the taxable income in the tax return were the same as book income. He testified that tax laws passed in 2002 and 2003 significantly affected the calculation of tax depreciation. The Job Creation and Worker Assistance Act of 2002 and the Jobs and Growth Tax Relief Act of 2003 allow taxpayers to claim additional ("bonus") tax depreciation for the first year in service. *See* Job Creation and Worker Assistance Act of

(footnote continued)

purposes, based on $1.2 billion in new plant construction, produced a net operating loss of $329 million.[332] Kern River asserts that it calculated its taxable income and tax NOL consistent with the Commission's long-standing "stand-alone" income tax policy. Kern River notes that participants, who contest the tax NOL and want to disregard the effects of the tax NOL in Account No. 190, also want to continue to recognize the ADIT in rates in Account No. 282, associated with the bonus depreciation that precipitated the tax NOL. It follows, according to Kern River, that if the tax NOL is not reflected in rates, the related deferred income taxes from bonus depreciation likewise should be disregarded.[333] Kern River further argued that Staff's claim that the effect of tax NOL on ADIT is unrelated to the jurisdictional cost-of-service is contradicted by Staff's recognition of ADIT related to the bonus depreciation that led to the NOL. Staff's view, according to Kern River, is not consistent with required income tax normalization.[334] The ALJ concluded that Kern River carried its burden of proving that it is entitled to claim deferred income taxes related to tax NOL in its rate base. The ALJ held that the Commission's regulation at 18 C.F.R. §154.305 allows for Account No. 190 items to be included in the cost-of-service and Kern River presented credible evidence that it expected to use the tax NOL within the statutory carry forward period of twenty years.

225. The Staff argues that deferred income taxes related to tax NOL must be removed from rate base in order to conform to Commission policy.[335] The Staff argues that the claimed change in ADIT resulting from the tax NOL must be removed from rate base because such a proposal does not comply with the Commission's regulations at 18 C.F.R. §154.305 (c) (2), which requires that to be recognized in rates, deferred income taxes must be related to the jurisdictional cost of service.[336] Staff asserts that in the test year cost of service methodology, there can be no operating loss allowed or any related deferred income tax in Account No. 190 and that the ultimate gains or losses produced by the rates are not includible in the cost of service, even though booked in accordance with

2002 (JCWAA), Public Law 107–147 (116 Stat. 21) and Jobs and Growth Tax Relief Reconciliation Act of 2003, P.L. 108-27, (117 Stat. 752). Ex. KR-15 at 5-18.

[332] Ex. KR-15 at 10, 17; KR-66 at 13.

[333] Kern River Initial Brief at 26-27.

[334] *Id.* at 25-26 and Kern River Reply Brief at 25.

[335] Staff Initial Brief at 36.

[336] Ex. S-1 at 6-7.

accepted accounting practices.[337] Staff therefore asserts that all deferred income taxes related to tax NOL should be removed from Account No. 190.[338]

226. Calpine argued that Kern River's treatment of the acquisition-related ADIT credit elimination and the treatment of the ADIT credit produced by bonus depreciation, does not support Kern River's claim to a tax NOL. Calpine argued that Kern River's claimed tax NOL and related ADIT adjustment should be rejected because, as a matter of tax law, Kern River cannot claim a tax-related NOL as Kern River has no Federal income tax liability.[339] As such, only Kern River's parent Mid American can accrue a tax NOL and can carry forward the balance to offset future tax liabilities because otherwise the stand alone method would be improperly applied here. Calpine thus concludes that the ALJ erroneously held that bonus depreciation should be recognized in rates, and for that reason the NOL must be included in the tax calculation.

227. On reply, Kern River argues that its treatment of bonus tax effects complies fully with generally accepted accounting principles, Commission guidelines and tax normalization regulations. Kern River also argues that it properly recorded its tax NOL in Account No. 190 as prescribed by the Commission's regulations. Kern River argues that Calpine's argument is inconsistent with stand-alone principles of calculating tax liabilities of a regulated entity within a consolidated corporate structure. Kern River states that Staff recognizes the tax NOL account and comports with the guidance provided by the chief accountant. Kern River responds to Staff arguments that tax NOL is not related to jurisdictional cost of service; however, all rate base and cost of service components that generate tax NOL are part of Kern River's cost of service and Staff's argument is contrary to longstanding tax normalization policy. If Staff's argument were accepted, it would preclude recognition of all tax timing differences. Kern River also argues that Staff's position is inconsistent in recognizing ADIT generated through bonus depreciation but opposing offsetting ADIT reduction attributible to tax NOL. Failure to credit the offset would result in a reduction in the rate base through ADIT in years in which Kern River in fact had no tax savings to offset through the ADIT account.

228. The Commission affirms the ALJ. As has been discussed, Kern River is taxed as a corporation, not a partnership, and the use of the stand-alone method is correct. Under this method differences in timing of depreciation, and the tax consequences that follow, are adjusted through normalization. The differences in tax timing can be caused by two different types of factors. If tax depreciation exceeds straight line regulatory

[337] *See* 18 C.F.R. § 154.305(c) (2) (2006).

[338] Ex. S-1 at 6.

[339] Calpine Initial Brief at 21-25.

depreciation, the regulated entity has a tax savings because taxable income for IRS purposes is less than regulatory income. However, the tax allowance embedded in the rate generates cash flow at the same rate whether or not the taxes are actually paid. If the taxes are deferred, the cash that is not paid out in taxes provides the regulated entity with an opportunity for an additional return by investing the cash it was able to retain. This is sometimes called a "tax free" loan to the entity, although in fact it represents an investment opportunity. Normalization requires the regulated entity to reduce its rate base by the amount of the taxes so deferred. This reduces the return component of the rate and passes the savings back to the rate payers. The required reduction is recorded in Account No. 282, and as noted reduces the rate base. Over time the regulatory depreciation comes to exceed IRS tax depreciation and the reverse occurs. More income results under IRS tax accounting because IRS based depreciation is lower than regulatory depreciation and results in more income. The ADIT total in Account No. 282 begins to decline and fewer dollars are deducted from the rate base, and return, and the related taxes, increase.

229. There is a second type of timing that can have the opposite effect. It is possible that some accounting entries will decrease expenses or increase income for IRS purposes faster than would be the case for accounting purposes. In this case the cash flow from the tax allowance embedded in the regulated entity's rates is less than the income tax payments that are generated by the higher income. When the regulated entity pays for an expense earlier than would be done under the Commission's regulatory accounting system, it is in essence committing more funds to the business. The difference is therefore capitalized and added to the rate base. The difference in the timing that results is capitalized and added to the rate base to allow a somewhat higher return on the additional funds that have been committed to the enterprise. As the accounting entries for these expenses are entered (usually allowance for funds used during construction), the difference in timing is reversed, the short term addition to the rate base decreases, and return drops. This timing difference is reflected as an ADIT debit, or regulatory asset, in Account No. 190.

230. In the instant case the NOL was properly included in Account No. 190. The large depreciation deduction for the "bonus" depreciation was properly reflected as a credit in Account No. 282 and served to reduce the rate base to reflect the difference in timing previously described. However, the impact of this deduction was so great that it exceeded the taxable cash that would have been generated under the straight line regulatory method. Thus, Kern River was not able to use the full extent of the deduction in the first year it was available. However, as discussed, the full accelerated depreciation amount is included in the credit ADIT in Account No. 282. Without a corresponding debit in Account No. 190, Kern River's rate base would be reduced even though it did not achieve the tax savings, and additional cash flow, that a credit entry in Account No. 282 is intended to offset. Therefore the NOL is carried forward as a regulatory asset in future years and is reduced as the tax savings actually accrue to Kern River. Offsetting the

NOL against the total ADIT reduction in the first year assures that the rate base is reduced only as the company actually obtains the additional cash flows, and hence the return, that the ADIT tax methodology captures for the ratepayer.

231. The NOL generated by the 2003 expansion and the related depreciation bonus is so large that it dramatically reduces the amount of the ADIT credit reflected in Kern River's 2004 test year, and hence, the related reduction to its rate base. This means that rates would increase accordingly because the overall rate base is higher, and given a certain percentage allowed return, more cash flow is required to achieve the allowed return. Absent a levelized rate design, this situation would continue until the pipeline's next rate case. As such, the rate impact of the NOL in the test year would continue even though the NOL declined sharply over four or five years, thus increasing actual return to the pipeline as the corresponding increase in ADIT credit (Account No. 282) would not be reflected in the pipeline's rates. However, this difficulty is not an issue here. The levelized method starts with a test year, in this case 2004, and then adjusts the pipeline's cost-of-service for each year to reflect changes in depreciation and return in future years to achieve a levelized rate. ADIT is directly driven by the depreciation accounts, the amount of return, and the tax allowance provided for the equity return component of the rate. As such, both factors are an integral part of the iterative, forward looking approach used to design Kern River's levelized rates. As Kern River works off the NOL, this will be reflected in the future years and the rates adjusted accordingly.

C. Allocation of ADIT

232. The instant case presents two ADIT issues that do not normally arise in gas pipeline rate cases. The first is caused by the pre-payment of the credit ADIT account as a result of the Williams Companies' sale of Kern River to Mid American in 2002. The second relates to the large ADIT account changes just described that resulted from the construction of the 2003 expansion and the use of the "bonus" deprecation. In each case the issue arises because Kern River has completed a number of expansions, each with a different rate base, composite depreciation cost, and a resulting ADIT account that is tied to the depreciation account for each expansion. These are embedded in the rates contained in the contracts for the various facilities, with adjustments as appropriate to reflect past settlements and the rolling-in of some of the historical facilities.

i. The Acquisition-Related ADIT

233. As noted, Kern River was purchased by Mid American from the Williams Companies in 2002. As part of the purchase of assets of Kern River, the then-existing accumulated deferred Federal and state income taxes (ADIT) of $136.9 million were

04:01 PM AUG 31 2012 PSC EXEC SEC DIV

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

At a session of the PUBLIC SERVICE COMMISSION OF WEST VIRGINIA in the City of Charleston on the ____ day of _______, 2012.

CASE NO. 11-1627-G-42T

MOUNTAINEER GAS COMPANY

Rule 42T Tariff Filing to Increase
Rates and Charges

COMPANY'S PROPOSED COMMISSION ORDER*

Respectfully submitted this 31st day of August, 2012.

MOUNTAINEER GAS COMPANY
By Counsel

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* Mountaineer Gas Company submits this proposed order as an appropriate, comprehensive decision of the Commission, without prejudice to its positions on any particular issue. See Tr. III at 70-71. In compromising any position for purposes of this Proposed Order, the Company does not waive its right to advocate for a different result on that issue in this or subsequent proceedings.

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INTRODUCTION

[to be completed by Commission]

PROCEDURAL BACKGROUND

I. Initial Rate Case Filing

The Company filed this general rate case on November 4, 2011 reflecting increased operating revenues of $12,187,218, or approximately 4.9% annually for furnishing gas service to approximately 218,000 customers. At the evidentiary hearing, the Company revised its position to seek a $8,691,224 net revenue increase which is equivalent to a gross revenue increase of $10,527,552. Co. Exs. SFK-R, at 5, SFK-2. By Commission Order issued November 29, 2011, the Commission suspended the proposed rates and charges until 12:01 a.m., August 31, 2012.

Resale customers of Mountaineer include Canaan Valley Gas Company, Consumers Gas Utility Company, Megan Oil and Gas Company, and Southern Public Service Company. Mountaineer proposed a 3.63% increase for resale customers.

With the initial November 4, 2011 filing, the Company filed a Motion for Limited Waiver in which the Company requested that it be permitted to complete individual mailings to each of its customers by bill insert.

II. Procedural History of Case No. 11-1627-G-42T

On November 8, 2011, the Consumer Advocate Division (CAD) filed a petition to intervene in this proceeding, asserting that the Company's application constitutes a major proceeding having the potential to adversely impact the Company's rate paying customers.

On November 18, 2011, the Company filed additional materials in support of its November 4, 2011 filing.

On November 29, 2011, the Commission named the Company as a respondent to the proceeding and suspended the use of rates and charges filed by the Company until 12:01 a.m. August 31, 2012, unless otherwise ordered by the Commission. The Commission also granted CAD's petition to intervene. The Commission granted the Company's request for a limited waiver of the fifteen-day individual notice requirements of Tariff Rule 23. The Company was allowed to include customers' individual notice in its next monthly bills. The Company was ordered to file its affidavits of publication and notice as soon as they are available. Finally, the Commission established a procedural schedule and ordered that this matter be called for an evidentiary hearing on May 9, 2012 and continuing as needed through May 11, 2012.

On December 1, 2011, the Staff filed its Initial Joint Staff Memorandum. In the Initial Joint Staff Memorandum, Staff stated it had no objection to the Commission's procedural schedule and that Staff stated that it will continue to investigate and will submit a final recommendation in a timely manner consistent with the procedural schedule.

On December 1, 2011, the Independent Oil and Gas Association of West Virginia, Inc. (IOGA) filed its petition to intervene, asserting it has over 600 members and the Company purchases or transports natural gas produced by IOGA members. The Commission granted intervenor status to the IOGA on February 22, 2012.

On December 23, 2011, the Company filed the direct testimony of Tom M. Taylor, Scott F. Klemm, C. David Lokant, William E. Avera, and Dale P. Lee.

On January 10, 2012, CAD filed a motion to dismiss the application, arguing that the prefiled direct testimony of Mr. Klemm was insufficient in several respects.

On January 18, 2012, Staff filed a motion in support of CAD's motion. Staff adopted all of the CAD's positions, and also asserted that, because the Company's Rule 42 financial exhibit was deficient in several respects, Staff's ability to fully investigate the tariff filing was fundamentally impaired.

On January 19, 2012, Walter Yates requested to intervene as a customer of the Company.

On January 27, 2012, the Company responded to Mr. Yates' petition and argued that Mr. Yates did not allege any interest except as a customer of Mountaineer, and that his interests were adequately represented by the CAD.

On January 20, 2012, the Company filed a response to the CAD motion to dismiss and provided several replacement schedules to the Rule 42 exhibit.

On January 25, 2012, CAD filed a reply arguing that the Company's response contained new evidence and representations by the Company in a pleading by counsel. CAD asserted the Company bears the burden of proof in this rate proceeding and that the Company cannot meet that burden simply by providing numbers with sparse supporting testimony.

On January 30, 2012, the Company filed a response to the Staff motion to dismiss and asserted that Staff complained about formatting discrepancies and insignificant omissions. The Company argued that dismissal or tolling would impose a substantial financial penalty upon the Company and that the items challenged by Staff could not materially hinder Staff's review of the filing.

On February 10, 2012, Staff filed a reply to the Company's response arguing that none of the information required in a Rule 42 financial exhibit is insignificant. Staff also alleged additional deficiencies in the Company's Rule 42 exhibit.

On February 22, 2012, the Commission granted in part the CAD and Staff motions to dismiss and ordered that the Company may request a tolling of the statutory period to process the tariff filing and that, if a tolling is granted, an amended Rule 42 exhibit and amended direct testimony must be filed by the Company. The Commission also granted the IOGA petition to intervene and denied Mr. Yates' petition to intervene.

On February 29, 2012, the Company filed a motion to toll the statutory time limit for 67 days.

On March 13, 2012, the Company filed the amended direct testimony for Scott F. Klemm, an amended Rule 42 financial exhibit, confidential and non-confidential supporting documents and work papers and a motion for limited waiver of the sequential numbering requirement.

On March 27, 2012, CAD filed a letter advising the Commission of the agreement of all parties to a proposed schedule.

On April 20, 2012, the Commission granted the Company's motion to toll, revised the previously established procedural schedule, and ordered that this matter be called for an evidentiary hearing on July 17, 2012 and continuing as needed through July 19, 2012. The Company was ordered to publish notice of the procedural schedule one time in newspapers published and of general circulation in each of the counties in which Mountaineer provides service, and to submit its affidavits of publication. The Commission also granted the Company's limited waiver of sequential number requirement of Tariff Rule 19.9.

On June 19, 2012, the Company filed its affidavits of publication of the procedural schedule for the 49 counties in which the Company provides service.

On June 21, 2012, CAD filed the direct testimony of Byron L. Harris, Deanna Lynne White, and Ralph S. Smith. A confidential version was also filed for Ms. White.

On June 21, 2012, Staff filed the direct testimony of Dixie L. Kellmeyer, Brian Dworsky, and Edwin Oxley, and Staff's Rule 42 Exhibit. A confidential version was also filed for Mr. Oxley.

On June 21, 2012, IOGA filed a notice that it does not intend to present direct testimony.

On June 22, 2012, exhibits for Mr. Harris' direct testimony were filed.

On June 25, 2012, a public comment hearing was held in Charleston, and the Commission received four comments from the public.

On July 5, 2012, a public comment hearing was held in Huntington, and the Commission received three comments from the public.

On July 6, 2012, a public comment hearing was held in Wheeling, and the Commission received one comment.

On July 9, 2012, the Company filed the rebuttal testimony of Tom M. Taylor, Scott F. Klemm, William E. Avera, and Dale P. Lee.

On July 11, 2012, Staff filed its opposition to the Company's request for confidential treatment of certain materials.

On July 12, 2012, a public comment hearing was held in Beckley, and the Commission received four comments.

On July 13, 2012, the Company filed the revised rebuttal testimony of Tom M. Taylor and Dale P. Lee.

On July 13, 2012, the Company filed its motion for protective order and response to Staff's July 11, 2012 filing. The Company its motion and response on July 16, 2012.

Beginning on Tuesday, July 17, 2012 and continuing through Thursday, July 19, 2012, an evidentiary hearing was held in this matter. During the evidentiary hearing, the parties were present and represented as follows: the Company by John Philip Melick, Esq. and Christopher L. Callas, Esq.; the Staff by Christopher L. Howard, Esq. and L. R. Sammons, III, Esq.; CAD by Tom White, Esq.; and IOGA by Britt A. Freund, Esq.

At the conclusion of the evidentiary hearing on July 19, 2012, the Commission established a briefing schedule, with initial briefs and/or proposed orders due on August 31, 2012 and reply briefs due on September 17, 2012.

On August 1, 2012, Staff filed a public version of Post-Hearing Exhibit 1.

On August 31, 2012, the Company filed a proposed order and initial brief, and the Staff and CAD filed ____________________.

On September 17, 2012, the Company, Staff and CAD filed their respective reply briefs.

TESTIMONY AND DISCUSSION

The parties have filed extensive direct and rebuttal testimony. In addition, the Commission conducted evidentiary hearings over three days and amassed a transcript of nearly 500 pages. The Commission has reviewed all of that material in connection with the drafting and preparation of this Order, but will not provide a detailed summary of all that testimony; rather, the Order will include references to the relevant portions of that testimony and evidence in the sections of this Order that address the issues in the case.

I. Capital Structure and Costs of Capital

Capital Structure

The capital structure of a utility is comprised of various types and sources of capital supporting its net utility assets. A utility capital structure will normally reflect the amount of capital acquired through borrowing, issuance of stock, retained earnings and other paid in equity capital. Capital structure for purposes of cost of capital calculations normally divides debt into component parts, including short-term and long-term debt, and equity capital into common equity and preferred equity. The measurement of the ratio of individual capital components to the total establishes the relationship between the various capital sources for subsequent use in determining a composite weighted cost of capital. Comm'n Order at 10, West Virginia-American Water Company, Case No. 10-0920-W-42T (April 18, 2011). The cost rate for each type of capital is multiplied by the percentage that component is of the total capital structure to derive a weighted cost of capital for each component. The weighted costs are then added to reach a total cost of capital that is generally regarded as the overall ROR a utility should be authorized to earn.

The Commission uses a variety of techniques, and its judgment and experience, to determine a reasonable capital structure. Depending on economic or other circumstances, the Commission may review various historic, projected and hypothetical capital structures. The aim of the Commission is to determine a capital structure that (i) is reasonable, (ii) fairly balances the interests of current and future customers, the general interests of the State's economy and the interests of the utilities and (iii) produces the lowest reasonable overall revenue requirements that maintain financial integrity and flexibility for the utility. Comm'n Order at 4, Black Diamond Power Company, Case No. 12-0064-E-42T (August 10, 2012); Comm'n Order at 10-11, West Virginia-American Water Company, Case No. 10-0920-W-42T (April 18, 2011); Comm'n Order at 17, West Virginia Water Company, Case No. 84-008-W-42T (January 25, 1985); W.Va. Code §24-1-1.

CAD agreed with the Company's filed capital structure of $191.2 million, but Staff has proposed different debt and equity levels and, as a result, a different structure, with lower levels of common equity and short-term debt:

	Company	CAD	Staff
Long-term Debt	$ 90,000,000	$ 90,000,000	$ 90,000,000
Short-term Debt	15,744,813	15,744,813	13,564,428
Total Debt	$ 105,744,813	$ 105,744,813	$ 103,564,428
Common Equity	85,533,709	85,533,709	80,750,114
	$ 191,278,522	$ 191,278,522	$ 184,314,542

The Company believes Staff's capital structure understates both equity and short-term debt levels, and to that extent does not recognize the level of capital the Company employs to support its operations and serve its customers. Co. Ex. SFK-R, at 5.

The Company submitted testimony objecting to Staff's equity recommendation of $80.7 million, the equity balance at September 30, 2011. While it was the end of the test year, it was also when common equity was at its lowest level for natural gas utilities in general, since they tend to lose money during the summer months due to the seasonal nature of the business and resulting low summertime sales volumes. According to Mr. Klemm, Mr. Dworsky's proposed balance does not fairly represent the equity balance during the test year, or prospectively. Co. Ex. SFK-R, at 5-6. Accordingly, the Company believes the 13-month average balance during the test year is the most appropriate method to determine common equity in the capital structure and has the added attribute of consistency with the methodology used by all the parties in the determination of rate base. Co. Ex. SFK-R, at 6. At the hearing, Mr. Dworsky acknowledged that the Company's equity balance was lower during the summer, and that Staff had failed to account for this in its recommended capital structure. Tr. III at 51-53 (Dworsky).

Staff's recommended capital structure includes the average daily balance of short-term debt outstanding during the test year, including the average amount per month of over-recovery during the test year, as well as the amortization of debt costs in the amount of $383,890. Staff recommended the cost of short-term debt be reflected as 6.74%. Staff Ex. BD-D, at 3-4.

The Company used a 13-month average for both capital structure and rate base amounts. According to Mr. Klemm, it is necessary to include the balance of September 30, 2010 since the Company had that excess of cash to reduce its daily short-term borrowings in October 2010. Since Staff has excluded the September 20, 2010 balance, Staff failed to recognize that the Company's short-term borrowing were lower in October 2010 due to this over-recovery. Co. Ex. SFK-R, at 7.

Staff's recommended capital structure includes the cost of long-term debt at 7.59%. Staff determined its recommendation based on the interest payments made by the Company. The Company interest expense on its Series B Note was $5,306,000, equating to an interest rate of 7.58%. The Company interest expense on its $20,000,000 Series A Note is $1,019,000. Also included in the cost rate is the amortization of the loss on reacquired debt of $334,602 and the amortization of debt expense of $166,992. The weighted cost of long term debt equates to 7.59%. Staff Ex. BD-D, at 4.

In the most recent rate cases involving West Virginia-American Water ("WVAWC") and Appalachian Power Company and Wheeling Power Company (together, "APCo"), the Commission treated unamortized debt costs as a reduction in the utility's long-term debt balance for capital structure purposes.[1] To be consistent with these decisions, the Company proposes similar treatment. The impact on rates is essentially the same whether such costs are included in

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1 *See* West Virginia-American Water Company, Case No. 10-0920-W-42T (Commission Order dated April 18 2011) ("WVAWC 2010 Rate Order") at 11-14; and Appalachian Power Company and Wheeling Power Company, Case No. 10-0699-E-42T (Commission Order dated March 30, 2011) ("APCo 2010 Rate Order") at 26-28.

rate base or deducted in the capital structure. Accordingly, the Company now proposes that the long-term debt component of the Company's capital structure be revised to $84,359,577. Co. Ex. SFK-R, at 8.

The Commission will discuss the cost rates recommended by the parties in the discussion of the cost of capital below. With regard to the capital structure, or percentage of each capital component to total capital, we will adopt the Company's and CAD's proposed capital structure percentages for purposes of calculating the overall cost of capital in this case. Mr. Dworsky's approach serves to understate both the Company's total capitalization and the level of equity actually invested in the Company's provision of public service.

Cost of Debt

CAD agreed with the Company's filed interest rates, but Staff has proposed slightly different rates. A summary of the positions are as follows:

	Company	CAD	Staff
Long-term Debt	7.9181%	7.9181%	7.5851%
Short-term Debt	6.3523%	6.3523%	6.7442%

NOTE: Interest rates based on $90,000,000 on long-term debt

Co. Ex. SFK-R, at 8

The difference is solely due to the methodology the Staff used to determine its average short term debt balance. Staff based its short-term debt balance on a 12-month average relating to over-recovery of gas costs, whereas the Company used a 13-month average relating to over-recovery of gas costs. Co. Ex. SFK-R, at 9.

Cost of Equity

Utility rates should allow a public utility the opportunity to earn a level of revenues sufficient to attract capital in the competitive money market, balanced with the interests of the consuming public in receiving fair and reasonable rates. Bluefield Water Works and Improvement Company v. Public Service Commission, 320 U.S. 679 (1923); Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591, 64 S.Ct. 281 (1944); Permian Basin Area Rate Cases, 390 U.S. 747, 88 S.Ct. 1344 (1968); Monongahela Power Company v. Public Service Commission, 276 S.E.2d 179 (W. Va. 1981). The Commission attempts to provide privately-owned utilities with a company-specific return on equity (ROE) based on empirical studies of returns in the market while balancing the interests of ratepayers in receiving fair and reasonable rates. Comm'n Order at 5, Black Diamond Power Company, Case No. 12-0064-E-42T (August 10, 2012); Comm'n Order at 15, West Virginia-American Water Co., Case Number 10-0920-W-42T (Apr. 18, 2011). The Commission employs the various ROE calculations as a guide, but relies primarily on its judgment to determine investor expectations. Id.

The Commission has, on numerous occasions, stated that recommendations of expert witnesses on cost of common equity are useful as guides, but that the determination of an appropriate cost of common equity for a utility must rest principally with the best judgment of the Commission. See, e.g., Comm'n Order at 18, West Virginia-American Water Company, Case No. 10-0920-W-42T (April 18, 2011). We recently stated that the data which underlie the recommendations of ROE witnesses must be evaluated and judged carefully and practically, based on our practical judgment of the methods used by the expert witnesses, the data presented by those witnesses and the current market conditions. Id. There is no absolute, correct answer with regard to ROE even though the determination of a reasonable ROE involves calculations on a mass of data presented by expert witnesses. Id. We have always held that the fair ROE result lies within a zone of reasonableness that is framed by the evidence, including the testimony and exhibits of the various witnesses. Id. The final determination of a ROE, however, rests with the Commission based on our judgment and the application of regulatory principles and policies that have been used by this Commission and previous Commissions. Id.

The Company requested an 11.25% return on equity, based on Dr. Avera's analysis and recommendations. Co. Ex. WEA-D. Dr. Avera first provided fundamental analyses of the Company, the utility industry, and capital market conditions. Id. at 6-14. He then estimated the cost of capital by means of applied economic standards, comparable risk groups, discounted cash flow (DCF) analyses, the capital asset pricing model (CAPM), the risk premium method, and an expected earnings approach. Id. at 14-49. Dr. Avera then summarized his quantitative results:

TABLE WEA-7
SUMMARY OF QUANTITATIVE RESULTS

	Gas Utility	Combination Utility	Non-Utility
DCF			
Dividend Growth	8.9%	9.8%	10.6%
Earnings Growth			
Value Line	10.1%	10.3%	11.7%
IBES	9.4%	10.3%	11.7%
Zacks	8.2%	9.6%	12.0%
br + sv	10.0%	9.1%	11.8%
CAPM – Current Bond Yield			
Unadjusted	10.2%	10.8%	
Size Adjusted	12.0%	11.6%	
CAPM – Projected Bond Yield			
Unadjusted	10.7%	11.2%	
Size Adjusted	12.5%	12.0%	
Utility Risk Premium			
Current Bond Yields	10.2%	10.2%	
Projected Bond Yields	11.1%	11.3%	
Expected Earnings			
Value Line	10.5%	10.5%	
Utility Proxy Group	11.5%	10.6%	

Id. at 49-50. Dr. Avera next addressed the implications of these quantitative analyses for the Company's financial integrity. Id. at 50-53. He also addressed the Company's relative risks in respect of such things as credit rating, the implications of its size relative to other firms, weather, regulation, declining usage, and capital structure. Id. at 54-61. On the basis of all of his quantitative and other analyses, Dr. Avera stated that, in his opinion, a ROE of 11.25% represents a fair and reasonable basis on which to calculate the Company's revenue requirement. Id. at 62-63.

Staff recommended the cost of equity capital for the Company be set at 7.70%. Staff Ex. BD-D at 3 If the Company is allowed to earn an equity return of 7.70% on a capital structure consisting of 7.36% short-term debt, 48.83% long-term debt, and 43.1% common equity, the overall cost of capital would be 7.57%. Such an allowance would allow the Company an opportunity to produce pre-tax interest coverage of 2.53 times current interest payments. Staff Ex. BD-D, at 13. Mr. Dworsky criticized only Dr. Avera's "inclusion of an additional size adjustment" as an "additional premium" that is "unreasonable," asserting that "[r]emoving these adders would decrease the Company's requested return on equity." Staff Ex. BD-D, at 13.

CAD's filing incorporates two scenarios, the first using a 9.0% ROE and the second using a 9.50% ROE. CAD Ex. BLH-D1, at 2. Neither of these ROEs was supported by analysis or testimony.

In his rebuttal testimony, Dr. Avera asserted that if various flaws, errors, and omissions in Mr. Dworsky's applications of the DCF and CAPM were properly considered, then the average ROE for his proxy group would be 10.61%. Co. Ex. WEA-R, at 2, 11-23. He also criticized Mr. Dworsky's failure to assess his recommendation for reasonableness, or for satisfying regulatory standards and financial benchmarks. Co. Ex. WEA-R, at 3-10. According to Dr. Avera, Mr. Dworsky's reliance on interest coverage as a test for a reasonable ROE disregards these more pertinent fundamentals, which focus on equity, not debt. Co. Ex. WEA-R, at 11.

At the evidentiary hearing, Dr. Avera indicated that his recommendation was consistent with recent financial and other economic reports, as "Mountaineer is a risky, small, highly leveraged, junk bond rate gas utility." Tr. III at 8-13, 24-27, 41-42, 46-47 (Avera). He also explained that the only firm size adjustment he made was in his CAPM analyses, and that he had not included any risk premium or other Company-specific "adders" of the type recently rejected by the Commission. Tr. III at 19-22 (Avera). Dr. Avera addressed why Mr. Dworsky's use of historic growth rates overstated the significance of those data in assessing the future performance that is the focus of any investment; analysts' projections have already taken historic performance into account. Tr. III at 27-28 (Avera). He also discussed the impact of weather normalization on the cost of capital. Tr. III at 44-46 (Avera).

During his cross-examination, Mr. Dworsky could not reconcile his recommendation with the higher ROEs determined for comparable firms, including those in his sample group, by other commissions. Tr. III at 54-56, 66-67 (Dworsky). He also acknowledged that, under the established Staff approach that he employed, no judgment is exercised to eliminate "outlier" or other financially dubious data, such as negative growth rates that were all given equivalent weight in his calculations, and that he is unaware of any academic or other support for such a mechanical application of the DCF and CAPM methodologies. Tr. III at 57-59, 64-66 (Dworsky). Mr. Dworsky acknowledged that Dr. Avera's size adjustment was limited to the CAPM analysis, and not an "adder" of the type previously rejected by the Commission. Tr. III at 60-62 (Dworsky). He also acknowledged that Staff's interest coverage analysis was a test that reflects only the Company's ability to meet debt payments, and not a means to determine a ROE. Tr. III at 62-64 (Dworsky).

The Commission finds that Dr. Avera has not made a "small utilities risk adjustment" such as that found unreasonable in our recent decisions. Comm'n Order at 5, Black Diamond Power Company, Case No. 12-0064-E-42T (August 10, 2012).

The Commission is concerned that Staff continues to give little consideration to actual operating results and ROE findings made by other regulatory commissions. While we must base our findings on the evidence presented in this record, the Commission also expects Staff to be able to reconcile its recommendations on ROE with the apparently widespread view that the cost of equity is substantially greater than that calculated by Mr. Dworsky.

The Commission recently found reasonable a 9.75% ROE that was recommended by Staff, based on Megan, Case Number 1 1-0532-G-42T, Bluefield, Case Number 1 1-0410-G-42T, and West Virginia-American Water Co., Case Number 10-0920-W-42T, and that adopted by an Administrative Law Judge. Comm'n Order at 5, Black Diamond Power Company, Case No. 12-0064-E-42T (August 10, 2012). As previously noted in our discussion of capital structure, that utility is exposed to less financial risk due to a much higher level of equity in its total capitalization. The Commission determines that an ROE of 10.5% is reasonable for Mountaineer, based on the Commission's analysis of the data presented by the cost of capital witnesses.

II. Rate Base

The parties' vastly different positions on the Company's rate base represents perhaps the most significant set of issues in this case, both from a revenue requirement perspective and as it relates to the substantive issues presented.

The Company presented a total rate base of $187,158,304. CAD and Staff have proposed total rate base levels of $165,039,295 and $164,096,158, respectively. CAD and Staff rate base proposals are each more than $20 million less than the Company's rate base calculation, and are far below each party's recommendations for the Company's capitalization. Mr. Taylor pointed out that the CAD and Staff rate base positions are also far below each party's recommendation for the Company's capitalization. Co. Ex. TMT-R, at 12-13.

Both Mr. Taylor and Mr. Klemm stressed that a utility's rate base for ratemaking purposes should not vary greatly from the total capitalization used in setting rates, at least not without a reasonable explanation. They contended that in the Company's situation, this is particularly true, as it operates only in West Virginia and provides only utility services. It is a stand-alone gas distribution utility with its own debt, and does not conduct any non-utility business, has not paid any premiums for the utility assets it has acquired, and does not have a consolidated corporate income tax issue. Moreover, Mr. Klemm asserted that the Company has been efficiently managed (at least that the other parties have not asserted to the contrary), and the Commission has not deemed any of the Company's planned expenditures to have been imprudent. Co. Ex. SFK-R, at 14. Except for the effect of the Commission's historical disallowance of construction work in process (CWIP) in rate base and the exclusion of certain assets from rate base pursuant to this Commission's order in Case No. 06-0838-G-PC, which in this case amount to approximately $4.1 million dollars in rate base in the aggregate, the Company asserts that there should be no material difference between the Company's capitalization and its demonstrated rate base. Co. Exs. TMT-R, at 13; SFK-R, at 12-13.

The CAD's position on this issue, not surprisingly, is different. Mr. Smith contended that this difference is acceptable given what he described as an expected difference between GAAP accounting and regulatory accounting. Tr. II at 119-124 (Smith). Neither Mr. Smith nor Mr. Oxley explained the reasons for their recommended variances between invested capital and rate base and capitalization, or explained how the additional, unaccounted for invested capital – ranging between $20.2 and $26.2 million – had been used. Co. Ex. SFK-R at 14.

Although the parties disagree on the causes and the acceptability of these variances, they do not necessarily disagree on the expected impact of them. The Company asserts that these variances, if incorporated into the Company's regulatory rate base in this case, "would make it nearly impossible for the Company to have the ability to earn its authorized rate of return." Co. Ex. TMT-R, at 13; Co. Ex. SFK-R, at 13. In his hearing testimony, Mr. Smith suggested that investors, lenders, and rating agencies are sophisticated and expect that there will be significant differences between a Company's regulatory earnings and GAAP financial results on one hand, and the financial returns made possible under regulatory accounting on the other. Mr. Smith contended that an informed investor would understand enough about the regulatory process to understand that authorized returns in a revenue requirement determination are established on a regulatory rate base. A major factor in differences between GAAP returns and regulatory returns could be explained if the utility "has a bunch of other assets on its books that are being financed in part by equity and debt capital that are not in rate base" – such investor would not expect to earn an equity return on those. Tr. II at 117 (Smith). The Commission merely applies its historic Rule 42T process to set the utility revenue requirement; Mr. Smith rejected the idea that the Commission should use GAAP financial statement results to determine the sufficiency of utility rates. Although the Commission may wish to look at GAAP performance to reflect on the sufficiency of utility rates and usefulness of the Commission's regulatory decision-making, he did not think that the Commission is "necessarily required" to do so. Only if the Commission perceives this disconnect "as a problem that is continuing" should the Commission conduct this analysis. Id. at 119-120. In Mr. Smith's view, as long as rates are determined using the established Rule 42T process, any disconnect between regulatory and GAAP earnings is something the Company needs to explain to its management, and if troubled by those outcomes, to ask for a generic proceeding to be open to the Commission. Id. at 120.

For purposes of our rate base analysis, then, the Commission needs not only to consider the relationship between rate base and capitalization and the differences the parties contend are permissible between those two figures, but also whether the impairment of the Company's ability to earn its authorized return that may arise from the Commission's rate base determination can be explained and justified. Although there were several rate base issues presented in this case, by far the most significant was the appropriate handling of accumulated deferred income taxes (ADITs) associated with accelerated depreciation. We will address this issue first.

Accumulated Deferred Income Tax Assets and Liabilities

The Company's utility operations and financial performance represent the vast majority of the results reflected in filed federal and state income tax returns. As a result, the Company's income tax positions are not clouded by consolidated tax adjustment issues that arise in other cases. As explained further below, the Company's originally filed rate base position reflects the appropriate treatment of ADITs under the Company's specific circumstances. Those circumstances include a history of net operating losses and significant shortfalls in its delivery volumes, resulting in the Company's inability to earn fair and reasonable returns over several years. Co. Ex. SFK-R, at 17-18.

Mr. Klemm's amended direct testimony explained the Company's ADIT adjustments in considerable detail. In summary, the Company contends that the federal ADIT liability on plant should be limited to only that portion of plant-related deferred tax liability that customers have actually been charged through and paid for in rates. In other words, only this amount should serve as a reduction to rate base; to the extent that the Company can demonstrate that ratepayers have provided revenues sufficient to allow the Company to realize the benefits of accelerated depreciation deductions on plant, rate base should not be reduced by that portion of the ADIT liability. *See*, generally Co. Ex. SFK-D, at 44. The Company's position on this issue effectively has two components. The first is a 13-month average of NOL and alternative minimum tax (AMT) carry-forwards, which together amount to approximately \$2.6 million dollars. Id. at 46. The Company recorded deferred tax assets on these amounts, calculating them using a "with-and-without" approach to determine the component of the calculations that can be attributed to the effects of accelerated depreciation. Id. The Company contended that failing to recognize these deferred tax assets is necessary at a minimum to avoid a potential normalization violation; this is the minimum amount of the Company's ADITs plant-related liability that needs to be added back to rate base. Id. Although the Staff did not include even this amount in its rate base recommendation, the CAD, through Mr. Smith's testimony, acknowledged that this amount should serve as a reduction to the ADITs rate base offset. Mr. Smith indicated that NOL carry-forward ADIT amounts on the Company's books that have yet to produce a tax benefit should be reflected in the rate base. Effectively, he supported the \$2.6 million minimum adjustment, supporting it not only with concerns about normalization violations but also a regulatory analysis validating the accounting rationale for deferred tax asset for ADITs that have not yet produced a tax benefit. CAD Ex. RCS-D, at 17, 21-22; Co. Ex. SFK-R, at 22-23. The Commission is persuaded that in order to avoid a normalization violation, at least the \$2.6 million dollar amount should serve as a reduction to the plant-related ADITs rate base offset.

The much more contentious issue relates to an additional \$11.4 million dollars in plant-related ADITs liabilities that the Company also contends should serve to reduce the ADITs rate base offset[2].

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2 Note that in the CAD's cross-examination of Mr. Klemm, its counsel repeatedly suggested that the Company sought to "add" this \$11.4 million to rate base. In response, Mr. Klemm conceded that with

The Company contends that its filed rate base position reflects the appropriate treatment of ADITs under the Company's specific circumstances: a history of NOLs and significant shortfalls in its delivery volumes, resulting in the Company's inability to make positive net-owned income during a several year period following the establishment of rates in its 2004 rate case. Co. Ex. SFK-R, at 17-18. There is no dispute that in the years 2006, 2007, 2008, and 2009, the Company had negative taxable income and paid no federal income taxes. *See*, Company Response to CAD-11-E-112, Attachment 1, introduced into evidence as Ex. LA-2, at 12 of 135, to CAD Ex. RCS-D. This prolonged period of negative taxable income arose in significant part from a dramatic drop in sales volumes during that period from those upon which rates were based in the Company's 2004 rate case. Co. Ex. TMT-D, at 3-4. The Company contends that because revenues generated from the Company's customers during this period were insufficient to meet the Company's cost of service, such that the Company repeatedly lost money and consequently had no taxable income upon which to pay federal income taxes, the interest free loan benefits of plant-related depreciation deductions could not have created and did not create any cash benefit for the Company that requires a rate base deduction. Co. Ex. SFK-D, at 44, 47-48; Co. Ex. SFK-R, at 19, 22-23.

The CAD opposed the Company's position on this issue. Mr. Smith insisted that the full amount of the Company's plant-related ADIT liabilities (both federal and state) should be reflected as an offset to rate base. CAD Ex. RCS-D, at 14. He offered several reasons for his position. First, Mr. Smith contended that the Company's customers have paid rates that have included "large amounts for income tax expense that Mountaineer has not paid to the federal government," and it would be unfair not to reduce rate base for the credit balance ADIT related to plant. Id. at 18-19. He suggested that the Company "holds the ratepayer-provided funds" without paying the related income taxes. Id. at 19. Second, Mr. Smith argued that the Company had not shown that reducing the ADIT liability by the $11.4 million amount was necessary to avoid a normalization violation. Id. Third, Mr. Smith argued that the Company's position would minimize or eliminate the ADITs liability and presumably that customers would lose the benefit of it in rates. Id. at 20.

In response to these concerns, Mr. Klemm asserted that the Company's justification for its position on the $11.4 million component was the same in principle as the justification for the $2.6 million minimum adjustment Mr. Smith supported: in each case, the tax benefit of the deduction had not yet been realized. To reduce rate base for deferred income tax amounts the Company has not yet realized, even if not associated with an NOL carryforward, is an unfair outcome, Mr. Klemm argued, for the same reasons failing to do so for the ADITs associated with the NOL carryforwards would be inappropriate. Co. Ex. SFK-R, at 23; Tr. II at 91-92 (Klemm). Finally, the Company contended that its reduction of the ADITs liability for the $11.4 million component would have no effect on the availability of that liability to reduce rate base in the future, when revenues and taxable income are sufficient to enable the Company to realize the benefits of them. Co. Ex. SFK-R at 23. If the Company's position on the $11.4 million were

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the Company's handling, this amount could be seen in that way, but actually that it was a recommended limitation on the ADITs plant-related liability balance that would then serve to reduce rate base. Tr. I at 156-57 (Klemm). The Commission attaches no significance to the characterization of this amount, and is more concerned with the substantive rationales of the parties' offer for handling it.

adopted, then the ADITs would still be there to create a cash benefit in the future. Tr. I at 97 (Taylor); Tr. II at 96 (Klemm).

The Staff also opposed the Company's $11.4 million plant-related ADITs reduction. Mr. Oxley's basis for opposing this adjustment was his reading of this Commission's recent Order in Bluefield Gas Company, Case No. 11-0410-G-42T (Commission Order dated January 17, 2012). Mr. Oxley contended that this Order stands for the proposition that ADIT liability should not be offset by deferred debits where there are net taxable income losses before accelerated depreciation. Staff Ex. ELO-D, at 27. The Company rejected Mr. Oxley's interpretation of this Order, contending that our decision had more to do with the appropriate level of federal income tax expense to include in rates given the utilities NOL carryforwards. Mr. Klemm also pointed out that the Commission concluded that it lacked sufficient data to properly consider several of the adjustments the utility in that case offered, and that in the context of deferred tax offsets, the Order addressed the assumption of potentially higher future tax rates defining the tax liability in future years, which is not the case in the Company's situation here. Co. Ex. SFK-R, at 20-21.

The Commission has thoroughly considered this issue, and finds that the Company's $11.4 million reduction in its plant-related ADITs liability balances appropriate. At the outset, we observe that there is no question about the losses the Company experienced in years 2006 through 2009, nor the fact that the Company's rates did not generate sufficient income to generate any taxable liability. Without tax liability in these years, the tax benefits of accelerated depreciation deductions did not materialize for the Company. In principle, this situation is no different than that which applies to NOL carryforwards generated by bonus depreciation that create deferred tax assets – in other words, the Company's $2.6 million adjustment that the CAD has conceded to be well-accepted and appropriate. The same rationale appears to apply to the Company's position on two other ADITs issues: (1) the ADITs associated with alternative minimum tax (AMT) carryforwards, which the Company would use to reduce the total ADIT rate base reduction (Co. Ex. SFK-R, at 31-32); and (2) the state ADITs on the Company's books, as the Company demonstrated that during the years between the 2004 and 2009 rate cases, state income taxes were "flowed through" and no state income tax expense was included in the cost of service (Id. at 32).

Moreover, we are unable to agree with the CAD's suggestion that during this extended period of losses, the Company generated revenues associated with federal income tax that it has subsequently held and not paid over to the federal government. *See* CAD Ex. RCS-D, at 19. Contrary to the CAD' suggestion, the plant-related ADITs liabilities are not eliminated or ignored if the Commission adopts the $11.4 million adjustment. We believe (and we insist) that these plant-related ADITs continue to be recorded on the Company's books and considered to the appropriate extent in establishing rates, such that like other timing differences, they will be reversed when book depreciation exceeds tax depreciation for those assets. This expectation corresponds with the Commission's preference that tax benefits generally correspond with the life of the asset, and that a single group of customers not receive, through lower rates, the entire benefit of an assumed interest free loan, the proceeds of which the utility has not yet received. We have also expressed our preference in the past for ratemaking mechanisms that foster intergenerational equity in the context of tax normalization. Finally, we are sensitive to the Company's arguments that the extended financial losses experienced during years 2006 through

2009, and very poor financial performance since then, not be used as a basis for creating yet another adverse financial impact on the Company.

To the extent that the $11.4 million adjustment represents the greatest portion of the difference or the parties' differences between the Company's capitalization and its regulatory rate base, failing to recognize the Company's adjustment would do just that. As we expressed elsewhere in this Order, our ratemaking efforts should strive to allow the utility a reasonable opportunity to earn its authorized return on equity investment, and should consider carefully ratemaking outcomes that would manifestly impair by the utility's ability to do so. This is one of those incidences.

ADITs – Unamortized Debt Costs; CIS Regulatory Asset

As noted in our discussion of the Company's long-term debt cost rate, the Company now believes that unamortized debt costs should be deducted from its long-term debt balance and, as a result, be excluded from rate base. The Staff proposed to remove unamortized debt costs from rate base in its testimony, so the issue of related ADITs reduction is not relevant to its recommendation. The CAD's position was different. Mr. Smith did not recommend removing unamortized debt costs from rate base, and proposed that the 13-month average of related federal and state ADIT liabilities be included in rate base. CAD Ex. RCS-D, at 15. Doing so would partially offset (or reduce) the amount of unamortized debt costs in rate base. Co. Ex. SFK-R, at 33-34. For some of the same reasons identified above, the Commission believes it is inappropriate to exclude from rate base the ADITs associated with unamortized debt costs. It is unreasonable to reduce rate base for the portion of ADIT liability that has not yet been realized and, as noted above, in the 2004 Rate Case, state income taxes were flowed through and no state income tax expense was included in the cost of service. For these reasons, the CAD's position should be rejected. Likewise, the Staff's position on ADITs associated with the CIS regulatory asset (discussed below under "CIS Regulatory Asset" in the rate base section of this order) should be rejected.

Prepayments

Both Staff and CAD refer to Rule 42 requirement number 19.4.f, which provides that prepayments will not be allowed in rate base "unless a working cash allowance calculation demonstrates that prepayments are not offset by negative working cash," to remove the entire prepayments amount of $3,640,444 from rate base. Staff Ex. ELO-D, at 28; CAD Ex. RCS-D, at 10.

The Company contended that because it was borrowing on its short-term debt line of credit throughout much of the year after consideration of the Company's over-recovery of gas cost situation as reflected on Statement C, Schedule 2.1, prepayments were clearly funded by short-term borrowings, and not from excess cash. Co. Ex. SFK-R, at 35-36. Although the Company did not perform a lead lag study in this case, it did perform one in conjunction with its last case, and Mr. Klemm contended that the Company's billing and recovery processes, as well as its payment of invoices, has not changed materially since that case. Tr. II at 97 (Klemm). The Commission is persuaded that the lead lag study from the 2009 case which supported inclusion of prepayments and rate base is an acceptable basis for the same outcome in this case. The Commission cautions the Company, however, that in the future it must either prepare a new lead lag study or provide other clear evidence in this case-in-chief that a working cash allowance calculation has demonstrated that prepayments are not offset by negative working cash, as the Rule 42 requirement provides.

Unamortized Debt Costs

Unamortized debt costs are costs such as bank fees and legal expenses incurred by a utility in connection with executing debt agreements. In the Company's case, it also includes the loss on reacquired debt when that debt is paid off prior to maturity. Co. Ex. SFK-R, at 16. Staff proposed to remove unamortized debt costs from rate base. Staff Ex. ELO-D at 28. The CAD did not, but it did propose that the 13-month average of related federal and state ADIT liabilities be included in rate base, which would partially offset, or reduce, the amount of unamortized debt costs in rate base. CAD Ex. RCS-D, at 15. In response, the Company contended that deducting unamortized debt costs from its long-term debt balance is consistent with the Commission's approach in recent West Virginia-American Water and APCo rate orders. Co. Ex. SFK-R, at 16. We agree, and for this reason we believe that unamortized debt costs should be excluded from rate base.

Regulatory Assets – CIS Investment, Clay County Receivership Costs, and Rate Case Expenses

The Company proposed to include in rate base regulatory assets for four items: (i) the Company's investment of approximately $2.7 million in its new customer information system ("CIS"), (ii) approximately $335,000 in receivership costs associated with its service as a receiver for the Clay County Gas Utilities before the Company acquired them in late 2007; approximately $232,000 in unamortized rate case expenses; and (iv) closing costs of approximately $1,300 related to the Ashford Gas acquisition. Co. Ex. SFK-R, at 36, 40. In each case, either the Staff or CAD or both opposed the inclusion in rate base of regulatory assets for these items.

The Staff did not oppose the CIS regulatory asset, but argued that the CIS deferred costs should be amortized over a ten year period, in a manner consistent with this Commission's treatment of call center transition costs in other cases. Staff Ex. ELO-D, at 21-22. The CAD opposed the Company's proposed rate base inclusion of the CIS regulatory asset based on its reading of the guidance on capitalization of such assets in the American Institute of Certified Public Accountants' statement of position (SOP) at 98-1. SOP 98-1 provides that:

> Costs of computer software developed or obtained for internal use that should be capitalized included only the following:
>
> a. External direct costs of materials and services consumed in developing or obtaining internal-use computer software. Examples of those costs include but are not limited to fees paid to third parties for services provided to develop the software during the

application development stage, costs incurred to obtain computer software from third parties, and travel expenses incurred by employees in their duties directly associated with developing software.

b. Payroll and payroll-related costs (for example, costs of employee benefits) for employees who are directly associated with and who devote time to the internal-use computer software project, to the extent of the time spent directly on the project. Examples of employee activities include but are not limited to coding and testing during the application development stage.

c. Interest costs incurred while developing internal-use computer software. Interest should be capitalized in accordance with the provisions of FASB Statement No. 34, Capitalization of Interest Cost.

Mr. Smith took the position that the guidance provided in SOP 98-1 for the proper capitalization under GAAP should also apply to regulatory accounting, resulting in exclusion of these amounts from rate base. CAD Ex. RCS-D, at 33. In response, the Company argued that the investments covered by the CIS regulatory asset related to the selection of CIS, the conversion of data for use in it, and various CIS training costs, should be included in rate base assets. Although SOP 98-1 requires these costs to be expensed as incurred for GAAP purposes, they relate directly to the fixed asset that is included in rate base. Also, Mr. Klemm asserted that these costs were funded through the Company's capital structure with debt and equity capital. For these reasons, the Company argued that these one-time costs should be treated as a fixed asset, just as other actual costs of implementing the CIS are to be treated. Co. Ex. SFK-R at 36-38. To exclude them from rate base would understate the assets and costs of providing service to the Company's customers and create a disconnect with the Company's capital structure, resulting in the Company's inability to recover its interest costs on the debt associated with these investments. Co. Ex. SFK-R, at 36.

Both Staff and CAD opposed the Company's proposed regulatory asset for the deferred Clay County receivership costs. The Staff proposed to allow recovery and expense, not rate base, of five remaining months' amortization ($69,916) but eliminated the test year amortization expense of $167,799. Staff Ex. ELO-D, at 22-23. The CAD took the position that these amounts were recovered through an amortization arising in the last rate case, and that there should be no remaining unamortized amount as of the rate effective date. For this reason, Mr. Smith opposed inclusion of this amount in rate base. CAD Ex. RCS-D, at 36-37. In response, the Company observed that the Clay County receivership costs were funded with short-term debt as well. If these costs were to be excluded from rate base, the Company would incur interest expense that is not recovered through rates. Mr. Klemm also pointed to this Commission's request to the Company to operate these systems during a time of turmoil. Even though the cost will be fully amortized in 2013, Mr. Klemm argued that it was appropriate to include them in rate base since the unrecovered balance of the costs were funded through a short-term debt during the test year. Co. Ex. SFK-R, at 39.

As for the unamortized rate case expenses, the Staff opposed including these expenses as a regulatory asset (Staff Ex. ELO-D, at 28), and the CAD did as well, contending that the Commission has not previously authorized utilities to treat rate case expense as a regulatory asset or as a deferred expense that is includable in rate base (CAD Ex. RCS-D, at 29). Mr. Klemm responded that these rate case expenses were funded with short-term debt, and to exclude them from rate base would cause the Company to incur interest expense that is not recovered from ratepayers. Co. Ex. SFK-R, at 40.

The Company agreed with the Staff's proposal to remove the Ashford Gas closing costs, since the amount was immaterial. Mr. Klemm noted, however, that in similar situations where customers are being acquired at a low cost, the Company believes that these costs should be included in rate base, giving the Company the opportunity to earn a return on and a return of the asset. Id.

On reviewing these arguments, the Commission will permit inclusion in rate base of the CIS implementation costs but deny the Company's recommended rate base inclusion of the unamortized balance of the Clay County receivership costs and the unamortized rate case expenses. The CIS implementation costs clearly are associated with a rate base asset, are one-time expenses, and were funded with components of the Company's capital structure. Moreover, no party asserts, and the Commission does not believe, that SOP 98-1 governs regulatory accounting or rate recovery of the CIS implementation costs referenced in it. On the other hand, the Commission believes it is reasonable to continue the Clay County receivership amortization initiated in the 2009 case. Although the Staff recommends that this recovery be truncated to reflect only the remaining months in the rate year, doing so would be inappropriate, in the same way that providing a termination of an amortization in advance is unworkable from a ratemaking perspective. The Company's unamortized rate case expenses are not appropriate for recovery as a regulatory asset in this case; we have previously ruled that rate case expenses should not be deferred and amortized, but considered a normal operating expense. Finally, we approve the Staff recommendation, concurred in by the Company, to remove the Ashford Gas closing costs from rate base.

Self-Funded Reserve

The Company established and maintains two accrual accounting-based reserves on its books. One reserve is for remaining estimated costs for pending personal injury claims, property damage claims, and customer complaint claims, and the second reserve is for incurred but not reported medical claims. The CAD argued that rate base should be reduced by the amount of this reserve, which results from accrued but not yet paid expenses, including expenses that the Company has included in the test year. CAD Ex. RCS-D, at 26-27. The CAD raised this same issue in Case No. 09-0878-G-42T. In that case, CAD claimed that these reserves, as well as other liabilities on the Company's books, were presumed to have been funded by operations. Co. Ex. SFK-R, at 40-41.

In response, Mr. Klemm noted that the Company had a book loss before taxes in all of its full years since being acquired by Mountaineer Gas Holdings Limited Partnership, and therefore one could not reasonably conclude that ratepayers could have funded all of these reserves, including pension and OPEB, through its rates. This liability was the result of actual expense, including both payments and accruals, being more than the amount funded by customers in rates. Co. Ex. SFK-R, at 41. The Company showed that as of March 31, 2010, when the Company increased its base rates as a result of the 2009 case, the total reserve of these two accounts was $925,000, nearly identical to the 13-month average of the test year. Co. Ex. SFK-R, at 40-41.

We believe the Company's position on this issue is reasonable. The test year average of $950,000 is effectively the same as the amount of these same reserves at the beginning of the rate year arising from the 2009 rate case. Thus, the CAD's proposed adjustment to reduce rate base by $950,000 should be rejected.

Materials and Supplies

CAD has proposed an adjustment to reduce rate base by $50,974 relating to accounts payable related to materials and supplies. CAD Ex. RCS-D, at 28. The Company believes that it is inappropriate to have a deduction for items that are in accounts payable. To the extent the timing of payment is deemed to have been paid, the timing impact is already considered in the Company's cash working calculation. Co. Ex. SFK-R, at 42. The Commission believes that amounts in accounts payable are typically a component of a working cash calculation. It is inappropriate to make a further deduction to rate base, which would effectively be a double counting of the same amounts. The Commission will reject the CAD adjustment.

III. Operating Income

Operating Revenues and Purchased Gas Expense

Local B&O Tax

In its Rule 42 Exhibit, the Company made a going-level adjustment to reduce local B&O Tax surcharge revenues in recognition of overall reductions in going-level revenues due primarily to reductions in PGA rates since the test year. The Company failed, however, to make a corresponding going-level adjustment to local B&O Tax expense. As a result, the Company's Rule 42 Exhibit reflects local B&O Tax expenses that exceed local B&O Tax revenues, thereby increasing the overall base rate revenue requirement. Staff Ex. ELO-D, at 5-6. Rather than adjusting both local B&O Tax revenues and expenses at going-level, Staff proposes to simply use the test year amounts for both revenues and expenses. Doing so requires that the Company's adjustment to reduce local B&O Tax surcharge revenues be reversed, resulting in an increase in revenues of approximately $413,000. Id. at 6. The Company indicated that it agrees with Staff's approach to this issue. Co. Ex. SFK-R, at 43. The Commission finds the Staff's approach to be reasonable and will adopt it.

Billing Determinants and Revenues – Former East Customers

When the Company acquired the former gas distribution system of East Resources, Inc. (East Resources) in 2010, it was stipulated that the current East Resources base rates and rate design would be continued for the former customers of East Resources until the effective date of the Company's nest base rate change. Staff Ex. ELO-D, at 7-8. The Company and Staff differed in the billing determinants they each used in making going-level revenue adjustments to reflect the merger of the former East Resources rates with the Company's rates. The Company applied the current rates applicable to all of its other customers to the former East Resources customers, while Staff used the current rates charged to former East Resources customers. Id. at 8. Staff believes that its approach, which results in an increase in going-level revenues of approximately $92,000, is consistent with the consolidation of rates envisioned by the Commission when it approved the transfer of the system. Id. The Company conceptually agrees with the Staff approach, but notes that while the harmonization of rates for the former East Resources customers will result in lower base rate revenues of $1.8 million, a total of approximately $10.5 million will ultimately need to be allocated to the Company's customers. Co. Ex. SFK-R, at 43-44. We believe that the Staff approach is reasonable and will be adopted.

Weather Normalization Volumes

Because the test year was colder than normal, the Company proposed a weather normalization adjustment to reduce test year revenues by $5,450,449 to reflect a normal weather year. Co. Ex. 2, Statement G, Schedule 2.1. Staff proposes to reduce the Company's adjustment by $181,296 to reflect a change in the Heating Degree Days (HDD) used in the calculation. Staff Ex. ELO-D, at 6-7. In its calculation, the Company included the HDD from each month of the test year, which ended September 30, 2011. Staff reasons that because gas sales are billed in arrears, a portion of the HDD for September, 2010 should be included in the calculation of a weather normalization adjustment while a corresponding portion of the HDD for the month of September, 2011 should be excluded. Id. at 7. The Company asserts that Staff's adjustment is incorrect because it fails to recognize unbilled revenue activity and the change in the balance of unbilled revenue from the beginning to the end of the test year. Co. Ex. SFK-R, at 46. The Company maintains that its weather adjustment calculation is accurate and should be approved since it properly considers both billed and unbilled sales volume activity. Id. at 46-47. We believe that the methodology used by the Company in computing its weather normalization adjustment is appropriate and the Company's adjustment will be accepted.

Unbilled Revenues

The Company raised several objections to the inclusion by Staff of various unbilled revenue items. The Company objects to the inclusion by Staff of unbilled customer charge revenues related to former customers of East Resources in its going level amounts for residential, general service and wholesale customers in view of the fact that twelve months of customer charge revenues are included in "billed" base rates. Staff Rule 42, Statement D; Co. Ex. SFK-R, at. 47-48. The Company noted that Staff did not include unbilled customer charge revenues for former East Resources large general service customers or for any of Mountaineer's other customers. Co. Ex. SFK-R, at 48.

The Company also objects that while "billed" going level sales volumes relating to former customers of East Resources have been adjusted to reflect twelve months of activity, Staff has nevertheless included the September 30, 2011 unbilled volumes for such customers without subtracting the estimated unbilled volumes at September 30, 2010 that are reflected in the going level "billed" volumes on the applicable Statement D schedules. As a result, going level sales volumes are overstated. Id.

The Company also asserts that the residential unbilled base rate charge revenues for current Company customers at September 30, 2010 that are being reversed are understated by $21,649 (after consideration of revenue factor) because such revenues should be based on the current base rate charge of $3.024 per Mcf rather than the old rate of $2.896. Id. The Company also states that the billed going level gas cost volumes used by Staff for the LGS customer class were understated by 461 Mcf, resulting in revenues being understated by $2,270 and gas cost being understated by $2,173. Id. at 48-49. We agree with, and will adopt, the Company's position on each of these issues concerning unbilled revenues.

PGA Revenues

The Company proposed an adjustment reducing purchased gas cost expense by $18,605,020. Staff proposed an adjustment reducing purchased gas cost expense by $20,086,952, a difference of $1,481,932. Most of that difference, $1,237,463, is due to the fact that the Company's calculation incorporated going-level PGA revenues attributable to former East Resources customers based on the Company's current PGA rates for its other customers rather than the current PGA rates for the former East Resources customers. Staff Ex. ELO-D, at 9-10. The Staff contends that going-level PGA revenues attributable to former East Resources customers should be based on the current PGA rates for those customers, which are lower than the Company's current PGA rates for its other customers. The remaining difference between the proposed adjustments, $244,469, is attributable to the fact, conceded by the Company, that it failed to apply the applicable revenue correction factor in making its calculation. Id. at 10; Co. Ex. SFK-R, at 49.

Staff's adjustment would result in lower going level revenues, gas cost, state B&O tax and bad debt expense. The Company objects to Staff's approach because it fails to reflect that the former customers of East Resources will begin paying a much higher PGA rate in November, 2012 when new, uniform PGA rates are established for all of the Company's customers, including the former customers of East Resources. The Company maintains that Staff's approach results in pro-forma revenues and gas costs that are understated by approximately $1.2 million, resulting in a lower bad debt expense in the Staff's cost of service calculation. Under the Company's approach, revenues, purchased gas expense, state B&O tax and bad debt expense would all be higher. Co. Ex. SFK-R, at 44. We find that the Company's approach reasonably reflects the financial impact of the pending unification of the rates to be charged to all of the Company's customers and we will adopt the Company's position.

Other Operating Revenues

Staff proposed an increase in miscellaneous revenues of $99,537 to normalize the amount of forfeited discounts in the test year. The Company accepts Staff adjustment as reasonable and it will be adopted.

<u>Uncollectible Expense</u>

Staff proposed an adjustment to increase going level uncollectible (bad debt) expense by $2,897 based on its proposed amount of going level <u>billed</u> revenues. Staff Ex. ELO-D, Exhibit ELO-1, Schedule 2, p. 2 of 5. The Company maintains that while billed revenues for an historical three-year period are used in computing the weighted average uncollectible ratio, that ratio should be applied to going level <u>operating</u> revenues, which includes unbilled revenues, to determine a proper amount of going level uncollectibles since unbilled revenues become billed revenues. Under the Company's calculation, bad debt expense should be increased by $25,902 over the amount in the Company's original filing. Co. Ex. SFK-D, at 50-51. The Company's proposed adjustment is reasonable and will be adopted.

<u>Payroll Expense and Related Expense Adjustments</u>

1. Agreed Adjustments

Staff proposed a series of adjustments to payroll and related expenses. The Company agrees with the following Staff adjustments, which shall be adopted:

- $194,920 increase in salaries and wages consisting of $20,161 in wage increases for salaried exempt employees based on actual pay increases effective February 1, 2012, $170,284 increase in overtime pay, $1,846 increase in first responder pay, and $2,629 increase in overtime meals, all based on actual costs for the test year;

- $260 increase in miscellaneous minor expense adjustments; and

$21,757 decrease in straight-time payroll based on August 31, 2011 wage rates.

2. Additional Full-Time Employees

The Company proposed a going level adjustment of $599,178 for twelve new distribution employees. Co. Ex. 2, Statement G, Schedule 4 and confidential supporting workpapers schedule SD G-4.2. Staff proposed an adjustment that would reduce the Company's proposed adjustment by $373,580 to eliminate all of the new employees other than two positions that Staff considers to be reasonable additions to test year salaries and wages expense and replacements for a former Company official who left the Company during the test year. Staff Ex. ELO-D, at 11-12. CAD proposed an adjustment that would reduce the Company's proposed adjustment by $332,953. CAD's proposed adjustment is based on the net change in employee salary expense from the end of the test year through April 16, 2012, during which time nine new employees were hired and four employees ceased being employed by the Company. CAD deducted the aggregate salary and wage costs of the four employees who left employment from the aggregate salary and wage costs of the nine new employees and subtracted the result from the Company's $599,178 proposed adjustment to arrive at its proposed adjustment. CAD Ex. DLW-DP, at 4-5. Company witness Scott Klemm testified that the Company believes that the adjustment proposed by CAD is more appropriate than the adjustment proposed by Staff and is more reflective of actual events. Co. Ex. SFK-R, at 44. The Commission finds the CAD adjustment to be reasonable and will adopt it.

Performance Payments

The Company proposed a going level adjustment in the amount of $365,500 for performance payments made in February, 2012. Co. Ex. 2, Statement G, Schedule 4; Co. Ex. SFK-D, at 53. CAD proposed an adjustment to eliminate all of the Company's proposed $365,500 going level adjustment. CAD Ex. DLW-DP, at 5. CAD witness Deanna Lynne White opposed the Company's entire adjustment for performance payments because the Company lacks a written incentive plan with performance goals benefitting ratepayers, resulting in performance payments that are based entirely on the discretion of Company management. Witness White further reasoned that because payments are entirely discretionary, it is possible that no payments may be made in future years and, thus, the costs of the incentive plan are not known and measurable. Id. at 5-7.

Staff proposed an adjustment reducing administrative and general salaries by $502,250 to eliminate $352,250 of the Company's proposed going level adjustment, as well as an additional $150,000 expense associated with the change in the liability for the test year. Staff Ex. ELO-D, at 13-14. Citing the methodology approved by the Commission in the last base rate case of Appalachian Power Company and Wheeling Power Company (Case No. 10-0699-E-42T), Staff would support the allowance of a going level adjustment in the amount of $13,250, which represents one-half of the amount of performance payments made to non-executive personnel. Id. at 14. The Company does not object to Staff's proposed adjustment to remove the additional $150,000, but does object to the remainder of Staff's adjustment. Co. Ex. SFK-D, at 53.

Company witness Tom Taylor stated that performance payments are awarded in recognition of employee performance that helps the Company meet its goals for customer service, safety, compliance with mandatory programs, and for helping the Company successfully complete special projects, such as integrating acquired gas systems or developing an in-house billing department and call center support. Co. Ex. TMT-R, at 18-19. Taylor noted that the compensation levels for many Company employees are near the mid-point of the range of compensation for similar positions in the area and that neither CAD nor Staff had suggested that Company employees are overpaid, even when performance payments are included. Id. Mr. Taylor argued that, as with other utilities, incentive compensation is an important part of the Company's compensation structure and that neither CAD nor Staff had provided justification for disallowing recovery of performance payment expenses. Id.

The issue of incentive compensation has arisen frequently in prior rate cases.[3] Historically, the Commission has permitted reasonable incentive compensation expenses to be recovered in rates because incentive compensation packages provide benefits over time to both shareholders and indirectly to ratepayers through reduced costs and improved compliance with

[3] See generally, West Virginia-American Water Company, Case No. 03-0353-W-42T, Case No. 08-0900-W-42T and Case No. 10-0920-W-42T; Hope Gas, Inc., dba Dominion Hope, Case No. 08-1783-G-42T; and Appalachian Power Company and Wheeling Power Company, both dba American Electric Power, Case No. 10-0699-E-42T.

operational goals. Quantifying the proportional benefit from incentive compensation, however, is difficult and the Commission has declined previous invitations to mathematically quantify the degree to which an incentive compensation program benefits shareholders versus ratepayers. Comm'n Order at 31, Hope Gas, Inc., dba Dominion Hope, Case No. 08-1783-G-42T (Nov. 20, 2009). The Commission has drawn distinctions between incentive compensation awarded to a utility's direct employees and awards to parent company or affiliated service company employees and officials. Comm'n Order at 49-50, Appalachian Power Company and Wheeling Power Company, both dba American Electric Power, Case No. 10-0699-E-42T (March 30, 2011). The Commission has also recognized that during protracted periods of economic hardship and unemployment, it may be inappropriate to require ratepayers to bear all incentive compensation expense, no matter how reasonable in amount.

While the current economic recovery in this Country and State is far from robust, things are improving. Among the things that are improving significantly are the increasing supply and decreasing cost of natural gas. Also improving is the quality of service provided by the Company, which has now become a West Virginia stand-alone utility with a local, modern customer service center. The Company has also taken over service previously provided by a number of small, undercapitalized utilities and has improved service to those customers, including significantly improved reliability. The performance payments at issue are for direct employees of the Company, are reasonable in amount and have been awarded based on employee performance in achieving operational goals, including significant customer service improvements and successful integration of recent acquisitions. Under these circumstances, which reflect considerable benefit to ratepayers, the Commission will allow the full amount of the Company's $365,500 in performance payments.

401K Matching Expense

In its amended Rule 42 Exhibit, the Company proposed a going level adjustment increasing employee pension and benefit expense by a total of $28,951 for 401K matching expense for new employees. Co. Ex. 2, Statement G, p. 2 of 3, Adj. No. 9. In his rebuttal testimony, Company witness Scott F. Klemm proposed an additional increase in the 401K matching expense, bringing the total proposed going level adjustment to $29,811. Co. Ex. SFK-R, at 54 and attached Ex. SFK-5. Staff proposed a going level adjustment for 401K matching expense of $21,213, which would reduce the Company's revised adjustment by $8,598. Staff Rule 42 Exhibit, Statement G, Adj. No. 20. Both the Company and Staff arrived at their respective adjustments using the same methodology, with the difference in results being attributable to the different amounts of going level payroll expense they each used in the calculation. The Company's calculation is based on a going level payroll amount of $30,531,831, while Staff used a payroll amount of $30,121,833. The $409,998 difference in going level payroll reflects the $365,500 performance payments and a $44,498 variance relating to additional full-time employees. Because the full amount of the performance payments are being allowed, the Company's $29,811 adjustment for 401K matching expense will also be allowed.

Payroll Taxes (Social Security/Medicare)

The Company proposed a going level adjustment increasing payroll taxes (Social Security and Medicare) by $69,676, based on a total going level payroll of $30,718,966 and an effective combined tax rate for the test year of 7.136%. Co. Ex. 2, Statement G, Schedule 5. Staff proposed a going level adjustment of $51,850, based on a total going level payroll of $30,121,833 and individual calculations of the applicable Social Security and Medicare taxes, including applicable deductions and current tax rates. Staff Rule 42 Exhibit, Statement G, Adj. No. 29. CAD proposed a going level adjustment of $22,104, based on a going level payroll of $29,988,786 and the same effective tax rate of 7.136% used by the Company. In his rebuttal testimony, Company witness Scott F. Klemm stated that the Company agrees with the methodology used by Staff to calculate the Social Security and Medicare taxes, but disagrees with the amount of total going level payroll used by Staff in its calculation. Mr. Klemm further testified that based on the Company's revised going level payroll of $30,531,831 and using the Staff methodology, the Company now proposes that its going level payroll tax adjustment be reduced from $69,676 to $59,796. Co. Ex. SFK-R, at 54-55 and attached Ex. SFK-6.

The Company also disagrees with the amount of total going level payroll used by CAD in its calculation. In addition the Company believes that CAD's calculation is erroneous because it assumes that if CAD's proposed elimination of performance payments is adopted, Social Security taxes will be reduced as a result. The Company maintains that Social Security taxes would not be reduced because the majority of performance payments are made to highly compensated employees whose salaries exceed the current limit on salaries subject to Social Security taxes. Co. Ex. SFK-R, at 54.

As indicated herein, the Commission will adopt a total going level payroll of $30,531,831 as proposed by the Company. As a result, the revised going level adjustment for payroll taxes proposed by the Company in the amount of $59,796 is appropriate and will also be adopted.

Vacation Pay Expense

Staff proposed a going level adjustment to reduce employee vacation pay expense by $55,036 to reflect a normalized amount for the test year. The Company agrees with this adjustment and it will be adopted.

Deferred Compensation Expense

Staff proposed an adjustment decreasing expenses for employee pensions and benefits by $409,207 to eliminate all test year expenses for obligations arising under deferred compensation agreements with two former Company executives. Staff Ex. ELO-D, at 19; Staff Rule 42 Exhibit, Statement G, Adj. No. 24. The expenses recorded by the Company in the test year resulted from the annual accretion of deferred compensation liability as affected by changes in the present value discount rate netted against investment returns from trusts that have been established to administer the Company's deferred compensation liabilities. Staff Ex. ELO-D, at 19. Staff does not believe that such deferred compensation can properly be characterized as an expense for an activity necessary for the provision of utility service by the Company. The

Company objects to the Staff adjustment and maintains that the deferred compensation is plainly part of the Company's overall employee benefit expense and is properly included as a recoverable component of the Company's cost of service. Recognizing the variability of this expense from year to year, the Company proposed to establish deferred compensation expense based on a three-year average. The deferred compensation expenses for calendar years 2009 through 2011 of ($37,393), $281,813 and $219,687, respectively, result in a three year average of $154,702. The Company proposed an adjustment to decrease deferred compensation expense by $254,505, which will result in a going level deferred compensation expense of $154,702. Co. Ex. SFK-R, at 55-56.

The Company's deferred compensation expense has been recognized as a valid, recoverable expense in past base rate cases and the Commission finds no compelling reason to reject a reasonable adjustment in this case. Basing such an adjustment on a three-year average as proposed by the Company is reasonable and will be adopted.

Healthcare Costs

The Company proposed a going level adjustment increasing medical and prescription drug costs by $747,110 to reflect going level costs for 417 active participating employees at January 1, 2012, plus five additional new hires. Co. Ex. 2, Statement G, Schedule 8. Staff proposed a corresponding adjustment of $699,959 based on employee participation levels at the end of the test year plus one additional employee. Staff Ex. ELO-D, at 16-17; Staff Rule 42 Exhibit, Statement G, Adj. No. 19. Although the Company does not agree with Staff's approach of using participation at the end of the test year, it nevertheless finds the Staff adjustment to be reasonable. Co. Ex. SFK-R, at 56.

CAD separately analyzed the costs associated with the Company's two health insurance plans, a premium-based HMO plan and the Company's self-insured Blue Cross Blue Shield plan. CAD proposed an adjustment increasing costs for the HMO plan by $225,583. CAD Ex. DLW-DP, at 17-18. CAD also proposed an adjustment decreasing costs for the self-insured plan by $50,859. Id. The Company objects to the methodology used by CAD in arriving at this adjustment. Specifically, the Company objects to CAD's use of the number of enrollees at the end of each fiscal year period, noting that, invariably, the number of enrollees changes between the beginning and the end of the fiscal year. As a result, both the cost per enrollee and the annual percentage cost increase are understated, as is the resultant proposed adjustment. Co. Ex. SFK-R, at 56-57. The collective approach used by the Company, as adjusted by Staff, is deemed to be reasonable and will be adopted.

Pension Expense

The Company records pension expense on its books based upon the Net Periodic Pension cost for the year prepared by its pension actuary in accordance with ASC 715-30 (formerly, and as referred to here, FAS 87). The Company included a Going Level adjustment to pension expense for its preliminary estimate of 2012 expense of $4,015,000; it revised this amount in Mr. Klemm's rebuttal testimony to $4,036,552, the latest amount per the actuarial valuation report dated March 28, 2012. Co. Ex. SFK-R, at 58. The Company makes an annual contribution to its employee pension plan that is different from the amount required to be expensed under FAS 87. In recent years, the Company's contribution to the plan has been substantially less than the FAS 87 level. In this testimony, Mr. Oxley adjusted pension expense to include recovery in rates of only the minimum required pension contribution for 2012 of $3,307,131, or $729,421 less than the Company.

The Company opposed the Staff's pension expense adjustment. Mr. Klemm indicated that the Company could elect, or potentially be required, to contribute more than the "minimum contribution amount." Furthermore, because the Company must reflect FAS 87 pension expense levels on its income statement, recovery in rates of a lesser amount, whether based on an ERISA minimum contribution or otherwise, will automatically erode the Company's ability to achieve its authorized rate of return, an impact that Mr. Oxley conceded. Co. Ex. SFK-R, at 57-58; Tr. II at 217-218 (Oxley).

In Mr. Klemm's rebuttal testimony and again at hearing, the Company committed to fund the FAS 87 amount recorded on its income statement, even if it were greater than the minimum ERISA contribution, if the Commission would grant recovery of its FAS 87 pension expense amount. Co. Ex. SFK-R, at 58; Tr. II at 74 (Klemm). Although Mr. Oxley indicated that the Company would need to make good on its pledge to do so and still believed that the minimum contribution amount should be the basis for rates, he agreed that the Company's proposal was reasonable. Tr. II at 216 (Oxley). The Commission agrees, and will provide for the FAS 87 amount in the Company's latest actuarial report. The Commission expects that the Company will make good on its pledge and fund its pension expenses at the amount at least equal to the amount it records on its books under FAS 87. Doing so will move the Company closer toward full funding of its pension plan, future ratepayers will benefit from this outcome, and the adverse impact on the Company's GAAP financial statements arising from this issue will be effectively addressed.

OPEB Expense

Both the Company and Staff reflected Going Level OPEB expense based upon the 2012 Net Periodic Post Retirement Benefit Cost - ASC 715-60 (formerly FAS 106), which is also prepared by the Company's actuary on an annual basis. The Company used the actuary's preliminary estimate of $341,000 for 2012 OPEB costs in its filing. Staff has updated the estimate by using the actual amount from the 2012 actuarial report ($276,299) which just recently became available to the Company. After removing the estimated capitalized costs, the difference between the Staff and Company OPEB expense levels was $59,072. Staff Ex. ELO-D, at 18.

The Company agreed with Staff witness Mr. Oxley's proposed adjustment to decrease OPEB expense by $59,072. Mr. Klemm indicated that the adjustment is appropriate since it reflects the most current information provided by the Company's actuary that was received after the Company filed its case. The gross amount was $64,701 but after applying a 91.3% O&M expense factor, the net reduction to OPEB expense is $59,072. Co. Ex. SFK-R, at 59. The Commission will incorporate the adjusted amount of $59,072 in the Company's revenue requirement.

IGS Management Fees

Effective in February of the test year, the Companies' management services fee contract with IGS Utilities was revised and the annual management fee paid in 24 equal installments was reduced from $1.718 million to initially $1.250 million per year. Since that time, the management fee was increased to $1.4 million annually, which is very close to the aggregate amount of $1,413,708 included in the test year. Tr. I at 23-24, 54-57 (Taylor); Tr. II at 11 (Klemm). Staff and CAD each proposed decreases to management fee expense. Staff adjusted the test year management services fee expense to an annualized amount of $1.25 million, based upon the February 2011 contract revision. Staff's adjustment reduced test year expense by $126,208. Staff Ex. ELO-D, at 19.

The CAD proposed an even greater reduction to management fees: a reduction of $788,712 from the test year amount. Mr. Smith contended that "it is questionable" whether the Company continues to require managers in West Virginia and "an additional management team in Tulsa" in the form of IGS Utilities. CAD Ex. RCS-D, at 50. Mr. Smith also argued that the fact that the management services agreement is an affiliate contract presented the possibility for "abuse" and "mischief" (Tr. II. at 133, 134 (Smith)) and thus required a higher level of regulatory scrutiny (CAD Ex. RCS-D, at 50). In general terms, Mr. Smith argued that the Company had failed to establish that the requested level of management fees is "necessary or reasonable." CAD Ex. RCS-D, at 50.

The Company opposed the Staff and CAD recommendations. Mr. Klemm testified that no party has indicated that the level of IGS management fees is inappropriate, or that the Company's expenditures on these services have been imprudent. If the Company had to replace these valuable services by hiring new employees or contracting with another third party, clearly that expense would be recoverable in rates. Co. Ex. SFK-R, at 59. Mr. Klemm also identified each of the services provided by IGS under the contract, which ranged from the lead role in regulatory matters, gas line and operational matters, risk management and insurance, human resources (in conjunction with Charleston-based management), labor contracts, information technology, treasury functions, and budgeting/auditing functions. Tr. II at 76-77 (Klemm).

The Commission recognizes that the management services contract has been in place continually since 2005, and the amounts paid under it have be represented in the Company's revenue requirement ever since. The Commission has no evidence of a material reduction in the services provided under that contract; indeed, the Company showed that the recent increase in the annual management fee back to $1.4 million was accompanied by a reduction in management resources in Charleston. Although the utility bears the burden of establishing that its investments and expenditures are prudent and should be recognized in rates, the Commission believes that parties seeking to disallow routine, recognized expense items should be expected to have a more sound basis for their proposed reductions than simply to contend that the utility has not shown the expense is reasonable, or to speculate that the possibility of "abuse" or "mischief" exists. The Commission will reject the Staff and CAD adjustments and approve $1,400,000 in the Company's revenue requirement, which is a reduction of $13,708.

Truck and Equipment Expense

The Company's adjustment to test year Truck and Equipment is $471,805. The increase is driven by a substantial rise in lease expense for Company trucks and an anticipated decline in salvage credits in 2012. Staff accepted the increase in truck leases but has adjusted salvage credits based on a three year average of salvage amounts from 2009-2011. The average salvage during the period was $275,925 or $175,925 greater than the Company's forecast of $100,000. Test year salvage was $314,960. Staff Ex. ELO-D, at 21.

The Company did not agree with Staff's adjustment as it was premised on the use of a three-year average of salvage value received from the disposal of trucks. The Company disposed of 57 vehicles and 1 trailer in 2011 generating $305,867 is salvage proceeds. The Company also disposed of a comparable number of vehicles in 2009 and 2010 relative to the number of vehicles leased. The Company only intends to dispose of 18 vehicles in 2012 since it only is going to lease 18 new vehicles in 2012. Thus, the $100,000 amount, or about $5,500 per vehicle on average, that the Company used in its filing is appropriate. Co. Ex. SFK-R, at 60.

Injuries and Damages Expense

Staff reduced the test year expense of $347,224 by $207,724 to reflect a Going Level cost for the average large damage claims from 2005 to date. Staff Ex. ELO-D, at 24.

CAD stated Injuries and Damages Expense can fluctuate significantly from year to year. The amount recorded by the Company in the test year ending September 30, 2011 is also higher than the expense recorded by the Company in calendar years 2009, 2010, and 2011. CAD adjusted the expense to a three-year average based on the calendar year expense for those three years. The Company's requested expense of $556, 428 is reduced by $153,816 to the three-year average of $402,612. CAD Ex. RCS-D, at 43-44.

The Company agrees with the $153,816 adjustment proposed by CAD. Given the nature of this account, CAD's methodology of using a three-year average to determine the going level amount seems reasonable and fair. The Company does not agree with Staff's adjustment which appears to use historical activity since 2005. Co. Ex. SFK-R, at 60. The Commission agrees with the adjustment proposed by CAD.

Workers' Compensation Expense

CAD determined a normalized level of workers' compensation expense by computing a three-year average of workers compensation expense to payroll, of 1.81%, and applying that percentage to CAD-adjusted payroll amount of $29,988,786. That produced a normalized workers' compensation cost of $542,450, of which 91.30% or $495,257 is charged to expense. The Company's requested amount of $512,008 (Statement A, Schedule 2, p. 3) is reduced by $16,751 to reflect the normalized workers' compensation expense of $495,257. CAD Ex. RCS-D, at 44.

The Company believes CAD's adjustment is flawed since CAD compares the test year expense, which is the gross amount prior to an allocation to capital, to an expense amount after the allocation to capital. To maintain consistency, CAD's gross going level expense of $542,450 should be compared to the test year gross expense of $512,008, resulting in an increase of $30,442. This amount should then be multiplied by 91.3% (the percent allocated to expense), resulting in an increase in going level expense of $27,793, rather than the $16,751 decrease CAD recommended. Nevertheless, the Company does not propose to increase workers' compensation expense by the $27,793 amount in this case. Co. Ex. SFK-R, at 61.

Amortization of CIS Regulatory Asset

In its amended filing at Statement G, Schedule 16, the Company included annual amortization expense of $552,798 for O&M expenses related to its Customer Information System (CIS) which it had deferred for accounting purposes. The CAD proposed to reduce annualized CIS amortization expense by $82,203 to reflect an allowed recovery over a remaining amortization period of 58 months of the estimated remaining unamortized balance at September 30, 2012, the approximate date for new rates in the current case. Amortizing the September 30, 2012 balance of $2,274,545 over a remaining amortization period of 58 months (which is the same amortization period requested by the Company) produces monthly amortization of $39,216 monthly and $470,595 annually. The $470,595 annual amortization is reflected as the going-level expense. CAD Ex. RCS-D, at 52-53. Staff provided for an amortization of the deferred costs associated with Mountaineer's conversion to a new CIS over a ten-year period. This treatment is consistent with the rate treatment afforded West Virginia American Water Company's Shared Services Center and Call Center transition costs in prior rate cases for that Company. Staff Ex. ELO-D, at 21-22.

The Company opposed the CAD and Staff adjustments. CAD's witness Mr. Smith accepted the Company's 58-month proposed amortization period, but his amortization is based on the asset balance the Company reflected on its 2010 Annual Form 2 Report filed with the Commission, without taking into account the accounting adjustments set forth in the Rule 42T filing which CAD has chosen to ignore. Co. Ex. SFK-R, at 61-62. Mr. Klemm argued that since the CIS went live on January 4, 2010, nearly three years will have elapsed when base rates established in this case will go into effect. Thus, the Company believes a 7-year amortization period is more appropriate than the 10-year amortization period proposed by Staff. Based on a 7-year amortization, the annual amount would be $381,694, resulting in a decrease of $171,104 from the Company's initial amortization of $552,798. Co. Ex. SFK-R, at 62.

The Commission believes that the Company's proposed amortization period is appropriate under the circumstances. It represents a significant reduction from the Company's initial position and should be approved.

Rate Case Expense

Staff made an adjustment to impute a normal level of rate case expense in its cost of service. The adjustment is based on estimated rate case expense of $385,000 for this proceeding and a period of three years between the Company's filing of base rate cases. The resulting normal annual rate case expense is $128,333. Since the Company's per books adjusted rate case expense is $231,939, Staff's adjustment reduces expenses by $103,606. Staff Ex. ELO-D, at 22. The CAD proposed a downward adjustment of $158,269, which reflects Mr. Smith's normalized total allowance, based on the Company's requested amount in the 2009 rate case, normalized over a period of three years. CAD Ex. RCS-D, at 43.

The Company agreed with the Staff amount of $103,606. The adjustment proposed by Staff's witness Mr. Oxley was based on projected costs by the Company for this case of $385,000. He divided this amount by three to reflect a three-year amortization and compared it to the amount the Company amortized during its test period. Co. Ex. SFK-R, at 62. By contrast, Mr. Smith's recommendation looks backward to a rate case three years ago. We will adopt the Staff/Company agreement.

Clay County Companies Amortization

The Company proposed this amortization in its last rate case and the CAD did not oppose it, with the understanding that the amortization would have been fully completed during the period in which the Company's rates established in Case No. 09-0878-G-42T would be in effect. Mr. Smith contended that continued amortization results in the deferred costs being fully amortized by March 31, 2012, well before new rates from the current rate case would become effective. Consequently, the expense in the test year should be removed. CAD Ex. RCS-D, at 53.

The Company contended that Mr. Smith's two-year amortization period is incorrect, and not what the Company has used. Mr. Klemm noted that in his rebuttal testimony in the 2009 case, the Company had agreed to use the three-year amortization period recommended by the Staff. Co. Ex. SFK-R, at 63.

The Staff proposed to permit the recovery of only $69,913 in the Company's cost of service. This amount reflects five months of amortization from November 2012, when new rates go into place, until March 2013, when the asset has been fully amortized. The Company agreed with the Staff's amortization period, but opposed its proposal to cut off the remainder of the amortization – effectively, to "look forward" into the rate year to determine going level expense, rather than using the standard historical test year approach. Co. Ex. SFK-R, at 63.

The Company argued that it does not necessarily disagree with ratemaking done on a projected test year, but that Staff should not be permitted to apply it selectively. If the Staff's approach to this adjustment were permitted, then the Company could easily identify a number of going level expense adjustments that it knows will be higher in the rate year. Co. Ex. SFK-R, at 63-64 (citing known wage rate increases that could have been annualized for the entire rate year, but were not). The Commission agrees, and will adopt the Company's proposed approach in this instance.

Regulatory Commission Expense

Staff updated the Company's adjustment to regulatory commission expenses to include the Commission's PSC fee billings issued in January and June 2012. This adjustment reduced the Company's adjustment by $195,689. Staff Ex. ELO-D, at 21.

Mr. Klemm observed that the Staff's proposed adjustment is based on invoices received in June 2012 that relate to costs that will be expensed during the period of July 2012 through June 2013. Consequently, the Staff adjustment here is similar in concept to the Staff's proposed amortization of Clay County receivership costs, in that it projects the Company's rate-year operating expenses. Notwithstanding its opposition to the Staff approach, the Company indicated that it would agree to the projected regulatory costs for calendar 2012 which would result in one-half of the Staff's proposed adjustment, or $97,845. Co. Ex. SFK-R, at 64. The Commission believes this is a reasonable outcome, and will adopt it.

Depreciation Expense

While the CAD proposed no adjustments to the Company's depreciation expense as filed, the Staff proposed three adjustments. First, the Staff made an adjustment to going-level depreciation expense, in which the Company concurred. Co. Ex. SFK-R, at 65. The Commission will adopt the Staff/Company agreement on the Staff's going-level depreciation expense adjustment.

Second, the Staff proposed to remove the Company's proposed calculation of depreciation expense based on plant balances as of September 30, 2011, the end of the test year, per Rule 42 filing requirements. Staff Ex. ELO-D, at 24-25. The Company argued that its investment in infrastructure replacement, which has been steady from year to year and has reflected a commitment in the 2004 case to expend an average of $10.2 million per year, means that its depreciation expense will always be increasing year over year. Mr. Klemm also illustrated a persistent rise in depreciation expense, and argued that its rate year depreciation expense would certainly be higher than the test year thirteen-month average, which is what the Staff recommended be used. Co. Ex. SFK-R, at 65-66. Mr. Oxley testified that he agreed with Mr. Klemm's observation that the test-year depreciation expense was approximately $1.2 million more than was included in the cost of service in the 2009 rate case, and with the proposition that all else equal, similar levels of investment year over year are likely to increase depreciation expense over time. Tr. II at 222 (Oxley). The Commission is interested in promoting infrastructure replacement, and like the Staff, the Commission recognizes that depreciation levels are likely to increase over time when a utility has a robust infrastructure replacement program. For this reason, the Commission will adopt the Company proposal to use test-year end asset balances for establishing depreciation expense.

Finally, Staff proposed to eliminate depreciation expense on Utility Plant balances funded by customer advances for construction. In its adjustment, Staff used the thirteen-month average balance of customer advances and the book depreciation rate for gas distribution mains (2.54%). Staff Ex. ELO-D, at 25. In response, Mr. Klemm contended that unlike contributions in aid of construction, which serve as an offset to project costs, customer advances are recorded as a liability and subject to refund, and are typically received well in advance of completion of the projects and their transfer from construction work in process to utility plant. It is only at that point, Mr. Klemm argued, that the Company begins to record depreciation expense. During the interim, customer advance amounts are available to lower short-term borrowings and interest expense; for this reason, it would be inappropriate to reduce depreciation expense for the same amounts. Mr. Klemm also observed that the Staff did not offer this adjustment in the 2009 rate case. Co. Ex. SFK-R, at 67. The Commission is persuaded by the Company's argument that to reduce depreciation expense by customer advances would fail to reflect the availability of these funds to reduce short-term borrowings before the associated plant additions are placed into service. The Staff's recommendation on this point is rejected.

Other Staff and CAD Adjustments

Staff's proposed test year expenses included a payment made to Roanoke Gas Company for rate case services. Since Staff had provided for rate case expense in its adjustment number 14, it is appropriate to eliminate the payment for $25,247 recorded to account 923. Staff Ex. ELO-D, at 23.

Staff proposed adjustment of the Software Maintenance Expense by $22,241. The Company has been able to negotiate a lower bill from Microsoft to properly license the Company's software. The $14,789 annual reduction in costs is reflected in adjustment number 26 of Staff s Rule 42. The remainder of the variance ($7,452) is due to including the actual test year amortization of Cogsdale (Customer Information System) software licensing fees in the adjustment. Staff Ex. ELO-D, at 20.

Staff calculated a slightly higher adjustment to account for the January 22, 2012 increase in US Postal rates than the Company but reduced test year postage expenses booked to reflect the actual cost of postage billing for the year. Staff's adjustment in total is $3,887 less than the Company. Staff Ex. ELO-D, at 20.

CAD proposed $9,688 of Membership and Industry Association dues should be disallowed. The cost of memberships in industry associations is a discretionary expenditure of a gas utility. Except for organizations related to reliability, these expenditures are not directly essential to the provision of gas service. The cost of membership in organizations should not be reflected in rates unless the Company can demonstrate the cost is necessary for the provision of safe, reliable, and reasonably priced gas service, or that such membership otherwise provides a direct benefit to ratepayers. The Company has neither explained nor justified these expenditures. Given the discretionary nature of these expenditures it would be unreasonable to include them in rates without some type of review for cost/benefit and appropriateness. At minimum, the lobbying portion of the dues should be disallowed. Additionally, for the American Gas Association ("AGA") dues, the portion of dues relating to certain NARUC-sponsored audit categories should be excluded. CAD Ex. RCS-D, at 55.

The Company accepts the Staff's proposed adjustments in the areas of outside service expense (a $25,247 reduction relating to RGC Resources), software maintenance expense (a

$22,241 reduction), and postage expense (a $3,887 reduction), as well as CAD's proposed adjustment for industry association dues (a $9,688 reduction). Co. Ex. SFK-R, at 67-68.

Taxes Other Than Income Taxes

West Virginia municipal B&O taxes are initially calculated based on the going level revenues and subsequently adjusted for the revenue adjustment approved in this case. The Staff proposed a reduction in State B&O tax of $32,189 based on its calculated going level revenues. In Mr. Klemm's rebuttal, the Company proposed an increase in State B&O tax of $76,641 based on going level revenues. Co. Exs. SFK-R, at 68 and SFK-8. This increase was primarily due to the billing determinants of former customers of East Resources with a higher PGA rate effective November 1, 2012. The Commission agrees with the going level revenues as determined by the Company and adopts the additional increase in State B&O tax of $76,641. Taking into account the annual revenues generated by the Commission's approved revenue requirement in this case, the Commission establishes an additional increase to State B&O taxes of $318,370.

Interest on Customer Deposits

The CAD stated the Company did not propose to include any interest on customer deposits as an operating expense. CAD Ex. RCS-D, LA-1, Schedule C-5. Mr. Smith determined the going level amount of interest on customer deposits by applying the most current interest rate of 0.10% per the Commission's Order dated February 3, 2009 (General Order No. 185.30) to the Company's balance of customer deposits. This adjustment increases test year operating expenses by $5,001. CAD Ex. RCS-D, at 45. The Company accepted the CAD's proposed increase to interest expense on this point. Co. Ex. SFK-R, at 68.

Interest Synchronization

The interest synchronization adjustment is dependent on the Commission's determination of the appropriate levels of rate base and the weighted average cost of debt to be used in calculating the revenue requirement, and in consequence the appropriate amount of interest to be included in the income tax calculation. CAD Ex. RCS-D, at 54. Because the CAD and Staff rate base recommendations vary dramatically from the Company's proposed rate base, there are significant differences between the Staff and CAD recommendations and the Company's position. The Staff proposed a combined decrease of $896,710, as compared with the Company's proposed increase of $163,607, for a difference of $1,060,317. Co. Ex. SFK-R, at 69. The difference between these two positions relates primarily to differences in the parties' respective rate base and weighted average cost of debt recommendations. In addition, the Staff did not include the amortization costs associated with the loss on the reacquired debt issuance, an adjustment the Company opposed because it ignored the fact that customers are benefiting from a lower interest rate on current long-term debt agreements. Id. The CAD's proposed interest synchronization adjustment would provide for additional state income tax expense of $72,837 and additional federal income tax of $303,450, for a total of $376,287.

Based on our determinations on rate base and cost of debt, and including the amortization costs on the loss on reacquired debt, and because in the rate year the Company is unlikely to experience the same over-recovery of gas cost position that prevailed during the test year, the Commission establishes an interest synchronization increase of $131,830.

Income Tax Expense

The Company calculated its income tax expense on the basis of statutory federal and state rates, with adjustments for the income tax effects of non-income tax related adjustments on Statement A of the Revised Rule 42 Exhibit, as well as the impact of eliminating various book-tax timing differences that affect current and deferred income taxes. Co. Ex. SFK-D, at 20. For many of the same reasons the Company proposed to reduce its ADITs liability by the amount of an NOL deferred tax asset, the Company's income tax calculations did not reflect a reduction associated with the impact of NOL carryforwards on the Company's projected income tax payments during the rate effective year. Id. at 22. Mr. Klemm supported the calculation of income tax expense on a normalization approach for all state and federal income taxes, identifying a number of reasons (matching of expenses and revenues, rate stability, intergenerational equity) that can be problematic under a flow-through approach in his view, and citing the Federal Energy Regulatory Commission's requirement for use of full tax normalization. Id. at 34-36. He also alerted the Commission to the possibility that a failure to normalize and to add back the NOL deferred tax asset to rate base might violate IRS normalization requirements. Id at 38.[4] In more practical terms, Mr. Klemm observed that income taxes are a cost of service like any other expense related to a year's economic activity. In the Company's presentation, all of its expenses were developed using the accrual basis of accounting, and the calculation of income tax expense should be no different. Unless income tax expense is included in the Company's cost of service, the Company will not collect the revenues necessary to cover its income tax expense. Id. at 42.

Staff and the CAD both proposed adjustment to income tax expense; the Staff's adjustments were far more significant. First, Staff adjusted tax depreciation at going level to reflect the reduction in available bonus tax depreciation from 100% for qualified investments in 2011 to only 50% in 2012, to reflect a reduction in tax depreciation from $29,653,313 in the test year to $20,938,128 at going level. The Company made a comparable but smaller adjustment for tax depreciation, to $16,281,179 at going level. Mr. Oxley noted that the Company's actual tax depreciation for years 2008- 2010 from its income tax returns averaged $19,767,474. The Staff also recommended that state income taxes should be calculated on a flow through basis, rather than the normalization approach that the Company used. Mr. Oxley argued that the Company had substantial state net operating income tax loss carryforwards and did not anticipate paying state income taxes until 2014. For this reason, Staff included no allowance for current state income tax expense. Staff Ex. ELO, at 25-26.

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4 Using these principles, Mr. Klemm indicated that the Company had normalized the impact of book-to-tax differences for (i) the net difference between book depreciation and tax depreciation, (ii) contributions in aid of construction; (iii) the timing of deductions for OPEBs, and (iv) meal expense, 50% of which cannot be deducted and therefore constitutes a permanent difference for which no deferred tax is computed. Co. Ex. SFK-R, at 40-41.

Other than the significant difference in revenue requirement recommendations, the CAD's methodology was fairly consistent with the Company's. However, like the Staff, Mr. Smith recommended a flow-through approach for state income tax expense. Mr. Smith explained that there is no requirement to normalize state income taxes, offering this as a justification for recommending the flow-through of deferred income tax benefits to customers. CAD Ex. RCS-D, at 60. Mr. Smith also argued that the Company had recorded state ADITs on its books at state tax rates that are higher than the currently applicable state income tax rate, and consequently that the Company has excess state ADIT on its books. Id. at 61.

The Company opposed a number of aspects of the Staff and CAD income tax expense recommendations. Mr. Oxley's recommended tax depreciation deduction of $20,938,128 was "clearly overstated," Mr. Klemm testified, because it failed to take into account the Company's explanation, provided in data responses, that test year tax depreciation was unusually high because the full amount of calendar 2010 bonus depreciation was reflected in December 2010 and, in 2011, the Company reflected monthly estimates of bonus depreciation impacts in its books. Thus, Mr. Klemm contended, Staff "doubled up" test year tax depreciation for a portion of the test year, resulting in an amount higher than the three-year of $19,767,474 reflected in the 2008 to 2010 tax returns. This result is illogical, Mr. Klemm said, given that bonus depreciation is only 50% in 2012. By contrast, Mr. Klemm defended the Company's use of $16,281,179 for tax depreciation, an estimate provided by the Company's audit and tax firm. Co. Ex. SFK-R, at 70-71.

Mr. Klemm strongly opposed the Staff and CAD positions that deferred state income related to accelerated tax depreciation should be flowed through to ratepayers instead of normalized. If the Company is not allowed to normalize tax depreciation for state income purposes, then it will have to strongly consider not claiming bonus depreciation, resulting in the Company and ultimately its ratepayers, failing to receive the benefit of a tax free loan from the government. Co. Ex. SFK-R, at 71. Mr. Klemm criticized Mr. Smith's justification that normalization for state tax expense should not be used simply because IRS normalization rules did not require it. Mr. Klemm also referenced decisions in which this Commission has cited the attributes of a normalization approach (including smoothing out fluctuations, avoiding inconsistent and possibly unfair results between rate cases, and addressing intergenerational inequities) and the fact that we are not precluded from normalizing timing differences where appropriate. Through a series of examples, Mr. Klemm also illustrated how intergenerational equities can occur and how, through the timing of rate cases, customers might actually pay higher current state income tax expense without the offsetting benefit of the ADIT rate base reduction that would be available under a normalization approach. Id. at 78-79.

Moreover, Mr. Klemm indicated that while a flow-through approach was used in the 2004 rate case, normalization was used in the 2009 rate case, and a return to the flow-through approach would be selective and inappropriate. "Regulatory fairness requires a consistent approach for this issue, rather than a changing, uncertain approach where in one case we are required to flow through and the next case we are required to normalize." Id. at 73. Mr. Klemm asserted that state and federal taxes should be calculated based on generally accepted accounting principles that are consistent with the Company's state and federal income tax returns, in which normalization accounting is used. Id.

Mr. Klemm also opposed the Staff position that the Company's NOL carryforward be used as a basis to disallow recovery of any state income tax in cost of service. According to Mr. Klemm, the Company had advised the Staff in data responses that based on its estimates, the Company would start making state tax payments in 2014, even assuming its claim of bonus depreciation on both its 2011 and 2012 tax returns. Mr. Klemm advised that the Company would have to strongly consider not claiming bonus depreciation (to accelerate paying state taxes by 2013) if that is a determinant of the inclusion of the recovery of state income taxes in its cost of service. Id. at 71-72.

The Commission recognizes that the recovery of federal and state income tax expense has been a controversial and sometimes heated issue over the last several years. Often disputes on this point center on the issue of consolidated tax savings, which as the Company points out, is not relevant to the Company as a stand-alone West Virginia gas utility with no parent impact on the Company's income tax status and no affiliates to affect a consolidated return. Despite the presence of NOL carryforwards, we are presented with a more basic set of issues to resolve in this case.

First, we believe that the Staff's recommendation of $20,938,128 for tax depreciation is unduly high, as it represents a higher level of tax depreciation than has been present over the last three years. In this situation, it is likely that the Company's estimate of $16,281,179, which was provided by the Company's auditing firm, is more reliable given the reduction in 2012 to 50% bonus depreciation.

On the state income tax question, we are persuaded that it is appropriate to continue the use of normalization in the calculation of state income tax expense. We agree with the Company that the normalization approach has a number of benefits, that its use is fairer to customers over time, and that it avoids the potential for adverse outcomes for customers in certain situations. Moreover, we do not believe that we are limited to the use of the flow-through method simply because the use of normalization is not required to prevent an IRS normalization violation. In consequence of this decision, the Commission will expect that the Company will transition to a calculation of rate base that include all state and federal ADITs.

Finally, the Staff's provision of zero income tax expense is not appropriate in this instance. The Company has proven that its NOL carryforward position is associated with its past insufficiency of revenues, and we believe a further reduction in its cost of service now would add insult to injury, and further impair the Company's ability to achieve its authorized return in the future. Additionally, we believe that ratemaking approaches that operate to disincentivize the use of all available tax deductions, as both a flow-through methodology and the Staff state income tax provision would, are not to be favored. The Commission wishes to encourage utilities to take advantage of all available tax deductions that make interest-free cash available, from which customers can benefit when the cash benefits of those deductions are realized and appropriate ADITs reductions to rate base are made.

Uncollectible Expense

Staff proposed an adjustment to increase going level uncollectible (bad debt) expense by $2,897 based on its proposed amount of going level billed revenues. The Company maintains that while billed revenues for an historical three-year period are used in computing the weighted average uncollectible ratio, that ratio should be applied to going level operating revenues, which includes unbilled revenues, to determine a proper amount of going level uncollectibles, since unbilled revenues ultimately become billed revenues. Under the Company's calculation, bad debt expense should be increased by $25,902 over the amount in the Company's original filing. The Company's proposed adjustment is reasonable and will be adopted.

IV. Cost of Service and Rate Design

The Company is not proposing any rate design changes in this proceeding. However, the Company proposed to move the customer charge portion of the rate more closely to the cost of that component. Ms. Lee explained that, in determining the cost of service for each customer rate class, the Company utilized methods which are consistent with the approach taken by the CAD in the Company's previous base rate case. The results of those methods demonstrate that, while raising the residential and commercial customer charges in the current Mountaineer rate structure is a step toward recovering the costs for those customer classes, additional increases would be required to fully recover their costs. Co. Ex. DPL-D, at 2-3; Tr. I at 114 (Lee).

According to Ms. Lee, several jurisdictions have adopted a variety of mechanisms to stabilize bills to customers. As of April 2011, 35 states have adopted some form of mechanism to stabilize bills to natural gas customers, such as revenue decoupling, fixed monthly fees, and weather normalization rates. Revenue decoupling separates pure gas cost from the rest of the billing components and sets a fixed, flat fee for all non-gas cost components, allowing utilities to more consistently recover their fixed costs while allowing customers to experience the saving on conservation, or any variable cost, through their usage. Revenue decoupling is often tied to a tracking mechanism that provides for a true-up when revenue either exceeds, or falls short, of fixed cost. Decoupling allows the utility to earn its authorized rate of return while making the recovery of fixed costs less dependent of the level of consumption. Ms. Lee also addressed another rate design, the straight-fixed variable rate (SFV), which takes decoupling one step further and charges customers a fixed monthly fee for all costs except for the pure gas cost component. This method eliminates any variable costs for the customers usage-based rates and puts all costs into the flat, fixed fee other than any cost that would be recovered through a 30-C proceeding. This rate design is structured so that all costs, other than gas cost, are fixed and should not be subject to consumption variations. One other rate design option is the use of a weather normalization rate which equalizes usage to eliminate a portion of the volatility from the weather. This type of rate design will stabilize bills to customers by minimizing the need for frequent rate filings tied simply to the utility's inability to earn its authorized rate of return due to fluctuations in the weather. The Company has not requested a decoupled or SFV rate, or weather normalization in this proceeding. Instead, the Company believes that an increase in the monthly customer charge is a step toward addressing the issue of customer rates that better match the cost of providing service. Co. Ex. DPL-D, at 7-9.

The Company is also requesting that it consolidate rates for customers previously served by East Resources so there will be one rate schedule for each class of customer, as contemplated in Case No. 10-0686-G-PC. The Company has included all of its customers in its cost study, and the resulting rate will be appropriate for all customers in each rate class. (In accordance with the stipulation reached in Case No. 10-0686-G-PC, the former East Resources customers will adopt the Company's purchase gas adjustment (PGA) rate at the time of the base rate change.) While consolidating a variety of rates into one resulting rate will have varying bill impacts for customers, this change will be a one-time occurrence. This transition is reflected in Statement D in the Company's Rule 42 exhibit as well as in the proposed Tariff. Co. Ex. DPL-D, at 3.

In this proceeding, Mountaineer is requesting to allocate the increase to classes as follows:

RS:	68.6%
GS:	30.9%
LGS:	0.0%
WS:	0.5%
IS:	0.0%

Co. Ex. DPL-D, at 3.

The existing and proposed customer charges by rate schedule are as follows:

	Existing		
Rate Schedule	Mountaineer ($)	East Resources ($)	Proposed ($)
RS	8.00	9.00	11.40
GS	25.00	9.00	39.63
LGS	365.00	18.00	365.00
IS/LIS	775.00/575.00	-	801.36
WS	66.00	9.00	169.32

Co. Ex. DPL-D at 5

A primary reason for including the increase in the customer charge is simplicity. Changes in rates that are included in the fixed monthly customer charges will enable customers to experience more stability in their bills throughout the year, have less susceptibility to cold weather impacts and provide more visibility for customers to understand the costs of providing utility services. Co. Ex. DPL-D, at 5.

Staff presented a Class Cost of Service Study (CCOS), based on Case No. 93-0005-G-42T. Staff Exs. DLK-D, at 2-10, DLK-1. Staff and the CAD recommended that the Commission reject the Company's proposal to recover any increase by a method that, in their view, places most of the burden on residential and general service customers because such proposal is contrary to the Company's own CCOS. Staff Ex. DLK-D, at 3; CAD Ex. BLH-D, at 7-8. Both Staff and the CAD also criticized the Company's inclusion of various costs as "customer costs" in justifying an increase in the customer charge. Staff Ex. DLK-D, at 4; CAD Ex. BLH-D, at 12-13. Mr. Harris recommended that the Company's base rates should be increased by the same percentage as the overall base rate increase. CAD Ex. BLH-D, at 14. He also summarized several asserted errors in the Company's CCOS. CAD Ex. BLH-D, at 14-16.

In her rebuttal testimony, Ms. Lee stated that many utilities have added riders and special rates to cover the cost of a variety of operating conditions that enhance their ability to earn their authorized rates of return. Ms. Lee further noted that natural gas rates only have two components – (i) a monthly fixed charge and (ii) a variable charge, made up of gas cost and other variable, non-gas cost related costs. Natural gas tariffs tend to label all fixed costs as a customer cost, but the "customer charge" component of the cost study is really a "fixed cost" component, in that it properly includes cost components that are not limited to pure "customer" costs. A fixed charge covers any cost that a utility has to pay independent of any business activity, and not just a customer cost component; it is the charge that will not vary by the level of consumption that a customer uses and is similar to a zero-intercept cost study. Co. Ex. DPL-R, at 2.

Ms. Lee maintained that the Company's proposed rate design is not in direct conflict with any CCOS, but that strict adherence to a class cost of service study is not the best way to design rates in today's utility industry. She pointed out that FERC abandoned the 1952/1973 Seaboard methodology in 1983 for the MFV (Modified Fixed-Variable) methodology, which gave way to the SFV methodology in 1992. There are many approaches to determine on which costs are fixed, variable, customer-related, and consumption-related, and the process of functionalization, classification, and allocation of costs has been the subject of many books on rate design theory. The fact remains that new methods of designing rates are being used in the states that surround West Virginia and in the majority of other states across the country. The Company encourages the Commission to consider a wide range of rate design options when allocating revenue in base rate proceedings, including in this case. Co. Ex. DPL-R, at 11-12.

At the evidentiary hearing, Ms. Lee agreed that the customer charge presently authorized for Hope Gas is $8.99. Tr. I at 102 (Lee). She also explained the allocation of the proposed rate increase in the context of customer classes and the former customers of East Resources. Tr. I at 103-108, 124 (Lee). Ms. Lee defended the proposed increase in the customer charge, including from the customer's perspective, as well as the benefits to the Company in terms of stability. Tr. I at 109-112, 122-125 (Lee). She also elaborated on the changes in ratemaking since the Company's 1993 rate case, and on the Company's declining usage. Tr. I at 118-121, 125-133 (Lee). Ms. Lee feels that the effect that adopting any of these innovations would have on the Company's risk profile for purposes of calculating a ROE would be minimal, as the effects are already reflected in the results for other comparable utilities in these other jurisdictions. Tr. I at 133-134 (Lee).

During his examination at the hearing, Mr. Harris stated that, while the CAD had for years "fought against customer charges, mostly because our phone would ring off the hook every time they went up[, w]e've changed that." Tr. II at 199 (Harris). Ms. Kellmeyer acknowledged that the Commission is not bound to the 1993 or any other CCOS methodology in allocating the Company's cost of service among customer classes or in designing rates in this proceeding. Tr. II at 239 (Kellmeyer).

The Commission accepts the Company's proposed cost allocations and rate design as reasonable. No particular methodology, particularly one adopted nearly 20 years ago, binds the Commission in its determinations as to the appropriate means by which to recover the revenue requirement. The Company's proposed customer charge increases are innovative and consistent with more recent ratemaking approaches Ms. Lee identified in other jurisdictions, and the resulting charges are reasonable under the circumstances. The Commission finds that the proposed customer charges shown in the last column of the table above are appropriate and should be implemented, and that the entirety of the revenue requirement increase in this case should be provided through the revised customer charges.

V. Rate Impact

The results of our decisions described above, as summarized in Appendix A, reflect an overall revenue requirement of $256,872,390, before the addition of increased uncollectible expense and increased state B&O tax. Accordingly, our decisions herein reflect that the Company should be granted an increase of $9,364,381. In addition, and as indicated above, the entirety of the revenue requirement increase in this case should be provided through the revised customer charges the Commission has approved.

VI. First Amendment to Motion For Protective Treatment

On July 13, 2012, the Company filed a Motion for Protective Order (Motion), seeking protective treatment of information filed under seal in response to various discovery requests and confidential supporting documents and workpapers filed with the amended direct testimony of Scott F. Klemm. Subsequently, on July 16, 2012, the Company filed its Amended Motion for Protective Order (First Amendment) requesting protective treatment for certain confidential information filed under seal in response to discovery requests and made available to parties that executed appropriate protective agreements in this case.

The Commission concludes that it is not necessary to decide the issue at present. The information for which protective treatment is sought was not submitted for filing as part of the case of any party. Additionally, no entity has requested the Commission provide copies of the information for which protective treatment is sought. The Commission will continue to segregate and keep filed under seal the sensitive documents until such future time, if any, that the Commission receives a Freedom of Information Act request for the documents. Upon such filing, the Commission will notify the Company and provide it with an opportunity to argue whether such documents should be given permanent protective treatment.

FINDINGS OF FACT

1. The capital structure proposed by the Company and endorsed by CAD for ratemaking purposes best reflects the Company's current financial structure, tempered by the recognition of the seasonality of gas sales and the effects upon levels of debt and equity.

2. Dr. Avera's analyses of the cost of equity for the Company addressed both the various theoretical models and the Company's particular circumstances.

3. Contrary to Staff's only criticism of his analyses, Dr. Avera did not use "adders" of the type previously rejected by the Commission.

4. Staff's proposed ROE is substantially lower than the findings of the regulatory bodies in the jurisdictions where Mr. Dworsky's sample group utilities do business.

5. The parties have significantly different positions on the Company's rate base, and those positions create a significant difference in their respective revenue requirement recommendations.

6. The CAD and Staff rate base proposals are each more than $20 million less than the Company's rate base calculation, and are far below each party's recommendations for the Company's capitalization.

7. The Company is a stand-alone West Virginia gas distribution utility with its own debt, does not conduct any non-utility business, and has not paid any premiums for the utility assets it has acquired.

8. The Company has experienced a history of net operating losses and significant shortfalls in its delivery volumes, resulting in its inability to earn its authorized equity returns over a several year period.

9. In the years 2006, 2007, 2008, and 2009, the Company had negative taxable income and paid no federal income taxes.

10. Without tax liability in these years, the tax benefits of accelerated depreciation deductions did not materialize for the Company.

11. There is no evidence that during this extended period of losses, the Company generated revenues associated with federal income tax that it has subsequently held and not paid over to the federal government.

12. To the extent the Company lost money and had no taxable income on which to pay federal income taxes, the interest free loan benefits of plant-related depreciation deductions could not have created and did not create any cash benefit for the Company.

13. The plant-related ADIT liabilities should be limited to only that portion of plant-related deferred tax liability that customers have actually been charged through and paid for in rates. Only this amount should serve as a reduction to rate base.

14. Reducing the Company's plant-related ADITs liability would have no effect on the availability of that liability to reduce rate base in the future.

15. Plant-related ADITs are to continue to be recorded on the Company's books and considered to the appropriate extent in establishing rates, such that like other timing differences, they will be reversed when book depreciation exceeds tax depreciation for those assets.

16. ADITs associated with alternative minimum tax (AMT) carryforwards, should reduce the total ADIT rate base reduction.

17. Accelerated depreciation tax benefits generally correspond with the life of the asset.

18. During the years between the 2004 and 2009 rate cases, state income taxes were "flowed through" for the Company and no state income tax expense was included in the cost of service.

19. It is inappropriate to exclude from rate base the ADITs associated with unamortized debt costs and the Company's CIS regulatory asset.

20. Unamortized debt costs are costs such as bank fees and legal expenses incurred by a utility in connection with executing debt agreements.

21. Deducting unamortized debt costs from the Company's long-term debt balance is consistent with the Commission's approach in recent West Virginia-American Water and APCo rate orders.

22. During the test year, the Company funded prepayments by short-term borrowings, and not from excess cash.

23. In this situation, the Company's lead lag study from the 2009 case supports inclusion of prepayments in rate base.

24. The Company is advised that in the future, it must either prepare a new lead lag study or provide other clear evidence in its case-in-chief that a working cash allowance calculation has demonstrated that prepayments are not offset by negative working cash.

25. The Company proposed to include in rate base regulatory assets for four items: (i) the Company's investment of approximately $2.7 million in its new CIS, (ii) receivership costs associated with its service as a receiver for the Clay County Gas Utilities; (iii) unamortized rate case expenses; and (iv) closing related to the Ashford Gas acquisition.

26. The Commission will permit inclusion in rate base of the CIS implementation costs but deny the Company's recommended rate base inclusion of the unamortized balance of the Clay County receivership costs and the unamortized rate case expenses. The Ashford Gas closing costs should also be removed from rate base.

27. The Company maintains two accrual accounting-based reserves on its books. One reserve is for remaining estimated costs for pending personal injury claims, property damage

claims, and customer complaint claims, and the second reserve is for incurred but not reported medical claims.

28. As of March 31, 2010, when the Company increased its base rates as a result of the 2009 case, the total reserve of these two accounts was $925,000, nearly identical to the 13-month average of the test year.

29. Reducing rate base by amounts that are in accounts payable, when they are a component of a working cash calculation, would effectively be a double counting of the same amounts.

30. It is reasonable to adopt the Staff adjustment to increase local B&O Tax surcharge revenues at going-level by approximately $413,000.

31. It is reasonable to adopt the Staff adjustment to increase going-level revenues by approximately $92,000 to reflect the consolidation of the rates charged to the former customers of East Resources and the rates charged to the Company's other customers.

32. The Company's proposed weather normalization adjustment is reasonable and will be adopted by the Commission.

33. It is appropriate, in calculating a going level adjustment to PGA revenues attributable to the former customers of East Resources, to apply the Company's current PGA rates for its other customers.

34. Unbilled customer charge revenues related to former customers of East Resources should not be included in Staff's going level amounts for residential, general service and wholesale customers because twelve months of customer charge revenues are included in "billed" base rates.

35. The Staff adjustment to going level billed sales volumes relating to former customers of East Resources to reflect twelve months of activity, including September 30, 2011 should not include estimated unbilled volumes at September 30, 2010.

36. The residential unbilled base rate charge revenues for current Company customers at September 30, 2010 should be based on the current base rate charge of $3.024 per Mcf rather than the old rate of $2.896.

37. The billed going level gas cost volumes used by Staff for the LGS customer class should be increased by 461 Mcf, with corresponding increases in revenues of $2,270 and in gas costs of $2,173.

38. Miscellaneous revenues shall be increased by $99,537 to normalize the amount of test year forfeited discounts.

39. It is reasonable to adopt the Company's proposed adjustment increasing going level uncollectible (bad debt) expense by $25,902.

40. Staff's uncontested adjustments to payroll and related expenses are reasonable and shall be adopted.

41. The proposed CAD adjustment to reduce the Company's proposed adjustment for new employee wage and salary costs by $332,953 is reasonable and shall be adopted.

42. It is reasonable to adopt the Company's going level adjustment increasing salaries and wages by $365,500 for performance payments made in February 2012.

43. The methodology used by both the Company and Staff in calculating the going level adjustment for 401K matching expense is appropriate. The Commission concludes that an adjustment of $29,811 is proper, based on a going level payroll of $30,531,831, and shall be adopted.

44. The Commission concludes that a going level adjustment increasing payroll taxes (Social Security and Medicare) by $59,796 is proper, based on a going level payroll of $30,531,831, and shall be adopted.

45. The Staff adjustment reducing vacation pay expense by $55,036 is reasonable and shall be adopted.

46. The Company's deferred compensation expense has been recognized as a recoverable expense in past base rate cases and there is no compelling reason to reject a reasonable adjustment in this case. Basing such an adjustment on a three-year average is reasonable.

47. The collective approach used by the Company for health care and related expenses, as adjusted by Staff, is reasonable and will be adopted.

48. The Company records pension expense on its books based upon the Net Periodic Pension cost for the year prepared by its pension actuary in accordance with ASC 715-30 (formerly FAS 87).

49. The Company included a Going Level adjustment to pension expense for its preliminary estimate of 2012 expense of $4,015,000; it revised this amount to $4,036,552, the latest amount per the actuarial valuation report dated March 28, 2012.

50. The Staff adjusted pension expense to include recovery in rates of only the minimum required pension contribution for 2012 of $3,307,131, or $729,421 less than the Company.

51. The Company committed to fund the FAS 87 amount recorded on its income statement, even if it were greater than the minimum ERISA contribution, if the Commission would grant recovery of its FAS 87 pension expense amount.

52. The Commission will provide for the FAS 87 amount in the Company's latest actuarial report. The Commission expects that the Company will fund its pension expenses at the amount at least equal to the amount it records on its books under FAS 87.

53. The Company agreed with Staff's proposed adjustment to decrease OPEB expense by $59,072, which reflects the most current information provided by the Company's actuary. After applying a 91.3% O&M expense factor, the net reduction to OPEB expense is $59,072.

54. The management services fee contract with IGS Utilities was revised and the annual management fee paid in 24 equal installments was reduced from $1.718 million to initially $1.250 million per year. Since that time, the management fee was increased to $1.4 million annually, which is very close to the aggregate amount of $1,413,708 included in the test year.

55. The IGS management services contract has been in place continually since 2005.

56. Services provided by IGS range from regulatory matters, gas line and operational matters, risk management and insurance, human resources (in conjunction with Charleston-based management), labor contracts, information technology, treasury functions, and budgeting/auditing functions.

57. There is no evidence that the level of IGS management fees is inappropriate, or that the Company's expenditures on these services have been imprudent. The Commission will include $1.40 million annually in the cost of service, a reduction of $13,708 in the test year expense.

58. The CAD proposal to use a three-year average of injuries and damages expense to determine the going-level amount is reasonable.

59. The Company included annual amortization expense for O&M expenses related to its CIS which it had deferred for accounting purposes.

60. Because the CIS went live in January 2010, nearly three years before the beginning of the rate year in this case, it is appropriate to use a 7-year amortization period in lieu of the 10-year amortization period proposed by the Staff.

61. The Staff proposed to permit the recovery of only five months of the amortization associated with the Clay County utilities acquisition expense. The Staff amortization period is appropriate, but it is inappropriate to cut off the remainder of the amortization. Doing so would effectively look forward into the rate year to determine going level expense, which in general terms is not consistent with the Commission's historical test year approach.

62. The Commission will adopt the Staff's proposed compromise on regulatory commission expense, to which the Company agreed.

63. The Commission will adopt the Staff/Company agreement on the Staff's going-level depreciation expense adjustment.

64. The Company's investment in infrastructure replacement has been steady from year to year and has reflected a commitment in the 2004 case to expend an average of $10.2 million per year.

65. All else equal, continued infrastructure replacement will result in depreciation expense that increases year over year.

66. The Commission is interested in promoting infrastructure replacement, and for this reason will use test-year end asset balances for establishing depreciation expense.

67. Customer advances are recorded as a liability and subject to refund, and are typically received well in advance of completion of the projects and their transfer from construction work in process to utility plant.

68. Reducing depreciation expense by customer advances would fail to reflect the availability of these funds to reduce short-term borrowings before the associated plant additions are placed into service.

69. The Company's acceptance of the Staff's proposed adjustments in the areas of outside service expense, software maintenance expense, and postage expense, as well as CAD's proposed adjustment for industry association dues is reasonable, and the Commission will adopt these adjustments.

70. Taking into account the annual revenues generated by the Commission's approved revenue requirement in this case, the Commission establishes an additional increase to State B&O taxes of $318,370.

71. The Company accepted the CAD's proposed increase to interest expense on customer deposits.

72. Based on our determinations on rate base and cost of debt, and including the amortization costs on the loss on reacquired debt, and because in the rate year the Company is unlikely to experience the same over-recovery of gas cost position that prevailed during the test year, the Commission establishes an interest synchronization increase of $131,830.

73. The Company calculated its income tax expense on the basis of statutory federal and state rates, with adjustments for the income tax effects of non-income tax related adjustments as well as the impact of eliminating various book-tax timing differences that affect current and deferred income taxes.

74. The Company supported the calculation of income tax expense on a normalization approach for all state and federal income taxes, identifying a number of reasons (matching of expenses and revenues, rate stability, intergenerational equity) that can be problematic under a flow-through approach.

75. Income taxes are a cost of service like any other expense related to a year's economic activity for a utility.

76. The Staff did not take into account the fact that test year tax depreciation was unusually high because the full amount of calendar 2010 bonus depreciation was reflected in December 2010 and, in 2011, the Company reflected monthly estimates of bonus depreciation impacts in its books. For this reason, the Staff's calculation "doubled up" test year tax depreciation for a portion of the test year.

77. While a flow-through approach was used to determine the Company's state income tax expense in the 2004 rate case, normalization was used in the 2009 rate case, and a return to the flow-through approach would be inappropriate at this time.

78. The normalization approach minimizes intergenerational inequity, is fairer to customers over time, and avoids the potential for adverse outcomes for customers in certain situations.

79. The Commission is not limited to the use of the flow-through method simply because the use of normalization may not be required to prevent an IRS normalization violation.

80. It is appropriate to continue the use of normalization in the calculation of state income tax expense.

81. The Company's NOL carryforward position is associated with its past insufficiency of revenues, and a further reduction in its cost of service on account of those insufficiencies would further impair the Company's ability to achieve its authorized return in the future.

82. Ratemaking approaches that operate to disincentivize the use of all available tax deductions are not to be favored. The Commission encourages utilities to take advantage of all available tax deductions that make interest-free cash available, from which customers can benefit when the cash benefits of those deductions are realized and appropriate ADITs reductions to rate base are made.

83. While billed revenues for an historical three-year period are used in computing the weighted average uncollectible ratio, that ratio should be applied to going level operating revenues, which includes unbilled revenues, to determine a proper amount of going level uncollectibles.

84. The Company's proposal to recover its revenue deficiency through increased customer charges is consistent with more recent ratemaking approaches, and the resulting charges are not disproportionate to those of other utilities.

CONCLUSIONS OF LAW

1. Utility rates should allow a public utility the opportunity to earn a level of revenues sufficient to attract capital in the competitive money market, balanced with the interests of the consuming public in receiving fair and reasonable rates. The Commission strives to adopt ratemaking methodologies that, when applied in practice, will provide this opportunity.

2. The Commission attempts to provide privately-owned utilities with a company-specific return on equity (ROE) based on empirical studies of returns in the market while balancing the interests of ratepayers in receiving fair and reasonable rates.

3. The recommendations of expert witnesses on cost of common equity are useful as guides, but the determination of an appropriate cost of common equity for a utility must rest principally with the best judgment of the Commission.

4. The findings of other regulatory agencies concerning the ROE for comparable companies can be instructive in evaluating the adequacy of ROE recommendations presented to the Commission.

5. A ROE of 10.5% is reasonable based on the Commission's analysis of the evidence presented.

6. The Commission is not constrained to the particular results of class cost of service studies or rate design methodologies in allocating the revenue requirement among customer classes or establishing particular rates and charges.

ORDERING PARAGRAPHS

IT IS THEREFORE ORDERED that the Company's cost of service, attached hereto as Appendix A, setting forth the revenue requirement approved herein, be, and it hereby is, adopted and established as the cost of service and revenue requirement approved in these proceedings for Mountaineer Gas Company for providing gas utility service to its customers in West Virginia, and the cost of service and revenue requirement reflected in Appendix A shall be the basis of the rates to be charged on and after the date of this Order.

IT IS FURTHER ORDERED that the proposed rates set forth on Appendix B are hereby approved for all service rendered by the Company on and after the date of this Order.

IT IS FURTHER ORDERED that within ten days of the date of this Order the Company shall file an original and six copies of its revised tariff sheets setting forth the rates approved herein.

IT IS FURTHER ORDERED that upon entry of this Order this case be removed from the Commission's docket of open cases.

IT IS FURTHER ORDERED that that the Commission's Executive Secretary serve a copy of this Order upon all parties of record by United States First Class Mail, and upon Commission Staff by hand delivery.

ATTACHMENT WHN-8

West Virginia Consumer Advocate Initial Brief in Mountaineer Gas Company Rate Case

FILED AUG 31 2012 PSC EXEC SEC DIV

CONSUMER ADVOCATE DIVISION
STATE OF WEST VIRGINIA
PUBLIC SERVICE COMMISSION
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(304) 558-0526

Aug. 31, 2012

Sandra Squire
Executive Secretary
Public Service Commission of West Virginia
201 Brooks Street
Charleston, West Virginia 25301

RE: MOUNTAINEER GAS COMPANY
CASE NO. 11-1627-G-42T

Dear Ms. Squire:

Enclosed for filing in the above-styled and numbered case, please find an original and 12 (twelve) copies of the CONSUMER ADVOCATE'S INITIAL BRIEF. A copy has been served upon all parties of record in accordance with the executed proprietary agreements.

Sincerely,

Tom White
Counsel for Consumer Advocate
State Bar No. 6393

Enclosures
cc: Christopher L. Callas, Esq.
Stephen N. Chambers, Esq.
L.R. Sammons, Esq.
Christopher Howard, Esq.
George A. Patterson, III., Esq.

MOUNTAINEER GAS COMPANY

CASE NO. 11-1627-G-42T

INITIAL BRIEF

OF THE CONSUMER ADVOCATE DIVISION

Aug. 31, 2012

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CONSUMER ADVOCATE'S INITIAL BRIEF

Introduction

This case began life as a standard base rate case pursuant to the Commission's Rule 42T. Through rebuttal testimony and at hearing, Mountaineer Gas Company (Mountaineer) has tried to turn this proceeding into an examination of the Commission's rules for setting utility rates and decades of established case law governing rate-making. Mountaineer's premise for the need for such a dramatic inquiry is the Company's purported financial losses since 2005.

The Commission should reject Mountaineer's attempts to depart from the Commission's rules and precedents for two reasons. First, the years during which Mountaineer contends that it earned a negative rate of return (2005-2009) are precisely the same years that the Company was under a rate moratorium agreed to by Company management and entered pursuant to Commission orders approving two settlements. Mountaineer's proposed treatment of the biggest issue in this proceeding -- accumulated deferred income taxes (ADIT) -- is a bold attempt to claw back the purported losses that occurred during that rate moratorium. Before the Commission decides to allow this special treatment, it should consider whether there will be any incentive to enter into rate moratoriums prospectively.

Second, Mountaineer is trying to convince this Commission that alleged losses booked under Generally Accepted Accounting Principles (GAAP) demonstrate that the Commission's rate-making process is broken. The Company suggests it should be entitled to earn a 10 percent or higher return on its recorded balance of book common equity,[1] despite the fact that utilities are only allowed to earn an authorized return on the portion of their capital that is invested in assets that are used and useful in providing public utility service. The Commission's Rule 42T provides a process whereby a utility's rate base is determined. The utility's revenue requirement is established based on a return on rate base plus reasonable and appropriate operating expenses. Mountaineer seeks to have the Commission override that process by keeping a side calculation consisting of Mountaineer's recorded book common equity amount multiplied by a 10 percent or higher return on common equity, and to provide additional revenues if the established Rule 42T process does not produce the desired return on book equity.

There typically are differences between a utility's book common equity under Generally Accepted Accounting Principles (GAAP) and the amount of common equity that is supporting the utility's rate base. Book common equity that is recorded under GAAP is not entitled to earn an authorized return. Common equity supporting utility base, however, is used to determine the utility's revenue requirement. Mountaineer is simply not entitled to earn a return on the portion of its book common equity that is not supporting the investment in rate base. If the Company truly believes that GAAP accounting and rate-making should produce identical rates of return, it should have raised this point in its case in chief, not at the 11th hour in rebuttal and hearing.

Finally, the Company has offered no evidence at all that the Commission's rate-making process produces unreasonable results. Mountaineer may not *like* the results, but there's nothing in the record to justify abandoning the Rule 42T process. And there is no evidence at all that any particular rate-making procedure produces an unreasonable GAAP result.

***

1 Tom Taylor, rebuttal pp. 4-5, 8-9

Mountaineer Gas Company (Company) has requested a $12 million base rate increase in this case; CAD recommended between $3.3 and $3.9 million and Staff recommended a $2.3 million decrease. A comparison looks like this:

	Company	CAD	Staff
Rate Base	$187,158,304	$165,039,295	$164,096,158
Rate of Return	9.28%	8.27%	7.57%
Return on Rate Base	$17,368,294	$13,648,750	$12,422,079
Rev.increase/(decrease)	$12,298,384*	$3,306,443	$(2,359,590)

- The Company is limited to its original requested revenue increase of $12,187,218. This table is based upon the Company's original and amended filing. In rebuttal, Mr. Klemm stated that the Company is adjusting its revenue increase from $12 million to $8.6 million to reflect reduced revenue from former East Resources customers. (Klemm rebuttal, p. 4 and Exhibit SFK-2)

There are two major differences between the Company's filing and CAD's and Staff's recommendations. First, the company has proposed adding back into rate base $11.4 million in accumulated deferred income taxes (ADIT) that would normally be booked as an offset to rate base. This accounts for the main difference between the Company and Staff and CAD rate base numbers. The second main difference is that Staff has recommended a much lower rate of return of 7.57% with a 7.7% return on equity (ROE). CAD's revenue requirement has used a 9-9.5% ROE, while the Company recommends an 11.25% ROE.

Between CAD and Mountaineer, the difference in ROE from Mountaineer's requested 11.25% to the 9.0% used by CAD accounts for a variance in revenue requirement of approximately $3.328 million as shown on Exhibit LA-1, Schedule A, p. 2, line 3. The difference in ADIT accounts for $14.237 million of the rate base difference and about $2.082 million of the revenue requirement difference. Exhibit LA-1, Schedule A, p. 2, line 7.

The Company has included a number of adjustments to its rate base and income statement that CAD believes are improper and/or contrary to established Commission precedent and rules. The most salient of these are:

- Treating $11.4 million in accumulated deferred income taxes (ADIT) as a deferred asset – an *addition* to rate base;
- Adding $3.6 million in prepayments to rate base in violation of Rule 19.4.f's directive concerning negative working cash;
- $2.6 million addition to rate base for deferred O&M expenses relating to the Company's Customer Information System (CIS);
- $231,936 added to rate base for rate case expense;
- Excessive O&M adjustments for health care and labor;
- Affiliated Management Fee expense in excess of current contract amount that reflects no allocation to shareholders;
- Excessive amortization expense for deferred O&M expenses for CIS system and expiring amortization of Clay County receivership costs;

In addition, the Company has offered no justification for why the entire $12 million requested increase should paid for by increased monthly customer charges to only select customers. The Company is basically asking the Commission to issue a $12 million bond on its behalf, paid for by customer charges.

PROCEDURAL BACKGROUND

In the interest of brevity CAD adopts the procedural background laid out in the Commission's Procedural Order April 20, 2012. There are no outstanding discovery or evidentiary issues. Settlement discussions were unsuccessful. CAD's brief will discuss in order rate base, operating income and expense, cost allocation and rate of return and will conclude with a discussion of GAAP and ratemaking.

DISCUSSION

RATE BASE

Accumulated Deferred Income Tax (ADIT):

Accumulated Deferred Income Taxes are the result of deferred income tax accounting and tax "normalization" that is applied for differences between (1) book income and expense and (2) taxable income and deductions. Typically the largest differences relate to the use of accelerated depreciation. Annual depreciation expense is treated as a deduction for income tax purposes. Straight line depreciation for plant is the rule for utility ratemaking. But for income tax purposes, accelerated depreciation is used. The result is a timing difference whereby a utility can include higher income tax expense in its base rate revenue requirement than it will actually pay to state and federal tax authorities. This means the utility gets more revenue from customers than it needs to cover its income tax obligation in early years of plant life and less revenue than it needs in later years. The difference between income taxes actually paid by the utility is recorded in account 410.1, Deferred Income Tax Expense, where it becomes part of the expenses that are included in the revenue requirement funded by utility ratepayers. The charges to account 410.1, Deferred Income Tax Expense, are directly related to the credit-balance entries that are recorded in account 283, ADIT Other Depreciation. See Ralph Smith testimony beginning at p. 10, and Exhibit LA-1, B-2.1, p. 2, line 13, Account No. 283.

The process of recording Deferred Income Tax Expense, including that expense in the utility's revenue requirement and accounting for the related accumulation of unpaid future income tax expense from accelerated depreciation in account 283, ADIT Other Depreciation, is referred to as tax "normalization." Normalization also refers to the process whereby a utility draws down this ADIT reserve in later years as the tax benefits of accelerated depreciation reverse; that is, in the future years when recorded book depreciation expense amounts exceed the amounts of deductions for tax depreciation. In the interim, for ratemaking, ADIT related to plant depreciation is booked as a deferred liability and is deducted from rate base so that the utility does not earn a return on rate-payer contributed capital. This account represents cost free capital provided to the Company by ratepayers.

> ADITS represent a financial accumulation on (Hope's) books resulting from timing differences between a deferral of the tax effect of timing differences between book income and expense items and comparable tax income and expense items. When these deferrals result in tax expense for ratemaking purposes that are higher than actual current taxes payable, the difference represents ratepayer supplied capital which is basically cost free to the utility and therefore is often credited against rate base to compensate customers for providing this capital to the utility. *Hope Gas, dba Dominion Hope*, 08-1783-G-42T, Order Nov. 20, 2009, p. 20.

It is important to note, however, that ADIT related to temporary differences between book and tax amounts can be recorded both as a deferred tax asset Account No. 1900, or a deferred tax liability Account No. 2830 depending on the specific differences. Where tax *deductions* exceed the related book expense – as is the case with accelerated depreciation -- the differences are accumulated in account 2830, the ADIT liability account.

The Company's Statement B, Schedule 13, p. 2, line 13 records a federal ADIT deferred liability from accelerated depreciation in account 2830.20 in the amount of $15.6 million. However the Company takes the position that because it has federal net operating loss carry forward (NOL) that it has not been able to enjoy the full benefit of all its depreciation deductions and ADITs.[2] Therefore, it only seeks to reflect a deferred federal income tax liability of $4,217,806 for ADIT from accelerated depreciation as a reduction to rate base. Statement B, Line 21, Adjustment G-32. The Company essentially is treating the remaining $11,440,656 in deferred tax liabilities as a *deferred asset*, a debit to account 2830, and adding it to rate base. Statement B, Schedule 13, p. 2, line 35, column 3.

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2 See amended testimony of Scott Klemm, pp. 21-23, 43-46, rebuttal pp. 18-19.

Here is Mr. Klemm at hearing, (Transcript, July 17, 2012, beginning at the bottom of p. 155):

> Q: Okay. So back to Statement B, Schedule 13, page two, which is the ADIT liabilities. You take the $4.217 million – and, again, that's the offset that you're agreeing to book here, (to) rate base. I'm good so far?
>
> A: Yes, that's correct.
>
> Q: But then you take that $11.4 million and you're adding it to the rate base, aren't you.
>
> A: I guess it could be interpreted that way. What the schedule is designed to do is to show, you know, based upon that income and loss of the Company during this time period, you know, what the actual federal income tax expense was. And through that is the amount that in the Company's opinion is the amount of federal income tax that the customers actually contributed through rates.
>
> Q: Okay. But it's fair to say that the treatment that you're giving, that $11.4 million, it's no longer liability, it's not a tax liability. It's a tax asset, isn't it?
>
> A: No, I would disagree with that statement. It is a tax liability because we do have that liability that we ultimately do have to pay to the Federal Government.
>
> Q: Bear with me. If you look at the bottom of page two, line 34, total – line 35 – net ADIT asset and then liability. And then you move on over and you'll see you've got that $4.2 as a liability and you got that 11.4 as an asset, don't you?
>
> A: Well, 11.4 is really just an adjustment to the original balance of the 15.6 to arrive at an adjusted liability balance of the $4.2 million.
>
> Q: But the way you're recording this, aren't you changing your rate base? You call it an adjustment, I call it an addition. You're adding to your rate base in the amount of $11.4 million. And if I'm good on that, that's money you get a return on, isn't it?
>
> A: Due to the fact that the amount is included in rate base and you see rate of return – then yes, that is an accurate statement.

Mountaineer's proposal is not only inappropriate; it is unprecedented. Here is Mr. Klemm's explanation beginning at p. 45, line 16 of his amended direct testimony:

Q. Has this approach ever been addressed by the Commission, or a commission in another jurisdiction?

A: No, not to my knowledge, but the factual situation underlying the Company's ADIT position is atypical. In this case, the Company's position is based on (1) the inability of the Company to earn a fair and reasonable return and (2) history of net operating loss carryforwards, both conditions indicating that the historical revenues have been inadequate.

Both Mr. Klemm and Mr. Taylor testified in prepared and live testimony that the reason the Company is proposing such unusual treatment for its ADIT liability is because the Company has earned insufficient revenues since its 2005 acquisition. Here is Mr. Klemm at p. 159, line 23:

> Q: All right. Accelerated depreciation is a tax -- is deducted from taxable income. That's true, isn't it?
>
> A: Yes, it is.
>
> Q: And accelerated depreciation creates more of a tax deduction. . . (than) straight line depreciation?
>
> A: Yes that's correct.
>
> Q: So if rates are set using straight line depreciation, aren't customers actually paying the difference between the actual taxes the Company pays and the taxes booked for regulatory purposes? Isn't that a fair characterization?
>
> A: No, not in its entirety. I think this is where it goes back to my testimony as it relates to the financial performance during the first five years of the Company. When you look at the 2004 case and what was provided for in the cost of service, that was, you know predicated on certain revenues. And those revenues were predicated on the achievement of certain values.
>
> And unfortunately in the first five years the actual values that (the) company sold, even with the activity of the former West Virginia Power Gas customers, was insufficient, and as a result the Company did not make any money. And from that perspective the rate payers did not contribute the amount of income tax expense that was designed in the 2004 case.
>
> Q: You're not trying to (relitigate) that old case, are you?
>
> A: Oh, absolutely not. The Company recognizes that there is no way that we're going to be able to ever get that – you know, those financial results back. But, you know, we are concerned that to the extent that they use that financial

> performance and it negatively impacts our rates and our ability to collect taxes on a going-forward basis, that is a cause for concern.

So, according to Mr. Klemm, Mountaineer is asking for special ADIT treatment in this case to make up for losses that occurred in the years since the 2005 acquisition. Put another way, the Company wants to earn a return on $11.4 million of ratepayer-supplied money because it had poor earnings from 2005 through 2009. It's right there in plain view on Statement B.

Since the Company is claiming that "historical revenues have been inadequate," CAD feels compelled to review a little of Mountaineer's revenue history.

- In Case No. 04-1595-G-42T, 04-1596-G-PC the Commission approved a Joint Stipulation in which Monongahela Power Company, *dba* Allegheny Power sold Mountaineer Gas Company to its current owner Mountaineer Gas Holdings Limited Partnership. As part of the settlement, the Commission approved a base rate revenue increase of $15.296 million effective Nov. 1, 2005 and a second increase of $2 million effective Nov. 1, 2006.

  The settlement also included a base rate moratorium – excluding 30C purchase gas filings – until Jan. 1, 2009, and further provided that no new rates from any general filing will be implemented prior to Nov. 1, 2009. Order dated Aug. 25, 2005.

- In Case No. 07-1442-G-30C, the Commission approved another Joint Stipulation which continued the rate moratorium through June 1, 2009, and provided that no such new general rates will be implemented prior to April 1, 2010. The agreement also provided for an extension of a transportation cost sharing mechanism approved in 03-1173-G-30C through Oct. 31, 2009. Order Oct. 30, 2007.

- Finally, in Case No. 09-0878-G-42T, Order March 22, 2010, the Commission approved another Joint Stipulation setting a $19 million base rate revenue increase, $16 million effective March 29, 2010 and $3 million Nov. 1, 2010.

Both CAD and Staff oppose the Company's ADIT proposal; it is a complete departure from established Commission precedent and the normal treatment for plant related ADIT across the country. Essentially, the Company is proposing to simply "disappear" a large portion of its ADIT rate base offset related to accelerated depreciation. Mr. Klemm's testimony notwithstanding, Mountaineer is seeking in this rate case to claw back money it says it has lost since the acquisition from Allegheny Power in 2005. This is after-the-fact, special-treatment rate-making that entirely disregards the test year concept embodied in the Commission's Rule 42 process. Here is Mr. Klemm on questioning from the Chairman July 18, 2012 beginning on p. 60:

> Chairman: If the Commission builds deferred taxes into customer rates and if the customer pays those rates, doesn't that provide cash for the customer – or cash from the customers. . .?
>
> A: Well, it's certainly included in the cost of service. And, you know, I guess the question, you know, comes into being, then, in our first five years where the Company didn't make any money, the reason for that, primarily, was that the sales of the volumes that were used to determine the rates in the 2004 case did not provide for the revenue stream.
>
> Chairman: And it is calculated on a basis of 24 billion cubic feet or something like that? If you remember?
>
> A: I believe it was based more on close to 26 bcf. And in that case, it was based on a 2003 test year. It was based upon the old Mountaineer Gas Company, which was prior to the West Virginia Power Gas customers. And of course with the transaction that occurred with Mountaineer Gas Holdings Limited Partnership effective with day one, you know, we started to get revenues from those customers. On an annualized basis that was 2.8 bcf. And I actually, you know, did provide a response to a CAD data request, you know, that illustrates the impact of these sales items that is actually in Mr. Smith's testimony to this ---.
>
> But essentially if we would have had the volumes that we would have anticipated in that case, essentially. . ., (t)hat's about a $5 million to $6 million annual impact right there. And I don't believe it was. . . the intent when rates were set at that point, to establish rates where the Company, you know, wouldn't make money for an extended period of time.
>
> And, again, I just want to clarify that as a part of this, the Company is not asking for any type of claw back in terms of the financial performance. Be we are asking that as we determine the rates in this case, to go prospectively, that as we establish rate base and determine what the appropriate income tax recovery is, is that the Company essentially not be penalized for its financial poor performance that it experienced in the past.

Mr. Klemm appears to say here that the Company did not make any money in its first five years because of inadequate sales volumes. Yet this 2005-2009 period is exactly the same time frame that the Company agreed to a moratorium. CAD's witness Mr. Smith notes that the Company has already recorded a federal ADIT asset debit balance for federal NOL carryforward in Account 1900.450 in the amount of $1,924,382. Statement B, Schedule 13, p. 1, line 11. By recording $1.9 million as an ADIT debit asset, Mountaineer has no justification to assert NOLs as a pretext to try to convert $11.4 million in ADIT liabilities to an asset that is added to rate base. By including this $1.9 million ADIT asset together with the full federal ADIT plant liability of $15.6 million in his net ADIT calculation, Mr. Smith reaches a reasonable net ADIT liability (credit balance) of $18.455 million to be offset against rate base.[3] Mr. Smith's Exhibit LA-1, B-2.1 shows complete details of the specific ADIT balances that are included in this adjustment:

- Page 2, line 13 reflects the actual amount recorded in account 2830.200, ADIT liability for plant -- accelerated depreciation/federal of ($15,658,462) – an adjustment that reduces rate base by $11,440,656 more than Mountaineer's proposed rate base deduction of $4,217,806.
- Page 2, line 30 shows the related state ADIT balance in account 2830.700 accelerated depreciation/state of ($4,156,034).
- Page 1, line 11 shows account 1900.450 ADIT asset for the Company's Federal NOL carryforward of $1,924,382.

CAD's net adjustment shown at p. 2, line 35 is a ($18,454,804) reduction in rate base. This approach reduces rate base by the amount of ADIT related to accelerated depreciation that has been normalized for rate-making purposes, while simultaneously preserving the Company's unrealized NOL tax benefits and avoiding any IRS normalization violation.[4]

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3 Exhibit LA-1, Schedule B-2.1, p. 2, lines 13 and 35. Smith direct testimony, p. 21, line 21 – p. 23, line 10.
4 Smith testimony, p. 15, beginning at line 18.

CAD witness Smith included in his calculation $4.156 million of state ADIT for accelerated tax depreciation that has been recorded by Mountaineer in account 2830.700 through Sept. 30, 2011, the end of the test year, to reflect amounts collected from ratepayers under normalization treatment. He has also recommended removing state deferred income tax expense prospectively from the rate effective date of this case and flowing it through directly to customers.[5] This latter treatment is consistent with state tax law requirements, as there is no requirement to normalize state income tax deductions for depreciation, and is also consistent with the Commission's general approach that utility rates should be set based on actual taxes paid unless there is a normalization requirement. CAD will address this more fully below.

Regulatory Asset

The Company has added $3.24 million to rate base for what it considers to be three regulatory assets: $231,936 in rate case expense; $2.673 million for its customer information system; and $335,600 for Clay County receivership costs. These adjustments are found at Statement B, Schedule 15 and 15.2 and Adjustment G-22 and its subparts. CAD removes each one:

- Rate Case Expense

Rate case expense has traditionally been included as an expense on Statement A that is typically spread -- normalized -- over three to five years, the approximate interval between base rate cases. See, e.g.: *Jefferson Utilities, Inc.,* Case No. 10-1329-W-42T, Order Feb. 18, 2011, p.11-12; *West Virginia American Water Co.,* 10-0920-W-42T, Order April 18, 2011, p. 32-33; *Monongahela Power and Potomac Edison, dba Allegheny Power,* Case No. 06-0960-E-42T, Order May 22, 2007; *West Virginia American Water Co.,* 08-0900-W-42T, Order March 25, 2009.

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5 Smith testimony, p. 25. See LA-1, C-11 and Statement A, Schedule 5, p. 2, lines 19-35.

Rate case expense has never been included in rate base as a regulatory asset upon which the Company can earn a return. CAD urges the Commission not to establish this precedent. Regulatory asset in rate base should be limited to expenses or investments that benefit customers. See for example, *Mountaineer Gas,* Case No. 11-0460-G-PC, Order No. July 14, 2011, in which the Commission approved Mountaineer's legal and other costs related to the acquisition of Ashford Gas Co. as a regulatory asset in rate base. At hearing, Mr. Klemm admitted that he is unaware of any other case in which rate case expenses has been included in rate base.[6] Mr. Smith's proposal, discussed further below, removes $231,942 in rate case expense from rate base. LA-1, B-5. Mr. Smith further provides a normalized allowance of rate case cost over three years in the annual amount of $73,667 in O&M. (Smith prepared testimony, p. 43, LA-1, C-2)

- Customer Information System (CIS)

The main issue here is that Mountaineer was allowed to defer O&M expenses related to its Customer Information System (CIS). Statement of Position (SOP) 98-1 cited by CAD witness Mr. Smith at p. 33 of his direct testimony delineates the types of costs related to software developed for internal use that are permitted to be capitalized under generally accepted accounting principles.[7] Other costs related to such software, such as training, data preparation, etc., are considered to be operating and maintenance expenses in the period in which they are incurred. Mountaineer received an accounting letter from Staff authorizing the deferral of the CIS O&M expenses in account 186 for consideration in Mountaineer's next rate case. See CAD Ex LA-2 at page p. 48-49, Response to CAD 7-E-83.

The $2.673 million that the Company wants to add to rate base that is at issue here is strictly the amount for deferred CIS O&M expenses, a portion of which were incurred prior to

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6 Transcript July 17, 2012, p. 168

7 See also, Statement G, Schedule 16, Notes

the test year. The costs that Mountaineer recorded as plant for the CIS are included in rate base, are being depreciated, and are not at issue here. Allowing a utility to defer and prospectively recover O&M costs, including O&M costs incurred prior to a test year, is a special treatment that can apply for rate-regulated public utilities. Other types of enterprises, under GAAP, would have recorded the O&M expenses during the accounting period in which they were incurred. The mere fact that Mountaineer was allowed to defer such O&M costs for future rate consideration does not justify rate base inclusion. O&M expenses, in fact, are typically not included in utility rate base. CAD witness Mr. Smith removed the deferred O&M expenses from rate base and, in a related adjustment, has allowed an amortization expense of the remaining unamortized balance estimated for September 30, 2012, the anticipated rate effective date for Mountaineer's new rates in this proceeding. LA-1, B-6, C-7. The prospective recovery of O&M expense is a benefit to the utility, and results in an additional cost to ratepayers under regulation that would not exist if the O&M expenses had been expensed in periods prior to the test year. O&M expenses, whether they are incurred in a current test year, or authorized for deferral from prior periods for future rate recovery, do not require a rate base return. Removing the deferred O&M expenses from rate base and allowing prospective recovery of the unamortized balance from ratepayers thus strikes the appropriate balance. Mr. Smith reflected the amortization in his adjustment shown at Exhibit LA-1, Schedule C-7.

In summary, Mountaineer's deferred CIS O&M expenses should be excluded from rate base because they are O&M expenses, not an investment in a plant asset. An amortization over an appropriate period is provided for the recovery of such costs from ratepayers. LA-1, C-7.

The result is that Mountaineer receives recovery of the deferred O&M expense but does not receive a return on O&M expenses.[8]

- Clay County receivership

Mountaineer included in rate base a 13-month average of $335,600 for Clay County receivership costs. Statement B, Schedule 15.2. CAD witness Mr. Smith removed this amount from rate base on the understanding that this cost should have been fully amortized over two years by the rate effective date of the present case. (Smith testimony, pp. 36-40, LA-1, B-7, LA-1, C-8.) At p. 10 of his amended direct testimony, Mr. Klemm states the company agreed to a three-year amortization period, but had been amortizing Clay County receivership over two years instead. As Mr. Smith points out at p. 37 of his prepared direct testimony, the Company made an unauthorized change to its amortization schedule that is clearly shown on Statement B, Schedule 15.2.

> In 2010 and through June 2011, the Company was recording amortization of $20,975 per month. Then in July 2011 the Company reversed $90,897 of amortization, and recorded amortization of only $13,983 in August and September 2011. (Smith testimony at p. 37, line 10)

Mr. Smith notes that the company's 2010 annual report recorded a two-year amortization schedule for Clay County receivership;[9] that full amortization should be completed by the rate effective date of this case and that therefore no allowance should be included in either rate base or amortization expense. (Smith direct, pp. 36-37, LA-1, B-7, C-8).

Mr. Klemm, in rebuttal, argues that this receivership was funded with short term debt during the test year.[10] CAD would argue that if the cost is fully paid off by the rate effective date this is irrelevant.

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8 See Smith cross, July 18, 2012 beginning at p. 130.
9 LA-2, p. 51.
10 Klemm, p. 39.

Prepayments

Rule 19.4.f. – Statement B, Schedule 6 reads in pertinent part:

> Prepayments will not be allowed unless a working cash allowance calculation demonstrates that prepayments are not offset by negative working cash.

A Lexis search did not reveal any cases where the Commission has directly applied this rule to deny prepayments in rate base. However, there has been no showing that there is no negative working cash (revenue received prior to expenditure). Nor has there been any explanation offered by the Company. The Company did a lead lag study for the 2009 case, but did not do one for this case, nor did it update the prior study.

Both Staff and CAD have recommended disallowing prepayments in rate base in this context. The rule is unambiguous. Accordingly, both CAD and Staff recommend removing from rate base the $3.64 million in prepayments that the Company has proposed. Exhibit LA-1, Schedule B-1, Oxley direct testimony p. 28.

Mr. Klemm again appears to argue that the Company was borrowing on its short term line of credit due to its gas cost over-recovery and so all prepayments on Statement B, Schedule 6 must therefore have been funded by borrowing not cash. (Klemm rebuttal, pp. 35-36). CAD submits that the one is not proof of the other.

Injuries and Damages

The Company has on its books an injuries and damages account. At the beginning of the test year Sept. 30, 2010, it was $650,000. At the end of the test year on Sept. 30, 2011, it was $950,000. This is a liability account that the Company should have offset from rate base. CAD witness Smith's Exhibit LA-1, Schedule B-3 removes $950,000 from rate base. (Smith testimony, beginning at p. 26).

Mr. Klemm at page 41 of his rebuttal appears to suggest that this money is investor-supplied money due to Company losses in the middle of last decade – once again using losses during the rate moratorium to justify extraordinary ratemaking treatment. CAD witness Smith removes this amount from rate base but includes an adjusted three-year average amount in O&M expense in the amount of $402,612. (Smith direct, p. 43, LA-1, C-3)

Accounts Payable

At p. 28 of his testimony, Mr. Smith also removes $50,974 from rate base for materials and supplies that are provided by outside vendors, rather than by investors. LA-1, B-4.

OPERATING INCOME AND EXPENSES

Labor -- Wages and Salaries

The Company proposed an increase in O&M expenses of $599,178 to hire 12 new distribution employees. Statement G, Schedule 4, SD G-4.2. CAD analyst Ms. White adjusted this downward to a net gain of five employees to reflect actual hires through April 16, 2012. The final result: $214,096.

CAD and the Company are in basic agreement on this, but it might not be apparent from the numbers each party uses. The company requested an increase to O&M expense of $599,178 for twelve employees. CAD recommended an increase of $234,498 for the net addition of five new employees (plus 9 minus 4). These numbers are prior to factoring in the O&M percentage of 91.3%. On page 52 of Mr. Klemm's rebuttal he describes the adjustment as a *reduction* to the company's request, but factors in the O&M percentage first. ($599,178 x 91.3% = $547,049.5) His math is as follows: $547,049 - $214,096 = ($332,953).

Labor -- Incentive or Bonus Compensation

As in the 2009 Mountaineer rate case, CAD recommends eliminating $365,000 recorded for incentive compensation in O&M expenses. Mr. Taylor testified that there are no written standards for employee incentive pay. The testimony indicated a striking difference between the number of employees who earned incentive pay in 2010 and those who did in 2011. Just two employees received close to half their base salary in incentive compensation in 2011; and only five employees received bonuses in excess of $25,000.[11] It is hard to imagine how the small number of employees receiving incentive pay provided much, if any benefit to customers.

The test for whether ratepayers should shoulder the burden of incentive pay is whether there is evidence that ratepayers likely benefit from such a program as a result of improved performance.

> Furthermore, at the bottom line, the Commission realizes that all employees of the Company are working not only to provide clean, safe, and potable water to the citizens of West Virginia but are also working as employees of the stockholders with an end towards maximizing stockholder wealth. The incentive compensation is merely a different means of providing such motivation. To the extent employee incentives result in efficiencies and/or increased productivity stockholders are benefitted, but eventually such benefits will be reflected in lower revenue requirements and lower rates. Thus, both stockholders and ratepayers benefit from increased productivity and operating efficiencies. *West Virginia American Water,* Case No. 03-0353, Jan. 2, 2004.
>
> As the Commission has stated in prior orders, incentive compensation packages provide benefits to both shareholders and indirectly to rate payers through reduced costs over time. 2008 WVAWC Order at 51. Quantifying the proportional benefit from incentive compensation, however, is difficult, and the Commission is unable to precisely allocate that benefit in this proceeding (*citation omitted)* Absent other specific proof about the extent to which these programs actually lower the cost of service, as long as the amount appears reasonable, and because both shareholders and ratepayers benefit from incentive compensation, the Commission will divide the cost of that burden equally by including one-half the cost of the WVAWC incentive compensation in its expense calculation as the Commission did in the APCo rate case. *(citation omitted).* Dividing the burden

11 This was discussed in camera; parties agreed that confidentiality provision need not apply to this information as presented here.

> between ratepayers and shareholders will also provide an incentive for shareholders to insist on increased value from WVAWC employees for that compensation, maximizing the benefits to all parties. The Commission believes that dividing the burden of incentive compensation is also a reasonable method of balancing the current economic climate with its responsibility to reflect the cost of service in the expense calculation. *WVAWC,* Case No. 10-0920-W-42T, April 18, 2011, pp. 39-40.

In this case, CAD recommends removing incentive pay altogether on the basis that it is entirely discretionary and because such large bonuses to so few people in 2011 could not possibly be considered an indirect benefit to ratepayers as a whole. Here is Ms. White on cross at hearing July 18, 2012 at p. 177, line 11:

> Q: Do you believe that the fact that the Company retains discretion to withhold or not pay in any given year performance incentive payments if they're not warranted is a reason not to provide for their recovery in rates?
>
> A: For O&M expense, you're looking for something that is not an occasional occurrence, but a known and measurable expense. In the absence of a written plan or something that tells me every year the Company is going to pay this incentive, then in my opinion it is not measurable and it's not known.

The combined effect of Ms. White's two labor adjustments is a labor expense of $27,379,761, which on an O&M basis is an increase of $298,393 -- $666,655 less than the Company proposal. DLW-direct, p. 7 and Exhibit DLW-4.

<u>Payroll Taxes for Social Security and Medicare</u>

The Company is proposing an increase in going level Social Security and Medicare taxes of $69,676 over the test year. Statement G, Schedule 5. Because Ms. White's total recommended payroll is slightly lower than the Company's this results in a lower adjustment for payroll taxes of $22,104. DLW-direct p. 8-9, Exhibit DLW-5.

<u>Health Care</u>

The Company requested a $747,110 increase in O&M for health care expense.[12] Statement G, Schedule 8. CAD witness Ms. White explained in her testimony at p. 12 that she agrees with the Company's request with regard to its HMO plan. This is a straightforward math:

Projected 2012 HMO premium expense[13]:		$626,964
Test year expense[14]	--	$379,885
		$247,079 x .913 = $225,583.

However, Ms. White does not agree with the Company's request for health care expenses for employees covered by the self-insured plan. As Ms. White explained beginning on p. 13 of her testimony, the Company's goal is for employees to pay 22% of the annual cost of the self-insurance program. However, there is no reconciliation between the 22% target and actual expenses paid. In Exhibit DLW-7, Ms. White removed the reserve account and the HMO premium to show the actual cost increases in the self-insured medical program over the last three years. She then calculated per enrollee expenses for FY 2009, 2010 and 2011 to reach an increased cost per enrollee in the self-insured plan of $210, or 2.2% over the three year period ending Dec. 31, 2011. To reach a more accurate projected expense for fiscal year 2012, Ms. White simply multiplied the average expense per enrollee in FY2011 by the average percentage increase during the three year period FY09 to FY11. DLW-7, Section 6. The result is $9,832 per FTE. Her final calculation on the last page of her testimony results in a reduction of ($50,859) in self-insured health care expense and a total net increase in O&M for health care of $175,024.

Mr. Klemm on p. 57 of his rebuttal argues Ms. White's understates costs for the self-insurance program by using enrollment numbers at the end of each fiscal year. But he offers no supporting data to show Ms. White's numbers to be inaccurate or misrepresentative.

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12 The original filing was for $701,556 – a 17% increase

13 G-8.1, column j, line 15

14 G-8

IGS Management Fee

As in the 2009 Mountaineer rate case, CAD recommends a reduction in the $1.4 million[15] expense for the IGS Utilities management fee in O&M Account 923. CAD believes that the terms of the management service agreement are so vague that it is unclear what benefit IGS is actually providing since Mountaineer has a resident management team in-state. Here is the relevant paragraph:

> 1.03 Services to be Provided. Manager shall, subject to the supervision and direction of Mountaineer, perform all management and administrative services as may be required for the reasonable conduct of the West Virginia Gas Distribution Business as presently or hereafter conducted. Manager shall provide general oversight of the business, operations and affairs of Mountaineer and its direct and indirect subsidiaries and all support of business functions reasonably requested by Mountaineer or its direct or indirect Subsidiaries. . . (See LA-2, pp. 96-97.)

Mr. Taylor's rebuttal notwithstanding, it is difficult to imagine what real benefit IGS in Tulsa provides to ratepayers in West Virginia.[16] Here is Ms. White at hearing July 18, beginning on p. 182:

> Q: Setting aside IGS, do you believe that if one were to combine the incentive comp that the Company's employees make along with their base pay, that any one of them, or them as a group, would be overcompensated in a way that ought to require you to make an adjustment to the recovery of that expense?
>
> A: And I say again, you cannot (set aside) the IGS management payment. It is part and parcel of your executive team, so you've got that payment and you have your executives onsite. The two of them together comprise your total executive compensation. So to answer your question, you have – you can't just carve out part and look at it. You have to look at all of it. And at some point for a company the size of Mountaineer, you start to have too much executive compensation.
>
> Including the IGS management fee into executive compensation, it's a very large number and you've got a full team here. . .

15 The latest version of the IGS amended contract from Feb. 2011 provided for an annual fee of $1.25 million. At hearing Mr. Taylor said the discrepancy was due to less staffing in West Virginia and additional staffing in Oklahoma. (Transcript July 17, 2012, pp. 23-24)

16 Mr. Klemm described respective duties at the July 18, 2012 hearing beginning on p. 75. But the rational for separate management in Tulsa remains murky.

As Mr. Smith points out on p. 51 of his direct, the IGS management fee is an affiliated transaction that deserves heightened regulatory scrutiny. Therefore CAD believes it is reasonable for shareholders to bear at least half the cost of this O&M expense. (Smith direct testimony, pp. 46-52). Total adjustment: ($788,708) See LA-1, C-6 of Mr. Smith's testimony.

Deferred Compensation

Staff eliminated a $409,207 going level expense for deferred compensation. (Oxley direct, p. 19). Testimony at hearing indicated that this expense is related to two trusts which will make annual payments of $198,000 to two former employees through 2055 and 2056 respectively.[17] CAD agrees with eliminating this expense as not something that ratepayers should fund.

Rate Case Expense

The Company wanted to include $231,942 in rate case expense in rate base *and* a two year amortization of $231,936 for the current rate case expense. Mr. Smith pointed out that prior rate case expense does not create a binding precedent on future rate case expense allowances. "Past rate case expense is not guaranteed in rates, and the level of rate case expense included for rate recovery should be a representative average or normalized amount of expected future rate case costs." (Smith direct, p. 41, *citations omitted)* Mr. Smith's solution: reduce prior rate case request by cost of an outside lead-lag study witness and normalize that cost over three years, the interval between base rate cases. The result: total of rate case expense of $221,000 for the present case, spread over three years is $73,667. (Smith testimony at p. 43, and Exhibit LA-1, C-2). This approach is consistent with Commission precedent cited previously.

Injuries and Damages Expense

17 Klemm cross by Staff, July 18, 2012, beginning at p. 17.

Mountaineer requested $556,428 in O&M for injuries and damages expense, which is higher than the last three years. Statement A, Schedule 2, p. 3, Account 925. CAD witness Smith adjusts this number to the three-year average 2009-2011 of $402,612, a reduction of $153,816, with which the Company agrees. (Smith testimony at p. 43-44, LA-1, C-3, Klemm rebuttal, p. 60, line 19)

Workers Compensation Expense

Mountaineer requested $512,008 in O&M for workers compensation expense. Statement A, Schedule 2, p. 3, Account 925.02. CAD witness Smith adjusts this amount by computing a three-year average of workers comp expense to payroll of 1.81% and applying that percentage to the CAD-adjusted payroll of $29,988,786. The result as a percentage of O&M is $495,257, a reduction of $16,751 from the Company's number. (Smith testimony at p. 44, LA-1, C-4)

Mr. Klemm at p. 61 of his rebuttal appears to indicate that the Company no longer seeks an increase in this expense.

Interest on Customer Deposits

Statement B, Schedule 12 records Customer Deposits of $5,000,987. At p. 45 of his testimony, CAD witness Smith states that the Company did not include interest on customer deposits into its O&M expenses. Using the most current interest rate of 0.10%, Mr. Smith books an addition to O&M expense of $5,001, to which the Company agrees.

Miscellaneous Adjustments

- At p. 54 of his direct testimony, CAD witness Mr. Smith proposed an addition to income tax expense of $376,287 for interest synchronization due to CAD adjustments to rate base. The company's achieved operating income is reduced by a similar amount. The Company disagrees primarily because of the difference in rate base used by Staff and

CAD.[18] As stated previously, the difference with the Mountaineer's rate base can be explained largely by Company treatment of ADIT.

- At pp. 54-60, CAD witness Smith removes $9,688 from industry association dues and memberships to reflect that portion of expense that relates to lobbying. LA-1, C-10, and CAD data requests 1-E-33, 1-E-36, LA-2, pp. 121-122.
- At p. 61, CAD witness Smith removes the amount of net positive deferred income tax expense that Mountaineer proposes to normalize. Adjustment LA-1, C-11 reduces Mountaineer's proposed deferred state income tax expense by $241,405 and increases federal income tax expense by $48,492 for a net reduction to going-level income tax expense of $156,913. This is consistent with his proposal at p. 25 of his direct testimony to remove state deferred income tax expense prospectively and flowing it through to customers.

  Mountaineer has opposed this treatment citing to two WVAWC and APCo decisions using normalization treatment for tax deductions for "retirement units" and capital repairs.[19] In this situation, CAD believes flow through is appropriate given the Company's current ADIT credit balance.

COST ALLOCATION

Mountaineer has chosen to place the entire burden of its $12.2 million revenue increase on the sales and transportation customers served under its RS, GS and WS tariff schedules.[20] The Company has exempted all sales and transportation customers served under tariff schedules LGS, IS and LIS from any responsibility for the revenue increase request. The Company has also chosen to exempt all Special Contract customers from any rate increase. Mr. Harris' Exhibit

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18 Klemm rebuttal beginning at p. 68, line 17.

19 Klemm rebuttal, p. 74.

20 Harris direct testimony at p. 8.

BLH-3 shows that Mountaineer is exempting 40.5% of its total throughput from any responsibility for its revenue increase, even though these are the tariff classes generating the lowest returns for the Company.[21]

Under the Company's plan, the residential customer charge will increase from $8/month to $11.40/month, and will generate approximately $8.3 million of the proposed revenue increase. Statement D, p. 1. Mountaineer's proposed customer charge of $11.40 is far higher than Hope's at $8.99/month. And, while the Company's revenue request would increase total revenues by about 4.9%, the increase to *base rate* revenues would be 11.58% and ranges across RS, GS and WS tariff classes from 12.19% to 19.72%.[22]

Logically, underperforming tariff classes should bear at least some of the burden of any requested revenue increase. Yet Mountaineer is ignoring its own cost of service study in Statement E. Statement E p. 2 shows that LGS, IS and LIS customers generate net losses going level of $14.7 million, $21.1 million and $11.5 million respectively. Yet these customer classes are exempted completely from any increase.

CAD asked Mr. Taylor and Ms. Lee about this at hearing. Here's Mr. Taylor:

> Q: Okay. Now, if you look at the net operating income column, if I'm reading this right, LGS, IS and LIS tariffs are all. . . These are the tariff classifications for categories that you've exempted from this rate case, but they're losing money. Is that a fair statement of what I'm seeing?
> A: Yes.
> Q: Why are you doing that?
> A: I'll have to defer that question to Ms. Lee. (Transcript, p. 27)

Asked the same question, Ms. Lee seemed to indicate that the main reason for exempting these tariffs was to protect a small group of LGS customers formerly served by East Resources.

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21 Harris direct, p. 9, line 5.

22 Harris direct, p. 9, BLH-4, BLH-5.

> Well, let me be real clear. LGS seems to be (the) one that everybody's focusing on. The customers in the LGS class are getting a very significant rate increase. The current East Resources customers that went to Mountaineer had a customer charge of $60. They are going to $365. . . When I did the rate design, I really didn't feel comfortable taking that customer charge any higher because those customers were getting a pretty significant customer charge increase anyway. . . (July 17, 2012 hearing transcript p. 105, beginning at line 7)[23]

CAD concedes this is a significant increase for East customers. However, that does not justify exempting some 5.4 billion cubic feet of throughput from any rate increase. See Statement E, Schedule 1, LGS throughput of 5,410,590 mcf.

In her direct and rebuttal Company witness Ms. Lee says the main benefit to placing all the increase on fixed customer charges is "simplicity" and "stability."[24] CAD witness Mr. Harris properly points out that in this context "stability" means earnings stability for Mountaineer.[25] At page 14 of his direct, Mr. Harris notes that Mountaineer currently collects about $25.7 million/year in revenues through customer charges, or about 25% of the Company's base rate. This would increase to $37.8 million, or about 34% of base rate revenues under the Company's proposal.

It is CAD's position that such a large increase in the customer charge is not supported by the Company's cost of service study or any other evidence in this case, and that if any rate increase is approved it should be allocated to all tariffs and special contract customers on an equal percentage basis. Mr. Harris' testimony shows that the Company's cost of service study is unreliable. Mountaineer erroneously allocated purchased gas costs based upon throughput volumes (as opposed to actual sales) for each tariff. This results in a significant cost shifting to LGS, IS and LIS tariff customers that are largely transportation customers that don't buy gas

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23 See Statement D, p. 5. It is unclear from the record and from Statement D, p. 5 how many customers we're talking about. Ms. Lee at p. 106 indicated it was 18. Statement D, p. 5 Going Level billing units suggests 4. CAD counsel believes this question was raised at hearing on redirect but the transcript appears to be silent.

24 Lee direct, p. 5, line 15, rebuttal pp. 4-5

25 Harris direct, pp. 13-14.

from Mountaineer.[26] In addition, the Company misapplied the Seaboard formula with the result that GS and LGS tariff transportation customers are exempt from any significant cost responsibility for the distribution system.[27] At pp. 10-11 of her rebuttal, Ms. Lee concurs with Mr. Harris' two concerns regarding purchased gas cost allocation and the Seaboard formula, but states that making these two corrections would have a "minimal" affect on fixed costs.[28]

In other words, everybody seems to agree that Mountaineer's Statement E is worthless. Ms. Lee does not mention it at all in her prepared testimony. The Commission has ruled in the past that when there is no reliable cost of service study in evidence that any rate increase should be in an across-the-board fashion. *Hope Gas,* Case No. 08-1783-G-42T, Order Nov. 20, 2009, beginning at p. 38; *Union Oil & Gas,* 06-0410-G-42T, order Sept. 14, 2006, p. 28 and order Oct. 26, 2006, pp. 5-6; and generally *West Virginai-American Water Co.*, 07-0998-W-42T order March 18, 2008 approving stipulation. CAD believes that is what should be done here. CAD's recommended revenue increase -- with a 9% return on equity -- is $3,306,443. LA-1, Schedule A. Hence Mr. Harris' proposed across the board percentage increase is 3.41% ($3,306,443/$105,238,663 = .0314). (See Ex. BLH-5).

One final point on all this: the 2009 case was settled by Joint Stipulation in which Mountaineer explicitly agreed NOT to oppose inclusion of special contract customers in its next base rate case. Page 5, Paragraph (h) reads:

> Notwithstanding the provisions of subparagraph (g) of this paragraph, in the Company's next general rate case, Company *will not oppose the allocation to special contract customers of a portion of any base rate increase awarded in that case* on the basis that the Company has a limited ability to increase the rates under those special contracts. Nothing in the preceding sentence will be deemed to restrict Company's advocacy for the appropriate allocation among customer classes of any such increase.

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26 Harris direct, p. 14-15, Statement E, Schedule 6

27 Harris direct, pp. 14-15, Statement E, Schedule 1.

28 Lee rebuttal, p. 11, line 5.

In revised rebuttal and at hearing, both Mr. Taylor and Ms. Lee make much of the idea that special contract customers do experience rate increases, just not at the same time as other tariff customers. The Commission should understand that, despite Mr. Taylor's testimony at hearing to the contrary, the Company really wants the Commission to drop its jurisdiction over rate-making for special contract customers. This is special treatment – not unlike what Century Aluminum recently requested – and the Commission should reject it outright. Should the Commission authorize a rate hike, it should be across the board and shared by all customers as proposed by Mr. Harris and consistent with prior Commission precedent.

Customer Charges

Mountaineer overstated its estimate of customer costs by including many plant and expense items in its cost of service study that are not customer related.[29]

In her rebuttal, Ms. Lee does not appear to disagree with any of Mr. Harris' assertions. Here is Ms. Lee at p. 7, line 1:

> Q: HOW DO YOU RESPOND TO MR. HARRIS' ASSERTION (PP. 12-13) THAT YOUR FIXED CHARGE CALCULATION INCLUDES A NUMBER OF PLANT AND EXPENSES ITEMS THAT "ARE NOT CUSTOMER RELATED?"
>
> A: My primary response is to stress the difference between purely "customer" charges, which seem to be Mr. Harris' focus, and fixed costs that are appropriately assigned to the fixed charge component of rates. Mr. Harris appropriately notes that the list of items shown on page. 13 of his testimony have little to do with the number of customers served. Moreover, those items have little to do with the amount of natural gas that customers use, with the exception of income taxes. The remaining items are fixed and do not vary with the level of natural gas that customers use.

In her direct, rebuttal and at hearing, Ms. Lee emphasized that customers actually benefit from a higher fixed customer charge.[30] Her reasoning is that a higher fixed charge will dampen

29 Harris direct, p. 12, line 20 – p. 13, line 7

variable useage charges. Perhaps there is some merit to that point. But what Ms. Lee is really saying is that cost of service studies do not matter. In fact, she essentially recommends abandoning cost of service studies embodied in the Commission's Rule 19.7 Statement E.

> Q: IS YOUR PROPOSED RATE DESIGN SUPPORTED BY YOUR COST STUDY OR ANY COST STUDY THAT HAS BEEN PRESENTED IN THIS CASE?
>
> A: The Company's proposed rate design is not in direct conflict with any cost study provided in this proceeding, nor do I believe that strict adherence to a class cost of service study is the best way to design rates in today's utility industry. Straight fixed variable rates, as one example, are not based on a strict interpretation of any one class cost of service study methodology. FERC abandoned the 1952/1973 Seaboard methodology in 1983 for the MFV (Modified Fixed-Variable) methodology, which gave way to the FV methodology in 1992. There are many approaches to determine on which costs are fixed, variable, customer-related and consumption-related, and the process of functionalization, classification, and allocation of costs has been the subject of many books on rate design theory. The fact remains that new methods of designing rates are being used in the states surrounding West Virginia and in the majority of other states across the country. I encourage this Commission to consider a wide range of rate design options when allocating revenue in base rate proceedings, including in this case. (Lee rebuttal, p. 11, lines 13 – p. 12, line 6)

RATE OF RETURN

Mountaineer's expert Mr. Avera has recommended an 11.25% return on equity (ROE). It is CAD's position that this recommendation is unrealistic, unreasonable and should be rejected outright. Mr. Avera has testified in close to 400 cases and admits that he has very rarely recommended an ROE less than 11%. "Well, a ballpark would probably be about 20 times out of almost 400." Avera cross, July 19, 2012, p. 9.

In fact, his recommendation bears little relation to the evidence he himself offers. WEA Ex. 10, p. 3 is a chart showing average authorized ROEs for gas utilities across the country by quarter all the way back to 1980. By his own admission, the last time average authorized ROEs

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30 Direct, p. 5, Rebuttal, p. 5, Hearing Transcript p. 109.

were at 11% was in the first quarter of 2004. And as of the third quarter of 2011 – the end of the test year -- were in the 9.65% range. Here is a list of the most recent ROEs approved by this Commission:

West Virginia American Water Company, 10-0920-W-42T, Order April 18, 2011, 9.75% ROE;

Appalachian Power Company, 10-0699-E-42T, Order March 30, 2011, 10% ROE;

Bluefield Gas Company, 11-0410-G-42T, Order Jan. 17, 2012, 9.75% ROE;

Hope Gas Company, 08-1783-G-42T, Order Nov. 20, 2009, 9.45% ROE;

Megan Oil, 11-0532, Oct. 27, 2011, upholds ALJ's 9/15/11 decision granting 9.75% ROE.

Black Diamond Power Company, 12-0064-E-42T, Order Aug. 10, 2012 upholding 9.75% ROE

CAD submits that given the current state of the economy, any prudent investor would be thrilled to earn a 9% ROE, or even lower. Mr. Avera is an excellent witness; reality is different.

GAAP vs. RATEMAKING

In rebuttal and at hearing, Mountaineer argues that it is not earning its authorized return, that Staff and CAD rate base recommendations are too low, and that the Commission should consider abandoning some, or all, of traditional rate-making to make this all work out nicely. At p. 4 of his rebuttal, Mr. Taylor says the Company earned a 1% ROE in 2010; 6% ROE in the test year ended Sept. 30, 2011; 3.8% ROE in calendar year 2011; and loss of $600,000 and a negative ROE of 0.7% for the 12 months ended March 31, 2012.[31] Here is Mr. Taylor's rebuttal beginning at p. 6, line 17:

Q: WHY DO YOU BELIEVE THE STAFF AND CAD RECOMMENDATIONS WOULD PRODUCE RATES THAT ARE NOT JUST AND REASONABLE?

A: First, let me acknowledge that the Commission, the Staff and the CAD have years of experience in the rate-setting process, and that they apply a rate-making methodology – cost-based rates, premised on an historical test year with known and measurable changes – that, for all its flaws, is well established in West

[31] See also Taylor direct, p. 8

Virginia. That said, the Commission needs to look beyond the mechanisms used, or even in the individual cost of service analyses that make up a general rate case, and evaluate whether the parties' revenue requirement recommendations are actually working in practice. This analysis should take into account how successful those same methods have been in establishing rates that generate revenues that are relatively close to the actual cost of service. These data are reflected in annual audited financial statements that utilities provide to the Commission and others, and the consistently prepared financial reports they file every three months. If a utility is unable to generate revenues sufficient to meet its cost of service in the rate effective year and soon thereafter, such that its achieved return on investor equity never even approaches its authorized equity return, and if this circumstance is repeated year after year, then the Commission (and, one would expect, its Staff) should begin to question whether the regulatory methods purportedly designed to provide a fair opportunity to earn authorized equity return are effective.

By this measure, it is clear to me that in the Company's case, the ratemaking process is not performing effectively. The Company's prolonged period of poor or negative returns before its 2009 Rate Case is well known to the Commission; since then, the circumstances have improved somewhat, yet as I've noted, the Company is again losing money, and its owners are effectively giving away much of the improved utility service enjoyed by our customers. Quite honestly, I believe this should greatly trouble the Commission, its Staff and the CAD.

Mr. Taylor next suggests a "reasonableness check" to assess the need for a base rate increase:

- Divide latest audited net income by average equity employed to see if the utility is earning a "reasonable" ROE;
- Estimate revenue requirement by multiplying invested equity by an acceptable ROE;
- Subtract audited net income from estimated revenue requirement

The result is under- or over-recovery. In his example, Mountaineer needs a $10 million base rate increase. Mr. Taylor goes on to say that the greater the disparity between his shorthand "reasonableness check" calculation and the parties' revenue recommendations the greater the need for the Commission to investigate why.

There should be no sacred cows in ratemaking. If we know that the ratemaking process is yielding unacceptable results, or that individual adjustments routinely contribute to this outcome, then it should not be a sufficient excuse to hide behind how 'traditional' or 'accepted' they have become. To suggest that an investor-owned utility is not *guaranteed* to earn its authorized return quite simply misses the point. (Taylor rebuttal at p. 11, line 8)

The problem with this statement is that neither Mr. Taylor nor anybody else in this proceeding has pointed to any particular ratemaking process or individual adjustment that *does* routinely yield unacceptable results. The closest anyone gets to doing that is Mr. Klemm stating that the Company overstated estimated sales volumes back in 2004.

Finally, Mr. Taylor argues that a utility's rate base should not vary greatly from its total capitalization, at least not without a reasonable explanation.[32] In the present case, the main difference between Staff and CAD's rate base and the Company's is explained almost entirely by the different approaches to treatment of $11.4 million of ADIT.

At hearing Mr. Callas asked CAD witness Mr. Smith what he makes of Mountaineer's latest ROE figures from Mr. Taylor.

> Q: On a GAAP basis, we'll take Mr. Taylor's statement at face value this morning. And it represents that the Company considerably under-earned, no matter what implicit ROE you might have taken out of that case, would you agree? One percent, 3.8 percent, those certainly are under-earning figures would you agree?
> A: Well, but it's an apples to oranges comparison. The GAAP basis earnings are not the same as the authorized earnings in a rate case, so it's comparing oranges and apples. (Transcript July 18, 2012, p. 111)

Mr. Smith explained that a principle difference between GAAP and rate-making is rate base treatment.

> There's a lot of other stuff on the assets on the balance sheet that's not included in a rate base, so nobody – no informed investor would expect to earn an equity return on something that's not included in a rate base. You would expect that an informed investor would understand enough of the regulatory process, if they're investing in a public utility, to understand that the authorized earnings in the revenue requirement are established on a rate base. And if a utility has a bunch of other assets on its books that are being financed in part by equity and debt capital that are not in rate base, then you wouldn't expect to earn an equity return on those. I believe that's probably one of the major factors.

32 Taylor rebuttal beginning at p. 12.

Then there's also a bunch of below-the-line expenses, which a utility records on its books under GAAP, but which are not considered in determining what their earned and authorized level of net operating income should be for ratemaking purposes. So if they're incurring expenses that are basically not allowed or not considered in the ratemaking process, that would also explain part of the difference.

And those two things are the – I think are probably the two major factors. But there's probably some other differences, because you are comparing apples to oranges. (Transcript p. 117, line 1 – 118, line 2)

On redirect, CAD asked Mr. Smith to review Exhibit CAD Cross 1, Mountaineer's 2011 Annual Report balance sheet and to identify some Asset items on the balance sheet per GAAP that *are typically not included* in rate base for regulatory purposes. His response:

Customer Accounts Receivable -- $23 million as of March 2012;

Gas stored underground -- $36 million. (July 18, 2012 Transcript pp. 166-167).[33] These items are recorded as assets on the 2011 balance sheet supported by capital on the liability side, but they are not in rate base.

Finally, at p. 121, Mr. Smith explains that GAAP earnings almost never match what utilities book as operating income. "They're on two considerably different bases of measurement, and you wouldn't necessarily expect them to measure up." (T-121, line 11) But the main difference is book equity as recorded by GAAP and rate base authorized by ratemaking.

> The key is on rate base. It's not guaranteeing or – an opportunity to earn that return on a book equity balance, which is not the same as rate base. So there's a major disconnect there. And I think the Company's got this idea that we should look at the equity balance on their books, multiply it by some return, like 10 percent, and use that to then mold the revenue requirement into producing those same results, even if you have to make strange adjustments that don't fit into the regulatory process. And we basically disagree with that. (Transcript, p. 126, line 18 – 127, line 3)

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[33] It is unclear from the transcript whether Special Funds -- $4.1 million is included in this group.

So, this exercise has morphed from a standard Rule 42T case to a challenge by Mountaineer to this Commission: change ratemaking to suit the Company, or else. The Commission should reject this outright. CAD recommends the Commission adhere to standard treatment for ADIT and deferred taxes; that any authorized rate increase be in an across-the-board fashion, including for special contract customers; and that the Commission expressly reject GAAP accounting results as any sort of substitute for the ratemaking process.

Consumer Advocate Division
By Counsel

Tom White
WV Bar No. 6393

CERTIFICATE OF SERVICE

I, Tom White, counsel for the Consumer Advocate Division of the Public Service Commission of West Virginia, certify that I have served a copy of the foregoing INITIAL BRIEF of the Consumer Advocate upon all counsel of record by mailing a true copy thereof by First Class, United States Mail, postage prepaid in accordance with the executed proprietary agreements.

Tom White
Counsel for Consumer Advocate
State Bar No. 6393

DATED: Aug. 31, 2012

ATTACHMENT WHN-9

Mountaineer Gas Company

2013 Financial Report

KPMG

MOUNTAINEER GAS COMPANY

Financial Statements

December 31, 2013 and 2012

(With Independent Auditors' Report Thereon)

KPMG LLP
1601 Market Street
Philadelphia, PA 19103-2499

Independent Auditors' Report

The Board of Directors and Shareholder
Mountaineer Gas Company:

We have audited the accompanying financial statements of Mountaineer Gas Company (the Company), which comprise the balance sheets as of December 31, 2013 and 2012, and the related statements of income, comprehensive income, changes in stockholder's equity, and cash flows for the years then ended, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with U.S. generally accepted accounting principles; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

KPMG

Opinion

In our opinion, the financial statements referred to above present fairly in all material respects, the financial position of Mountaineer Gas Company as of December 31, 2013 and 2012, and the results of its operations and its cash flows for the years then ended in accordance with U.S. generally accepted accounting principles.

KPMG LLP

Philadelphia, Pennsylvania
March 21, 2014

MOUNTAINEER GAS COMPANY

Balance Sheets

December 31, 2013 and 2012

(In thousands)

Assets	2013	2012
Current assets:		
Cash	$ 1,093	6,208
Accounts receivable, net of allowance for doubtful accounts of $1,900 and $1,600, respectively	17,344	15,943
Unbilled revenues	27,826	24,605
Gas in storage	31,370	24,648
Prepaid expenses	7,371	6,814
Inventory	2,978	3,042
Deferred income taxes	1,894	1,735
Total current assets	89,876	82,995
Property, plant and equipment:		
Distribution	418,902	408,195
Other property, plant and equipment	31,952	28,582
	450,854	436,777
Accumulated depreciation and amortization	(255,990)	(245,510)
	194,864	191,267
Construction work in progress	2,424	1,854
Total property, plant and equipment, net	197,288	193,121
Investments available for sale	5,426	5,639
Deferred charges and other assets:		
Unamortized debt expense	3,819	4,865
Other regulatory assets	6,031	6,358
Other	2,666	966
Total deferred charges	12,516	12,189
Total assets	$ 305,106	293,944

(Continued)

MOUNTAINEER GAS COMPANY

Balance Sheets

December 31, 2013 and 2012

(In thousands, except for number of shares and par value)

Liabilities and Stockholder's Equity	2013	2012
Current liabilities:		
Accounts payable	$ 28,054	36,256
Obligation to purchase gas in storage	2,106	24,648
Line of credit	39,000	—
Accrued payroll and vacation	3,728	3,458
Accrued other taxes	7,604	7,399
Customer deposits	5,023	4,863
Over-recovery of purchased gas costs	3,786	8,625
Pension and other retirement benefits	3,876	4,945
Other	975	917
Total current liabilities	94,152	91,111
Long-term debt	90,000	90,000
Deferred credits and other liabilities:		
Pensions and other retirement benefits	16,544	24,652
Deferred income taxes	20,372	10,509
Construction advances	1,059	1,725
Other	12	361
Total deferred credits and other liabilities	37,987	37,247
Stockholder's equity:		
Common stock – par value $25 per share. Authorized 2,200,000 shares, issued and outstanding 1,831,687 shares	45,792	45,792
Other paid-in capital	40,874	40,874
Accumulated deficit	(1,936)	(2,921)
Accumulated other comprehensive loss, net of income taxes of $1,138 and $5,338, respectively	(1,763)	(8,159)
Total stockholder's equity	82,967	75,586
Total liabilities and stockholder's equity	$ 305,106	293,944

See accompanying notes to financial statements.

MOUNTAINEER GAS COMPANY

Statements of Income

Years ended December 31, 2013 and 2012

(In thousands)

		2013	2012
Operating revenues	$	231,501	212,564
Operating expenses:			
Cost of gas		114,201	110,973
Operation and maintenance expense		64,383	62,136
Depreciation		12,533	12,099
Taxes other than income taxes		18,337	17,104
Total operating expenses		209,454	202,312
Operating income		22,047	10,252
Other expenses, net		2	14
Interest expense		7,496	7,082
Income before income taxes		14,549	3,156
Income tax expense (benefit)		5,564	(1,044)
Net income	$	8,985	4,200

See accompanying notes to financial statements.

MOUNTAINEER GAS COMPANY

Statements of Comprehensive Income

Years ended December 31, 2013 and 2012

(In thousands)

		2013	2012
Net income	$	8,985	4,200
Other comprehensive income (loss), net of tax:			
Pension and other postretirement benefit plans:			
Current year actuarial gain (loss)		4,424	(2,401)
Plan change – prior service cost		—	(81)
Reclassification of prior service cost included in net periodic pension cost		406	417
Reclassification of actuarial loss included in net periodic pension cost		605	320
Pension and other postretirement benefit plans		5,435	(1,745)
Unrealized holding losses on securities:			
Unrealized holding losses arising during the year		(142)	(63)
Less reclassification adjustment for gains losses included in net income		—	(3)
Changes in fair value of available for sale securities		(142)	(66)
Cash flow hedge		1,313	(201)
Reclassification adjustment for (gains)/losses included in net income		(210)	5
Changes in fair value of cash flow hedge		1,103	(196)
Comprehensive income	$	15,381	2,193

See accompanying notes to financial statements.

MOUNTAINEER GAS COMPANY

Statements of Changes in Stockholder's Equity

Years ended December 31, 2013 and 2012

(In thousands)

		Common stock	Other paid-in capital	Accumulated deficit	Accumulated other comprehensive loss	Total
Balances as of December 31, 2011	$	45,792	40,874	(3,821)	(6,152)	76,693
Net income		—	—	4,200	—	4,200
Dividends		—	—	(3,300)	—	(3,300)
Change in fair value of available-for-sale securities net of tax of benefit of $45		—	—	—	(66)	(66)
Actuarial loss and periodic service cost for retirement plans, net of tax benefit of $1,057		—	—	—	(1,745)	(1,745)
Change in fair value of cash flow hedge, net of tax benefit of $129		—	—	—	(196)	(196)
Balances as of December 31, 2012		45,792	40,874	(2,921)	(8,159)	75,586
Net income		—	—	8,985	—	8,985
Dividends		—	—	(8,000)	—	(8,000)
Change in fair value of available-for-sale securities net of tax benefit of $93		—	—	—	(142)	(142)
Actuarial gain and periodic service cost for retirement plans, net of tax expense of $3,579		—	—	—	5,435	5,435
Change in fair value of cash flow hedge, net of tax expense of $714		—	—	—	1,103	1,103
Balances as of December 31, 2013	$	45,792	40,874	(1,936)	(1,763)	82,967

See accompanying notes to financial statements.

MOUNTAINEER GAS COMPANY

Statements of Cash Flows

Years ended December 31, 2013 and 2012

(In thousands)

		2013	2012
Cash flows (used in) provided by operating activities:			
Net income	$	8,985	4,200
Adjustments for noncash charges and (credits):			
Bad debt expense		2,154	2,033
Depreciation		12,533	12,099
Depreciation charged to other accounts		300	271
Amortization of debt costs and other regulatory assets		1,475	1,369
Deferred income tax (benefit) expense		5,402	(1,044)
Changes in certain assets and liabilities:			
Accounts receivable		(3,555)	547
Unbilled revenues		(3,221)	862
Gas in storage		(6,722)	11,657
Regulatory assets		—	(3,597)
Other		(1,088)	3,368
Accounts payable		(8,202)	1,329
Obligation to purchase gas in storage		(22,542)	(11,657)
Accrued other taxes		205	(235)
Over/under-recovered purchased gas cost		(4,839)	2,057
Net cash (used in) provided by operating activities		(19,115)	23,259
Cash flows used in investing activities:			
Capital expenditures		(17,000)	(13,738)
Net cash used in investing activities		(17,000)	(13,738)
Cash flows provided by (used in) financing activities:			
Line of credit borrowings, net		39,000	—
Dividends paid		(8,000)	(3,300)
Payment for debt issuance costs		—	(104)
Net cash provided by (used in) financing activities		31,000	(3,404)
Net increase (decrease) in cash		(5,115)	6,117
Cash at beginning of period		6,208	91
Cash at end of period	$	1,093	6,208
Supplemental cash flow information:			
Cash paid during the year for:			
Interest	$	6,439	6,036
Income taxes		250	—
Supplemental noncash investing activity:			
Capital expenditures included in accounts payable and other current liabilities	$	220	221

See accompanying notes to financial statements.

MOUNTAINEER GAS COMPANY

Notes to Financial Statements

December 31, 2013 and 2012

(In thousands)

(1) Organization and Description of Business

Mountaineer Gas Company (MGC or Company) is a privately held public utility engaged in the distribution and transportation of natural gas. MGC serves approximately 220,000 customers in West Virginia and is subject to regulation by the Public Service Commission of West Virginia (WVPSC). Approximately two-thirds of the Company's revenues are from residential customers; the remainder is from commercial and industrial customers.

(2) Significant Accounting Policies

(a) Basis of Presentation

The financial statements of the Company were prepared in conformity with accounting principles generally accepted in the United States of America (GAAP), giving recognition to the rate making actions of the WVPSC and the provisions of Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) Topic 980, *Regulated Operations*. In preparing these financial statements, the Company has evaluated subsequent events known through March 21, 2014, the date these financial statements were available to be issued. Management believes that there were no subsequent events to disclose.

(b) Reclassifications

Certain reclassifications in the statement of cash flows have been made for the year ended December 31, 2012 to conform to the December 2013 presentation.

(c) Use of Estimates

The preparation of these financial statements required management to make estimates and assumptions that affect reported amounts. Actual results could differ from these estimates and such differences could be material.

The more significant management estimates and assumptions relate to the calculation of unbilled revenues, allowance for doubtful accounts, depreciation, regulatory assets, income taxes, pension and other postretirement benefits, and contingencies. The Company bases its estimates on historical experience and other factors that are believed to be reasonable under the circumstances.

(d) System of Accounts

The accounts of MGC are maintained in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (FERC) and adopted by the WVPSC.

(e) Rate Regulation

MGC is subject to regulation by the WVPSC which has jurisdiction over, among other things, the Company's rates, standards of service and accounting procedures. See cost of gas below and note 5, *Regulatory Assets and Liabilities*, for additional information.

MOUNTAINEER GAS COMPANY

Notes to Financial Statements

December 31, 2013 and 2012

(In thousands)

(f) ***Investments Available for Sale***

Investments available for sale are recorded at fair value, with unrealized gains and losses, net of income taxes, reported in stockholder's equity as a component of accumulated other comprehensive income. See note 11, *Fair Value of Financial Instruments*, and note 13(e), *Deferred Compensation Obligations*, for further information.

(g) ***Accounts Receivable***

Accounts receivable are recorded at the amount billed to customers. The allowance for doubtful accounts is the Company's best estimate of the amount of probable credit losses in existing accounts receivable and unbilled revenues. The allowance for doubtful accounts is based on historical data, the aging of receivables, economic conditions, credit risk of specific customers, and other factors. Individual accounts are charged off when the Company determines it is probable that the account will not be collected. Bad debt expense of $2,154 and $2,033 for the years ended December 31, 2013 and 2012, respectively, is included in operation and maintenance expense on the statements of income.

(h) ***Inventory and Gas in Storage***

The Company's materials and supplies inventory of $2,978 and $3,042 as of December 31, 2013 and 2012, respectively, is valued at average cost.

In 2008, the Company sold all of its then existing natural gas inventory as part of an Asset Management Agreement (AMA). Under this agreement, which expired in May 2013, the Company did not hold legal title to natural gas that was being stored for its future use and that it had committed to purchase.

Upon the expiration of the AMA in May 2013, the Company began to hold legal title to its gas in storage. The Company's gas in storage continues to be valued using the weighted average cost method. In general, commodity costs and variable transportation costs are capitalized as gas in storage. Fixed costs, primarily pipeline demand charges and storage charges, are expensed as cost of gas when incurred.

The Company also regularly sells gas it purchases from certain local producers in the summer months under agreements (Sales/Repurchase Agreements) that require the Company to repurchase the same volumes during the winter heating season.

The Company had accounted for the AMA and continues to account for the Sales/Repurchase Agreements in accordance with FASB ASC Topic 470.40, *Product Financing Arrangement*, and as such, reflected a gas in storage asset in the amount of $2,106 and $24,648 as of December 31, 2013 and 2012, respectively, along with a corresponding current liability to reflect the amount to be paid to repurchase the gas. See note 3, *Asset Management Agreement*, for additional information.

MOUNTAINEER GAS COMPANY

Notes to Financial Statements

December 31, 2013 and 2012

(In thousands)

(i) ***Property, Plant and Equipment***

The Company's property, plant, and equipment are recorded at cost. Cost includes direct labor and materials, work performed by third-party contractors, allocated overheads, and an allowance for funds used during construction (AFUDC). Given the short duration of the Company's construction projects, no AFUDC was recorded in 2013 or 2012.

The Company provides for depreciation using composite rates on a straight-line basis based on estimated service lives that range from 5 to 50 years. The weighted average depreciation rate was 2.8% for both 2013 and 2012. Depreciation of transportation and construction equipment of \$300 and \$271 for the years ended December 31, 2013 and 2012, respectively, were allocated to accounts other than depreciation expense.

When property is retired, sold, or otherwise disposed of in the ordinary course of business, the cost of the property is charged to accumulated depreciation, along with actual removal costs, less any salvage proceeds. Accordingly, no gain or loss is recognized in connection with ordinary retirements.

The Company has not recorded any asset retirement obligations associated with its properties as there are no legal obligations associated with the retirement of its assets.

(j) ***Impairment of Long-Lived Assets***

The Company performs an evaluation of long-lived assets, including utility plant and regulatory assets subject to amortization, for potential impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Regulatory assets are charged to expense in the period in which they are no longer probable of future recovery. Regulatory developments may impact this assessment in the future. As of December 31, 2013 and 2012, based upon management's analysis, no impairment losses for long-lived assets were recorded.

(k) ***Debt Issuance and Extinguishment Costs***

The Company defers expenses incurred in connection with the issuance or refinancing of debt and amortizes these deferred expenses over the terms of the related debt.

The Company also defers, as a regulatory asset, losses incurred in connection with the retirement of debt. Such costs are amortized over the term of the newly incurred debt.

(l) ***Customer Security Deposits, Construction Advances and Construction Contributions***

The Company receives security deposits from certain customers to minimize credit risk. Deposits are equal to one-twelfth of the annual estimated charge for residential service and one-sixth of the annual estimated charge for commercial and industrial service. These deposits are returned upon a customer's request to discontinue service or after the customer has paid their bills for twelve consecutive months without a delinquency. These deposits are reported as current liabilities in the balance sheets.

(Continued)

MOUNTAINEER GAS COMPANY

Notes to Financial Statements

December 31, 2013 and 2012

(In thousands)

The Company also receives construction advances from customers related to certain extensions of gas lines. These advances may be returned to customers based upon future customer additions to the line extension. After ten years, any advances that have not been refunded are forfeited by the customer. Forfeited advances are accounted for as a reduction to the cost of property, plant, and equipment. Construction advances are reported as noncurrent liabilities in the balance sheets.

In certain circumstances, customers are required to contribute to the cost of gas distribution construction required to provide them service. These contributions-in-aid of construction are accounted for as a reduction to the cost of property, plant, and equipment. Such contributions were $1,254 and $675 for the years ending December 31, 2013 and 2012, respectively.

(m) Pensions and Other Postretirement Employee Benefit Plans

The Company records annual amounts relating to its pension and postretirement benefit plans based on calculations that incorporate various actuarial and other estimates, including discount rates, mortality, assumed rates of return, compensation increases, turnover rates and healthcare cost trend rates. The Company reviews its assumptions on an annual basis and makes modifications to the assumptions when it is appropriate to do so. The effect of changes to assumptions is recorded in accumulated other comprehensive income (loss) and amortized to net periodic cost over future periods. The Company believes that the assumptions utilized in recording its obligations under its plans are reasonable. See note 10, *Pension Plan and Other Postretirement Employee Benefits*, for additional information.

(n) Revenue Recognition

The Company recognizes revenues on an accrual basis and estimates revenues for natural gas delivered to customers but not yet billed. At December 31, 2013 and 2012, unbilled revenues were $27,826 and $24,605, respectively. Revenues include late payment charges on past due accounts receivable.

(o) Cost of Gas and Unrecovered Purchased Gas Costs

The Company has a purchased gas adjustment (PGA) mechanism, approved by the WVPSC, that allows it to pass through to customers all of its purchased gas costs, subject to an annual prudence review. Any difference between the actual cost of gas and the amount of PGA revenues is deferred on the balance sheet as either a regulatory asset (unrecovered purchased gas costs) or a regulatory liability (over-recovery of purchased gas cost) and recovered from or returned to customers over the following year.

(p) Self-Insurance

The Company is predominantly self-insured for healthcare costs, including medical and prescription drug benefits. Stop-loss insurance coverage is carried for risks in excess of certain levels for medical costs. For employees who elect coverage under the managed healthcare option (HMO) offered by the Company, the Company incurs medical insurance premium expense. The Company recognized self-insured healthcare expenses of $3,068 and $2,796 for the years ended December 31, 2013 and

MOUNTAINEER GAS COMPANY

Notes to Financial Statements

December 31, 2013 and 2012

(In thousands)

2012, respectively. These expenses are included in operation and maintenance expense in the statements of income.

The Company estimates and accrues for claims incurred but not reported. The accruals for such claims were $225 at December 31, 2013 and 2012, and are included in other current liabilities on the balance sheets.

(q) ***Revenue and Excise Taxes***

Revenue taxes (West Virginia state and local Business and Occupation Taxes) are imposed on MGC and billed to its customers. These amounts are recorded gross in the statements of income. The amount of such taxes included in operating revenues was $12,898 and $11,796 for the years ended December 31, 2013 and 2012, respectively. The related revenue tax expense is included in taxes other than income taxes in the statements of income.

Excise taxes are imposed on the Company's customers and included on MGC's billings. The Company records the billing of excise taxes as a receivable with an offsetting payable to the applicable taxing authority, with no impact on the statements of income.

(r) ***Income Taxes***

The Company accounts for income taxes under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amount of existing assets and liabilities and their respective tax basis, and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those differences are expected to be recovered or settled.

The Company recognizes the effect of income tax positions only if those positions are more likely than not of being sustained. Recognized income tax positions are measured at the largest amount that is greater than 50% likely of being realized. Changes in recognition or measurement are reflected in the period in which the change in judgment occurs.

The Company is included in the consolidated federal and state tax returns filed by its sole shareholder, Mountaineer Gas Holdings Limited Partnership (MGH). MGC records tax expense as if it were a stand-alone taxpayer. To the extent that MGC generates a current tax liability, it pays MGH the same amount it would otherwise pay on a stand-alone basis to the taxing authorities. To the extent that MGC generates current losses or credits, MGC will be paid by MGH for the benefit that MGH receives from the taxing authorities for use of MGC's losses or credits. Any unrealized tax losses or credits are reflected as a deferred tax asset until utilized by MGH and paid to MGC. See note 12, *Related-Party Transactions*, for additional information.

(s) ***Derivative Instruments and Hedging Activities***

The Company accounts for derivatives and hedging activities in accordance with FASB ASC Topic 815, *Derivatives and Hedging*, which requires entities to recognize all derivative

MOUNTAINEER GAS COMPANY

Notes to Financial Statements

December 31, 2013 and 2012

(In thousands)

instruments as either assets or liabilities in the balance sheet at their respective fair values. For derivatives designated in hedging relationships, changes in the fair value are either offset through earnings against the change in fair value of the hedged item attributable to the risk being hedged or recognized in accumulated other comprehensive income, to the extent the derivative is effective at offsetting the changes in cash flows being hedged until the hedged item affects earnings.

For all hedging relationships, the Company formally documents the hedging relationship and its risk-management objective and strategy for undertaking the hedge, the hedging instrument, the hedged transaction, the nature of the risk being hedged, how the hedging instrument's effectiveness in offsetting the hedged risk will be assessed prospectively and retrospectively, and a description of the method used to measure ineffectiveness. The Company also formally assesses, both at the inception of the hedging relationship and on an ongoing basis, whether the derivatives that are used in hedging relationships are highly effective in offsetting changes in cash flows of hedged transactions. For derivative instruments that are designated and qualify as part of a cash flow hedging relationship, the effective portion of the gain or loss on the derivative is reported as a component of other comprehensive income and reclassified into earnings in the same period or periods during which the hedged transaction affects earnings. Gains and losses on the derivative representing hedge ineffectiveness are recognized in current earnings.

The Company had not elected to designate its interest rate swap that expired in 2012 as a hedge; accordingly, changes in its fair value were recorded in operating results in the period of change. However, the Company did elect to designate the interest rate swap entered into in December 2012 as a cash flow hedge. Thus, changes in its fair value, that effectively offset the variability of cash flows associated with its $20,000 senior note, are reported in accumulated other comprehensive income (loss).

See note 8, *Derivative Financial Instruments,* for additional information.

(t) ***Fair Value Measurements***

The Company utilizes valuation techniques that maximize the use of observable inputs and minimizes the use of unobservable inputs to the extent possible. The Company determines fair values based on assumptions that market participants would use in pricing an asset or liability in the principal or most advantageous market. When considering market participant assumptions in fair value measurements, the following fair value hierarchy distinguishes between observable and unobservable inputs, which are categorized in one of the following levels:

- Level 1 Inputs: Unadjusted quoted prices in active markets for identical assets or liabilities accessible to the reporting entity at the measurement date.
- Level 2 Inputs: Other than quoted prices included in Level 1 inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the asset or liability.

MOUNTAINEER GAS COMPANY

Notes to Financial Statements

December 31, 2013 and 2012

(In thousands)

- Level 3 Inputs: Unobservable inputs for the asset or liability used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at measurement date.

See note 11, *Fair Value of Financial Instruments*, for additional information.

(3) Asset Management Agreement

Under the AMA, entered into in 2008 and which expired in May 2013, MGC had released its contracted interstate pipeline transportation and storage capacity to Sequent, and sold to Sequent its then existing natural gas inventory. Under the AMA, MGC continued to buy its gas supply from various suppliers, but immediately sold this gas to Sequent at cost. Sequent then had title to the gas.

Sequent was obligated to sell to MGC the same volume of natural gas that it previously purchased from MGC. MGC's purchase price was based on Sequent's weighted average commodity cost paid to MGC, plus its variable transportation and storage costs.

Under the AMA, Sequent had the right to use, for its own financial benefit, the released transportation and storage capacity in excess of what was needed to serve MGC. For this right, Sequent would pay MGC a share of the profit it makes from using such capacity. Sequent paid MGC $3,000 and $3,200 for the AMA measurement periods ending May 31, 2013 and 2012, respectively. These amounts received by MGC resulted in a reduction in gas costs.

(4) Regulatory Matters

The PGA mechanism compares the revenue received for the cost of gas to the actual gas costs incurred by MGC. Any difference is deferred as a regulatory asset or liability to be collected from or returned to customers. As such, the PGA has no direct effect on earnings.

Each year, MGC makes a PGA filing (a 30-C proceeding) with the WVPSC. This filing allows the WVPSC to review the prudence of MGC's incurred gas costs, to review the computation of any over or undercollection of gas costs, and to establish a PGA billing rate for the next year. The new PGA billing rate is intended to settle past over or undercollections and allow the Company to recover its projected gas costs for the next year. The annual PGA filing is typically made mid-summer and a new PGA rate is normally effective November 1. The new PGA rate generally continues until October 31 of the following year, unless an earlier rate adjustment is approved by the WVPSC.

On November 4, 2011, the Company filed a request for a $12,187 increase in its annual base revenues (non-PGA revenues). On October 31, 2012, the WVPSC issued a Rate Order approving a $6,265 increase in the Company's annual base revenues (non-PGA revenues) effective November 1, 2012. The increase is to be recovered completely through fixed monthly customer charges. Subsequently, in conjunction with WVPSC's Order on April 9, 2013 denying the Company's Second Petition for Reconsideration, the WVPSC also corrected a mathematical error in its October 31, 2012 Rate Order resulting in the WVPSC approving an additional $522 increase in the Company's annual base revenues, to also be recovered through fixed monthly customer charges.

MOUNTAINEER GAS COMPANY

Notes to Financial Statements

December 31, 2013 and 2012

(In thousands)

In the October 31, 2012 Rate Order, the WVPSC rejected the Company's position that the thirteen-month average federal net operating loss and alternative minimum tax credit carryforward, resulting from the Company's election of accelerated depreciation, should be added back to rate base. The WVPSC did not believe that this created a potential tax normalization violation. However, the Company believed this action may have created a potential tax normalization violation. On November 21, 2012, the Company filed a Limited Petition for Reconsideration with the WVPSC, asking it to reconsider its decision on this issue. This Limited Petition for Reconsideration was denied on February 11, 2013. On February 21, 2013, the Company filed a Second Petition for Reconsideration. On April 9, 2013, the WVPSC issued its Order once again denying the Company's request. Thus, on July 30, 2013, the Company requested a private letter ruling from the Internal Revenue Service (IRS). The IRS has since issued its private letter ruling, PLR-133813-13, concluding that such action by the WVPSC did not create a tax normalization violation. The IRS concluded that because the WVPSC had taken the federal net operating loss and alternative minimum tax credit carryforward into account when setting the Company's rates, the WVPSC's decision to reduce the Company's rate base does not violate normalization requirements.

(5) Regulatory Assets and Liabilities

The Company accounts for the impact of rate regulation in accordance with FASB ASC Topic 980, *Regulated Operations*. Topic 980 requires MGC to recognize the economic effects of rate regulation, and results in the recording of regulatory assets and liabilities. Regulatory assets represent probable future revenue associated with incurred costs that are expected to be recovered from customers through rates. Regulatory liabilities represent probable future refunds to customers, or amounts collected from customers for future expenditures. Continued applicability of Topic 980 requires that rates be designed to recover specific costs of providing regulated services and be charged to and collected from customers. Management believes that current facts and circumstances support the continued application of Topic 980 for MGC.

Regulatory assets and liabilities reflected in the balance sheets at December 31 are as follows:

		2013	2012
Current assets:			
Prepaid property taxes	$	4,365	4,405
Long-term assets:			
Deferred regulatory state income tax expense		3,794	3,693
Unamortized debt reacquisition costs		3,017	3,641
Customer information system costs		2,227	2,608
Receivership costs		—	42
Acquisition costs		10	15
Total regulatory assets	$	13,413	14,404
Current liabilities:			
Over-recovery of purchased gas costs	$	3,786	8,625

MOUNTAINEER GAS COMPANY

Notes to Financial Statements

December 31, 2013 and 2012

(In thousands)

Regulatory assets are either currently being collected in rates or are expected to be collected through rates in a future period, as described below:

- For ratemaking purposes, state property taxes are recovered on a cash basis. Therefore, accrued taxes representing one and a half years of assessed tax are recorded as a regulatory asset until paid. This amount is included in prepaid expenses on the balance sheets. The Company does not earn a return on these costs.
- Upon finalizing the 2011 rate case, it was determined that the WVPSC's position is to allow for recovery of state income tax expense on a flow-through basis (as cash tax payments are made) as opposed to a fully normalized basis (at the statutory rate). Prior to 2013, the Company had recorded state income tax expense at the statutory rate. As a result, the Company recorded a regulatory asset of $3,693 in 2012 for the cumulative 2005 through 2012 deferred state income tax expense attributable to its temporary book vs. tax differences related to accelerated depreciation of property, plant and equipment. The Company adjusts the regulatory asset for deferred state income tax expense attributable to its temporary book vs. tax differences related to accelerated depreciation of property, plant and equipment. The Company will realize the benefit of this regulatory asset as it recovers state income tax payments in rates that exceed state income taxes calculated at the statutory rate. The Company does not earn a return on this regulatory asset.
- Unamortized debt reacquisition costs relate to debt retirement and re-financings. The Company does not currently earn a return on these costs, which are included in unamortized debt expense on the balance sheets.
- Customer information system costs relate to the development and implementation of a new customer service and billing system. This includes data conversion, training, and other implementation costs that have been deemed recoverable in conjunction with the Company's most recent Rate Order. These costs are included in other regulatory assets on the balance sheets and are being amortized. The WVPSC has allowed the Company to earn a return on its deferred customer information system costs in its most recent Rate Order. The costs are being amortized to operation and maintenance expense at the rate of 14.36% annually, or approximately 7 years.
- Receivership costs were incurred by MGC while acting in the capacity of receiver for several smaller West Virginia utilities. These costs were being amortized to operation and maintenance expense over 3 years, and were included in other regulatory assets on the balance sheets.
- Acquisition costs were incurred by MGC in conjunction with its 2011 purchase of the assets of a small West Virginia gas distribution company.

The Company's only regulatory liability as of December 31, 2013 and 2012 was for the over-recovery of purchased gas costs. These amounts are typically returned to customers in the year following the year that they occur.

(Continued)

MOUNTAINEER GAS COMPANY

Notes to Financial Statements

December 31, 2013 and 2012

(In thousands)

(6) Line of Credit

On December 15, 2011, the Company entered into an Amended and Restated Credit Agreement (Amended Facility). The Amended Facility is an unsecured revolving credit facility with a maximum borrowing capacity of $70,000 with a Company option to increase to a maximum principal amount of $125,000 assuming certain conditions are met. The scheduled maturity date is December 14, 2014. Through June 14, 2014, the Company has an option to request a one year extension.

Borrowings under the Amended Facility may occur under various interest rate options and are generally made at the prime rate of the lending agent or at a rate equal to the London Interbank Offered Rate (LIBOR) plus an applicable margin depending on the Company's unsecured debt rating.

The Company's average effective interest rate for its revolving credit facilities for 2013 and 2012 was 2.53% and 4.26%, respectively. The Company also pays a commitment fee on the unused portion of the Amended Facility at a rate determined by the Company's unsecured debt rating. Commitment fees are included in operating expenses.

At December 31, the Company's borrowing and utilization capacity under its credit facilities were as follows:

		2013	2012
Borrowings	$	39,000	—
Unused – available for borrowing		31,000	70,000
Total credit facility	$	70,000	70,000

Covenants in the Amended Facility require the Company to provide annual and quarterly financial reports to the lenders and their agent. The Company is also required to deliver to the agent and lenders a quarterly certificate indicating that the Company has complied with all conditions and covenants under the agreements.

The Amended Facility (as amended by the First Amendment), requires the Company to maintain a minimum EBITDA to interest coverage ratio of 2.0 to 1.0 and a maximum debt-to-capital ratio of 0.65 to 1.00. The maximum allowable annual capital expenditures are $25,000. Additionally, the amount of dividends that can be declared and paid is restricted, including a required tangible net worth requirement of at least $70,000, before and after giving effect to the dividend payment. Management believes that the Company was in compliance with all such required ratios as of December 31, 2013.

(7) Long-Term Debt

The Company's long-term debt consists of a $20,000 floating rate senior note due in 2022 and $70,000 in 7.58% senior notes due in 2017 (collectively, the Senior Notes). The $20,000 floating rate senior note was originally scheduled to mature in December 2012, however the Company entered into a Third Amendment to the Note Purchase Agreement (Third Amendment) to extend the maturity to December 2022.

(Continued)

MOUNTAINEER GAS COMPANY

Notes to Financial Statements

December 31, 2013 and 2012

(In thousands)

The Senior Notes require no annual principal payments. Interest is payable on a semi-annual basis in June and December. The floating interest rate on the $20,000 senior note is calculated based on the three-month LIBOR rate set two business days before the commencement of the three-month interest period, plus 2.50%. As described in note 8, the Company's existing interest rate swap expired in 2012 in conjunction with the $20,000 senior note's original maturity. Thus, as required in the Third Amendment, the Company entered into a new interest rate swap in December 2012 to hedge the LIBOR related portion of the interest rate. The effective interest rate on the $20,000 senior note was 4.48% at December 31, 2013 and 2012.

The Company's average effective interest rate on all long-term debt for 2013 and 2012 was 6.90% and 7.03%, respectively, and reflects the impact of financial hedges.

A summary of borrowings at December 31 is as follows:

		2013	2012
Long-term:			
Floating rate senior note, Series A due 2022	$	20,000	20,000
7.58% senior notes, Series B due 2017		70,000	70,000
Long-term debt	$	90,000	90,000

Covenants in the Company's long-term borrowings require it to provide annual and quarterly financial reports to the note-holders. The Company is also required to deliver to the note-holders a quarterly certificate indicating that the Company has complied with all conditions and covenants under the agreements.

The Senior notes also require the Company to maintain certain financial conditions including a minimum EBITDA to interest coverage ratio of 2.0 to 1.0, a maximum indebtedness to EBITDA ratio of 8.00 to 1.0, and a maximum debt-to-capital ratio of 0.65 to 1.00. The amount of dividends that can be declared and paid continues to be restricted, including a newly required tangible net worth requirement of at least $70,000, before and after giving effect to the dividend payment. Management believes that the Company was in compliance with all such required ratios as of December 31, 2013.

(8) Derivative Financial Instruments

The Company uses derivatives only for hedging purposes; it does not enter into derivative agreements to speculate. Specifically, the Company uses derivative instruments to manage its exposure to interest rate changes on its $20,000 floating rate senior note. To meet this objective, the Company enters into LIBOR based interest rate swap agreements to manage fluctuations in cash flows resulting from changes in the benchmark interest rate of LIBOR. These swaps change the variable-rate cash flow exposure on the debt obligations to fixed cash flows. Under the terms of the interest rate swaps, the Company receives LIBOR based variable interest rate payments and makes fixed interest rate payments, thereby creating the equivalent of fixed-rate debt for the $20,000 floating rate senior note being hedged.

MOUNTAINEER GAS COMPANY

Notes to Financial Statements

December 31, 2013 and 2012

(In thousands)

The Company did not elect to account for its interest rate swap that expired in December 2012 as a cash flow hedge. Accordingly, the fair value of the interest rate swap was reflected on the balance sheet in other current liabilities, with changes in fair value recognized in earnings as part of interest expense. The Company has, however, designated the new interest rate swap entered into in December 2012 as a cash flow hedge. Thus, the fair value of the interest rate swap is reflected on the balance sheet in other liabilities, with the changes in the fair value of the interest rate swap that effectively offset the variability of cash flows associated with the $20,000 floating rate senior note reported in accumulated other comprehensive income. These amounts are subsequently reclassified into interest expense as a yield adjustment of the hedged interest payments in the same period in which the related interest affects earnings.

Details of the Company's derivative contracts related to the $20,000 floating rate senior note are as follows:

Transaction type		Notional amount	Effective date	Termination date	Rate	Rate type
Swap	$	20,000	12/20/2012	12/20/2022	1.98	Fixed

Receipts or payments under the contracts are based on the three-month LIBOR rate and are made quarterly or at the termination date. As of December 31, 2013, the fair value of the Company's interest rate swap was an asset of $1,491, which is included in other assets. As of December 31, 2012, the fair value of the Company's interest rate swap was a liability of $355, which was included in other liabilities.

(9) Income Taxes

MGC is subject to federal and West Virginia income tax. All periods after 2009 remain open to examination by the IRS and West Virginia. The Company has made no provision for taxes or interest related to the potential impacts of tax audits or tax uncertainties, and believes that no such accruals are necessary.

(Continued)

MOUNTAINEER GAS COMPANY

Notes to Financial Statements

December 31, 2013 and 2012

(In thousands)

Details of federal and state income tax expense (benefit) for the years ended December 31, 2013 and 2012, respectively, are as follows:

		2013	2012
Current:			
Federal	$	162	—
State		—	—
Total current expense		162	—
Deferred:			
Federal		4,692	2,323
State		710	(3,367)
Total deferred tax expense (benefit)		5,402	(1,044)
Total income tax expense (benefit)	$	5,564	(1,044)

See note 5, *Regulatory Assets and Liabilities*, for additional information regarding the $3,693 regulatory asset recorded in 2012 for deferred regulatory state income tax expense. In conjunction with recording this regulatory asset, the Company recorded the associated accumulated federal deferred tax liability of $1,202 and accumulated state deferred tax liability of $259.

For 2013 and 2012, the income tax expense presented differs from the amount computed by applying the U.S. federal income tax rate of 35% to pretax income due to the effect of state income taxes. The following table represents a reconciliation between the statutory federal income tax rate and the effective tax rate:

		2013	2012
Computed "expected" tax expense at federal statutory rate	$	5,092	1,105
Increase (decrease) in income taxes resulting from:			
State and local income taxes, net of federal income tax benefit		615	143
Deferred state income tax benefit from regulatory assets net of federal income tax expense		(74)	(2,232)
Other, net		(69)	(60)
Income tax expense (benefit) on statements of income	$	5,564	(1,044)

(Continued)

MOUNTAINEER GAS COMPANY

Notes to Financial Statements

December 31, 2013 and 2012

(In thousands)

The tax effects of temporary differences that give rise to deferred tax assets and liabilities as of December 31 were as follows:

		2013	2012
Deferred tax assets:			
Net operating loss and tax credit carryforwards	$	3,260	7,118
Pension postretirement benefits		3,837	7,116
Postretirement benefits other than pensions		2,428	2,658
Vacation accrual		863	851
Bad debt accrual		745	633
Other		1,254	1,444
Injuries and damages accruals		261	227
Interest rate hedge		—	129
Total deferred tax assets		12,648	20,176
Deferred tax liabilities:			
Property, plant, and equipment		27,494	25,649
Regulatory assets		2,362	2,491
Unamortized debt expense		685	810
Interest rate hedge		585	—
Total deferred tax liabilities		31,126	28,950
Total net deferred tax liabilities	$	(18,478)	(8,774)
Current net deferred tax assets	$	1,894	1,735
Long-term net deferred tax liabilities		(20,372)	(10,509)
Total net deferred tax liabilities	$	(18,478)	(8,774)

At December 31, 2013, the Company has a federal net operating loss carryforward of $4,675 that begins to expire in 2028, a state net operating loss carryforward of $15,172 that begins to expire in 2027, and an alternative minimum tax credit carryforward of $983 that does not expire. Utilization of the net operating loss may be subject to annual limitation as result of a change in ownership as provided by the Internal Revenue Code and similar state provisions. Such a limitation could result in the expiration of the net operating loss before utilization.

The Company believes that it is more likely than not that the results of future operations will generate sufficient taxable income to realize its deferred tax assets.

(Continued)

MOUNTAINEER GAS COMPANY

Notes to Financial Statements

December 31, 2013 and 2012

(In thousands)

(10) Pension Plan and Other Postretirement Employee Benefits

The Company has a noncontributory defined benefit pension plan covering substantially all employees. Pension benefits are based on years of service and compensation.

The Company also provides medical insurance benefits on a contributory basis to eligible retired employees hired through December 31, 2012 until the earlier of age 65 or Medicare eligibility. Employees who were eligible to retire at age 55 or current retirees as of January 1, 2008, are eligible for continued benefits. Reduced life insurance benefits are also made available to all eligible retirees.

The measurement date for all plans is December 31.

Net periodic benefit costs for the years ended December 31, 2013 and 2012 were as follows:

		Pension benefits		Postretirement benefits	
		2013	2012	2013	2012
Components of net periodic benefit cost:					
Service cost	$	2,760	2,314	298	275
Interest cost		1,748	1,578	306	326
Expected return on assets		(1,710)	(1,363)	—	—
Amortization of prior service cost		883	883	(208)	(213)
Amortization of net actuarial (gain) loss		1,084	625	(80)	(112)
Net periodic benefit cost	$	4,765	4,037	316	276

Typically, about 10% of the net periodic benefit cost has been capitalized as part of the cost of constructing gas distribution property. The remainder is included in operating expenses.

(Continued)

MOUNTAINEER GAS COMPANY

Notes to Financial Statements

December 31, 2013 and 2012

(In thousands)

The following table sets forth the benefit obligations, the plan assets, and the funded status of the plans at December 31:

		Pension benefits		Postretirement benefits	
		2013	2012	2013	2012
Accumulated benefit obligation at end of year	$	30,896	30,130	—	—
Projected benefit obligation at beginning of year	$	38,681	30,235	7,827	7,282
Service cost		2,760	2,314	298	275
Interest cost		1,748	1,578	306	326
Net actuarial (gain) loss		(4,779)	4,694	(1,148)	(18)
Plan change – prior service cost		—	—	—	130
Plan participant contributions		—	—	45	83
Benefits paid		(173)	(140)	(38)	(251)
Projected benefit obligation at end of year		38,237	38,681	7,290	7,827
Fair value of plan assets at beginning of year		20,689	15,079	—	—
Actual return on plan assets		3,118	2,185	—	—
Company contributions		4,820	3,565	—	168
Plan participant contributions		—	—	45	83
Benefits paid		(173)	(140)	(38)	(251)
Other		—	—	(7)	—
Fair value of plan assets at end of year		28,454	20,689	—	—
Funded status	$	(9,783)	(17,992)	(7,290)	(7,827)

The following table sets forth the amounts recognized on the balance sheets at December 31:

		Pension benefits		Postretirement benefits	
		2013	2012	2013	2012
Current liabilities	$	(3,600)	(4,700)	(276)	(245)
Noncurrent liabilities		(6,183)	(13,292)	(7,014)	(7,582)
Accumulated other comprehensive loss (income), net of tax		4,074	8,982	(1,431)	(904)

(Continued)

MOUNTAINEER GAS COMPANY

Notes to Financial Statements

December 31, 2013 and 2012

(In thousands)

Amounts recognized in accumulated other comprehensive income (loss) at December 31 consist of:

	Pension benefits		Postretirement benefits	
	2013	2012	2013	2012
Prior service (credits) costs	$ 1,546	2,429	33	(175)
Net actuarial (gain) loss	5,158	12,430	(2,387)	(1,320)
Income tax expense (benefit)	(2,630)	(5,877)	923	591
	$ 4,074	8,982	(1,431)	(904)

A reconciliation of changes in the pre-tax amounts included in other comprehensive income (loss) attributable to pension and postretirement benefits is as follows:

	Pension benefits	Postretirement benefit
December 31, 2011	$ 12,495	(1,932)
Current year actuarial (gain) loss	3,872	(18)
Plan change – prior service cost	—	130
Amortization of prior service cost	(883)	213
Amortization of actuarial (gain) loss	(625)	112
December 31, 2012	14,859	(1,495)
Current year actuarial gain	(6,188)	(1,148)
Amortization of prior service cost	(883)	209
Amortization of actuarial (gain) loss	(1,084)	80
December 31, 2013	$ 6,704	(2,354)

The prior service costs and the net actuarial loss for the defined benefit pension plan that are expected to be amortized from accumulated other comprehensive income (loss) into net periodic benefit cost during fiscal 2014 are $883 and $302, respectively. The prior service credits and the net actuarial gain for the postretirement health and life benefits that are expected to be amortized from accumulated other comprehensive income (loss) into net periodic benefit cost over the next fiscal year are $61 and $168, respectively.

MOUNTAINEER GAS COMPANY

Notes to Financial Statements

December 31, 2013 and 2012

(In thousands)

The assumptions used to determine benefit obligations at December 31, 2013 and 2012 and to determine net periodic benefit cost for the years ended December 31, 2013 and 2012 were as follows:

	Pension benefits		Postretirement benefits	
	2013	2012	2013	2012
Discount rate – benefit obligation	5.28%	4.49%	4.89%	4.08%
Discount rate – benefit cost	4.49	5.20	4.08	4.83
Expected long-term rate of return on plan assets	7.50	7.50	N/A	N/A
Rate of compensation increase	3.00	3.00	3.00	3.00

The expected long-term rate of return on plan assets is established by considering historical and projected returns of the pension trust investment portfolio as a whole, and not on the sum of the returns on individual asset categories. Projected returns are determined with the assistance of independent advisors, involve management judgment, and take into account current and forecast economic conditions.

For measurement purposes in 2013, the annual rate of increase in the per capita cost of covered healthcare benefits was assumed to be 10% for the pre-65 years of age group decreasing 1% per year to the ultimate rate of 5% in 2018, and 7% was assumed for the post-65 years of age group decreasing 0.5% per year to the ultimate rate of 5% in 2017.

Since plan provisions limit the amount of company contributions, a 1% change in the assumed healthcare cost trend rate would have a minimal effect on the amounts displayed in the tables above.

Assets of the Company's pension plan are invested in a mix of asset classes based on targeted allocations by asset category. The objective of the targeted allocations is to diversify investments in order to reduce risk. The investment objective is to generate sufficient funds to meet plan liabilities. Plan assets are therefore invested to maximize long-term returns consistent with the plan's liabilities, cash flow requirements and a low risk tolerance. The targeted allocations were modified during 2013 to begin moving from the prior targeted allocation of 40% to 60% equity securities and 40% to 60% fixed income securities toward a targeted allocation of 70% equity securities and 30% fixed income securities. The shift is expected to be completed by April 2014.

The fair value of plan assets and the actual allocation by asset class at December 31 are as follows:

	2013		2012	
	Fair value	Percentage	Fair value	Percentage
Equity securities	$ 17,844	63%	$ 9,877	48%
Debt securities	9,369	33	9,875	50
Cash and cash equivalents	1,241	4	937	2
	$ 28,454	100%	$ 20,689	100%

(Continued)

MOUNTAINEER GAS COMPANY

Notes to Financial Statements

December 31, 2013 and 2012

(In thousands)

The fair value of plan assets is determined based on the fair value hierarchy levels described in note 11, *Fair Value of Financial Instruments*. The fair value of equity securities and cash and equivalents were based on Level 1 inputs. The fair value of debt securities was based on Level 2 inputs; no Level 3 unobservable inputs were utilized. During 2013, the Company decided to shift its investments from a combination of mutual fund and individual securities to a single diversified equity fund and a single diversified fixed income fund. Management does not believe there are any significant concentrations of risk within plan assets.

The Company's pension plan assets are exposed to various risks such as interest rate, market, and credit risks. Due to the level of risk associated with certain investments, it is at least reasonably possible that changes in the values of the investments will occur in the near term and that such changes could materially affect the amounts reported in the financial statements.

The postretirement health and life benefits are unfunded.

The Company expects to contribute $3,600 to the pension trust in 2014.

The benefits expected to be paid from the pension plan and the postretirement health and life plans are as follows:

		Pension benefit	Postretirement benefit
2014	$	619	276
2015		845	368
2016		1,062	435
2017		1,384	518
2018		1,635	601
2019 – 2023		12,034	3,258

The expected benefits are based on the same assumptions used to measure the Company's benefit obligation at December 31, 2013 and include estimated future employee service.

The Company has a defined contribution plan, commonly referred to as a 401(k) plan, covering eligible employees. The plan contains provisions for the Company to match 50% of an employee's before-tax contribution, up to a maximum of 3% of the employee's eligible compensation. The amounts expensed for the Company matching provisions were $729 and $702 for the years December 31, 2013 and 2012, respectively.

MOUNTAINEER GAS COMPANY

Notes to Financial Statements

December 31, 2013 and 2012

(In thousands)

(11) Fair Value of Financial Instruments

The fair value of assets and liabilities accounted for at fair value on a recurring basis in the Company's financial statements are categorized in the table below according to fair value hierarchy levels.

Asset (liability)		Quoted prices in active markets (Level 1)	Significant observable inputs (Level 2)	Significant unobservable inputs (Level 3)	Total
December 31, 2013:					
Derivative financial instruments:					
Hedge of interest rate on long-term debt	$	—	1,491	—	1,491
Investments available for sale:					
U.S. government agencies		—	3,508	—	3,508
U.S. Treasury securities		—	1,746	—	1,746
Cash and cash equivalents		172	—	—	172
Net fair value	$	172	6,745	—	6,917
December 31, 2012:					
Derivative financial instruments:					
Hedge of interest rate on long-term debt	$	—	(325)	—	(325)
Investments available for sale:					
U.S. government agencies		—	3,328	—	3,328
U.S. Treasury securities		—	1,932	—	1,932
Cash and cash equivalents		379	—	—	379
Net fair value	$	379	4,935	—	5,314

The fair value of the $70,000 fixed rate portion of long-term debt, which is recorded in the balance sheets at the principal amount outstanding, is approximately $80,300 (Level 2). The carrying value of the floating rate note payable is a reasonable estimate of fair value due to the nature of the financial instrument.

The carrying value of cash and cash equivalents, accounts receivable, unbilled revenues, income taxes receivable, accounts payable, accrued other taxes, customer deposits liability, and borrowings under the line of credit are a reasonable estimate of fair value due to the short-term nature of these financial instruments.

The Company's determination of Level 2 fair value maximized the use of observable inputs. The estimate for long-term debt was determined by discounting the future cash flows of the debt at interest rates currently believed to be available to the Company for similar debt instruments of comparable maturities.

MOUNTAINEER GAS COMPANY

Notes to Financial Statements

December 31, 2013 and 2012

(In thousands)

The primary input in determining the fair value of derivative financial instruments and investments available for sale was interest rates.

(12) Related-Party Transactions

MGC is owned by MGH, a West Virginia partnership composed of general partner MGH LLC and limited partner Mid Mountain Holdings II LLC, formerly ArcLight WV Holdings II LLC.

The Company has an agreement with IGS Utilities LLC (IGS LLC), a partner in MGH LLC, to provide general management oversight of its business. The Company paid IGS LLC $1,424 and $1,387 during the years ended December 31, 2013 and 2012, respectively, for these services. These amounts are included in operation and maintenance expense on the statements of income. The Company had no accounts receivable from or accounts payable to IGS LLC at either December 31, 2013 or 2012. In 2012, the management agreement with IGS LLC was extended until June 30, 2015.

As described in note 2(r), MGC is included in consolidated federal and state tax returns of MGH. At December 31, 2013 and 2012, income taxes receivable from MGH were $951 and $863, respectively, which are included in other assets on the balance sheets. Income taxes receivable from MGH consists of estimated tax payments on deposit with taxing authorities, and consolidated tax benefits received by MGH but not yet paid to MGC. The Company is unable to determine when it will be paid the amounts due from MGH because MGH does not have sufficient funds to make payment. The Company has not made any allowance related to the collectability of this receivable because it believes MGH will be able to make payment in the future. Future sources of funds to MGH that can enable it to make payment include dividend distributions from the Company.

The Company has a long-term agreement to purchase stated volumes of natural gas from a natural gas supplier that was under common ownership until 2012. This agreement is generally at 85% of a market index price and expires on October 31, 2032. Purchase commitments under this agreement are not included in the amounts shown in note 13(c) due to the Company's inability to reasonably estimate future market index prices. The volumes required to be purchased under the contract decline annually from 715,000 mcf in 2014 to 439,000 mcf in 2032. Additional purchases can also be made under this contract at market prices. During the years ended December 31, 2013 and 2012, the Company purchased $3,880 and $3,378, respectively, of natural gas under the terms of this contract.

(13) Commitments

(a) Construction and Capital Program

The Company has a construction and capital program in its ordinary course of business. The Company has not entered into any significant capital program commitments beyond 2013.

(b) Leases

The Company has lease agreements with various terms and expiration dates, primarily for vehicles, buildings, and computer equipment. The leases are classified as operating leases for accounting purposes.

MOUNTAINEER GAS COMPANY

Notes to Financial Statements

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(In thousands)

Total operating lease rental payments of $2,231 and $2,250 during the years ended December 31, 2013 and 2012, respectively, were recorded as rent expense.

The Company's estimated future minimum lease payments as of December 31, 2013 for operating leases with terms in excess of one year are as follows:

		Lease obligations
2014	$	2,086
2015		1,692
2016		929
2017		408
2018		45
Thereafter		18
	$	5,178

(c) ***Natural Gas Transportation, Storage, and Fuel Supply***

The Company is a party to certain natural gas transportation and storage agreements and has various fuel supply commitments. The estimated future payments of these agreements are as follows:

		Future commitments
2014	$	49,225
2015		28,420
2016		23,229
2017		23,229
2018		23,229
Thereafter		20,229
	$	167,561

(d) ***Customer Call Center***

The Company outsources substantially all of its customer call center operations. The initial five year term expires in April 2014. After this initial five year term, the agreement continues in full force and effect until either party provides the other at least one year's notice of its intent to terminate the agreement. The Company recorded expenses of $1,605 and $1,673 in 2013 and 2012, which are included in operation and maintenance expense in the statements of income.

MOUNTAINEER GAS COMPANY

Notes to Financial Statements

December 31, 2013 and 2012

(In thousands)

(e) Deferred Compensation Obligations

In 1995, MGC entered into deferred compensation agreements with two executives, and established trusts to ensure payment to the executives or their beneficiaries. The Company is required to maintain a minimum funding level that exceeds 100% of the present value of the existing liability. Any excess above the minimum funding level can be withdrawn by the Company for operating purposes. The Company was not required to contribute to the trust in 2013 and contributed $1,050 to the trust in 2012.

The cost and estimated fair value of trust assets as of December 31 were as follows:

		2013		2012	
		Cost	Fair value	Cost	Fair value
U.S. government agencies	$	3,530	3,508	3,207	3,328
U.S. Treasury securities		1,722	1,746	1,818	1,932
Cash and cash equivalents		172	172	379	379
	$	5,424	5,426	5,404	5,639

Trust investments in debt securities mature at various times from 2014 to 2019. These securities are expected to be held to maturity and unrealized gains and losses are temporary.

The trusts make annual payments to the plan participants of $198. Such payments will continue through March 2055 when the deferred compensation obligation to one former executive expires. The deferred compensation obligation to the other former executive expires in December 2056.

The deferred compensation liability (presented on a present value basis) at December 31, 2013 and 2012 is $3,348 and $3,778, respectively, and is included in deferred credits and other liabilities as part of pensions and other retirement benefits in the Company's balance sheets.

The annual accretion of the deferred compensation liability, including the impact of changes in the present value discount rate, is netted with investment returns of the trusts, and included in operation and maintenance expense.

(f) Labor Subject to Collective Bargaining Agreements

The Company has labor agreements with Locals 426 of the Utility Workers Union of America, AFL-CIO and with Locals 372, 628, and 628B of the United Steel Workers International Union. Together, both unions represent approximately 65% of the Company's employees. All of the labor agreements were renewed at various times during 2013 for five-year periods expiring in 2017.

MOUNTAINEER GAS COMPANY

Notes to Financial Statements

December 31, 2013 and 2012

(In thousands)

(14) Contingencies

The Company is involved in litigation, claims, and investigations arising in the normal course of business. Although unable to predict the outcome of these contingencies, management believes that they will not have a material adverse effect on the financial position, results of operations or cash flows of the Company. The Company accrues appropriate liabilities for these contingencies when they are reasonably estimable. These accrued liabilities, inclusive of estimated legal fees, were $440 and $350 at December 31, 2013 and 2012, respectively, and are included in other current liabilities on the balance sheets.

ATTACHMENT WHN-10

IRS Private Letter Ruling for Mountaineer Gas Company

C
PLR 201418024, 2014 WL 1743212 (IRS PLR)

Internal Revenue Service (I.R.S.)
IRS PLR

Private Letter Ruling

Issue: May 2, 2014
January 27, 2014

Section 167 -- Depreciation167.00-00 Depreciation

167.22-00 Public Utility Property

167.22-01 Normalization Rules

CC:PSI:B06
PLR-133813-13

LEGEND:
Taxpayer =

Parent =

State =

Commission =

Year A =

Year B =

Year C =

Year D =

Year E =

X =

Y =

Date A =

Date B =

Date C =

Date D =

Date E =

Case =

Director =

Dear ***:

This letter responds to the request, dated July 30, 2013, of Taxpayer for a ruling on whether the Commission's treatment of Taxpayer's Accumulated Deferred Income Tax (ADIT) account balance in the context of a rate case is consistent with the requirements of the normalization provisions of the Internal Revenue Code.

The representations set out in your letter follow.

Taxpayer is a regulated public utility incorporated in State. It is wholly owned by Parent. Taxpayer distributes and sells natural gas to customers in State. Taxpayer is subject to the regulatory jurisdiction of Commission with respect to terms and conditions of service and particularly the rates it may charge for the provision of service. Taxpayer takes accelerated depreciation where available and, for the period beginning in Year A and ending in Year E, Taxpayer has, in the aggregate, produced more net operating losses (NOL) than taxable income. After application of the carryback and carryforward rules, Taxpayer represents that it has net operating loss carryforward (NOLC), produced in Year C and Year E, of $X as of the end of Year E. The amount of claimed accelerated depreciation in Year C and Year E exceeded the amount of the NOLCs for those years. In Year D, Taxpayer produced regular taxable income as well as alternative minimum taxable income (AMTI); the regular taxable income was offset by the NOLCs from Year B and year C but could not offset the entire alternative minimum tax (AMT) liability due to the limitation in § 56(d). Taxpayer paid $Y of AMT in Year D and had a minimum tax credit carryforward (MTCC) as of the end of year E of $Y.

On its regulatory books of account, Taxpayer "normalizes" the differences between regulatory depreciation and tax depreciation. This means that, where accelerated depreciation reduces taxable income, the taxes that a taxpayer would have paid if regulatory depreciation (instead of accelerated tax depreciation) were claimed constitute "cost-free capital" to the taxpayer. A taxpayer that normalizes these differences, like Taxpayer, maintains a reserve account showing the amount of tax liability that is deferred as a result of the accelerated depreciation. This reserve is the accumulated deferred income tax (ADIT) account. Taxpayer maintains an ADIT account and also maintains an offsetting series of entries that reflect that portion of those 'tax losses' which, while due to accelerated depreciation, did not actually defer tax because of the existence of an NOLC. With respect to the $Y AMT liability from Year D, Taxpayer carried that amount as an offset to the ADIT because the AMT increased the payment of tax.

Taxpayer filed a general rate case on Date A (Case). The test year used in the Case was the 12 month period ending on Date B. In establishing the income tax expense element of its cost of service, the tax benefits attributable to accelerated depreciation were normalized in accordance with Commission policy and were not flowed thru to ratepayers. In establishing the rate base on which Taxpayer was to be allowed to earn a return Commission generally offsets rate base by Taxpayer's plant based ADIT balance, using a 13-month average of the month-end balances of the relevant accounts. Taxpayer argued that the ADIT balance should be reduced by the amounts that Taxpayer calculates did not actually defer tax due to the presence of NOLCs or the AMT. Commission, in an order issued on Date C, did not use the amounts that Taxpayer calculates did not defer tax due to NOLCs or AMT but only the amount in the ADIT account. Taxpayer filed a petition for reconsideration based on the normalization implications of the order. On Date D, Commission rejected Taxpayer's request. Taxpayer again requested reconsideration and the Commission denied that request on Date E. Commission asserts that, in setting rates it includes a provision for deferred taxes based on the entire difference between accelerated tax and regulatory depreciation, including situations in which a utility has, such as in this case, an NOLC or AMT. Thus, Commission asserts that it has already recognized the effects of the NOCL in setting rates and there is no need to reduce the ADIT by the other amounts due to NOLCs or AMT.

Taxpayer requests that we rule as follows:

Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account without regard to the balances in its NOLC-related account and its MTCC-related account was consistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

Law and Analysis

Section 168(f)(2) of the Code provides that the depreciation deduction determined under section 168 shall not apply to any public utility property (within the meaning of section 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

In order to use a normalization method of accounting, section 168(i)(9)(A)(i) of the Code requires the taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under section 168(i)(9)(A)(ii), if the amount allowable as a deduction under section 168 differs from the amount that-would be allowable as a deduction under section 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under section 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Section 168(i)(9)(B)(i) of the Code provides that one way the requirements of section 168(i)(9)(A) will not be satisfied is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with such requirements. Under section 168(i)(9)(B)(ii), such inconsistent procedures and adjustments include the use of an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under section 168(i)(9)(A)(ii), unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base.

Former section 167(l) of the Code generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a ""normalization method of accounting." A normalization method of accounting was defined in former section 167(l)(3)(G) in a manner consistent with that found in section 168(i)(9)(A) .Section 1.167(1)-1(a)(1) of the Income Tax Regulations provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under section 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 1.167(l)-1(h)(1)(i) provides that the reserve established for public utility property should reflect the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes.

Section 1.167(1)-1(h)(1)(iii) provides that the amount of federal income tax liability deferred as a result of the use of different depreciation methods for tax and ratemaking purposes is the excess (computed without regard to credits) of the amount the tax liability would have been had the depreciation method for ratemaking purposes been used over the amount of the actual tax liability. This amount shall be taken into account for the taxable year in which the different methods of depreciation are used. If, however, in respect of any taxable year the use of a method of depreciation other than a subsection (1) method for purposes of determining the taxpayer's reasonable allowance under section 167(a) results in a net operating loss carryover to a year succeeding such taxable year which would not have arisen (or an increase in such carryover which would not have arisen) had the taxpayer determined his reasonable allowance under section 167(a) using a subsection (1) method, then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director.

Section 1.167(1)-1(h)(2)(i) provides that the taxpayer must credit this amount of deferred taxes to a reserve for deferred taxes, a depreciation reserve, or other reserve account. This regulation further provides that, with respect to any account, the aggregate amount allocable to deferred tax under section 167(1) shall not be reduced except to reflect the amount for any taxable year by which Federal income taxes are greater by reason of the prior use of different methods of depreciation. That section also notes that the aggregate amount allocable to deferred taxes may be reduced to reflect the amount for any taxable year by which federal income taxes are greater by reason of the prior use of different methods of depreciation under section 1.167(1)-1(h)(1)(i) or to reflect asset retirements or the expiration of the period for depreciation used for determining the allowance for depreciation under section 167(a).

Section 1.167(1)-(h)(6)(i) provides that, notwithstanding the provisions of subparagraph (1) of that paragraph, a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under section 167(l) which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking.

Section 1.167(1)-(h)(6)(ii) provides that, for the purpose of determining the maximum amount of the reserve to be excluded from the rate base (or to be included as no-cost capital) under subdivision (i), above, if solely an historical period is used to determine depreciation for Federal income tax expense for ratemaking purposes, then the amount of the reserve account for that period is the amount of the reserve (determined under section 1.167(1)-1(h)(2)(i)) at the end of the historical period. If such determination is made by reference both to an historical portion and to a future portion of a period, the amount of the reserve account for the period is the amount of the reserve at the end of the historical portion of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during the future portion of the period.

Section 55 of the Code imposes an alternative minimum tax on certain taxpayers, including corporations. Adjustments in computing alternative minimum taxable income are provided in § 56. Section 56(a)(1) provides for the treatment of depreciation in computing alternative minimum taxable income. Section 56(a)(1)(D) provides that, with respect to public utility property the Secretary shall prescribe the requirements of a normalization method of accounting for that section.

Section 1.167(l)-1(h) requires that a utility must maintain a reserve reflecting the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes. Taxpayer has done so. Section 1.167(1)-(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Section 56(a)(1)(D) provides that, with respect to public utility property the Secretary shall prescribe the requirements of a normalization method of accounting for that section.

In the rate case at issue, Commission has excluded from the base to which the Taxpayer's rate of return is applied the reserve for deferred taxes, unmodified by the accounts which Taxpayer has designed to calculate the effects of the NOLCs and MTCC. There is little guidance on exactly how an NOLC or MTCC must be taken into account in calculating the reserve for deferred taxes under §§ 1.167(1)-1(h)(1)(iii) and 56(a)(1)(D). However, it is clear that both must be taken into account in calculating the amount of the reserve for deferred taxes (ADIT) for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking.

Both Commission and Taxpayer have intended, at all relevant times, to comply with the normalization requirements. Commission has stated that, in setting rates it includes a provision for deferred taxes based on the entire difference between accelerated tax and regulatory depreciation, including situations in which a utility has an NOLC or MTCC. Such a provision allows a utility to collect amounts from ratepayers equal to income taxes that would have been due absent the NOLC and MTCC. Thus, Commission has already taken the NOLC and MTCC into account in setting rates. Because the NOLC and MTCC have been taken into account, Commission's decision to not reduce the amount of the reserve for deferred taxes by these amounts does not result in the amount of that reserve for the period being used in determining the taxpayer's expense in computing cost of service exceeding the proper amount of the reserve and violate the normalization requirements. We therefore conclude that the reduction of Taxpayer's rate base by the full amount of its ADIT account without regard to the balances in its NOLC-related account and its MTCC-related account was consistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

This ruling is based on the representations submitted by Taxpayer and is only valid if those representations are accurate.

Except as specifically determined above, no opinion is expressed or implied concerning the Federal income tax consequences of the matters described above. In particular, while we accept as true for purposes of this ruling Commission's assertions that it includes a provision for deferred taxes based on the entire difference between accelerated tax and regulatory depreciation, including situations in which a utility has an NOLC or AMT, we do not conclude that it has done so and those assertions are subject to verification on audit.

This ruling is directed only to the taxpayer who requested it. Section 6110(k)(3) of the Code provides it may not be used or cited as precedent. In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative. We are also sending a copy of this letter ruling to the Direct- or.

Sincerely,
Peter C. Friedman
Senior Technician Reviewer, Branch 6 (Passthroughs & Special Industries)

cc:

Section 6110(j)(3) of the Internal Revenue CodeThis document may not be used or cited as precedent. .

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