COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

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PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF GAS RATES	)))	CASE NO. 2006-00464

ATTORNEY GENERAL'S PRE-FILED TESTIMONY

Comes the Attorney General of the Commonwealth of Kentucky, Gregory D. Stumbo, by and through his Office of Rate Intervention, and submits his pre-filed testimony in the above case.

Respectfully submitted,
GREGORY D. STUMBO
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Certificate of Service and Filing

Counsel certifies that an original and ten photocopies of the Attorney General's Pre-Filed Testimony were served and filed by hand delivery to Beth O'Donnell, Executive Director, Public Service Commission, 211 Sower Boulevard, Frankfort, Kentucky 40601; furthermore, it was served by mailing a true and correct copy of the same, first class postage prepaid, to:

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all on this 27th day of April, 2007.

Assistant Attorney General

COMMONWEALTH OF KENTUCKY
BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

RATE APPLICATION OF	)	Case No. 2006-00464
ATMOS ENERGY CORPORATION	)	

DIRECT TESTIMONY

AND EXHIBITS

OF

ROBERT J. HENKES

ON BEHALF OF THE OFFICE OF RATE INTERVENTION
OF THE ATTORNEY GENERAL FOR
THE COMMONWEALTH OF KENTUCKY

April 27, 2007

Atmos Energy Corporation - Kentucky
Case No. 2006-00464
Direct Testimony and Exhibits of Robert J. Henkes

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I. STATEMENT OF QUALIFICATIONS

Q. WOULD YOU STATE YOUR NAME AND ADDRESS?

A. My name is Robert J. Henkes, and my business address is 7 Sunset Road, Old Greenwich, Connecticut, 06870.

Q. WHAT IS YOUR PRESENT OCCUPATION?

A. I am Principal and founder of Henkes Consulting, a financial consulting firm that specializes in utility regulation.

Q. WHAT IS YOUR REGULATORY EXPERIENCE?

A. I have prepared and presented numerous testimonies in rate proceedings involving electric, gas, telephone, water and wastewater companies in jurisdictions nationwide including Arkansas, Delaware, District of Columbia, Georgia, Kentucky, Maryland, New Jersey, New Mexico, Pennsylvania, Vermont, the U.S. Virgin Islands, and before the Federal Energy Regulatory Commission. A complete listing of jurisdictions and rate proceedings in which I have been involved is provided in Appendix I attached to this testimony.

Q. WHAT OTHER PROFESSIONAL EXPERIENCE HAVE YOU HAD?

A. Prior to founding Henkes Consulting in 1999, I was a Principal of The Georgetown Consulting Group, Inc. for over 20 years. At Georgetown Consulting, I performed the same type of consulting services that I am currently rendering through Henkes Consulting. Prior to my association with Georgetown Consulting, I was employed by the American Can Company as Manager of Financial Controls. Before joining the American Can Company, I was employed by the management consulting division of Touche Ross & Company (now Deloitte & Touche) for over six years. At Touche Ross, my experience, in addition to regulatory work, included numerous projects in a wide variety of industries and financial disciplines such as cash flow projections, bonding feasibility, capital and profit forecasting, and the design and implementation of accounting and budgetary reporting and control systems.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I hold a Bachelor degree in Management Science received from the Netherlands School of Business, The Netherlands in 1966; a Bachelor of Arts degree received from the University of Puget Sound, Tacoma, Washington in 1971; and an MBA degree in Finance received from Michigan State University, East Lansing, Michigan in 1973. I have also completed the CPA program of the New York University Graduate School of Business.

II. SCOPE AND PURPOSE OF TESTIMONY

Q. WHAT IS THE SCOPE AND PURPOSE OF YOUR TESTIMONY?

A. I was engaged by the Office of Rate Intervention of the Attorney General of Kentucky ("AG") to conduct a review and analysis and present testimony regarding the petition of Atmos Energy - Kentucky ("Atmos" or the "Company") for an increase in its base rates for gas service.

The purpose of this testimony is to present to the Kentucky Public Service Commission ("KPSC" or "the Commission") the appropriate forecasted test period overall rate of return, rate base and operating income, as well as the appropriate revenue requirement for the Company in this proceeding.

In the determination of the recommended revenue requirement for Atmos in this proceeding, I have relied on and incorporated the recommendations of other AG witnesses as follows:

- <u>Dr. J. Randall Woolridge</u>, concerning the appropriate overall rate of return for the Company in this proceeding; and
- <u>Mr. Michael J. Majoros, Jr.</u>, concerning the appropriate depreciation expenses, plant in service balance and accumulated depreciation reserve balance to be reflected for ratemaking purposes in this proceeding.

Q. WHAT INFORMATION HAVE YOU RELIED UPON IN THE DEVELOPMENT OF YOUR TESTIMONY?

A. In developing this testimony, I have reviewed and analyzed the Company's petition; testimonies, exhibits, workpapers and filing requirements; responses to AG and KPSC initial and supplemental interrogatories; and other relevant financial documents and data.

III. SUMMARY OF FINDINGS AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS IN THIS CASE

A. The findings and conclusions reached by me in this case are as follows:

1. The appropriate Forecasted Test Period rate base for Atmos in this case amounts to $168,629,815 which is $775,726 lower than the Company's originally proposed rate base of $169,405,541 (Schedule RJH-1, line 1 and Schedule RJH-3).

2. The appropriate overall rate of return on rate base, as recommended by Dr. J. Randall Woolridge, the AG's expert rate of return witness, is 7.47%, incorporating a recommended return on equity of 9.00%. This compares to Atmos' proposed overall rate of return on rate base of 8.82%, including a requested return on equity rate of 11.75% (Schedule RJH-1, line 2 and Schedule RJH-2).

3. The appropriate Forecasted Test Period net after-tax operating income amounts to $11,115,922, which is $2,341,345 higher than Atmos' originally proposed net after-tax operating income of $8,774,577 (Schedule RJH-1, line 4 and Schedule RJH-5).

4. The appropriate gross revenue conversion factor to be used for rate making purposes in this case is 1.633302. This recommended conversion factor is lower than Atmos' originally proposed conversion factor of 1.688011.

5. The application of the recommended overall rate of return of 7.47% to the recommended Forecasted Test Period rate base of $168,904,325, combined with the recommended Forecasted Test Period operating income of $11,115,922 and gross revenue conversion factor of 1.633302 indicates that the Company has the need for an annual rate increase of $2,419,099. This is $7,990,851 lower than the Company's originally proposed rate increase request of $10,409,950 (Schedule RJH-1, lines 1-7).

6. The Company's proposal to recover through its Gas Cost Adjustment (GCA) clause the uncollectible expenses associated with gas cost revenues should be rejected by the Commission.

7. The Company's proposed Customer Rate Stabilization (CRS) mechanism should be rejected by the Commission as this proposed tracker mechanism:
   a) is in violation of accepted ratemaking principles and inconsistent with appropriate regulatory policy;
   b) reduces the incentive for the Company to manage its business in the most efficient manner and at the lowest possible costs;
   c) represents a request for extraordinary rate remedy that is not needed and

is unsubstantiated; and

d) produces no benefits for the ratepayers and inappropriately shifts virtually all risks from the stockholders to the ratepayers.

IV. REVENUE REQUIREMENT ISSUES

A. GROSS REVENUE CONVERSION FACTOR

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN YOUR RECOMMENDED AND THE COMPANY'S ORIGINALLY PROPOSED GROSS REVENUE CONVERSION FACTORS.

A. As shown in Schedule RJH-1, footnote (2), the difference is caused by the inclusion of different Kentucky state income tax rates and the recommended addition of a Late Payment Fee ratio in the derivation of the Gross Revenue Conversion Factors. Specifically, the Company assumed the old Kentucky state income tax rate of 8.25% while the AG reflected the correct Kentucky state income tax rate of 6.00% which became effective January 1, 2007. Also, as described on pages 16 and 17 of the testimony of Company witness Smith, the Company has assumed that the Late Payment Fees are a function of the Company's residential, commercial and public authority revenues at a ratio of .87%. However, the Company does not propose to recognize the incremental Late Payment Fees that would be generated by the requested rate increase in this case. The reflection of this Late Payment Fee ratio, which has the effect of reducing the Gross Revenue Conversion factor, is consistent with the way the Company's uncollectible expenses and PSC assessments are treated in the calculation of the Gross Revenue Conversion Factor. The Company's uncollectible expenses and PSC assessments are also a function of the Company's operating revenues and appropriate ratios for these expenses have therefore been incorporated into the Company's proposed Gross Revenue Conversion Factor in order to reflect the incremental uncollectible expenses and PSC assessments associated with the proposed rate increase.

Schedule RJH-1, footnote (2) shows that the recommended Kentucky state income tax rate of 6.00% and addition of the .87% Late Payment Fee ratio reduces the Company's proposed Gross Revenue Conversion Factor from 1.688011 to 1.633302. The recommended Gross Revenue Conversion Factor of 1.633302 was also calculated by the Company in its response to AG-2-22.

Q. IN ITS RESPONSE TO AG-2-22, THE COMPANY ARGUES THAT THE LATE PAYMENT FEE RATIO OF .87% SHOULD NOT BE INCLUDED IN THE GROSS REVENUE CONVERSION FACTOR BECAUSE THE LATE PAYMENT FEES ARE A FUNCTION OF RESIDENTIAL, COMMERCIAL AND PUBLIC AUTHORITY REVENUES, NOT TOTAL GROSS REVENUES. COULD YOU COMMENT ON THAT?

A. Yes. The inclusion of the .87% Late Payment Fee ratio in the Gross Revenue Conversion Factor is entirely consistent with the Company's proposal to include an uncollectible ratio of .50% in the Gross Revenue Conversion Factor. The uncollectible ratio of .50% is also a function of the Company's residential, commercial and public authority revenues,[1] not total gross revenues, and the Company has always found it appropriate to include this unadjusted uncollectible ratio in its Gross Revenue

[1] See bottom of page 15 of testimony of Greg Waller.

Conversion factor for ratemaking purposes.

B. OVERALL RATE OF RETURN

Q. PLEASE DESCRIBE THE AG'S RECOMMENDED AS COMPARED TO THE COMPANY'S PROPOSED OVERALL RATE OF RETURN IN THIS CASE.

A. As shown on Schedule RJH-2, the AG's expert rate of return witness, Dr. J. Randall Woolridge, has recommended an overall rate of return of 7.47% as compared to the Company's proposed overall rate of return of 8.82%. Similar to the Company's proposal, Dr. Woolridge used the capital structure of the consolidated Atmos corporation in the determination of his recommended overall rate of return. However, while the Company's proposed capital structure excludes short term debt, Dr. Woolridge, for reasons explained in his testimony, has included short term debt in his recommended capital structure. Dr. Woolridge's recommended return on equity rate is 9.00%, which is substantially lower than the Company's proposed return on equity rate of 11.75%.

C. RATE BASE

Q. PLEASE SUMMARIZE THE COMPANY'S ORIGINALLY PROPOSED AND THE AG'S RECOMMENDED NET RATE BASE INVESTMENT LEVELS FOR THE FORECASTED TEST PERIOD IN THIS CASE.

A. The Company's originally proposed rate base of $169,405,541 is summarized by specific rate base component in first column of Schedule RJH-3. As shown in the middle column of Schedule RJH-3, I have recommended 6 rate base adjustments involving the rate base components for plant in service, accumulated deprecation, cash working capital, materials and supplies, prepayments, and customer advances. These recommended rate base adjustments reduce the Company's originally proposed net rate base by $775,727 to a recommended net rate base level of $168,629,815. Each of the recommended rate base adjustments will be discussed in detail in the subsequent sections of this testimony.

Q. WHY HAVE YOU USED THE COMPANY'S FORECASTED TEST PERIOD RATE BASE AS THE APPROPRIATE INVESTMENT VALUATION BASIS IN THE DETERMINATION OF THE COMPANY'S REVENUE REQUIREMENT IN THIS CASE?

A. I have done so because the capitalization used in this case is the consolidated Atmos corporation capitalization and because no Forecasted Test Period data are available for the combined Atmos Kentucky-Only and allocated Shared Service Unit (SSU) and Kentucky/Mid-States Division General Office capitalizations. By contrast, the rate base used in this case reflects the appropriate total Kentucky-Only and allocated SSU/General Division net rate base investment balances.

- **<u>Plant In Service</u>**

Q. PLEASE EXPLAIN THE RECOMMENDED PLANT IN SERVICE BALANCE SHOWN ON SCHEDULE RJH-3, LINE 1.

A. The recommended Forecasted Test Period plant in service balance of $321,881,192 reflects the Forecasted Test Period plant in service balance recommended by AG witness Michael Majoros.

- **Accumulated Depreciation & Amortization**

Q. PLEASE EXPLAIN THE RECOMMENDED ACCUMULATED DEPRECATION RESERVE BALANCE SHOWN ON SCHEDULE RJH-3, LINE 3.

A. The recommended Forecasted Test Period reserve balance of $149,560,075 reflects the re-calculated Forecasted Test Period reserve balance recommended by AG witness Michael Majoros based on his recommended depreciation rates.

- **Cash Working Capital**

Q. PLEASE EXPLAIN YOUR RECOMMENDED CASH WORKING CAPITAL ADJUSTMENT SUMMARIZED ON SCHEDULE RJH-3, LINE 5.

A. The Company has proposed to calculate the cash working capital in this case based on the so-called "1/8th formula" method. This method assumes that 1/8th of the pro forma Forecasted Test Period operation and maintenance expenses, net of purchased gas costs, represents a reasonable cash working capital approximation. I believe that only a properly performed detailed lead/lag study would generate an accurate approximation of a utility's cash working capital. However, based on my review of the Company's prior base rate proceedings, it is my understanding that the Commission has consistently allowed this Company's cash working capital to be determined based on this modified 1/8th method. I have therefore chosen not to challenge this method in this case.

As summarized on Schedule RJH-3, line 5 and further detailed on schedule RJH-4, the appropriate cash working capital requirement based on this modified 1/8th method amounts to $2,494,217. This is $111,623 lower than the Company's proposed cash working capital. The derivation of my recommended Forecasted Test Period operation and maintenance expenses to which the 1/8 ratio was applied is shown in detail on Schedule RJH-17.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING THIS ISSUE?

A. Yes. The appropriate cash working capital that should eventually be reflected for ratemaking purposes should be based on 1/8th of the Commission's allowed Forecasted Test Period O&M expenses net of purchased gas costs.

- **<u>Materials and Supplies</u>**

Q. PLEASE EXPLAIN THE RECOMMENDED MATERIALS AND SUPPLIES

ADJUSTMENT SHOWN ON SCHEDULE RJH-3, LINE 6a.

A. As confirmed by the Company in its response to AG-1-1, this adjustment is required to correct the Company's originally filed Forecasted Test Period materials and supplies rate base balance.

- **<u>Prepayments</u>**

Q. PLEASE EXPLAIN YOUR RECOMMENDED PREPAYMENT ADJUSTMENT SHOWN ON SCHEDULE RJH-3, LINE 6b.

A. The recommended prepayment adjustment of $231,715 represents the removal of the Forecasted Test Period PSC assessments which the Company claims to be prepaid. I have removed this amount from rate base to reflect well-established and long-standing PSC policy that such PSC assessment balances are not considered to be prepayments.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING THE COMPANY'S PROPOSED FORECASTED TEST PERIOD PREPAYMENT BALANCE?

A. Yes. As confirmed in the response to AG-2-5, the Company's proposed Forecasted Test Period prepayment balance includes a prepayment balance of $183,270[2] associated with a credit facility fee paid to NationsBank which is directly related to the Company's cost of short term debt. Since the AG recommends that short term debt be considered for ratemaking purposes in this case, I have left this prepayment balance in the AG's recommended rate base. However, as acknowledged by the Company, if no short term

[2] Prior to allocation to the Kentucky jurisdiction.

debt were to be considered for ratemaking purposes in this case, this prepayment balance should be removed from the Forecasted Test Period rate base.

- **Customer Advances**

Q. PLEASE EXPLAIN YOUR RECOMMENDED CUSTOMER ADVANCES ADJUSTMENT SHOWN ON SCHEDULE RJH-3, LINE 7.

A. This adjustment is to correct for the erroneous inclusion in rate base of the customer advances for Division 91, as acknowledged by the Company in its response to AG-2-10.

D. OPERATING INCOME

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED AND THE AG'S RECOMMENDED NET AFTER-TAX OPERATING INCOME LEVELS FOR THE FORECASTED TEST PERIOD.

A. The Company originally proposed a net after-tax operating income level of $8,774,577 for the Forecasted Test Period. On Schedule RJH-5, lines 2 through 14, I show that I have made numerous adjustments to the Company's proposed net after-tax operating income, resulting in a recommended Forecasted Test Period net after-tax operating income amount of $11,115,922. Each of the recommended net after-tax operating income adjustments shown on Schedule RJH-5 will be discussed in the following sections of this testimony.

- **Income Tax Adjustment**

Q. PLEASE EXPLAIN THE INCOME TAX ADJUSTMENT SUMMARIZED ON SCHEDULE RJH-5, LINE 2 AND SHOWN IN MORE DETAIL ON SCHEDULE RJH-6.

A. The Company's originally proposed Forecasted Test Period net after-tax operating income of $8,774,577 shown on Schedule RJH-5, line 1 reflects a composite federal and state income tax rate of 40.363% based on a 35% federal tax rate and 8.25% Kentucky state income tax rate. As confirmed in the Company's response to AG-1-1, the correct composite income tax rate should be 38.90% based on a 35% federal tax rate and 6.00% Kentucky state income tax rate. As calculated on Schedule RJH-6, the correction of the composite income tax rate from 40.363% to 38.90% decreases the Company's originally proposed Forecasted Test Period income tax by $83,932, which is equivalent to an increase in net after-tax operating income by that same amount.

- **Property Tax Adjustment**

Q. PLEASE EXPLAIN THE RECOMMENDED PROPERTY TAX ADJUSTMENT SUMMARIZED ON SCHEDULE RJH-5, LINE 3 AND SHOWN IN MORE DETAIL ON SCHEDULE RJH-7.

A. The Company has proposed a Forecasted Test Period property tax expense of

$4,011,420[3] based on an initial 2006 property assessment received from the Kentucky Department of Revenues (KDR). In its response to AG-1-29a, Atmos states with regard to this initial property tax assessment:

> The $4,011,420 referred to in the above testimony represents the estimated property taxes for tax year 2006 based upon the current KDR assessment of $336,242,098. The initial KDR assessment is currently under appeal. While under appeal, Atmos will pay the KDR and Local Tax Districts based on Atmos' claimed value of $214,983,174. Upon resolution of the appeal, Atmos will pay the difference, if any, between the claimed value and finalized value.

The Company's response to PSC-3-8 further confirms that:

> The Company is still working and negotiating with the Department of Revenue (DOR) on an acceptable value. The DOR has offered a settlement which falls in line with the Company's proposed assessment .... Since the Company has an offer from the DOR which is very close to its initial proposal, it is more accurate to use the DOR offer for the assessment and tax estimation on the 2006 property taxes ....

In this same response to PSC-3-8, the Company then computed a revised total estimated 2006 property tax amount of $2,632,247 based on the latest DOR settlement offer.

I recommend at this time that this revised 2006 property tax estimated be used as the starting point for the Company's Forecasted Test Period property tax liability. As shown on Schedule RJH-7, line 2 and footnote (2), I then increased this recommended tax amount to reflect the Company's estimated 3% increase effective November 2007 to arrive at the total recommended Forecasted Test Period property tax amount of

[3] This proposed property tax amount is prior to an additional estimated property tax expense increase of 3% effective November 2007. The Company's proposed total Forecasted Test Period property taxes, including the 3% increase effective November 2007, amounts to $4,091,648, as shown on filing Schedule C-2.3.

$2,684,892. This recommended tax amount is $1,406,756 lower than the Company's proposed Forecasted Test Period property tax amount of $4,091,648 and results in a recommended increase of $859,528 in the Company's proposed Forecasted Test Period after-tax operating income.

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS REGARDING THIS ISSUE?

A. Yes. If the results of the pending property tax appeal and the associated actual 2006 property tax liability for Atmos become available prior to the close of record in this case, I recommend that this final actual property tax amount be used as the starting point for calculating the Forecasted Test Period property tax amount in this case.

- **PSC Assessment Adjustment**

Q. PLEASE EXPLAIN THE BASIS FOR THE COMPANY'S PROPOSED RECOMMENDED PSC ASSESSMENT FOR THE FORECASTED TEST PERIOD.

A. As confirmed in the response to AG-1-2, the Company's proposed Forecasted Test Period PSC assessment amount of $401,635 was determined by applying the current PSC assessment rate of .1643% to gross intrastate receipts of $244,452,110. In its response to AG-2-4, the Company further confirmed that the gross intrastate receipt amount of $244,452,110 does not represent the Forecasted Test Period gross intrastate receipts; rather, it "represents the amount used in the calculation of the 2006 actual calculation of the PSC assessment."

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED FORECASTED TEST YEAR PSC ASSESSMENTS?

A. No. As shown on Schedule C-1, Sheet 1, the Forecasted Test Period gross intrastate receipts amount to $226,698,846. As confirmed in the response to AG-1-31, this amount includes total Forecasted Test Period base rate revenues as well as 100% of the projected Forecasted Test Period gas cost revenues that are recovered via the GCA mechanism. Thus, the Forecasted Test Period PSC assessment amount should be based on applying the PSC assessment rate of .1643% to Forecasted Test Period total gross intrastate receipts of $226,698,846. As shown on Schedule RJH-8, this results in recommended PSC assessments of $372,466 rather than the Company's proposed PSC assessments of $401,635. Schedule RJH-8 also shows that this recommended PSC assessment adjustment increases the Company's proposed Forecasted Test Period net after-tax operating income by $17,822.

- **<u>Rate Case Expense Amortization</u>**

Q. PLEASE EXPLAIN THE RECOMMENDED RATE CASE EXPENSE ADJUSTMENT SUMMARIZED ON SCHEDULE RJH-5, LINE 5 AND SHOWN IN MORE DETAIL ON SCHEDULE RJH-9.

A. The Company has estimated total rate case expenses of $370,000 to process this case and is proposing to normalize this total expense amount over a 3-year period for an annual normalized expense of $123,333. I take no exception to the proposed 3-year normalization period as this would appear to be consistent with prior Commission rulings. I also have not adjusted the estimated rate case expenses at this time. It has been Commission practice to allow rate recognition for all prudently incurred rate case expenses actually incurred as of the close of record in utility base rate proceedings. The Commission's Order in this case should reflect an adjustment for the difference between the actual rate case expenses and the currently estimated rate case expense amount of $370,000.

Since the Company's original filing failed to include its proposed normalized annual rate case expense amount of $123,333, I have made an adjustment to reflect this expense. As shown on Schedule RJH-9, this recommended expense adjustment decreases the Company's originally proposed Forecasted Test Period net after-tax operating by $75,356.

- **Incentive Compensation Adjustment**

Q. ARE ATMOS EMPLOYEES ELIGIBLE FOR INCENTIVE COMPENSATION PLANS?

A. Yes. Atmos employees are eligible for three incentive compensation plans: (1) the Long

Term Incentive Plan for Management (LTIP), (2) the Management Incentive Plan (MIP), and (3) the Variable Pay Plan (VPP).

Q. PLEASE PROVIDE BRIEF DESCRIPTIONS OF EACH OF THESE INCENTIVE COMPENSATION PLANS.

<u>LTIP</u>

A. The LTIP is an equity-based incentive program that, since 2003, has provided long-term incentives to its executive and management teams in the form of time-lapsed or performance-based restricted stock shares. As described in the response to AG-1-62, the purpose of the LTIP is as follows:

> …to attract and retain the services of able persons as employees of the Company and its Subsidiaries and as Non-employee Directors (as herein defined), to provide such persons with a proprietary interest in the Company through the granting of incentive stock options, non-qualified stock options, stock appreciation rights, or restricted stock, and to motivate employees and Non-employee Directors using performance-related incentives linked to longer-range performance goals and the interests of the Company's shareholders…

As confirmed in the response to AG-2-39b, the employees eligible to participate in the LTIP are corporate vice-presidents and directors and division presidents and vice-presidents.

The performance measure for the determination of the earned stock shares is Atmos' actual cumulative 3-year earnings per share (EPS) number as compared to the targeted level of EPS during the same period.

MIP

The response to AG-1-62 states that the purpose of MIP is:

> ... to provide the Company a means by which it can engender and sustain a sense of personal commitment on the part of its executives and senior managers in the continued growth, development, and financial success of the Company and encourage them to remain with and devote their best efforts to the business of the Company, thereby advancing the interests of the Company and its shareholders.....

The MIP, which was first implemented in fiscal year 1999, is limited to a select group of management employees[4] and provides the Company's management team with the opportunity to earn a cash-based incentive award based upon Atmos' return on equity performance which is expressed to participants as an EPS target. The Plan did not pay incentive awards in either 1999 or 2000 since Atmos did not achieve its threshold level of EPS performance in those years.

VPP

The VPP is a broad based incentive compensation plan in which virtually all employees of the Company participate (except for those included in the MIP). Similar to the MIP, the purpose of the VPP is to provide all eligible employees with the opportunity to earn a cash-based incentive award based on Atmos' return on equity performance, thereby advancing the interests of the Company and its shareholders. The response to AG-1-62 further explains that:

> The range of outcomes between the threshold, target and maximum for awards under the VPP are based upon the Company's budgeted return on equity target and moving 100 basis points below budgeted return on equity

[4] As confirmed in the response to AG-2-39b, the employees eligible to participate in the MIP are corporate vice-presidents and directors and division presidents and vice-presidents.

> target and 100 basis points above budgeted return on equity ROE for maximum performance ... <u>As designed, the plan offers awards only when the Company reaches or exceeds desired levels of profitability as measured by both return on equity and earnings per share</u> [emphasis supplied]

The VPP, which was first implemented in 1999, paid no awards in 1999 and 2000 since Atmos failed to reach the threshold ROE and EPS performance levels in those years.

In summary, each of these incentive compensation plans is 100% based on the achievement of corporate profitability goals in the form of targeted Atmos return on equity (ROE) or earnings per share (EPS) levels. Incentive compensation awards are only paid out if Atmos reaches or exceeds these profitability goals.

Q. HAS THIS COMMISSION PREVIOUSLY DISALLOWED FOR RATEMAKING PURPOSES INCENTIVE COMPENSATION THAT IS A FUNCTION OF CORPORATE FINANCIAL PERFORMANCE GOALS?

A. Yes. In Union Light Heat & Power Company's ("ULH&P") 2005 base rate case, Case No. 2005-00042, the Commission disallowed 100% of that utility's LTIP incentive compensation that was entirely based on Total Shareholder Return performance. The Commission also disallowed portions of ULH&P's AIP incentive compensation program to the extent that the AIP program was based on corporate financial performance goals.[5] In the three ULH&P base rate cases[6] prior to Case No. 2005-00042,

[5] In ULH&P's (now Duke Energy Kentucky) most recent base rate case, Case No. 2006-00172, which was resolved by stipulation, ULH&P, pursuant to the KPSC's incentive compensation ruling in Case No. 2005-00042, voluntarily removed for ratemaking purposes all incentive compensation that was a function of corporate financial performance goals.

[6] Case Nos. 2001-092, 92-346 and 91-370.

the Commission disallowed 100% of ULH&P's incentive compensation expenses based on its finding, among other things, that the corporate performance goals in ULH&P's incentive compensation plan placed more weight on the interest of shareholders than customers. In addition, while the AG in Kentucky American Water Company's ("KAWC") most recent rate case, Case No. 2004-00103, recommended the disallowance of 60% of KAWC's incentive compensation (representing the portion of KAWC's incentive compensation program that was a function of the achievement of corporate financial performance goals), the Commission went further and disallowed 100% of KAWC's incentive compensation expenses.

Q. DO YOU AGREE WITH THE COMMISSION'S RATEMAKING POLICY THAT INCENTIVE COMPENSATION EXPENSES THAT ARE A FUNCTION OF CORPORATE FINANCIAL PERFORMANCE GOALS SHOULD BE CHARGED TO THE SHAREHOLDERS RATHER THAN THE RATEPAYERS?

A. Yes. Shareholders are the primary beneficiaries of the achievement of corporate financial performance goals such as return on equity or earnings per share. To the extent that a utility's incentive compensation awards are completely a function of the utility achieving certain profitability levels, the stockholder, as the primary beneficiary, should be made responsible for the costs associated with these incentive compensation awards. I believe that Atmos' LTIP, MIP and VPP incentive compensation plans clearly place more weight on the interest of shareholders than ratepayers. Also, since these incentive compensation plans only pay awards in case Atmos reaches or exceeds certain profitability levels, it is my opinion that these plans should be characterized as *bonus* or *profit sharing* plans that provide compensation that is clearly additive to the employees' total base compensation rather than being characterized as the "at risk" portion of the employees' total base compensation.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO THE COMPANY'S INCENTIVE COMPENSATION EXPENSES?

A. Based on the foregoing findings and conclusions, I recommend that all of the Company's incentive compensation expenses included in the Forecasted Test Period be disallowed for ratemaking purposes in this case.

Q. WHAT AMOUNT OF INCENTIVE COMPENSATION EXPENSES IS INCLUDED IN THE COMPANY'S FORECASTED TEST PERIOD O&M EXPENSES?

A. As detailed on Schedule RJH-10, the Forecasted Test Period above-the-line O&M expenses include total incentive compensation expenses of $446,635.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDED ADJUSTMENT ON THE COMPANY'S PROPOSED FORECASTED TEST PERIOD NET AFTER-TAX OPERATING INCOME?

A. As shown on Schedule RJH-10, line 6, my recommendation increases the Company's proposed Forecasted Test Period net after-tax operating income by $272,894.

- **Overtime Expense Adjustment**

Q. HOW DOES THE COMPANY BUDGET FOR OVERTIME HOURS AND ASSOCIATED OVERTIME DOLLARS?

A. As confirmed in its response to AG-1-69d, the Company budgets overtime hours and overtime dollars "based on historical averages."

Q. WHAT IS THE ACTUAL HISTORIC EXPERIENCE OF THE RATIO OF THE COMPANY'S OVERTIME HOURS TO STRAIGHT-TIME HOURS DURING THE LAST 5 FISCAL YEARS?

A. As shown on Schedule G-2, line 8, the actual ratios were 2.656% in 2002, 1.407% in 2003, 1.438% in 2004, 1.820% in 2005 and 2.957% in 2006 for an actual 5-year average of 2.055%.

Q. WHAT OVERTIME HOURS TO STRAIGHT-TIME HOURS RATIO HAS THE COMPANY USED FOR THE FORECASTED TEST PERIOD AND WHAT ARE THE RESULTING FORECASTED TEST PERIOD OVERTIME COSTS PROPOSED BY THE COMPANY IN THIS CASE?

A. As shown on Schedule G-2, lines 8 and 12, the Company has proposed Forecasted Test Period overtime costs of $462,654 based on an assumed Overtime Hours to Straight-Time Hours ratio of 3.286%. This ratio, in turn, is apparently based on the overtime experience in FY 2006. When the Company was asked in AG-2-40a why it believes a Forecasted Test Period overtime ratio of 3.286% to be reasonable given that the actual 5-year historical average overtime ratio is only 2.055%, it responded as follows:

> Although the Company utilizes historical averages to prepare the budget, in this case, the Company thought that recent history represented a better indication of future activity. FY '06 and calendar '06 percentages are at 2.96% and 3.85%, respectively.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED FORECASTED TEST PERIOD OVERTIME COSTS OF $462,654 BASED ON AN OVERTIME RATIO OF 3.286%?

A. No. As shown on Schedule G-2, lines 8 and 12, the Company's actual overtime ratios and associated overtime dollars can fluctuate significantly from year to year and this is most likely the reason why the Company normally budgets its overtime costs based on historical averages. The Company has provided no convincing evidence in this case that the actual overtime experience in FY 2006 and calendar 2006 is appropriately representative of the overtime experience for the Forecasted Test Period.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO THIS ISSUE IN THIS CASE?

A. In response to AG-2-40b, the Company has calculated that the Forecasted Test Period overtime cost amount based on the actual 5-year historic overtime ratio of 2.10%[7] is $295,693. I recommend that this overtime cost be used for ratemaking purposes in this

[7] Actual average ratio of 2.055%, rounded upwards to 2.10%.

case. It is based on an average overtime ratio that appropriately smoothes out the effect of annual fluctuations and is calculated consistent with the Company's normal practice of budgeting for overtime costs "based on historical averages."

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON THE COMPANY'S PROPOSED FORECASTED TEST PERIOD O&M EXPENSES AND AFTER-TAX OPERATING INCOME?

A. As shown on Schedule RJH-11, based on an O&M expense ratio of 49.953%, my recommendation decreases the Company's proposed Forecasted Test Period O&M expenses by $83,402 and increases the Company's proposed after-tax operating income by $50,959.

- **Public and Community Relations Expenses**

Q. PLEASE EXPLAIN THE RECOMMENDED PUBLIC RELATIONS AND COMMUNITY RELATIONS EXPENSE ADJUSTMENT SHOWN ON SCHEDULE RJH-12.

A. The Company's Forecasted Test Period above-the-line operating expenses include a net amount of $178,809 for public relations and community relations expenses. Generally, such expenses are primarily associated with promoting a utility's efforts to be involved in the community. These efforts could include such activities as, for example, community relationship outreach projects; promotions for community activities;

community advertising; supporting media tours and open houses; administering visitors centers; work time contributed to support community activities and organizations; participating in local civic organizations; coordinating employee volunteer programs, and so on. Contrary to the Company's statement in its response to PSC-3-24, these activities have very little, if anything, to do with the provision of safe, adequate and reliable gas service. Rather, they involve activities that have as their primary purpose the promotion of goodwill for the Company and enhance the Company's image as a good corporate citizen. For these reasons, I do not believe that these expenses should be charged to the Company's captive ratepayers. They should properly be assigned to the Company's shareholders.

As shown on Schedule RJH-12, my recommendation to remove these public and community relations expenses from the Forecasted Test Period increases the Company's proposed after-tax operating income by $109,252.

Q. IS YOUR RECOMMENDATION CONSISTENT WITH PRIOR COMMISSION RULINGS REGARDING PUBLIC AND COMMUNITY RELATIONS EXPENSES?

A. Yes. Based on my experience in prior rate proceedings in Kentucky, I know of at least two fully litigated rate proceedings in which the Commission approved the exclusion of public/community relations expenses for ratemaking purposes. These cases involved the prior Union Light Heat & Power Company Cases 2005-00042 and 2001-00092.

- **Employee Welfare Expenses**

Q. PLEASE EXPLAIN THE RECOMMENDED EMPLOYEE WELFARE EXPENSE ADJUSTMENT SHOWN ON SCHEDULE RJH-13.

A. The Company's proposed Forecasted Test Period above-the-line operating expenses include a net amount of $175,633 for expenses associated with employee awards, gifts and parties as well as other employee welfare expenses[8] that should not be allowed for ratemaking purposes in this case. Schedule RJH-13, lines 1-5 and footnotes (1) – (4) show the various sources for these expenses. I recommend that this net expense amount of $175,633 be removed in this case because they have nothing to do with the provision of safe, adequate and reliable service. My recommendation is consistent with long-standing and well-established Commission policy to remove this type of expense for ratemaking purposes.

As shown on Schedule RJH-13, lines 6 – 8, my recommendation increases the Company's proposed Forecasted Test Period after-tax operating income by $107,312.

- **Miscellaneous Expense Adjustments**

Q. PLEASE EXPLAIN THE MISCELLANEOUS EXPENSE ADJUSTMENTS YOU SHOW ON SCHEDULE RJH-14.

[8] Including golf tournaments, picnics, flower funds, receptions, and break room supplies.

A. As shown on Schedule RJH-14, line 1 and footnote (1), the first expense adjustment concerns the recommended removal of dues for various home builders associations and a number of other organizations. I believe that the main motivation for a gas utility to join home builders associations is to promote the building of homes that use natural gas for heating and other purposes as opposed to oil or electric power. In my opinion, it is inappropriate to saddle the ratepayers with the costs associated with the promotion of one energy source over another as the ratepayers do not benefit from these promotional activities. With regard to the dues for the other organizations listed under footnote (1) of Schedule RJH-14, the Company itself has acknowledged in its response to AG-1-55 that these dues should not be allowed for ratemaking purposes.

The second expense adjustment concerns the removal of certain Gas Supply Services expenses. The Forecasted Test Period above-the-line operating expenses in Account 9230 include $64,769 for Gas Supply Service expenses. In its response to AG-1-48, the Company stated with regard to these expenses:

> Beginning January 1, 2007, gas supply services are no longer a direct charge to Kentucky. Our FY2007 budgeting process reflected this change. However, the methodology used to convert our budget to FERC account, as described on page 6, lines 8 through 23 of the direct testimony of Mr. Greg Walter, inadvertently applied a portion of the total forecast to FERC Account 9230-95430. The total amount of O&M forecasted by category remains accurate.

My reading of this statement leaves me to understand that, even though these expenses are no longer chargeable to the Kentucky jurisdiction after January 1, 2007, the Forecasted Test Period Account 9230 operating expenses inadvertently include $64,769 worth of these expenses. Based on this understanding, I have removed these expenses from the Forecasted Test Period.

The third expense adjustment concerns the removal of certain donation and promotional expenses. The response to AG-1-49 shows that the Forecasted Test Period above-the-line expenses include approximately $5,344 for donations and a small amount of $51 for promotional expenses. In this same data response, the Company stated with regard to the donation expenses:

> Beginning October 1, 2006, donations are no longer an above the line charge. Our FY2007 budgeting process reflected this change. However, the methodology used to convert our budget to FERC account, as described on page 6, lines 8 through 23 of the direct testimony of Mr. Greg Walter, inadvertently applied a portion of the total forecast to FERC Account 9230-07520. The total amount of O&M forecasted by category remains accurate.

My reading of this statement leaves me to understand that, even though donations should be treated below-the-line, the Forecasted Test Period Account 9230 operating expenses inadvertently include $5,344 worth of these donation expenses. Based on this understanding, I have removed these expenses, together with the small amount of promotional expenses. As a final point on this issue, I note that the Company maintains in its response to AG-2-33a that the donation expense of $5,344 is *not* included in the Forecasted Test Period above-the-line Account 930.2 expenses. I am puzzled by this claim. The Company's filing schedules clearly show that its Forecasted Test Period above-the-line operating expenses include a total amount of $56,049 for Account 930.2 and the response to AG-1-49 clearly shows that this total expense of $56,049 includes $5,344 for donations.

The fourth expense adjustment concerns the removal of certain unspecified Miscellaneous General expenses in Account 930.2. The response to AG-1-49 shows that the Forecasted Test Period total Account 930.2 expenses include approximately $288 for membership fees, $43,720 for association dues, and $6,646 for other miscellaneous expenses. In AG-2-33c, the Company was requested to provide a detailed breakout and description of all of the items making up these three separate expense items. The Company response was as follows:

> These amounts were determined in the same manner as explained on page 12 of the direct testimony of Company's witness Mr. Greg Waller, therefore there is no detailed breakout of these costs. However, in general, the membership fess and association dues forecasted are similar to those on schedule F-1 in the original filing. The miscellaneous expense would generally relate to miscellaneous Chamber costs...

Since the Company is not able to provide a detailed listing and description of the items making up these three expense items, I do not believe it has met its burden of proof that these expenses should be included for ratemaking purposes.

Finally, the fifth expense adjustment concerns the removal of the portion of the Company's Forecasted Test Period AGA dues associated with AGA's legislative and lobbying activities on behalf of the gas industry as a whole. As confirmed in the Company's response to AG-1-53, the Forecasted Test Period total AGA dues amount to $29,503. The same response indicates that 23.29%[9] of the AGA's 2007 budget is dedicated to legislative and lobbying activities. Consistent with Commission policy to

[9] "Public Affairs" portion.

treat lobbying expenses below-the-line, I recommend that $6,871 (23.29% x $29,503) worth of lobbying expenses be removed for ratemaking purposes in this case.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDED MISCELLANEOUS EXPENSE ADJUSTMENTS ON THE COMPANY'S PROPOSED FORECASTED TEST PERIOD AFTER-TAX OPERATING INCOME?

A. As shown on Schedule 14, my recommended miscellaneous expense adjustments have the effect of increasing the Company's proposed Forecasted Test Period after-tax operating income by $80,553.

- **Depreciation Expense Adjustment**

Q. PLEASE EXPLAIN THE OPERATING INCOME ADJUSTMENT WITH REGARD TO DEPRECIATION EXPENSES SHOWN ON SCHEDULE RJH-15.

A. This operating income adjustment reflects my adoption of the depreciation rate and depreciation expense recommendations contained in the testimony of Michael J. Majoros, the AG's expert depreciation witness. As shown on Schedule RJH-15, Mr. Majoros' depreciation recommendations reduce the Company's originally proposed Forecasted Test Period depreciation expenses by $1,273,486 which, in turn, increases Atmos' proposed Forecasted Test Period net after-tax income by $778,100.

- **Interest Synchronization Adjustment**

Q. ON SCHEDULE RJH-16 YOU SHOW THE COMPANY'S PROPOSED AND YOUR RECOMMENDED INTEREST SYNCHRONIZATION ADJUSTMENTS. ARE THERE ANY ISSUES ASSOCIATED WITH THE INTEREST SYNCHRONIZATION ADJUSTMENT IN THIS CASE?

A. No, there are no issues per se. I agree with the approach and calculation components of the Company's proposed interest synchronization adjustment, and the only reason for the difference between the two adjustments is that the Company's proposed and my recommended rate base balances and weighted cost of debt percentages are different.

As shown on Schedule RJH-16, the difference between my recommended and the Company's proposed interest synchronization adjustments increases the Company's proposed Forecasted Test Period net after-tax operating income by $56,349.

- **Proposed Recovery of Gas Cost Uncollectibles through the GCA**

Q. WHAT IS THE COMPANY'S PROPOSAL IN THIS CASE REGARDING UNCOLLECTIBLE GAS COST REVENUES?

A. The Company is proposing to recover the uncollectible expenses associated with its gas cost revenues through the Gas Cost Adjustment clause. The reason for this proposal is described on page 29 of the testimony of Gary Smith:

> There is a clear distinction between the uncollectible portion of gas costs and other expenses included in the company's cost of service. The total bad

debt expense is directly related to the total billings for residential, commercial and public authority accounts, which is largely driven by gas costs. As I have stated previously, gas costs have exhibited much greater volatility in recent years due to national market issues beyond our local control. Providing for recovery of these gas costs through the GCA seems logical and eliminates the risk for customers and the Company that the level of expense set in base rates is too high or too low in future periods.

Q. DO YOU AGREE WITH THIS PROPOSAL?

A. No. This proposal represents an attempt by the Company to receive guaranteed dollar-for-dollar rate recovery for another component of its cost of service that traditionally has been recovered in base rates. There are several reasons why this proposal should be rejected by the Commission.

First, this kind of "reimbursement ratemaking" is inconsistent with the important ratemaking principle that a utility should have a *reasonable opportunity* for cost recovery, but not a guarantee.

Second, I do not believe that the uncollectible expense at issue is sufficiently material to warrant inclusion in a tracker such as the GCA. As described in the testimony of Mr. Smith, the total Forecasted Test Period uncollectible expenses amount to approximately $1 million, of which approximately $185,000 represents non-gas cost uncollectibles and $815,000 represents gas cost uncollectibles that would be eligible for GCA inclusion under the Company's proposal. The $815,000 represents only .4% of the Company's total Forecasted Test Period O&M expenses of approximately $198 million.

Third, despite the arguments of Mr. Smith[10] to the contrary, I believe that the Company's proposal would produce a disincentive for Atmos to aggressively pursue the recovery of its uncollectibles. Under the Company's proposal, approximately 82% of its total uncollectible expenses would be automatically recovered through the GCA and only 18% of uncollectibles would be "at risk" in the base rates.

Finally, there are other cost of service components directly related to the Company's gas cost revenues that have always been and will continue to be treated for ratemaking purposes through base rates. For example, Mr. Smith argues that gas cost uncollectibles should be treated in the GCA because they "are directly related to the total billings for residential, commercial and public authority accounts, which is driven largely by gas costs." However, PSC assessments and late payment fees, that are similarly a direct function of the total billings for residential, commercial and public authority accounts, have always been and will continue to be recovered through base rates.

In summary, for all of the foregoing reasons, it is my recommendation that the uncollectibles associated with gas cost revenues should continue to be recovered through base rates, consistent with similar base rate recovery for PSC assessments and late payment fees associated with gas cost revenues.

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10 These arguments are described on page 30 of the testimony of Mr. Smith.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING THIS ISSUE?

A. Yes. If the Commission were to accept the Company's proposal, then an adjustment must be made to reduce the Forecasted Test Period uncollectible expenses from approximately $1 million to approximately $185,000.

V. CUSTOMER RATE STABILIZATION MECHANISM

Q. PLEASE GENERALLY DESCRIBE THE CUSTOMER RATE STABILIZATION ("CRS") MECHANISM THE COMPANY HAS PROPOSED IN THIS CASE.

A. In this case, Atmos has proposed a revolutionary new rate mechanism (the CRS) which would allow Atmos to implement, on an annual basis and without testimony and hearings, a reconcilable surcharge to guarantee that the actual return on equity earned by Atmos between rate cases will always be exactly equal to the return on equity authorized by the KPSC in the Company's most recent preceding base rate proceedings. This novel surcharge proposal, which is equivalent to a request for an annual reconcilable adjustment clause for each and every component of the ratemaking formula that determines Atmos' revenue requirement and rate of return, is unprecedented in Kentucky.

The proposed CRS mechanism is designed to accomplish two review exercises with each filing, one historical and one prospective. The historical review covers the so-called Evaluation Period, defined as the twelve-month period ending December 31 of each calendar year. The prospective review covers the so-called Rate Effective Period, defined as the twelve-month period in which rates determined under the CRS mechanism will be in effect, running from May 1 to April 30. The first review exercise is to true-up the historical Evaluation Period. This review will consider actual rate base investments, costs and revenues and then calculate the amount of revenue to be increased or decreased such that the earned rate of return for the historical Evaluation Period equals the return authorized by the Commission in the most recent rate case. The second review exercise is to project rate base investments, revenues and costs for the Rate Effective Period. This prospective review would identify an amount of revenue to be increased or decreased such that the expected return for the Rate Effective Period equals the return authorized by the Commission in the most recent rate case. The sum of the revenue adjustment required for the Evaluation Period and the revenue adjustment required for the Rate Effective Period will determine the total amount of revenue for which rates will then be adjusted. Those rates will stay in effect for the entire Rate Effective Period. To the extent that the projections for the Rate Effective Period vary from actual results, the following year's historic true-up review for the Evaluation Period will correct for such variances.

Q. IN ITS RESPONSE TO AG-2-60, THE COMPANY ESSENTIALLY CLAIMS THAT THE PROPOSED CRS MECHANISM DOES *NOT* PROVIDE FOR A GUARANTEED RATE OF RETURN LEVEL. COULD YOU COMMENT ON THAT CLAIM?

A. Yes. The Company's response to AG-2-60 is as follows:

> ... There is no guarantee that the Company will earn its authorized rate of return, because rates will be set prospectively not retroactively. While the proposed mechanism is intended to better enable the Company to earn its authorized return (and no more), certain circumstances will affect the actual earned return. For example, if expected revenues are not attained or if expected expenses are greater than forecasted, then actual returns could fall below the Company's authorized return.

It is true that during any Rate Effective Period the Company may not earn its authorized rate of return if expected revenues are not attained or expected expenses are greater than forecasted in a CRS filing. However, the proposed CRS mechanism provides for a *retroactive true-up*[11] of this temporary shortfall from the authorized rate of return and this earnings shortfall true-up will be charged to the ratepayers in the next Rate Effective Period. Thus, if the Company did not earn its authorized return in CRS year 1, this earnings shortfall will be made up in CRS year 2 so that after the end of CRS year 2 the actual achievement of the authorized return for CRS year 1 has been guaranteed. Through this retroactive rate of return true-up mechanism, the Company's rate of return for each CRS year is eventually guaranteed. So it is true that the proposed CRS rates are set prospectively, however, *the prospective CRS rates include a true-up for retroactive variations from the Company's authorized rate of return, thereby rendering the CRS rate setting process both prospective and retroactive in nature.*

Q. PLEASE SUMMARIZE YOUR OVERALL RECOMMENDATION REGARDING THE COMPANY'S PROPOSED CRS MECHANISM.

A. I recommend that Atmos' proposed CRS mechanism be rejected by the Commission, as this proposed surcharge mechanism:

1) is in violation of accepted ratemaking principles and inconsistent with appropriate regulatory policy;

2) reduces the incentive for the Company to manage its business in the most

[11] As determined in the subsequent historical review of the particular Rate Effective Period.

efficient manner and at the lowest possible costs;

3) represents a request for extraordinary rate remedy that is not needed and is unsubstantiated; and

4) produces no benefits for the ratepayers and inappropriately shifts virtually all risks from the stockholders to the ratepayers.

Q. WHY IS THE COMPANY'S PROPOSED CRS MECHANISM IN VIOLATION OF ACCEPTED RATEMAKING PRINCIPLES AND INCONSISTENT WITH APPROPRIATE REGULATORY POLICY?

A. The proposed CRS surcharge mechanism represents a significant move away from traditional regulation and instead seeks a guaranteed, dollar-for-dollar recovery of any deficiency in the Company's authorized rate of return experienced between rate cases. It is a well-known principle of traditional ratemaking that utilities are not <u>guaranteed</u> a return on investment; rather, the ratemaking process entitles the utility no more than a <u>reasonable</u> <u>opportunity</u> to earn a fair rate of return. Regulation is not intended to be a mechanism whereby a utility is guaranteed dollar-for-dollar recovery of either its costs or a particular level of profit and rate of return. As stated in the preceding section of this testimony, I call this kind of regulation reimbursement ratemaking. Instead, traditional regulation has been founded on the principle that the utility has an opportunity to earn its rate of return. Returns have never been guaranteed because the production of utility services at the lowest possible cost requires that a company exert itself and work efficiently.

Through the proposed CRS mechanism, the Company has lost sight of the foundation upon which the regulatory process was developed, i.e., regulation is intended to be a substitute for competition. This principal of regulation was designed to stimulate a utility to act as it would if it were in a competitive industry. Clearly, if a utility's rate of return is guaranteed, this represents a departure from traditional ratemaking foundations. Competitive entities do not have any such return guarantees. Since regulation is supposed to be a substitute for competition, regulated entities should not receive guaranteed recovery of their authorized rate of return if such guarantees are not available in the competitive marketplace.

In summary, the Commission has to make some major policy decisions in this case. Either it can retain the current regulatory process, which sets rates on a prospective basis and provides the opportunity for a utility to earn its authorized rate of return, or it can go down the slippery slope of reimbursement ratemaking. For all of the preceding and following reasons, I would respectfully urge the Commission to favor the first alternative.

Q. WHY MAY THE COMPANY'S PROPOSED CRS MECHANISM NEGATIVELY INFLUENCE THE INCENTIVE OF MANAGEMENT TO RUN ITS BUSINESS IN THE MOST EFFICIENT MANNER AND AT THE LOWEST POSSIBLE COST?

A. In my opinion, the automatic, dollar-for-dollar true-up of the Company's actual achieved rate of return to its authorized rate of return between rate cases reduces the Company's incentive to control its costs. Currently, an increase in costs in any one area will stimulate cost cutting elsewhere as the Company strives to reach its rate of return goals. This incentive will be lost if the CRS is adopted. The guarantees provided by the proposed CRS remove or reduce the regulatory incentives for the Company to provide utility services in the most efficient manner and at the lowest possible cost. Removal or reduction of such incentives will only leave ratepayers funding bloated budgets with little prospect for management attention to cost containment. Any mechanism that diminishes the incentive for a utility to actively manage its costs removes some of the ratepayer protections provided under traditional regulation.

Management is responsible for planning and anticipating the cost of providing utility service, setting appropriate budgets, and obtaining rate relief through the regulatory process when necessary. The management of Atmos-Kentucky should continue to be held accountable for these tasks under the umbrella of traditional regulation. Ratepayers should pay for attentive management, not pampered management that is immune from the consequences of its own decision making.

Q. HAS THE COMPANY SUBSTANTIATED THE NEED FOR THE PROPOSED CRS MECHANISM?

A. No. As I explained before, traditional ratemaking involves the establishment of a base rate that allows the utility a reasonable opportunity to recover its cost of service and to earn a fair rate of return but does not guarantee either because some expenses and revenues will rise and others will fall while the base rate remains the same. Both the risk and reward of the efficient operation of the company are on the utility when the cost of service is recovered through base rates. Adjustment clauses such as the proposed CRS rate mechanism, are formula rates that set up the elements of expense or revenue to be collected/credited under the rate. The adjustment clauses may result in a credit or charge based on how the included expenses and revenues actually materialize. The purpose of an adjustment clause is to guarantee rate recovery for the particular ratemaking element for which the clause was set up.

From a regulatory policy standpoint, the impact of an adjustment clause established in the context of a general rate case - where the base rates are set on traditional principles of ratemaking - is to *declare that the general rates established in the case cannot in and of themselves be fair, just and reasonable* because the expenses and revenues covered by the clause cannot be accommodated within the traditional ratemaking expectation that some expenses and revenues will rise and others will fall, but the *opportunity* to earn will continue to be present until new rates are sought. Outside of (i) clauses agreed to by all parties to allow the parties to give and/or receive the benefits of settlements, and (ii) clauses allowed or required by the state's regulatory scheme, my experience has been that adjustment clauses are generally utilized only when the covered costs or revenues are outside the control of management and exhibit extreme volatility and unpredictability. These are the properties that underlie the most commonly utilized adjustment clauses such as fuel adjustment clauses and gas recovery clauses. Rate recovery through an automatic rate adjustment mechanism should continue to be allowed only when management has little or no control over the item at issue and specific requirements of volatility and unpredictability can be met.

In this case, Atmos' proposed CRS clause mechanism does not meet these requirements. Atmos' rate of return (which the CRS seeks to guarantee) is mostly within the control of management and the Company has provided no evidence that would support the need for the extraordinary remedy sought by the proposed CRS mechanism. With regard to this latter point, Atmos has presented no analyses showing that it needs the additional rate increases from the CRS to address any potential future rate of return erosions.

I should also note that I find the concept of the proposed CRS especially egregious to the ratepayers when it is bundled with the adjustment clauses that are already in effect for Atmos-Kentucky and which already provide guaranteed rate recovery of significant cost of service components that determine the Company's achieved rate of return. These adjustment clauses concern the Gas Cost Adjustment (GCA) clause, Weather Normalization Adjustment (WNA) clause, Performance Based Rate (PBR) mechanism, and Margin Loss Recovery (MLR) rider. The GCA provides Atmos with guaranteed, dollar-for-dollar rate recovery of the largest component of the Company's cost of service, the purchased gas cost. The WNA clause protects Atmos' achieved rate of return from the financial consequences of abnormal weather conditions. The MLR provides Atmos with guaranteed recovery of 50% of the distribution charge losses that result from (1) discounts pursuant to the Alternate Fuel Responsive Flex Provision; (2) special contracts approved by the KPSC; or (3) a customer's bypass of the Company's system. And the PBR represents a gas purchasing incentive plan that gives Atmos an opportunity to share in certain savings in the gas purchasing function. As evidenced by data request PSC-2-57e, the Commission apparently has the same concerns regarding the proposed implementation of the CRS on top of the currently existing tracking clauses:

> Explain why Atmos's concerns over its revenue recovery are not fully addressed by its Performance Based Ratemaking mechanism, its Weather Normalization Adjustment mechanism and its Margin Loss Recovery mechanism.

In summary, there is no substantiation for the need of the proposed CRS mechanism and Atmos has not met the burden of proof that there is a true and legitimate need for the extraordinary remedy sought by it in this case through the proposed surcharge.

Q. WHAT DOES ATMOS CLAIM TO BE THE BENEFITS TO THE RATEPAYERS FROM THE IMPLEMENTATION OF THE PROPOSED CRS MECHANISM?

A. As described on page 24 of the testimony of Company witness Gary Smith, Atmos has claimed two ratepayer benefits resulting from the proposed CRS mechanism. First, the Company claims that ratepayers will benefit …" by the additional assurance that the Company's earnings are reasonable and appropriate and that their rates are appropriate."

Second, the Company claims that the costs (ultimately to be born by the ratepayers) associated with regulation through the proposed CRS rate mechanism will be less than the cost of continued traditional regulation. I don't see why the "assurance that the Company's earnings are reasonable and appropriate and that their rates are appropriate" represents a real benefit to the ratepayers. It would seem to me that the Company's stockholders would benefit infinitely more from this annual "assurance" than the ratepayers since I believe that the true stimulus for the proposed CRS is stockholder protection from rate of return erosion between rate cases. In addition, the proposed CRS mechanism, with its backward and forward review exercises to assure that the authorized rate of return will always be actually achieved, shifts virtually all risks from the stockholder to the ratepayers.

The Company has also not proven its second ratepayer benefit claim; i.e., that the proposed CRS mechanism will be less costly than the cost of traditional regulation. On page 22 of his testimony, Mr. Smith states with regard to the claimed cost benefit of the CRS:

> We believe the CRS mechanism will provide benefits to the customer by avoiding the costly and resource-intensive process to review adjustments through the traditional rate case process replacing it instead with a simple, straightforward and financially transparent process that would ensure that the customer pays only the appropriate rate.

However, on page 23 of his testimony, Mr. Smith then states that, under the proposed CRS mechanism, the Company will file "numerous financial schedules" containing "accounting and pro-forma adjustments" that "would be applied and identified consistent with treatment in a full rate proceeding." This certainly does not seem as simple and straightforward a process as Mr. Smith makes it sound.

In PSC-2-7b, the Company was asked:

> Explain in detail how Atmos has determined that the proposed annual reviews would be "at a very low cost and provide for customer rate protection." Include any studies or analyses Atmos conducted that support these conclusions.

The Company's response to this request was that it had not conducted any studies in this regard. Even though the Company did not conduct any studies or analyses regarding its claimed "very low cost" associated with the proposed CRS process, in response to another PSC data request[12] the Company nevertheless came up with an estimated annual CRS filing cost of around $50,000 and stated that "a greater expense [than $50,000] would clearly indicate a litigious response to its annual filing." Even if one believes this $50,000 cost estimate to be reasonably accurate, it does not include the costs to be incurred by the Commission and the AG's office in their review of the annual CRS filings which the Company proposes to include in the CRS rates to be charged to the ratepayers. In response to AG-1-80, the Company confirms that it "has not made an estimate of the incremental costs to be incurred by the Commission and the AG." Furthermore, it must be assumed that the Company's $50,000 cost estimate is based on a "simple and straightforward" 45-day review without any significant challenges by the PSC or AG and, as confirmed by Atmos, without a litigious response to the CRS filing. Thus, it is highly likely that the total CRS cost estimate will be

[12] PSC-2-58d.

significantly higher than $50,000 once one adds in the costs of the PSC's and AG's filing reviews and the costs of a review that will last longer than 45 days with significant challenges or a litigious response to the CRS filing. Next, one has to consider the fact that these CRS related regulatory expenses would be incurred *annually* between rate cases. This means that during the Company's proposed 5-year CRS experiment, the ratepayers would be charged at least $250,000 or significantly higher[13] for additional regulatory expenses associated with 5 CRS filings for which they would not be chargeable under traditional regulation. And these additional costs would be incurred on top of the costs associated with the Company's traditional base rate proceedings which would still have to take place periodically, such as the instant rate proceeding with an estimated cost of $370,000. It should also be noted that we are not here dealing with a company that, under the current traditional rate regulation, incurs general base rate costs every two or three years. In fact, the Company's last base rate case, Case No. 99-070, was filed in June 1999, or almost 8 years ago. And the average filing frequency of the Company's most recent three base rate proceedings is approximately 5 ½ years. Thus, the Company has not proven that the regulatory costs to the ratepayers with the CRS mechanism in place will be lower than the regulatory costs associated with the continuation of traditional regulation. In fact, I believe that the opposite will turn out to be the case.

In summary, while the Company claims that the proposed CRS is of benefit to the

[13] Based on assumed annual CRS filing costs of $75,000 to $100,000, the total 5-year CRS filing costs would be $375,000 to $500,000.

ratepayers, the mechanism focuses predominantly on the interests of Atmos and its stockholders rather than the ratepayers and shifts significant risks from the stockholders to the ratepayers. The Company is simply dangling the unsubstantiated promise of lower regulatory costs under the CRS mechanism as bait to get a tremendous benefit for shareholders in the form of a guaranteed rate of return.

Q. ARE THERE OTHER SHORTCOMINGS IN ATMOS' PROPOSED CRS MECHANISM THAT SHOULD BE OF CONCERN TO THE COMMISSION?

A. Yes. There are a number of other issues associated with the proposed CRS mechanism that should be of concern to the Commission. I note, though, that even if the Company were to fix these additional issues, this should not render the CRS appropriate for implementation in this case. The proposed CRS mechanism should be rejected by the Commission for all of the reasons and regulatory policy issues previously described in this testimony. The additional issues that I will discuss now are to be considered supplemental reasons for rejecting the proposed CRS.

What should first be of concern to the Commission is the fact that the proposed CRS mechanism does not include any decrease in the Company's requested return on equity in the instant base rate case. While I am not the AG's rate of return expert in this case, it is my understanding that the Company's return on equity rate to be established in this proceeding is partially a function of the degree of earnings risk to be experienced by Atmos. As previously discussed, the CRS mechanism provides for a guaranteed rate of return between rate cases and thereby completely removes the Company's earnings risk. For that reason, it is inappropriate for the Company to propose the CRS mechanism without a concomitant reduction in its requested return on equity.

Second, Atmos has proposed that no testimony be filed in support of the annual CRS filings and that the total filing review period be limited to 45 days. As discussed on page 23 of Mr. Smith's testimony, each CRS filing will consist of numerous financial schedules, including accounting and pro-forma adjustments "consistent with treatment in a full rate proceeding," for both a historic Evaluation Period and a prospective Rate Effective Period. In my opinion, it will be rather difficult, if not impossible, for the Commission and the AG to determine the reasonableness of the historic as well as projected rate base investment levels, expenses and revenues, and potentially challenge and change the filing results in a time frame of only 45 days and without supporting testimony on the part of Atmos.

Third, Atmos takes the position that no hearings are necessary to implement the CRS rates. While the proposed CRS filings may not be equivalent to full-blown rate cases, they can certainly be characterized as "mini rate cases" that have as their purpose to adjust the then-current base rates. I believe it would be appropriate to include hearings in the process of establishing the new rates produced by these mini rate cases, particularly since no pre-filed testimonies are proposed to be included in the CRS filings.

Finally, there may well be other reasons for rejecting the proposed CRS mechanism that fall outside of my area of expertise such as, for example, legal reasons.

Q. MR. HENKES, DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

ATMOS ENERGY - KENTUCKY
REVENUE DEFICIENCY

	ATMOS (1)	Adjustment	AG	
1. Rate Base	$169,405,541	$ (775,726)	$ 168,629,815	Sch. RJH-3
2. Rate of Return	8.82%		7.47%	Sch. RJH-2
3. Operating Income Requirement	14,941,569		12,597,032	
4. Pro Forma Operating Income	8,774,577	2,341,345	11,115,922	Sch. RJH-5
5. Operating Income Deficiency	6,166,992		1,481,110	
6. Gross Revenue Conversion Factor	1.688011		1.633302	(2)
7. Revenue Deficiency	$ 10,409,950	$ (7,990,851)	$ 2,419,099	

(1) Original Schedule A

		ATMOS		AG
(2) Operating revenue		100.000000		100.000000
Less: Uncollectible accounts		(0.500000)		(0.500000)
Less: PSC fees		(0.164300)		(0.164300)
Plus: Late payment fees		0		0.870000
Net revenues		99.335700		100.205700
State income taxes	at 8.25%	8.195195	at 6.00%	6.012342
Income before federal income tax		91.140505		94.193358
Federal income tax @ 35%		31.899200		32.967675
Operating income percentage		59.241305		61.225683
Gross revenue conversion factor		1.688011		1.633302

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Sch. RJH-2

ATMOS ENERGY - KENTUCKY
RATE OF RETURN

ATMOS PROPOSED:

		Capitalization ($000)	Ratios	Cost Rates	Weighted Cost Rates
		(1)	(1)	(1)	(1)
Long Term Debt	$	2,179,529	51.85%	6.10%	3.16%
Short Term Debt		-	0.00%	0.00%	0.00%
Common Equity		2,024,314	48.15%	11.75%	5.66%
Total	$	4,203,843	100.00%		8.82%

AG RECOMMENDED:

		Capitalization	Ratios	Cost Rates	Weighted Cost Rates
		(2)	(2)	(2)	(2)
Long Term Debt	$	2,179,529	50.36%	6.10%	3.07%
Short Term Debt		123,886	2.86%	6.58%	0.19%
Common Equity		2,024,314	46.78%	9.00%	4.21%
Total	$	4,327,729	100.00%		7.47%

(1) Original Schedule J-1
(2) Testimony of Dr. J. Randall Woolridge

ATMOS ENERGY - KENTUCKY
RATE BASE

	ATMOS (1)	Adjustment	AG	
1. Plant in Service	$322,898,092	$(1,016,900)	$ 321,881,192	(2)
2. Construction Work in Progress	1,543,040		1,543,040	
3. Accumulated Depr. & Amort.	(150,189,986)	629,911	(149,560,075)	(2)
4. Net Plant and Equipment	174,251,145	(386,989)	173,864,157	
5. Cash Working Capital Allowance	2,605,840	(111,623)	2,494,217	Sch. RJH-4
6. Other Working Capital:				
a. Materials and Supplies	575,401	(32,329)	543,072	(3)
b. Prepayments	799,159	(231,715) (4)	567,444	
c. Gas Stored Underground	21,792,727		21,792,727	
d. Total Other Working Capital	23,167,287	(264,044)	22,903,243	
7. Customer Advances for Constr.	(3,685,193)	(13,071)	(3,698,264)	(5)
8. Deferred ADIT & ADITC	(26,933,538)		(26,933,538)	
10. Net Rate Base	$169,405,541	$ (775,727)	$ 168,629,815	

(1) Original Schedule B-1, Sheet 2 of 2
(2) Testimony of Michael J. Majoros Jr.
(3) Corrected Schedule B-4.1, Sheet 2 of 2, per response to AG-1-1
(4) Removal of prepaid PSC assessment fees, per responses to AG-1-18 and AG-1-20.
(5) Per Schedule B-5, Sheet 3 (Division 09 advances). Disregard Division 91 advances per AG-2-10

ATMOS ENERGY - KENTUCKY
CASH WORKING CAPITAL ALLOWANCE

	ATMOS (1)	Adjustment	AG	
1. Total Pro Forma O&M Expense Exclusive of Purchased Gas Costs	$ 20,846,717	$ (892,984)	$ 19,953,733	Sch. RJH-17
2. CWC Ratio	0.125	0.125	0.125	
3. Cash Working Capital	$ 2,605,840	$ (111,623)	$ 2,494,217	

(1) Original Schedule B-4.2, Sheet 2 of 2

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ATMOS ENERGY - KENTUCKY
OPERATING INCOME

	Impact on After-Tax Income	
1. Operating Income Originally Proposed by ATMOS	$ 8,774,577	(1)
AG-Recommended Operating Income Adjustments:		
2. Composite Income Tax Rate of 38.900% vs. 40.363%	83,932	Sch. RJH-6
3. Property Tax Adjustment	859,528	Sch. RJH-7
4. PSC Assessment Adjustment	17,822	Sch. RJH-8
5. Rate Case Expense Amortization	(75,356)	Sch. RJH-9
6. Incentive Compensation Adjustment	272,894	Sch. RJH-10
7. Overtime Expense Adjustment	50,959	Sch. RJH-11
9. Removal of Public and Community Relations Expenses	109,252	Sch. RJH-12
10. Removal of Certain Employee Welfare Expenses	107,312	Sch. RJH-13
11. Miscellaneous Expense Adjustments	80,553	Sch. RJH-14
12. Depreciation Expense Adjustment	778,100	Sch. RJH-15
13. Interest Synchronization Adjustment	56,349	Sch. RJH-16
14. AG-Recommended Income Adjustments	2,341,345	
15. AG-Recommended Pro Forma Operating Income	$ 11,115,922	

(1) Original Schedule C-1

ATMOS ENERGY - KENTUCKY
INCOME TAX ADJUSTMENT

1. ATMOS's Originally Filed Taxable Income per Schedule E, Line 3:		$	5,736,979
2. Composite Income Tax Correction:			
a. Originally Filed Composite Tax Rate	40.363%		
b. Corrected Composite Tax Rate	38.900%		
c. Tax Rate Difference			-1.463%
3. Recommended Income Tax Reduction		$	(83,932)

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Sch. RJH-7

ATMOS ENERGY - KENTUCKY
PROPERTY TAX ADJUSTMENT

1.	Total Revised Estimated 2006 Property Taxes	$ 2,632,247	(1)
2.	Recommended Property Taxes Based on 2006 Tax Estimate in Line 1 and Estimated 3% increase Effective November 2007	2,684,892	(2)
3.	ATMOS Proposed Property Tax Based on Initial KDR Value and Estimated 3% increase Effective November 2007	4,091,648	(3)
4.	Recommended Property Tax Redu([L2-L3]	(1,406,756)	
5.	After-Tax Operating Income Factor	61.10%	(4)
6.	Impact on After-Tax Operating Income	$ 859,528	

(1) Response to PSC-3-8
(2) [($2,632,247 / 12) x 4 months] + [($2,632,247 / 12 x 1.03) x 8 months]
(3) Schedule C-2.3
(4) 100% - composite income tax rate of 38.90% = 61.10%

ATMOS ENERGY - KENTUCKY
PSC ASSESSMENT ADJUSTMENT

	ATMOS (1)	Adjustment	AG	
1. Gross Intrastate Receipts	$244,452,110		$ 226,698,846	(2)
2. PSC Assessment Rate	0.001643		0.001643	
3. PSC Assessment	$ 401,635	$ (29,169)	$ 372,466	
4. After-Tax Operating Income Factor		61.10%	(3)	
5. Impact on After-Tax Operating Income		$ 17,822		

(1) Response to AG-1-2
(2) Schedule C-1, Sheet 1
(3) 100% - composite income tax rate of 38.90% = 61.10%

ATMOS ENERGY - KENTUCKY
RATE CASE EXPENSE AMORTIZATION

1. Three-Year Amortization of Estimated Rate Case Exp.	$	123,333	(1)
2. After-Tax Operating Income Factor		61.10%	(2)
3. Impact on After-Tax Operating Income	$	(75,356)	

(1) Corrected Schedule F-6, per response to AG-1-1
(2) 100% - composite income tax rate of 38.90% = 61.10%

ATMOS ENERGY - KENTUCKY
INCENTIVE COMPENSATION EXPENSE ADJUSTMENT

	Allocated to KY	
1. MIP-Only Incentive Compensation Plan Expense	145,995	(1)
2. VPP-Only Incentive Compensation Plan Expense	94,743	(1)
3. LTIP - Restricted Stock Incentive Compensation Plan Exp.	205,897	(1)
4. Total Incentive Compensation Expense in Forecasted Period	446,635	(1)
5. After-Tax Operating Income Factor	61.10%	(2)
6. After-Tax Operating Income Impact of Expense Removal	$ 272,894	

(1) Response to AG-2-39a
(2) 100% - composite income tax rate of 38.90% = 61.10%

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Sch. RJH-11

ATMOS ENERGY - KENTUCKY
OVERTIME EXPENSE ADJUSTMENT

	ATMOS (1)	Adjustment	AG	
1. Total Forecasted Test Period Overtime Cost				
a. Based on Overtime Ratio of 3.286%	$ 462,654			
b. Based on Overtime Ratio of 2.10%			$ 295,693	(2)
2. O&M Expense Ratio	49.953%		49.953%	
3. Overtime Expense Charged to O&M	$ 231,110	$ (83,402)	$ 147,708	
4. After-Tax Operating Income Factor		61.10% (3)		
5. Impact on After-Tax Operating Income		$ 50,959		

(1) Schedule G-2, lines 12 and 19
(2) Response to AG-2-40b
(3) 100% - composite income tax rate of 38.90% = 61.10%

ATMOS ENERGY - KENTUCKY
REMOVAL OF PUBLIC AND COMMUNITY RELATIONS EXPENSES

1. Public Relations and Community Relations Expenses Included in Forecasted Test Period	$	178,809	(1)
2. After-Tax Operating Income Factor		61.10%	(2)
3. Impact on After-Tax Operating Income of Expense Removal	$	109,252	

(1) Response to AG-1-51 and AG-2-32d: $178,970 net of $161 = $178,809
(2) 100% - composite income tax rate of 38.90% = 61.10%

ATMOS ENERGY - KENTUCKY
REMOVAL OF CERTAIN EMPLOYEE WELFARE EXPENSES

1. Forecasted Test Period Employee Welfare Expenses Identified in Response to AG-1-56	$	123,358	(1)
2. Forecasted Test Period Employee Welfare Expenses Identified in Response to AG-1-57		15,808	(2)
3. Additional Forecasted Test Period Employee Welfare Expenses Identified in Response to AG-1-85e and AG-2-37b		37,261	(3)
4. Total Employee Welfare Expenses in Forecasted Test Period		176,427	(4)
5. Less: Employee Welfare Expenses Removed from Test Period		(794)	(4)
6. Net Expenses to be Removed from Forecasted Test Period		175,633	
7. After-Tax Operating Income Factor		61.10%	(5)
8. Impact on After-Tax Operating Income of Expense Removal	$	107,312	

(1) Per response to AG-1-56: Kentucky Direct of $72,474 + allocated of $50,884 = $123,358
(2) Per response to AG-1-57: $12,040 + $3,179 + $589 = $15,808
(3) Per responses to AG-1-85e and AG-2-37(b): $176,427 - $123,358 - $15,808 = $37,261
(4) Response to AG-2-37
(5) 100% - composite income tax rate of 38.90% = 61.10%

ATMOS ENERGY - KENTUCKY
MISCELLANEOUS EXPENSE ADJUSTMENTS

1. Various Social and Club Dues Listed on Sch. F-1	$	4,149	(1)
2. Gas Supply Services Expenses		64,769	(2)
3. Donation and Promotional Expenses		5,395	(3)
4. Unspecified Acct. 930.2 Miscellaneous General Expenses		50,654	(4)
5. Lobbying Portion of AGA Dues		6,871	(5)
6. Total Expense Removal From Forecasted Test Period		131,838	
7. After-Tax Operating Income Factor		61.10%	(6)
8. Impact on After-Tax Operating Income of Expense Removal	$	80,553	

(1) Remove following dues on Sch. F-1, pp. 4-6:

Home builders association dues (lines 3, 6, 26, 29, 30, 36, 50 and 52)	$	2,690
Expenditures inappropriately included (lines 51, 55, 57 and 58)		1,459
Total	$	4,149

(2) Responses to AG-1-48 and AG-2-30
(3) Responses to AG-1-49 and AG-2-33: $5,344.21 + $51.20 = $5,395.41
(4) Responses to AG-1-49 and AG-2-33: $288 + $43,720 + $6,646 = $50,654
(5) Per response to AG-1-53: total annual AGA dues of $29,503 x 23.29% (public affairs portion) = $6,871
(6) 100% - composite income tax rate of 38.90% = 61.10%

ATMOS ENERGY - KENTUCKY
DEPRECIATION EXPENSE ADJUSTMENT

	ATMOS (1)	Adjustment	AG (2)	
1. Pro forma Depreciation Expense	$ 12,878,199	$ (1,273,486)	$ 11,604,713	
2. After-Tax Operating Income Factor		61.10%		(3)
3. Impact on After-Tax Operating Income		$ 778,100		

(1) Original Schedule C-2, Line 13
(2) Testimony of Michael J. Majoros Jr.
(3) 100% - composite income tax rate of 38.90% = 61.10%

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Sch. RJH-16

ATMOS ENERGY - KENTUCKY
INTEREST SYNCHRONIZATION ADJUSTMENT

	ATMOS (1)	Adjustment	AG	
1. Rate Base	$169,405,541		$ 168,629,815	Sch. RJH-3
2. Weighted Cost of Debt	3.16%		3.26%	Sch. RJH-2
3. Pro Forma Interest Tax Deduction	$ 5,353,215	$ 144,857	$ 5,498,072	
4. Composite Income Tax Rate		38.90% (2)		
5. Impact on After-Tax Income		$ 56,349		

(1) Original Schedule E
(2) Composite of federal income tax rate of 35% and state income tax rate of 6%

ATMOS ENERGY - KENTUCKY
RECOMMENDED ADJUSTED OPERATION AND MAINTENANCE EXPENSES

1. Pro Forma O&M Expenses Proposed by ATMOS	$ 20,846,717	(1)
AG-Recommended O&M Expense Adjustments:		
- Three-Year Amortization of Rate Case Expenses	123,333	Sch. RJH-9, L1
- Incentive Compensation Expense Adjustment	(446,635)	Sch. RJH-10, L4
- Overtime Expense Adjustment	(83,402)	Sch. RJH-11, L3
- Public & Community Relations Expense Adjustment	(178,809)	Sch. RJH-12, L1
- Employee Welfare Expense Adjustment	(175,633)	Sch. RJH-13, L6
- Miscellaneous Expense Adjustment	(131,838)	Sch. RJH-14, L6
- Pro Forma O&M Expenses Recommended by AG	$ 19,953,733	

(1) Schedule B-4.2, Sheet 2 of 2

APPENDIX I

PRIOR REGULATORY EXPERIENCE OF ROBERT J. HENKES

* = Testimonies prepared and submitted

ARKANSAS

Southwestern Bell Telephone Company Divestiture Base Rate Proceeding*	Docket 83-045-U	09/1983

DELAWARE

Delmarva Power and Light Company Electric Fuel Clause Proceeding	Docket 41-79	04/1980
Delmarva Power and Light Company Electric Fuel Clause Proceeding	Docket 80-39	02/1981
Delmarva Power and Light Company Sale of Power Station Generation	Complaint Docket 279-80	04/1981
Delmarva Power and Light Company Electric Base Rate Proceeding	Docket 81-12	06/1981
Delmarva Power and Light Company Gas Base Rate Proceeding*	Docket 81-13	08/1981
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 82-45	04/1983
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 83-26	04/1984
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 84-30	04/1985
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 85-26	03/1986
Delmarva Power and Light Company Report of DP&L Operating Earnings*	Docket 86-24	07/1986
Delmarva Power and Light Company Electric Base Rate Proceeding*	Docket 86-24	12/1986 01/1987
Delmarva Power and Light Company	Docket 85-26	10/1986

Report Re. PROMOD and Its Use in Fuel Clause Proceedings*		
Diamond State Telephone Company Base Rate Proceeding*	Docket 86-20	04/1987
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 87-33	06/1988
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 90-35F	05/1991
Delmarva Power and Light Company Electric Base Rate Proceeding*	Docket 91-20	10/1991
Delmarva Power and Light Company Gas Base Rate Proceeding*	Docket 91-24	04/1992
Artesian Water Company Water Base Rate Proceeding*	Docket 97-66	07/1997
Artesian Water Company Water Base Rate Proceeding*	Docket 97-340	02/1998
United Water Delaware Water Base Rate Proceeding*	Docket 98-98	08/1998
Delmarva Power and Light Company Revenue Requirement and Stranded Cost Reviews	Not Docketed	12/1998
Artesian Water Company Water Base Rate Proceeding*	Docket 99-197 (Direct Test.)	09/1999
Artesian Water Company Water Base Rate Proceeding*	Docket 99-197 (Supplement. Test)	10/1999
Tidewater Utilities/ Public Water Co. Water Base Rate Proceedings*	Docket No. 99-466	03/2000
Delmarva Power & Light Company Competitive Services Margin Sharing Proceeding*	Docket No. 00-314	03/2001
Artesian Water Company Water Base Rate Proceeding*	Docket No. 00-649	04/2001

Chesapeake Gas Company Gas Base Rate Proceeding*	Docket No. 01-307	12/2001
Tidewater Utilities Water Base Rate Proceeding*	Docket No. 02-28	07/2002
Artesian Water Company Water Base Rate Proceeding*	Docket No. 02-109	09/2002
Delmarva Power & Light Company Electric Cost of Service Proceeding	Docket No. 02-231	03/2003
Delmarva Power & Light Company Gas Base Rate Proceeding*	Docket No. 03-127	08/2003
Artesian Water Company Water Base Rate Proceeding*	Docket No. 04-42	08/2004
United Water Delaware Water Base Rate Proceeding*	Docket No. 06-174	10/2006

<u>DISTRICT OF COLUMBIA</u>

District of Columbia Natural Gas Co. Gas Base Rate Proceeding*	Formal Case 870	05/1988
District of Columbia Natural Gas Co. Gas Base Rate Proceeding*	Formal Case 890	02/1990
District of Columbia Natural Gas Co. Waiver of Certain GS Provisions	Formal Case 898	08/1990
Chesapeake and Potomac Telephone Co. Base Rate Proceeding*	Formal Case 850	07/1991
Chesapeake and Potomac Telephone Co. Base Rate Proceeding*	Formal Case 926	10/1993
Bell Atlantic - District of Columbia SPF Surcharge Proceeding	Formal Case 926	06/19/94
Bell Atlantic - District of Columbia Price Cap Plan and Earnings Review	Formal Case 814 IV	07/1995

GEORGIA

Southern Bell Telephone Company Base Rate Proceeding	Docket 3465-U	08/1984
Southern Bell Telephone Company Base Rate Proceeding	Docket 3518-U	08/1985
Georgia Power Company Electric Base Rate and Nuclear Power Plant Phase-In Proceeding*	Docket 3673-U	08/1987
Georgia Power Company Electric Base Rate and Nuclear Power Plant Phase-In Proceeding*	Docket 3840-U	08/1989
Southern Bell Telephone Company Base Rate Proceeding	Docket 3905-U	08/1990
Southern Bell Telephone Company Implementation, Administration and Mechanics of Universal Service Fund*	Docket 3921-U	10/1990
Atlanta Gas Light Company Gas Base Rate Proceeding*	Docket 4177-U	08/1992
Southern Bell Telephone Company Report on Cash Working Capital*	Docket 3905-U	03/1993
Atlanta Gas Light Company Gas Base Rate Proceeding*	Docket No. 4451-U	08/1993
Atlanta Gas Light Company Gas Base Rate Proceeding	Docket No. 5116-U	08/1994
Georgia Independent Telephone Companies Earnings Review and Show Cause Proceedings	Various Dockets	1994
Georgia Power Company Earnings Review - Report to GPSC*	Non-Docketed	09/1995
Georgia Alltel Telecommunication Companies Earnings and Rate Reviews	Docket No. 6746-U	07/1996
Frontier Communications of Georgia Earnings and Rate Review	Docket No. 4997-U	07/1996

Georgia Power Company Electric Base Rate / Accounting Order Proceeding	Docket No. 9355-U	12/1998
Savannah Electric Power Company Electric Base Rate Case/Alternative Rate Plan*	Docket No. 14618-U	03/2002
Georgia Power Company Electric Base Rate / Alternative Rate Plan Proceeding*	Docket No. 18300-U	12/2004
Savannah Electric Power Company Electric Base Rate Case/Alternative Rate Plan*	Docket No. 19758-U	03/2005

FERC

Philadelphia Electric/Conowingo Power Electric Base Rate Proceeding*	Docket ER 80-557/558	07/1981

KENTUCKY

Kentucky Power Company Electric Base Rate Proceeding*	Case 8429	04/1982
Kentucky Power Company Electric Base Rate Proceeding*	Case 8734	06/1983
Kentucky Power Company Electric Base Rate Proceeding*	Case 9061	09/1984
South Central Bell Telephone Company Base Rate Proceeding*	Case 9160	01/1985
Kentucky-American Water Company Base Rate Proceeding*	Case 97-034	06/1997
Delta Natural Gas Company Base Rate Proceeding*	Case 97-066	07/1997
Kentucky Utilities and LG&E Company Environmental Surcharge Proceeding	97-SC-1091-DG	01/1999
Delta Natural Gas Company Experimental Alternative Regulation Plan*	Case No. 99-046	07/1999

Delta Natural Gas Company Base Rate Proceeding*	Case No. 99-176	09/1999
Louisville Gas & Electric Company Gas Base Rate Proceeding*	Case No. 2000-080	06/2000
Kentucky-American Water Company Base Rate Proceeding*	Case No. 2000-120	07/2000
Jackson Energy Cooperative Corporation Electric Base Rate Proceeding*	Case No. 2000-373	02/2001
Kentucky-American Water Company Base Rate Rehearing*	Case No. 2000-120	02/2001
Kentucky-American Water Company Rehearing Opposition Testimony*	Case No. 2000-120	03/2001
Union Light Heat and Power Company Gas Base Rate Proceeding*	Case No. 2001-092	09/2001
Louisville Gas & Electric Company and Kentucky Utilities Company Deferred Debits Accounting Order	Case No. 2001-169	10/2001
Fleming-Mason Energy Cooperative Electric Base Rate Proceeding	Case No. 2001-244	05/2002
Northern Kentucky Water District Water District Base Rate Proceeding	Case No. 2003-0224	02/2004
Louisville Gas & Electric Company Electric Base Rate Proceeding*	Case No. 2003-0433	03/2004
Louisville Gas & Electric Company Gas Base Rate Proceeding*	Case No. 2003-0433	03/2004
Delta Natural Gas Company Base Rate Proceeding*	Case No. 2004-00067	07/2004
Union Light Heat and Power Company Gas Base Rate Proceeding*	Case No. 2005-00042	06/2005
Big Sandy Rural Electric Cooperative Electric Base Rate Proceeding	Case No. 2005-00125	08/2005

Louisville Gas & Electric Company Value Delivery Surcredit Mechanism*	Case No. 2005-00352	12/2005
Kentucky Utilities Company Value Delivery Surcredit Mechanism*	Case No. 2005-00351	12/2005
Kentucky Power Company Electric Base Rate Proceeding*	Case No. 2005-00341	01/2006
Cumberland Valley Electric Cooperative Electric Base Rate Proceeding	Case No. 2005-00187	05/2006
South Kentucky Rural Electric Cooperative Electric Base Rate Proceeding	Case No. 2005-00450	07/2006
Duke Energy Kentucky Electric Base Rate Proceeding*	Case No. 2006-00172	09/2006
Atmos Energy Corporation Gas Show Cause Proceeding*	Case No. 2005-00057	09/2006
Inter County Electric Cooperative Electric Base Rate Proceeding	Case No. 2006-00415	04/07

MAINE

Continental Telephone Company of Maine Base Rate Proceeding	Docket 90-040	12/1990
Central Maine Power Company Electric Base Rate Proceeding	Docket 90-076	03/1991
New England Telephone Corporation - Maine Chapter 120 Earnings Review	Docket 94-254	12/1994

MARYLAND

Potomac Electric Power Company Electric Base Rate Proceeding*	Case 7384	01/1980
Delmarva Power and Light Company Electric Base Rate Proceeding*	Case 7427	08/1980
Chesapeake and Potomac Telephone Company Western Electric and License Contract	Case 7467	10/1980

Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7467	10/1980
Washington Gas Light Company Gas Base Rate Proceeding	Case 7466	11/1980
Delmarva Power and Light Company Electric Base Rate Proceeding*	Case 7570	10/1981
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7591	12/1981
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COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF ATMOS ENERGY	**)**
CORPORATION FOR AN ADJUSTMENT	**) CASE NO. 2006-00464**
OF GAS RATES	**)**

AFFIDAVIT OF ROBERT J. HENKES

State of Connecticut)
)
)

Robert J. Henkes, being first duly sworn, states the following: The prepared Pre-Filed Direct Testimony, and the Schedules and Appendix attached thereto constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the Pre-Filed Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further affiant saith not.

Robert J. Henkes

SUBSCRIBED AND SWORN to before me this 20 day of April, 2007.

LISA A LATTANZIO
Notary Public
State of Connecticut
My Commission Expires 02/28/2010

NOTARY PUBLIC

My Commission Expires: 2/28/10

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of:

APPLICATION OF ATMOS ENERGY	)
CORPORATION FOR AN ADJUSTMENT	) CASE NO. 2006-00464
OF GAS RATES	)

DIRECT TESTIMONY OF MICHAEL J. MAJOROS, JR.
ON BEHALF OF
THE ATTORNEY GENERAL OF THE COMMONWEALTH OF KENTUCKY

Date: April 27, 2007

Table of Contents

Direct Testimony
Of
Michael J. Majoros, Jr.

Introduction

Q. Please state your name, position and business address.

A. My name is Michael J. Majoros, Jr. I am Vice President of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"), located at 1111 14th Street, N.W., Suite 300, Washington, D.C. 20005.

Q. Please describe Snavely King.

A. Snavely King is an economic consulting firm, founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated firms and industries. We represent the interests of government agencies, businesses and individuals who are consumers of telecom, public utility and transportation services. In addition to consumer cost and anti-trust issues, we have provided our expertise in support of a clean environment and personal damages resulting from discrimination in agricultural programs. We believe in accountability, fair competition and effective regulation. We seek and use new ideas, findings and opportunities when appropriate, and avoid reliance upon traditional approaches based on faulty premises.

The firm has a professional staff of 11 economists, accountants, engineers and cost analysts. Most of our work involves the development, preparation and presentation of expert witness testimony before Federal and state regulatory agencies. Over the course of our 37-year history, members of the firm have participated in more than 1,000 proceedings before almost all of the state commissions and all Federal commissions that regulate utilities or transportation industries.

Q. Have you prepared a summary of your qualifications and experience?

A. Yes. Appendix A is a summary of my qualifications and experience. Appendix B contains a tabulation of my appearances as an expert witness before state and Federal regulatory agencies.

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Attorney General of the Commonwealth of Kentucky ("AG").

Q. What is the subject of your testimony?

A. This testimony addresses Atmos Energy Corporation's ("Atmos" or "the Company') depreciation rates and expense proposals.

Q. Do you have any specific experience in the field of public utility depreciation?

A. Yes, I and other members of my firm specialize in the field of public utility depreciation. We have appeared as expert witnesses on this subject before the regulatory commissions of almost every state in the country, including several appearances before the Kentucky Public Service Commission ("KPSC"). I have testified in over one hundred proceedings on the subject of public utility depreciation and represented various clients in several other proceedings in which depreciation was an issue but was settled. I have also negotiated on behalf of clients in fifteen of the Federal Communications Commissions' ("FCC") Triennial Depreciation Represcription conferences.

Q. Does your experience specifically include gas company depreciation?

A. Yes, I have testified in many proceedings on the subject of gas company depreciation, and I have prepared testimony in several other gas proceedings in which depreciation was ultimately settled.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. The AG asked me to review and express an opinion regarding the reasonableness of the Company's gas and shared services depreciation rates and proposals. The AG asked me to make alternative recommendations if warranted.

Present Depreciation Rates

Q. When were the Company's present depreciation rates approved?

A. Atmos states that the present gas depreciation rates received defacto approval in the settlement agreement and December 21, 1999 Order in Case No. 99-070.[1] According to Atmos:

> The current rates for Kentucky are based on the 1997 study provided as an attachment to AG DR 1-145. The rates from this study were proposed in case 99-070 and were not at issue in the case.[2]

The Company makes a similar statement about the present shared services rates:

> The rates from this [1993] study were utilized in both the 95-010 and 99-070 rate cases and were not at issue in either case. The Company believes that the settlement agreements and subsequent orders provided de facto approval of these depreciation rates for Kentucky.[3]

[1] See response to AG-DR-1-145.
[2] See response to AG-DR-2-53.
[3] See response to AG-DR-2-54.

Q. How were the present depreciation rates calculated?

A. The current gas plant rates are straight-line, remaining life rates calculated using the equal life group ("ELG") procedure. They are based on plant balances and reserves as of September 30, 1997.[4] The shared services rates are also straight-line, remaining life rates, calculated using ELG. They are based on plant and reserves as of September 30, 1992.[5]

Atmos's Proposed Depreciation Rates

Q. Summarize the Company's depreciation proposal in this proceeding.

A. Mr. Donald Roff sponsors Atmos's depreciation studies. Mr. Roff conducted separate studies for gas plant and shared services plant. In both cases, he calculated remaining life rates using ELG. His gas plant study is based on plant and reserve balances as of September 30, 2005, and his shared services study is based on balances as of September 30, 2006.[6]

Mr. Roff's recommendations result in a $123,599 increase to gas plant depreciation expense, based on September 30, 2005 balances, and a $2,662,501 increase to shared services depreciation expense, based on September 30, 2006 balances.[7]

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[4] See AG DR1-145 ATT1, p. 2.
[5] See AG DR 2-54 ATT, p. 2.
[6] Direct Testimony of Donald Roff, p. 1, Exhibit DSR-3, p. 3 and Exhibit DSR-4, p. 3.
[7] Exhibits DSR-3, p. 3 and DSR-4, p. 3.

<u>Conclusions</u>

Q. Did you review Mr. Roff's studies?

A. I reviewed Mr. Roff's studies, his responses to staff's and my data requests, and I conducted independent analysis. I have accepted some aspects of Mr. Roff's proposals, but overall I disagree with Mr. Roff's proposed depreciation rates and accruals.

Q. What do you recommend?

A. I recommend that the future cost of removal factors be based on Atmos's recent actual experience. This approach will keep Atmos whole regarding its actual expenditures; it will provide for inflationary increases as they occur; and it will reduce the build-up of the $23.9 million regulatory liability Atmos reported on its GAAP and SEC financial statements.

Q. Which aspects of Mr. Roff's studies have you accepted?

A. I have accepted all of Mr. Roff's life proposals. I have also accepted his depreciation proposals relating to cushion gas, but I have corrected his interpretation of depreciable cushion gas.

Q. Why have you accepted Mr. Roff's life proposals?

A. I have compared Mr. Roff's life proposals with the existing lives. In general, Mr. Roff has lengthened the lives. While there are a few life changes with which I might not ordinarily agree, there are other, more important issues at stake in this case. In fact, Mr. Roff raises these major issues at page 6 of his testimony where he states:

> This [1968] quotation is important because it addresses several key accounting and ratemaking issues concerning the treatment of net salvage as a component of depreciation.[8]

I agree that net salvage is a very important issue. It is also very interesting that Mr. Roff relied upon a 1968 text to make his point. That particular quotation will highlight how the net salvage issue has gained prominence over the years. I will discuss this in more detail later in this testimony. Consequently, I have accepted Mr. Roff's proposed lives and focused my attention on net salvage.

Q. Why do you disagree with Mr. Roff's depreciation rates and accruals overall?

A. I disagree because Mr. Roff has included inflated provisions for estimated future cost of removal in his depreciation rate calculations. I disagree with charging ratepayers for estimated future cost of removal, unless the utility has a legal obligation to incur those costs. *Recent* accounting pronouncements have highlighted and demonstrated that regulated utility companies are charging ratepayers far more for cost of removal than they will ever spend. At a minimum, charges to today's ratepayers should not include future inflation out for thirty to forty years. Therefore, I disagree with Mr. Roff's proposed rates and accruals. I have replaced Mr. Roff's inflated estimates with more reasonable factors based upon Atmos's recent actual experience.

[8] Roff – Direct, page 6.

Recommendations

Q. What do you recommend?

A. The Commission should disallow Atmos's inclusion of excessive cost of removal in its depreciation expense. Atmos's proposed gas depreciation rates result in the collection of $2.2 million annually for cost of removal even though it is only incurring $975 thousand of actual cost of removal on average.

As of December 31, 2006, the Company had already collected $23.9 million over and above what it has actually spent for gas and gas common plant cost of removal.[9] Atmos recognized and reported this as a regulatory liability for GAAP purposes.[10] Mr. Roff's additional $2.2 million per year charge greatly increases the regulatory liability each year because the Company is only incurring $975 thousand on average.

I am replacing Mr. Roff's excessive cost of removal factors with more reasonable factors based on the average of the most recent five years of Atmos's actual experience. This approach will result in cost of removal collections of approximately $975 thousand per year.

My recommendations result in a $1.3 million reduction relative to Mr. Roff's proposals for gas depreciation rates based on September 30, 2005 plant balances, and a $621 increase relative to Mr. Roff's proposals for shared services depreciation rates based on September 30, 2006 plant balances.

[9] The $23.9 million regulatory liability emanates from non-legal asset retirement obligations ("AROs") discussed later in this testimony.

[10] GAAP is the acronym for *generally accepted accounting principles*, which are the rules Atmos must follow for general purpose and SEC financial reporting purposes.

Depreciation Parameters

Q. What are depreciation parameters?

A. Depreciation parameters are the basic assumptions upon which depreciation rate calculations are based. Atmos's proposed depreciation rates are based on three fundamental parameters, all of which are estimates: an average service life, a retirement dispersion pattern and a net salvage ratio. Usually, the two most significant parameters in a case are the average service life and the net salvage ratio. A shorter service life translates to a higher resulting depreciation rate. Similarly, the more negative the net salvage ratio – the higher the resulting depreciation rate. In both cases, the higher depreciation rate is charged to ratepayers.

In this case, another significant parameter is the estimated retirement dispersion pattern. Mr. Roff used "Iowa Curves" to define these patterns. These patterns have relevance in estimating average lives and they have a direct impact on Mr. Roff's remaining life calculations, particularly since he used the equal life group ("ELG") procedure to calculate remaining lives. ELG is very sensitive to the Iowa Curve shape and results in a shorter remaining life calculation, ergo a higher depreciation rate than other alternative procedures.

ELG

Q. What is the ELG procedure?

A. ELG is a procedure sometimes used in depreciation calculations to calculate an average life and average remaining life once a judgmental estimate is made of the service life and retirement pattern for a group of assets. The details of the

ELG procedure are complex, but from a practical standpoint, it results in a higher depreciation rate than the alternative vintage group ("VG") procedure.

Q. Would you summarize the pros and cons regarding ELG and VG?

A. Yes, from a theoretical standpoint ELG provides a more precise cost allocation assuming perfect foresight. On the other hand, ELG requires annual depreciation rate changes and produces precisely the wrong answer when the retirement pattern forecast is inaccurate. The alternative to ELG is the vintage group ("VG") procedure. VG assumes a constant depreciation rate, and is more flexible concerning retirement pattern forecasts. VG, in my opinion, provides a higher probability of producing a correct overall result notwithstanding forecasting inaccuracies. On the other hand, VG is premised on the averaging concept of offsetting underecoveries with overrecoveries within a vintage.

Q. Is ELG necessary?

A. ELG is not necessary because both VG and ELG target full recovery.

Q. What are the practical consequences of ELG?

A. From a practical standpoint, ELG will produce a higher depreciation rate because it is a front-loaded approach. Unfortunately, the rate typically does not decline as is assumed in the adoption of ELG.

Q. Is Mr. Roff's use of ELG new for Atmos?

A. No, ELG was used to calculate the existing depreciation rates.

Q. Do you agree with the use of ELG?

A. No, although ELG has some theoretical merit, it also has negative aspects and it is not necessary.

Q. Are you recommending a change?

A. No. Because ELG has already been implemented for this Company, I will not challenge it in this case.

Q. Why are you addressing this issue in this case?

A. I am addressing the issue because ELG creates unnecessary depreciation expense for ratepayers. The Commission should be aware of this issue and not allow companies to switch to, or continue with, ELG without challenge.

<u>**Cost of Removal**</u>

Q. Has Mr. Roff included a provision for estimated future cost of removal in his proposed depreciation rates?

A. Yes, he has.

Q. What is your opinion about the incorporation of estimated future cost of removal in depreciation rates?

A. I do not object to including future cost of removal estimates in depreciation rates as long as the resulting charges are just and reasonable and reflect current activity. On the other hand, a Company has a special burden of proof to justify charging ratepayers today for any speculative future cost thirty to forty years from now. In this case, Atmos proposes to charge inflated future cost estimates to today's ratepayers, but will not even agree that it has a refundable obligation to ratepayers for any excess charges over and above its actual cost of removal expenditures. Atmos will not even acknowledge a $23.9 million regulatory liability for its past over collections.[11]

Q. Regarding your reference to a "special burden," how are normal expenses estimated in a rate case?

A. An extrapolation of recent historical costs into the near-term future is a reasonable approach for most normal ongoing operation and maintenance expenses, but even those extrapolations are subject to challenge and rationalization. A utility must demonstrate that charging such costs to ratepayers is just and reasonable.

Q. Is this approach available for cost of removal?

A. Yes, Atmos maintains its actual expenditures for cost of removal. Consequently, those costs can be extrapolated into the near-term future. Mr. Roff, however, has employed another approach to increase the normal charges to today's ratepayers for future cost of removal.

Q. Has either Atmos or Mr. Roff provided any special evidence that should cause this Commission to require Atmos's ratepayers to pay more than twice what it is actually spending for cost of removal each year?

A. Neither Atmos nor Mr. Roff provided any credible evidence to rationalize overcharging ratepayers for cost of removal. They merely attempt to convince the Commission of the wisdom of overcharging ratepayers.

Q. Why are you opposed to these charges?

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[11] Response to AG DR 167 a., b.

A. As I stated above, I do not object to including reasonable estimates of near-term cost of removal expenditures in depreciation rates. I do object, however, to the super-inflated estimates Mr. Roff is proposing. I object because the result is that Atmos will charge ratepayers far more for cost of removal than it will ever spend. Recent accounting pronouncements have highlighted and addressed this fact.

Q. Identify and explain the recent accounting pronouncements.

A. The Financial Accounting Standards Board's ("FASB") Statement of Financial Accounting Standard No. 143 ("SFAS No. 143") and the Federal Energy Regulatory Commission's ("FERC") Order No. 631 have identified and highlighted utilities' prior excess collections for future cost of removal. Order No. 631 defines these excess collections as non-legal asset retirement obligations ("non-legal AROs").

If a utility has charged cost of removal for a non-legal ARO, that amount is to be segregated within accumulated depreciation for FERC purposes and reclassified as a regulatory liability for GAAP purposes. Furthermore, if a utility has collected too much depreciation for a legal ARO, the excess also becomes as a regulatory liability for both FERC and GAAP purposes.[12]

In other words, if a utility has collected for future cost of removal in its depreciation rates, but does not and never had a legal obligation to spend the money, these excesses are to be segregated and to be reported as a regulatory liability.[13] FERC identified these amounts as "non-legal" asset retirement

[12] SFAS No. 143.
[13] Id., paragraph B.73.

obligations, because utilities do not have actual legal obligations and liabilities to incur these costs in the future.

Atmos reported regulatory liabilities in compliance with SFAS No. 143 as follows:

Atmos Energy Corporation
Regulatory Liabilities Resulting from Non-Legal AROs
($millions)[14]

Period Ending	Atmos Energy Total	KY Jurisdiction	KY SSU
Sept. 30, 2005	$ 263.4	$ 22.8	$ 0.03
Sept. 30, 2006	261.4	23.7	0.03
Dec. 31, 2006		23.9	0.03

The regulatory liability for the KY jurisdiction increased by the amount that Atmos collected from KY ratepayers, over and above its actual removal costs for each period.

Q. What do you recommend?

A. I recommend that the Kentucky Public Service Commission adopt a more reasonable approach to include future cost of removal in depreciation rates.

Q. Have you made other recommendations relating to this issue in the past?

A. Yes. Normally I would recommend that the KPSC recognize a regulatory liability for regulatory and ratemaking purposes. Based on the policy decisions of some

[14] See Atmos Energy, September 30, 2006 10-K Report, p. 66 and response to AG-DR-1-165.

consumer advocate clients, I have also recommended that the regulatory liability be returned to ratepayers through a specific amortization period.

Q. Has the Commission already taken a position on any of these issues?

A. Yes. I proposed the establishment of a regulatory liability for ratemaking purposes in Case No. 2005-00042, Union Light, Heat and Power Company's most recent rate case. The proposal was not accepted.[15]

Q. Are you making the same proposal for Atmos?

A. I am not reintroducing that proposal here. On the other hand, I do believe it is fair, from the ratepayers' perspective, to reduce the build-up of the regulatory liability that Atmos recorded on its GAAP and SEC financial statements. Even though the Commission does not recognize the regulatory liability, ratepayers directly fund all increases to that amount.

Q. How much non-legal ARO cost has Mr. Roff included in Atmos's annual depreciation expense?

A. Based on September 30, 2005 balances the amount is $2.2 million for Kentucky plant.[16] He has included no cost of removal in his Shared Services rates.

Q. What is Atmos's actual experience?

For the period from 2001 through 2005, the actual average was $975 thousand for Kentucky plant.[17] Nevertheless, Mr. Roff proposes to charge $2.2 million per year for cost of removal collections. If this pattern continues, the regulatory

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[15] Case No. 2005-00042, Order issued December 22, 2005, p. 39.

[16] See Exhibit___(MJM-4), page 3 of 4, column (c).

[17] For the period 2002-2006, the SSU plant experienced an average of $621 in cost of removal, all related to a 2004 retirement in account 397.

liability will continue to grow at an exponential rate.

<u>Atmos's Approach to Future Cost of Removal</u>

Q. What causes Atmos's charges for future cost of removal to be so excessive?

A. Atmos's charges for future cost of removal are excessive due to the process it uses to derive these estimates and then convert them into depreciation expense. The process results in inflated annual charges for future cost of removal that vastly exceed actual expenditures.

Atmos bundles the inflated cost of removal factors in most of its depreciation rates, and then applies those rates for years to an ever-expanding depreciable plant base. This latter feature results in a double-inflationary effect. The factors are inflated and then they are applied to plant balances which also increase with inflation.

The accruals resulting from this approach have vastly exceeded, year-by-year, the money that Atmos actually spent or allocated for cost of removal, thus producing the $23.9 million regulatory liability – from charges to Kentucky ratepayers.

Q. How does Atmos's approach result in inflated cost of removal factors?

A. Atmos's net salvage studies relate removal costs in current dollars to asset retirements expressed in very old historical original cost dollars. The inflation experienced between the asset's in-service date and its retirement date results in current removal cost dollars that are many multiples of the historical original cost dollars of the retired asset.

Q. Does Atmos's approach result in an increase to depreciation rates?

A. Yes, it does. Any cost of removal factor will increase a depreciation rate. Atmos's inflated cost of removal factors will increase depreciation rates even more, and then will produce yet higher charges when applied to increasing plant balances.

Q. Does Mr. Roff specifically address the issue of inclusion of inflated cost of removal factors in depreciation rates?

A. Yes. At page 6 of his Direct Testimony, Mr. Roff offers the following quote, taken from the 1968 Edition of the NARUC Public Utility Depreciation Practices manual.

> Under presently accepted concepts, the amount of depreciation to be accrued over the life of an asset is its original cost less net salvage. Net salvage, as the name implies, is the difference between the gross salvage that will be obtained when the asset is disposed of and the cost of removing it. Positive net salvage occurs when gross salvage exceeds cost of removal, and negative salvage occurs when cost of removal exceeds gross salvage. Thus the intent of the present concept is to allocate the net cost of an asset to annual accounting periods, making due allowance for the net salvage, positive or negative, that will be obtained when the asset is retired. This concept carries with it the thought that ownership of property entails the responsibility for its ultimate abandonment or removal. Hence if current users of the property benefit from its use, they should pay their pro rata share of the costs involved in the abandonment or removal of the property.
>
> This treatment of salvage is in harmony with generally accepted accounting practices and tends to remove from the income statement fluctuations caused by erratic, although necessary, abandonment or uneconomical removal operations. It also has the advantage that current customers pay a fair share, even though

> estimated, of costs associated with the property devoted to their service.[18]

Q. Why did Mr. Roff include this quotation in his testimony?

A. Mr. Roff states that:

> This quotation is important because it addresses several key accounting and ratemaking issues concerning the treatment of net salvage as a component of depreciation. First and foremost, net salvage is a component of depreciation.[19]

Q. Do you agree with this quotation?

A. No, I do not agree with the quotation and I think it was incorrect for Mr. Roff to have included it in his testimony.

Q. Why was it incorrect for Mr. Roff to have included this quotation in his testimony?

A. Exhibit___ (MJM-1) is a copy of Mr. Roff's response to Staff DR Item 2-26. Staff asked Mr. Roff why he relied on the 1968 NARUC Depreciation Practices Manual for the above quotation rather than the more recent August 1996 Edition. Mr. Roff responded, "Essentially the same quotation appears at page 18 of the 1996 edition."[20]

I agree that a similar quotation appears in the 1996 Edition, but a few words changed. The 1996 Edition claims that Mr. Roff's treatment of net salvage "is in harmony with generally accepted accounting *principles*" rather than "generally accepted accounting *practices*" as was used in the 1968 Edition.

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[18] Roff Direct Testimony, p. 6. Taken from *Public Utility Depreciation Practices*, NARUC, 1968 Edition, p. 24.

[19] Roff-Direct, Page 6.

[20] Roff Response to Staff DR Item 2-26.

Mr. Roff was employed for many years by a major international accounting firm and he is well aware of the concept of GAAP. The subtle but salient point about Mr. Roff's use of the 1968 words "generally accepted accounting practices" is that they are not GAAP. Nor is Mr. Roff's use of cost of removal factors in depreciation rates. Notwithstanding the NARUC's 1996 claim, GAAP depreciation rates have never allowed cost of removal factors and SFAS No. 143 most recently affirmed this. Thus, Mr. Roff's use of a quotation implying that his approach is in harmony with GAAP is incorrect.

Q. What is at the heart of NARUC's thinking regarding the above quote?

A. The matching principle is at the heart of NARUC's thinking. NARUC focuses on the timing or pattern of cost of removal allocation and intergenerational equity. Unfortunately, NARUC does not address the fundamental questions of whether a company will actually incur the costs, and the intergenerational **inequity** of charging these inflated amounts to ratepayers when there is some doubt that the money will ever be spent on cost of removal, and the inflation element is so overstated. Again, it is worth noting that even the 1996 NARUC manual pre-dates SFAS No. 143. Thus, it reflects earlier deliberations, and did not consider, or even know about the huge regulatory liabilities emanating from the use of this approach.

Q. Has anybody addressed these fundamental questions?

A. Yes, FASB addressed the fundamental questions in SFAS No. 143. The matching principle is in harmony with GAAP when the future costs are genuine obligations and are recognized at their fair value. However, the matching principle of accounting does not require allocation of a fallacious future expenditure to any accounting period.

NARUC focuses on an objective of achieving a particular expense recognition pattern rather than the need to recognize whether or not an actual obligation and liability exists. In paragraph B21, SFAS 143 specifically addresses the tendency to focus on the expense pattern rather than the reality of the cost, and the problems that can result:

> B21. Prior to this Statement, the objective of many accounting practices was not to recognize and measure obligations associated with the retirement of long-lived assets. Rather, the objective was to achieve a particular expense recognition pattern for those obligations over the operating life of the associated long-lived asset. Using that objective, some entities followed an approach whereby they estimated an amount that would satisfy the costs of retiring the asset and accrued a portion of that amount each period as an expense and a liability. Other entities used that objective and the provision in paragraph 37 of FASB Statement No 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies*, that allows them to increase periodic depreciation expense by increasing the depreciable base of a long-lived asset for an amount representing estimated asset retirement costs. Under either of those approaches, the amount of liability or accumulated depreciation recognized in a statement of financial position usually differs from the amount of obligation that an entity actually has incurred. In effect, by focusing on an objective of achieving a particular expense recognition pattern, accounting practices developed that disregarded or circumvented the recognition and measurement requirements of FASB Concepts Statements.[21]

[21] Id., paragraph B21, (emphasis supplied).

The process focuses on achieving a particular expense pattern rather than "recognition and measurement requirements," that is, the reality of the cost. Thanks to SFAS No. 143, we now know that Mr. Roff's inflated future removal cost estimates do not meet baseline tests as liabilities.

Q. Why do you say that Mr. Roff's inflated future cost of removal estimates do not meet baseline tests as liabilities?

A. Atmos does in fact have certain costs that meet these baseline tests. There are assets for which Atmos has identified legal asset retirement obligations ("AROs") as defined by SFAS No. 143. They are discussed in the Company's 2006 10-K Report.[22]

On the other hand, Atmos has collected, and will continue to collect, unchecked, estimates of future cost of removal relating to the rest of its plant for which it does not have any such legal retirement obligation. These are the non-legal AROs. Atmos does not have any probable obligation to make these expenditures, as "probable" is used in SFAS No. 143. They therefore do not meet the definition of a liability.[23]

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[22] Atmos Energy, September 30, 2006 10-K Report, p. 74.

[23] Id., paragraph 4. "Liabilities are *probable* future sacrifices of economic benefits arising from present obligations of a particular entity to transfer assets or provide services to other entities in the future as a result of past transactions or events. Probable is used with its general meaning, rather than in a specific accounting or technical sense (such as Statement 5, par.3), and refers to that which can be reasonably expected or believed on a basis of available evidence or logic but neither certain nor proved (Webster's New World Dictionary, p.1132). Its inclusion in the definition is intended to acknowledge that business and other economic activities occur in an environment characterized by uncertainty in which few outcomes are certain."

All that is necessary to create a legal obligation is for Atmos to promise the Commission and the public at large that it will do the work, incur the cost, and spend the money it collects for that cost on that cost.

As evident from its response to AG DR 1-171, Atmos seems unwilling to make the promise necessary to create a legal obligation for its cost of removal collections.

> **Data Request:** Does Atmos promise to remove each asset for which it is collecting cost of removal and does it promise to spend all of the money it is collecting for cost of removal, on cost of removal? Please explain.
>
> **Response:** The company will continue to remove assets that need to be removed in the course of providing gas utility service. See also the response to item 167.[24]

Atmos's response to AG DR 1-171 is not sufficient to establish legal AROs or inflated future cost of removal ratios. Atmos's response to AG DR 1-171 is sufficient, however, to adopt reasonable cost of removal factors for inclusion in its depreciation rates.

Going-Forward Cost of Removal Recommendations

Q. What do you recommend?

A. On a going-forward basis, I recommend the elimination of the existing inflated cost of removal ratios and the adoption of reasonable cost of removal factors based on Atmos's recent actual experience.

Q. How did you implement these cost of removal factors?

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[24] See Exhibit___(MJM-2).

A. Mr. Roff provided the cost of removal component of his proposed depreciation rates.[25] Consequently, I was able to remove it thus leaving the plant-only rate. I replaced Mr. Roff's cost of removal rates with my cost of removal factors based on the five-year average experience. These cost of removal factors allow Atmos to collect approximately $975 thousand per year from Kentucky customers.

<u>Snavely King Net Salvage Study</u>

Q. Explain your net salvage study.

A. My net salvage study, Exhibit___(MJM-3), shows Atmos's average cost of removal experience from 2001 through 2005 for KY plant.[26] The data was provided in response to AG DR 1-087. For each individual account, I have divided the five-year average cost of removal by the September 30, 2005 average plant balance to calculate the resulting cost of removal rate.[27] I carried these rates forward to Exhibit___(MJM-4), where I have shown my recommended rates and expense.

Q. What if Atmos's actual cost of removal was to exceed its annual cost of removal accrual at any point in the future?

A. As mentioned above, Atmos uses remaining life rates. Any differences between actual cost of removal and the normalized cost of removal allowance will be picked-up by virtue of the mechanics of the remaining life technique.

Q. Will this approach account for any future inflation which may occur?

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[25] See Exhibits DSR 3 and 4, Schedule 2 for Roff COR rate.
[26] To match Mr. Roff's analysis, the years 2002 through 2006 were used for shared services.
[27] September 30, 2006 balances were used for shared services.

A. Yes, since I have calculated a rate, it will be applied to plant balances, which are themselves, subject to increase due to inflationary impacts on the cost of additions. Thus, Atmos is protected against future inflation.

Q. Have you provided any protections for ratepayers?

A. The primary protection I have provided for ratepayers is to file this testimony and propose that they pay Atmos its actual costs of removal, but that they not pay for future inflation in multiple ways before incurred.

<u>Cushion Gas</u>

Q. Has Mr. Roff proposed a new policy of depreciating cushion gas?

A. Yes. Mr. Roff has proposed depreciating cushion gas using a 50-year life.

Q. What is cushion gas?

A. Mr. Roff describes cushion gas as "that level of natural gas consistently maintained within an underground storage reservoir to ensure the operational integrity of the reservoir."[28]

Q. Can Mr. Roff cite any precedent for depreciating cushion gas?

A. In response to AG DR 1-136, Mr. Roff stated that he "is aware that in their Washington Jurisdiction, Avista Corporation is allowed the depreciation of cushion gas." However, he was unable to cite to a specific order approving this treatment.[29] In response to KPSC DR 2-28 he stated, "There are numerous tax cases allowing a depreciation deduction for non-recoverable cushion gas."[30]

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[28] Roff Direct Testimony, p. 12, footnote 10.
[29] See response to AG DR 1-136.
[30] See response to KPSC DR 2-28.

Q. What is the IRS's thinking on this issue?

A. In Revised Rule 97-54 the IRS reiterated that the "cost of *unrecoverable* line pack gas or *unrecoverable* cushion gas is depreciable under sections 167 and 168."[31]

Q. Did Mr. Roff's depreciation proposal relate only to unrecoverable gas?

A. No, it did not. The gas in account 352.03 that Mr. Roff proposed to depreciate was not all unrecoverable. In response to DR AG 2-52 the Company subsequently revised its estimate of the gas in that account, transferring 60 percent to recoverable gas, account 117. I have adjusted the plant balance in my schedules to reflect this. The cushion gas plant I have calculated depreciation expense for is all unrecoverable.

Summary of Recommendations

Q. Have you prepared a summary of your recommendations?

A. Yes. Exhibit___(MJM-4) shows the calculation of my recommended rates and expense. My recommended depreciation and cost of removal expense, based on September 30, 2005 balances for KY plant is $9.6 million, $1.3 million less than the Company's $10.9 million. Exhibit___(MJM-5) calculates the Company's cost of service depreciation expense using my recommended rates. For the 2008 forecasted test period, my recommended rates result in a $1.4 million reduction from the Company's proposal.

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[31] IRS Rev. Rule 97-54, 1997-52 I.R.B. 9, published December 29, 1997.

Q. Does this conclude your testimony?

A. Yes, it does.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
KPSC 2nd Data Request Dated February 23, 2007
DR Item 26
Witness: Don Roff

Data Request:

Refer to the Roff Testimony, page 6. Mr. Roff includes a quotation on net salvage taken from the National Association of Regulatory Utility Commissioners' ("NARUC") Public Utility Depreciation Practices, 1968 Edition. Explain why Mr. Roff did not reference NARUC's Public Utility Depreciation Practices, August 1996 Edition.

Response:

Essentially the same quotation appears at page 18 of the 1996 edition.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 171
Witness: Tom Petersen

Data Request:

Does Atmos promise to remove each asset for which it is collecting cost of removal and does it promise to spend all of the money it is collecting for cost of removal, on cost of removal? Please explain.

Response:

The company will continue to remove assets that need to be removed in the course of providing gas utility service. See also the response to item 167.

ATMOS ENERGY CORPORATION - KENTUCKY
Book Depreciation Study as of September 30, 2005
Snavely King Recommended COR Rates and Allowances

Account	Description	9/30/2005 Balance (a)	2001-2005 5-Year Avg. COR (b)	SK COR Rate (c)=(b)/(a)	SK COR Allowance (d)=(a)*(c)
	PRODUCTION PLANT				
325.20	Producing Leaseholds	2,353	0	-	0
325.40	Rights-of-Way	83,422	0	-	0
336.00	Purification Equipment	44,369	0	-	0
	Total Production Plant	130,144	0	-	0
	STORAGE PLANT				
351.00	Structures and Improvements	309,065	0	-	0
352.00	Well Construction and Equipment	2,176,341	0	-	0
352.03	Cushion Gas	1,694,833	0	-	0
352.11	Storage Rights	54,614	0	-	0
354.00	Compressor Station Equipment	546,780	0	-	0
355.00	M&R Station Equipment	288,851	0	-	0
	Total Storage Plant	5,070,484	0	-	0
	TRANSMISSION PLANT				
365.20	Rights-of-Way	812,196	0	-	0
366.00	Structures and Improvements	283,237	0	-	0
367.00	Mains	22,044,698	5,700	0.03	5,700
369.00	M&R Station Equipment	2,952,222	0	-	0
	Total Transmission Plant	26,092,353	5,700	0.02	5,700
	DISTRIBUTION PLANT				
374.02	Land Rights	145,459	0	-	0
375.00	Structures and Improvements	468,328	0	-	0
376.00	Mains	95,924,845	49,138	0.05	49,138
378.00	M&R Station Equipment	2,617,970	0	-	0
379.00	City Gate Equipment	2,804,310	0	-	0
380.00	Services	69,190,312	414,083	0.60	414,083
381.00	Meters	13,775,723	0	-	0
382.00	Meter Installations	33,358,910	503,122	1.51	503,122
383.00	House Regulators	4,816,804	0	-	0
384.00	House Regulator Installations	154,276	0	-	0
385.00	Industrial M&R Equipment	4,433,322	1,579	0.04	1,579
	Total Distribution Plant	227,690,259	967,922	0.43	967,922
	GENERAL PLANT				
390.00	Structures and Improvements	966,202	0	-	0
390.09	Improvements to Leased Premises	1,382,343	0	-	0
391.00	Office Furniture and Equipment	2,305,350	6	0.00	6
392.00	Transportation Equipment	761,620	929	0.12	929
394.00	Tools, Shop and Garage Equipment	2,118,023	1	-	0
396.00	Power Operated Equipment	663,629	0	-	0
397.00	Communication Equipment	1,498,100	0	-	0
398.00	Miscellaneous Equipment	2,160,051	0	-	0
399.01	OTP - Servers Hardware	175,990	0	-	0
399.03	OTP - Network Hardware	511,781	0	-	0
399.06	OTP - PC Hardware	2,702,795	0	-	0
399.07	OTP - PC Software	242,979	0	-	0
399.08	OTP - Application Software	522,254	0	-	0
	Total General Plant	16,011,117	936	0.01	935
	Total Depreciable Plant	274,994,357	974,558	0.35	974,557
	Intangible Plant	128,183			
	Non-Depreciable Plant	486,462			
	Fully Depreciated Plant	2,303,510			
	Total Plant in Service	277,912,512			

Sources:
Col. (a) from Exhibit DSR-3, Schedule 1.
Col. (b) from pages 3-4.

ATMOS ENERGY CORPORATION - SHARED SERVICES
Book Depreciation Study as of September 30, 2006
Snavely King Recommended COR Rates and Allowances

Account	Description	9/30/2006 Balance	2002-2006 5-Year Avg. COR	SK COR Rate	SK COR Allowance
		(a)	(b)	(c)=(b)/(a)	(d)=(a)*(c)
	GENERAL PLANT				
390.09	*Improvements to Leased Premises*	9,949,143	-	-	-
391.00	Office Furniture and Equipment	9,074,352	-	-	-
397.00	Communication Equipment	25,311,861	621	0.002	621
398.00	Miscellaneous Equipment	633,466	-	-	-
399.00	Other Tangible Property	224,866	-	-	-
399.01	Servers Hardware	14,567,322	-	-	-
399.02	Servers Software	8,647,580	-	-	-
399.03	Network Hardware	2,377,029	-	-	-
399.06	PC Hardware	6,691,156	-	-	-
399.07	PC Software	3,928,199	-	-	-
399.08	Application Software	111,323,312	-	-	-
399.24	General Startup Cost	23,172,326	-	-	-
	Total Depreciable General Plant	215,900,612	621	0.000	621
	Fully Depreciated	5,331,910			
	Late Retirements	4,363,383			
	Total Shared Services Facilities	225,595,905			

Sources:
Col. (a) from Exhibit DSR-4, Schedule 1.
Col. (b) from page 5.

ATMOS ENERGY CORPORATION - KENTUCKY
Five-Year Average Net Salvage Experience
2001-2005

Account (a)	Year (b)	Retirements (c)	Salvage (d)	Cost of Removal (e)	Net Salvage (f)=(d)-(e)
36700000	2001	6,910	-	-	-
36700000	2002	2,750	-	-	-
36700000	2003	-	-	-	-
36700000	2004	-	-	-	-
36700000	2005	22,519	-	28,499	(28,499)
Five Year Total		**32,179**	-	**28,499**	**(28,499)**
Five Year Average		**6,436**	-	**5,700**	**(5,700)**
36900000	2001	2,183	-	-	-
36900000	2002	-	-	-	-
36900000	2003	-	-	-	-
36900000	2004	-	-	-	-
36900000	2005	-	-	-	-
Five Year Total		**2,183**	-	-	-
Five Year Average		**437**	-	-	-
37600000	2001	180,309	-	100,246	(100,246)
37600000	2002	112,370	-	20,416	(20,416)
37600000	2003	112,104	-	42,202	(42,202)
37600000	2004	63,595	-	50,731	(50,731)
37600000	2005	305,582	-	32,095	(32,095)
Five Year Total		**773,960**	-	**245,690**	**(245,690)**
Five Year Average		**154,792**	-	**49,138**	**(49,138)**
37900000	2001	-	-	-	-
37900000	2002	-	-	-	-
37900000	2003	-	-	-	-
37900000	2004	302	-	-	-
37900000	2005	-	-	-	-
Five Year Total		**302**	-	-	-
Five Year Average		**60**	-	-	-
38000000	2001	1,081,065	-	450,538	(450,538)
38000000	2002	353,920	-	282,498	(282,498)
38000000	2003	573,781	-	600,977	(600,977)
38000000	2004	127,032	-	479,035	(479,035)
38000000	2005	540,726	-	257,366	(257,366)
Five Year Total		**2,676,524**	-	**2,070,414**	**(2,070,414)**
Five Year Average		**535,305**	-	**414,083**	**(414,083)**
38100000	2001	-	-	-	-
38100000	2002	-	-	-	-
38100000	2003	9,244,466	-	-	-
38100000	2004	-	-	-	-
38100000	2005	-	-	-	-
Five Year Total		**9,244,466**	-	-	-
Five Year Average		**1,848,893**	-	-	-
38200000	2001	57,297	-	161,169	(161,169)
38200000	2002	250,858	-	1,139,462	(1,139,462)
38200000	2003	312,393	-	536,125	(536,125)
38200000	2004	203,956	-	521,798	(521,798)
38200000	2005	110,560	-	157,057	(157,057)
Five Year Total		**935,064**	-	**2,515,611**	**(2,515,611)**
Five Year Average		**187,013**	-	**503,122**	**(503,122)**
38300000	2001	-	-	-	-
38300000	2002	-	-	-	-
38300000	2003	68	-	-	-
38300000	2002	-	-	-	-
38300000	2005	4,054	-	-	-
Five Year Total		**4,122**	-	-	-
Five Year Average		**824**	-	-	-
38500000	2001	16,167	-	7,896	(7,896)
38500000	2002	-	-	-	-
38500000	2003	-	-	-	-
38500000	2004	-	-	-	-
38500000	2005	-	-	-	-
Five Year Total		**16,167**	-	**7,896**	**(7,896)**
Five Year Average		**3,233**	-	**1,579**	**(1,579)**
39100000	2001	72,169	-	28	(28)

ATMOS ENERGY CORPORATION - KENTUCKY
Five-Year Average Net Salvage Experience
2001-2005

Account (a)	Year (b)	Retirements (c)	Salvage (d)	Cost of Removal (e)	Net Salvage (f)=(d)-(e)
39100000	2002	94,992	-	-	-
39100000	2003	15,380	-	-	-
39100000	2004	38,289	-	-	-
39100000	2005	-	-	-	-
Five Year Total		**220,830**	**-**	**28**	**(28)**
Five Year Average		**44,166**	**-**	**6**	**(6)**
39200000	2001	549,771	7,561	-	7,561
39200000	2002	216,646	35,292	-	35,292
39200000	2003	2,732,280	79,320	-	79,320
39200000	2004	559,510	-	-	-
39200000	2005	394,260	67,019	4,646	62,373
Five Year Total		**4,452,467**	**189,192**	**4,646**	**184,546**
Five Year Average		**890,493**	**37,838**	**929**	**36,909**
39400000	2001	18,601	-	-	-
39400000	2002	764,651	-	-	-
39400000	2003	61,408	-	-	-
39400000	2004	517,271	-	-	-
39400000	2005	43,563	200	6	194
Five Year Total		**1,405,494**	**200**	**6**	**194**
Five Year Average		**281,099**	**40**	**1**	**39**
39600000	2001	1,617	-	-	-
39600000	2002	278,879	22,479	-	22,479
39600000	2003	357,777	-	-	-
39600000	2004	204,050	-	-	-
39600000	2005	42,281	12,486	-	12,486
Five Year Total		**884,604**	**34,965**	**-**	**34,965**
Five Year Average		**176,921**	**6,993**	**-**	**6,993**
39700000	2001	-	-	-	-
39700000	2002	38,139	-	-	-
39700000	2003	4,941	-	-	-
39700000	2004	-	-	-	-
39700000	2005	32,436	-	-	-
Five Year Total		**75,516**	**-**	**-**	**-**
Five Year Average		**15,103**	**-**	**-**	**-**
39906000	2001	-	-	-	-
39906000	2002	190,623	-	-	-
39906000	2003	158,354	2,788	-	2,788
39906000	2004	176,848	-	-	-
39906000	2005	-	-	-	-
Five Year Total		**525,825**	**2,788**	**-**	**2,788**
Five Year Average		**105,165**	**558**	**-**	**558**
39907000	2001	-	-	-	-
39907000	2002	-	-	-	-
39907000	2003	54,807	-	-	-
39907000	2004	-	-	-	-
39907000	2005	-	-	-	-
Five Year Total		**54,807**	**-**	**-**	**-**
Five Year Average		**10,961**	**-**	**-**	**-**
Total All Accounts					
	2001	1,986,089	7,561	719,877	(712,316)
	2002	2,303,828	57,771	1,442,376	(1,384,605)
	2003	13,627,759	82,108	1,179,304	(1,097,196)
	2004	1,890,551	-	1,051,564	(1,051,564)
	2005	1,495,981	79,705	479,669	(399,964)
Five Year Total		**21,304,208**	**227,145**	**4,872,790**	**(4,645,645)**
Five Year Average		**4,260,842**	**45,429**	**974,558**	**(929,129)**

Source: Response to AG 1-087.

ATMOS ENERGY CORPORATION - SHARED SERVICES
Five-Year Average Net Salvage Experience
2001-2005

Account (a)	Year (b)	Retirements (c)	Salvage (d)	Cost of Removal (e)	Net Salvage (f)=(d)-(e)
39009000	2002	-	-	-	-
39009000	2003	-	-	-	-
39009000	2004	-	-	-	-
39009000	2005	-	-	-	-
39009000	2006	178,757	-	-	-
Five Year Total		**178,757**	-	-	-
Five Year Average		**35,751**	-	-	-
39100000	2002	-	-	-	-
39100000	2003	-	-	-	-
39100000	2004	-	-	-	-
39100000	2005	-	-	-	-
39100000	2006	1,420,965	-	-	-
Five Year Total		**1,420,965**	-	-	-
Five Year Average		**284,193**	-	-	-
39700000	2002	-	-	-	-
39700000	2003	-	-	-	-
39700000	2004	34,015	26,609	3,107	23,502
39700000	2005	-	-	-	-
39700000	2006	792,568	-	-	-
Five Year Total		**826,583**	**26,609**	**3,107**	**23,502**
Five Year Average		**165,317**	**5,322**	**621**	**4,700**
39800000	2002	-	-	-	-
39800000	2003	56,637	-	-	-
39800000	2004	-	-	-	-
39800000	2005	-	-	-	-
39800000	2006	-	-	-	-
Five Year Total		**56,637**	-	-	-
Five Year Average		**11,327**	-	-	-
39900000	2002	8,143	-	-	-
39900000	2003	-	-	-	-
39900000	2004	-	-	-	-
39900000	2005	-	-	-	-
39900000	2006	-	-	-	-
Five Year Total		**8,143**	-	-	-
Five Year Average		**1,629**	-	-	-
39903000	2002	-	-	-	-
39903000	2003	-	-	-	-
39903000	2004	-	-	-	-
39903000	2005	-	-	-	-
39903000	2006	11,472	-	-	-
Five Year Total		**11,472**	-	-	-
Five Year Average		**2,294**	-	-	-
39906000	2002	6,189,732	-	-	-
39906000	2003	-	-	-	-
39906000	2004	-	-	-	-
39906000	2005	-	-	-	-
39906000	2006	2,632,955	-	-	-
Five Year Total		**8,822,687**	-	-	-
Five Year Average		**1,764,537**	-	-	-
39907000	2002	861,539	-	-	-
39907000	2003	-	-	-	-
39907000	2004	-	-	-	-
39907000	2005	-	-	-	-
39907000	2006	16,495	-	-	-
Five Year Total		**878,034**	-	-	-
Five Year Average		**175,607**	-	-	-
39908000	2002	9,573,067	-	-	-
39908000	2003	-	-	-	-
39908000	2004	-	-	-	-
39908000	2005	-	-	-	-
39908000	2006	731,136	-	-	-
Five Year Total		**10,304,203**	-	-	-
Five Year Average		**2,060,841**	-	-	-

Source: Response to AG 1-087

ATMOS ENERGY CORPORATION - KENTUCKY
Book Depreciation Study as of September 30, 2005
Snavely King Recommended Rates and Accruals

Account	Description	9/30/2005 Balance	Company Proposed ASL	Company Proposed Iowa Curve	Company Proposed Remaining Life	Company Proposed ELG Rate	Company Proposed COR Rate	Company Proposed Plant Only Rate	Plant Only Depreciation Expense	SK COR Rate	SK COR Allowance	Snavely King Total Rate	Snavely King Total Depreciation and COR
		(a)	(b)	(c)	(d)	(e)	(f)	(g)=(e)-(f)	(h)=(a)*(g)	(i)	(j)=(a)*(i)	(k)=(g)+(i)	(l)=(h)+(j)
	PRODUCTION PLANT												
325.20	Producing Leaseholds	2,353	50	R5	17.0	5.89	0.00	5.89	139	-	0	5.89	139
325.40	Rights-of-Way	83,422	50	R5	43.7	2.29	0.00	2.29	1,910	-	0	2.29	1,910
336.00	Purification Equipment	44,369	50	R5	20.0	5.26	0.10	5.16	2,289	-	0	5.16	2,289
	Total Production Plant	130,144						3.33	4,338	-	0		4,338
	STORAGE PLANT												
351.00	*Structures and Improvements*	*309,065*	*50*	R2	*27.4*	*0.60*	0.00	0.60	1,854	-	0	0.60	1,854
352.00	Well Construction and Equipment	2,176,341	50	R3	28.9	2.11	0.80	1.31	28,510	-	0	1.31	28.510
352.03	Cushion Gas	677,933 1/	50	SQ	41.5	2.38	0.00	2.38	16,135	-	0	2.38	16,135
352.11	Storage Rights	54,614	50	R5	18.4	0.44	0.00	0.44	240	-	0	0.44	240
354.00	Compressor Station Equipment	546,780	50	R1.5	24.7	0.60	0.00	0.60	3,281	-	0	0.60	3.281
355.00	M&R Station Equipment	288,851	50	R2	25.8	0.12	0.00	0.12	347	-	0	0.12	347
	Total Storage Plant	4,053,584						1.24	50,367	-	0		50,367
	TRANSMISSION PLANT												
365.20	Rights-of-Way	812,196	55	R5	36.5	1.65	0.00	1.65	13,401	-	0	1.65	13,401
366.00	Structures and Improvements	283,237	50	R3	36.7	2.05	0.00	2.05	5,806	-	0	2.05	5,806
367.00	Mains	22,044.698	55	R1	30.1	1.85	0.45	1.40	307,624	0.0259	5,700	1.42	313,324
369.00	M&R Station Equipment	2,952,222	45	R0.5	25.9	1.48	0.04	1.44	42,381	-	0	1.44	42,381
	Total Transmission Plant	26,092,353						1.42	369,212	0.0218	5,700		374,912
	DISTRIBUTION PLANT												
374.02	Land Rights	145,459	55	R5	46.8	1.86	0.00	1.86	2.706	-	0	1.86	2,706
375.00	Structures and Improvements	468,328	50	L0	25.6	3.18	0.20	2.98	13,956	-	0	2.98	13,956
376.00	Mains	95,924,845	55	R0.5	31.7	2.43	0.45	1.98	1,894,952	0.0512	49.138	2.03	1,944.090
378.00	M&R Station Equipment	2,617,970	50	R1	28.1	1.92	0.10	1.82	47,647	-	0	1.82	47,647
379.00	City Gate Equipment	2,804,310	50	R1	29.0	2.43	0.30	2.13	59,732	-	0	2.13	59,732
380.00	Services	69,190,312	40	R1.5	24.3	5.23	1.88	3.36	2,321,335	0.5985	414,083	3.95	2,735,418
381.00	Meters	13,775.723	25	R0.5	14.7	8.06	1.00	7.06	972,566	-	0	7.06	972,566
382.00	Meter Installations	33,358,910	40	R1	23.4	4.60	0.63	3.98	1,326,017	1.5082	503,122	5.48	1,829,139
383.00	House Regulators	4,816,804	30	S6	17.2	2.90	0.00	2.90	139,687	-	0	2.90	139,687
384.00	House Regulator Installations	154,276	35	R2	20.1	2.02	0.00	2.02	3,116	-	0	2.02	3,116
385.00	Industrial M&R Equipment	4,433,322	40	L5	27.6	2.61	0.43	2.19	96,868	0.0356	1,579	2.22	98,447
	Total Distribution Plant	227,690,259						3.02	6,878,582	0.4251	967,922		7,846,504
	GENERAL PLANT												
390.00	Structures and Improvements	966,202	15	L2	8.4	9.91	0.00	9.91	95,751	-	0	9.91	95.751
390.09	Improvements to Leased Premises	1,382,343	25	R4	10.8	2.36	0.00	2.36	32.623	-	0	2.36	32,623
391.00	Office Furniture and Equipment	2,305,350	18	L0	9.4	6.22	0.00	6.22	143,393	0.0002	6	6.22	143,398
392.00	Transportation Equipment	761,620	8	S5	2.6	59.79	0.00	59.79	455,373	0.1220	929	59.91	456,302
394.00	Tools, Shop and Garage Equipment	2,118,023	20	S6	10.5	6.63	0.00	6.63	140,425	-	0	6.63	140,425
396.00	Power Operated Equipment	663,629	15	L5	4.8	20.76	0.00	20.76	137,769	-	0	20.76	137,769
397.00	Communication Equipment	1,498,100	20	S2	10.8	5.43	0.00	5.43	81,347	-	0	5.43	81,347
398.00	Miscellaneous Equipment	2,160,051	20	R5	17.0	4.26	0.00	4.26	92,018	-	0	4.26	92,018
399.01	OTP - Servers Hardware	175,990	10	SQ	3.5	2.71	0.00	2.71	4,769	-	0	2.71	4,769
399.03	OTP - Network Hardware	511,781	10	SQ	4.0	5.22	0.00	5.22	26,715	-	0	5.22	26,715
399.06	OTP - PC Hardware	2,702,795	10	L1	5.1	0.61	0.00	0.61	16,487	-	0	0.61	16,487
399.07	OTP - PC Software	242,979	5	S1.5	1.8	19.16	0.00	19.16	46,555	-	0	19.16	46,555
399.08	OTP - Application Software	522,254	8	R5	2.4	17.49	0.00	17.49	91,342	-	0	17.49	91,342
	Total General Plant	16,011,117						8.52	1,364,567	0.0058	935		1,365,502
	Total Depreciable Plant	273,977,457						3.16	8,667,066	0.3557	974,557		9,641,623
	Intangible Plant	128,183											
	Non-Depreciable Plant	486,462											
	Fully Depreciated Plant	2,303,510											
	Total Plant in Service	276,895,612											

1/ Plant balance updated per response to AG DR 2-52.

Sources:
Cols. (a) - (c) and (e) from Exhibit DSR-3
Col. (d) from response to AG 1-87.
Col. (i) from Exhibit___(MJM-3).

ATMOS ENERGY CORPORATION - SHARED SERVICES
Book Depreciation Study as of September 30, 2006
Snavely King Recommended Rates and Accruals

			Company Proposed									Snavely King	
Account	Description	9/30/2006 Balance	ASL	Iowa Curve	Remaining Life	Study Rate	COR Rate	Plant Only Rate	Plant Only Depreciation Expense	SK COR Rate	SK COR Allowance	Total Rate	Total Depreciation and COR
		(a)	(b)	(c)	(d)	(e)	(f)	(g)=(e)-(f)	(h)=(a)*(g)	(i)	(j)=(a)*(i)	(k)=(g)+(i)	(l)=(h)+(j)
	GENERAL PLANT												
390.09	Improvements to Leased Premises	9,949,143	10.0	SQ	4	9.10	0.00	9.10	905,372	-	0.00	9.10	905,372
391.00	Office Furniture and Equipment	9,074,352	30.0	R2	16	2.13	0.00	2.13	193,284	-	0.00	2.13	193,284
397.00	Communication Equipment	25,311,861	10.0	L3	8.4	8.45	0.00	8.45	2,138,852	0.0025	621.40	8.45	2,139,474
398.00	Miscellaneous Equipment	633,466	10.0	S6	4.3	8.15	0.00	8.15	51,627	-	0.00	8.15	51,627
399.00	Other Tangible Property	224,866	5.0	SQ	1	4.66	0.00	4.66	10,479	-	0.00	4.66	10,479
399.01	Servers Hardware	14,567,322	5.0	SQ	5.7	6.95	0.00	6.95	1,012,429	-	0.00	6.95	1,012,429
399.02	Servers Software	8,647,580	5.0	SQ	6.3	4.00	0.00	4.00	345,903	-	0.00	4.00	345,903
399.03	Network Hardware	2,377,029	5.0	SQ	8.4	9.30	0.00	9.30	221,064	-	0.00	9.30	221,064
399.06	PC Hardware	6,691,156	4.0	SQ	3.9	14.86	0.00	14.86	994,306	-	0.00	14.86	994,306
399.07	PC Software	3,928,199	4.0	SQ	5.3	9.02	0.00	9.02	354,324	-	0.00	9.02	354,324
399.08	Application Software	111,323,312	8.0	S1.5	5	11.11	0.00	11.11	12,368,020	-	0.00	11.11	12,368,020
399.24	General Startup Cost	23,172,326	10.0	SQ	2.5	15.89	0.00	15.89	3,682,083	-	0.00	15.89	3,682,083
	Total Depreciable General Plant	215,900,612						10.32	22,277,742				22,278,363
	Fully Depreciated	5,331,910											
	Late Retirements	4,363,383											
	Total Shared Services Facilities	225,595,905											

Sources:
Cols. (a) - (c) and (e) from Exhibit DSR-4.
Col. (d) from response to AG 1-87.
Col. (i) from Exhibit___(MJM-3).

ATMOS ENERGY CORPORATION - KENTUCKY
Comparison of Atmos and Snavely King COR Rates and Accruals

			Company Proposed		SK Recommended		
Account	Description	9/30/2005 Balance (a)	COR Rate (b)	COR Expense (c)=(a)*(b)	SK COR Rate (d)	COR Allowance (e)=(a)*(d)	Difference (f)=(e)-(c)
	PRODUCTION PLANT						
325.20	Producing Leaseholds	2,353	0.00	-	0.000	-	-
325.40	Rights-of-Way	83,422	0.00	-	0.000	-	-
336.00	Purification Equipment	44,369	0.10	44	0.000	-	(44)
	Total Production Plant	130,144		44	0.000	-	(44)
	STORAGE PLANT						
351.00	Structures and Improvements	309,065	0.00	-	0.000	-	-
352.00	Well Construction and Equipment	2,176,341	0.80	17,411	0.000	-	(17,411)
352.03	Cushion Gas	1,694,833	0.00	-	0.000	-	-
352.11	Storage Rights	54,614	0.00	-	0.000	-	-
354.00	Compressor Station Equipment	546,780	0.00	-	0.000	-	-
355.00	M&R Station Equipment	288,851	0.00	-	0.000	-	-
	Total Storage Plant	5,070,484		17,411	0.000	-	(17,411)
	TRANSMISSION PLANT						
365.20	Rights-of-Way	812,196	0.00	-	0.000	-	-
366.00	Structures and Improvements	283,237	0.00	-	0.000	-	-
367.00	Mains	22,044,698	0.45	100,203	0.026	5,700	(94,503)
369.00	M&R Station Equipment	2,952,222	0.04	1,312	0.000	-	(1,312)
	Total Transmission Plant	26,092,353		101,515	0.022	5,700	(95,815)
	DISTRIBUTION PLANT						
374.02	Land Rights	145,459	0.00	-	0.000	-	-
375.00	Structures and Improvements	468,328	0.20	937	0.000	-	(937)
376.00	Mains	95,924,845	0.45	436,022	0.051	49,138	(386,884)
378.00	M&R Station Equipment	2,617,970	0.10	2,618	0.000	-	(2,618)
379.00	City Gate Equipment	2,804,310	0.30	8,413	0.000	-	(8,413)
380.00	Services	69,190,312	1.88	1,297,318	0.598	414,083	(883,236)
381.00	Meters	13,775,723	1.00	137,757	0.000	-	(137,757)
382.00	Meter Installations	33,358,910	0.63	208,493	1.508	503,122	294,629
383.00	House Regulators	4,816,804	0.00	-	0.000	-	-
384.00	House Regulator Installations	154,276	0.00	-	0.000	-	-
385.00	Industrial M&R Equipment	4,433,322	0.43	18,842	0.036	1,579	(17,262)
	Total Distribution Plant	227,690,259		2,110,400	0.425	967,922	(1,142,478)
	GENERAL PLANT						
390.00	Structures and Improvements	966,202	0.00	-	0.000	-	-
390.09	Improvements to Leased Premises	1,382,343	0.00	-	0.000	-	-
391.00	Office Furniture and Equipment	2,305,350	0.00	-	0.000	6	6
392.00	Transportation Equipment	761,620	0.00	-	0.122	929	929
394.00	Tools, Shop and Garage Equipment	2,118,023	0.00	-	0.000	-	-
396.00	Power Operated Equipment	663,629	0.00	-	0.000	-	-
397.00	Communication Equipment	1,498,100	0.00	-	0.000	-	-
398.00	Miscellaneous Equipment	2,160,051	0.00	-	0.000	-	-
399.01	OTP - Servers Hardware	175,990	0.00	-	0.000	-	-
399.03	OTP - Network Hardware	511,781	0.00	-	0.000	-	-
399.06	OTP - PC Hardware	2,702,795	0.00	-	0.000	-	-
399.07	OTP - PC Software	242,979	0.00	-	0.000	-	-
399.08	OTP - Application Software	522,254	0.00	-	0.000	-	-
	Total General Plant	16,011,117		0	0.0058	935	935
	Total Depreciable Plant	274,994,357		2,229,370	0.3544	974,557	(1,254,813)
	Intangible Plant	128,183					
	Non-Depreciable Plant	486,462					
	Fully Depreciated Plant	2,303,510					
	Total Plant in Service	277,912,512					

Sources:
Cols (a) and (b) from Exhibit DSR-3.
Col. (d) from Exhibit___(MJM-3).

ATMOS ENERGY CORPORATION - SHARED SERVICES
Comparison of Atmos and Snavely King COR Rates and Accruals

Account	Description	9/30/2006 Balance	COR Rate	Plant Only Depreciation Expense	SK COR Rate	SK COR Allowance	Difference
		(a)	(b)	(c)=(a)*(b)	(d)	(e)=(a)*(d)	(f)=(e)-(c)
	GENERAL PLANT						
390.09	Improvements to Leased Premises	9,949,143	0.00	-	0.0000	-	-
391.00	Office Furniture and Equipment	9,074,352	0.00	-	0.0000	-	-
397.00	*Communication Equipment*	25,311,861	0.00	-	0.0025	621	621
398.00	Miscellaneous Equipment	633,466	0.00	-	0.0000	-	-
399.00	Other Tangible Property	224,866	0.00	-	0.0000	-	-
399.01	Servers Hardware	14,567,322	0.00	-	0.0000	-	-
399.02	Servers Software	8,647,580	0.00	-	0.0000	-	-
399.03	Network Hardware	2,377,029	0.00	-	0.0000	-	-
399.06	PC Hardware	6,691,156	0.00	-	0.0000	-	-
399.07	PC Software	3,928,199	0.00	-	0.0000	-	-
399.08	Application Software	111,323,312	0.00	-	0.0000	-	-
399.24	General Startup Cost	23,172,326	0.00	-	0.0000	-	-
	Total Depreciable General Plant	215,900,612		0		621	621
	Fully Depreciated	5,331,910					
	Late Retirements	4,363,383					
	Total Shared Services Facilities	225,595,905					

Sources:
Cols (a) and (b) from Exhibit DSR-4.
Col. (d) from Exhibit___(MJM-3).

Atmos Energy Corporation, KY
Case No. 2006-00464
Jurisdictional Depreciation Expense, Accum. Reserve & Accrual Rates by Account
Forecasted Period ended June 30, 2008 - Reflecting Snavely King Rates

Line No. (A)	Acct. No. (B)	Account Titles (C)	Total Company Adjusted Jurisdiction 13 Month Avg. Investment (D)	Total Company Adjusted Jurisdiction 13 Month Avg. Reserve 1/ (E)	SK Recommended 12 Month Expense (F)	SK Recommended Annual Accrual Rate (G) See Note	Current 12 Month Expense (H)	Current Annual Accrual Rate (I) See Note
1		*Intangible Plant*						
2	301.00	Organization	76,480	8,330	0		0	
3	302.00	Franchises & Consents	119,853	119,853	0		0	
4	303.00	Misc. Intangible Plant	408,053	0	0		0	
5								
6		Total Intangible Plant	604,386	128,182	0		0	
7								
8		*Natural Gas Production Plant*						
9	325.20	Producing Leaseholds	2,353	69	137		0	
10	325.40	Rights of Ways	83,422	955	1,888		0	
11	331.00	Production Gas Wells Equipment	3,492	3,492	0		0	
12	332.01	Field Lines	47,163	47,163	0		0	
13	332.02	Tributary Lines	528,218	529,956	0		0	
14	334.00	Field Meas. & Reg. Sta. Equip	198,469	198,469	0		0	
15	336.00	Purification Equipment	44,369	1,145	2,263		0	
16								
17		Total Natural Gas Production Plant	907,486	781,249	4,288		0	
18								
19		*Storage Plant*						
20	350.10	Land	261,127	0	0		0	
21	350.20	Rights of Way	4,682	4,757	0		0	
22	351.00	Structures & Improvements	4,700	2,503	28		90	
23	351.02	Compression Station Equipment	159,811	118,199	948		3,049	
24	351.03	Meas. & Reg. Sta. Structues	23,138	24,976	0		0	
25	351.04	Other Structures	144,554	132,962	857		2,758	
26	352.00	Wells \ Rights of Way	62,814	51,214	813		1,683	
27	352.01	Well Construction	2,113,527	1,786,598	27,368		56,616	
28	352.02	Well Equipment	531,954	579,757	0		0	
29	352.03	Cushion Gas 2/	677,933	17,389	15,949		0	
30	352.10	Leaseholds	178,530	179,464	0		0	
31	352.11	Storage Rights	54,614	52,586	238		988	
32	353.01	Field Lines	178,501	186,188	0		0	
33	353.02	Tributary Lines	209,458	219,495	0		0	
34	354.00	Compressor Station Equipment	546,780	481,599	3,243		8,161	
35	355.00	Meas & Reg. Equipment	288,851	290,474	0		0	
36	356.00	Purification Equipment	243,119	248,386	0		0	
37								
38		Total Storage Plant	5,684,093	4,376,545	49,444		73,344	
39								
40		*Transmission Plant*						
41	365.10	Land	26,970	16	0		0	
42	365.20	Rights of Way	838,245	342,444	13,672		7,374	
43	366.02	Structures & Improvements	214,065	17,431	4,338		2,941	
44	366.03	Other Structues	69,172	63,126	1,402		950	
45	367.00	Mains - Cathodic Protection	406,111	337,167	5,700		5,098	
46	367.01	Mains - Steel	23,217,765	15,580,995	325,892		291,467	
47	369.00	Meas. & Reg. Equipment	185,854	60,644	2,645		4,189	
48	369.01	Meas. & Reg. Equipment	2,968,370	1,961,127	42,252		66,899	
49								
50		Total Transmission Plant	27,926,553	18,362,950	395,901		378,918	
51								
52		*Distribution Plant*						
53	374.00	Land & Land Rights	98,315	57,145	0		0	
54	374.01	Land	51,571	0	0		0	
55	374.02	Land Rights	244,565	26,362	4,496		4,061	
56	374.03	Land Other	2,784	0	0		0	
57	375.00	Structures & Improvements	312,033	33,961	9,191		6,015	
58	375.01	Structures & Improvements T.B.	105,699	81,973	3,114		2,037	
59	375.02	Land Rights	46,591	38,779	1,372		898	
60	375.03	Improvements	4,005	51,327	0		0	
61	376.00	Mains Cathodic Protection	10,874,159	2,470,479	218,201		256,897	
62	376.01	Mains - Steel	68,360,296	39,694,946	1,371,718		1,614,978	
63	376.02	Mains - Plastic	27,804,905	8,562,599	557,933		656,877	
64	378.00	Meas. & Reg. Sta. Equip - General	3,132,686	1,440,773	56,358		77,105	
65	379.00	Meas. & Reg. Sta. Equipment - City Gate	1,277,515	166,911	26,897		32,454	
66	379.05	Meas & Reg. Sta. Equipment T.B.	1,636,212	1,727,745	0		0	
67	380.00	Services	79,748,813	39,058,865	3,113,767		5,407,707	
68	381.00	Meters	14,802,451	2,453,491	1,033,007		490,166	
69	382.00	Meter Installations	36,781,828	7,005,807	1,992,410		1,112,550	
70	383.00	House Regulators	5,400,323	2,713,334	154,804		152,135	
71	384.00	House Reg. Installations	154,276	140,951	3,080		5,139	
72	385.00	Ind. Meas. & Reg. Sta. Equipment	4,926,403	2,139,293	108,105		132,941	
73	386.00	Other Property on Cust Prem	0	2,511	0		0	
74								
75		Total Distribution Plant	255,765,430	107,867,253	8,654,454		9,951,959	
76								

Atmos Energy Corporation, KY
Case No. 2006-00464
Jurisdictional Depreciation Expense, Accum. Reserve & Accrual Rates by Account
Forecasted Period ended June 30, 2008 - Reflecting Snavely King Rates

			Total Company Adjusted Jurisdiction 13 Month Avg.		SK Recommended		Current	
Line No. (A)	Acct. No. (B)	Account Titles (C)	Investment (D)	Reserve 1/ (E)	12 Month Expense (F)	Annual Accrual Rate (G)	12 Month Expense (H)	Annual Accrual Rate (I)
						See Note		See Note
77		General Plant *						
78	389.00	Land & Land Rights	71,393	28,459	0		0	
79	390.01	Structures Frame	65,954	8,423	1,645		1,645	
80	390.02	Structures & Improvements	193,598	109,629	18,964		4,057	
81	390.03	Improvements	774,269	134,945	75,846		16,225	
82	390.04	Air Conditioning Equipment	14,251	8,084	1,188		254	
83	390.09	Improvement to Leased Premises	1,939,014	1,571,253	81,576		108,597	
84	391.00	Office Furniture & Equipment	2,496,243	1,425,957	105,852		131,478	
85	391.02	Remittance Processing Equip	956	1,551	0		0	
86	391.03	Office Machines	119,984	4,045	6,500		7,279	
87	392.00	Transportation Equipment	509,135	(509,535)	304,887		45,395	
88	392.01	Trucks	16,597	25,470	0		0	
89	392.02	Trailers	111,671	154,739	0		0	
90	393.00	Stores Equipment	3,856	3,119	278		278	
91	394.00	Tools, Shop & Garage Equip	1,449,163	72,973	93,816		47,312	
92	396.00	Power Operated Equipment	3,125	3,704	0		0	
93	396.03	Ditchers	223,756	(133,021)	45,916		6,171	
94	396.04	Backhoes	267,602	38,654	54,914		7,380	
95	396.05	Welders	33,959	(1,713)	6,969		937	
96	397.00	Communication Equipment	2,653,181	1,297,724	187,921		166,732	
97	397.01	Communication Equip. - Mobile Radios	3,338	(18,709)	179		172	
98	397.02	Communication Equip. - Fixed Radios	41,432	8,828	2,224		2,134	
99	397.05	Communication Equip. - Telemetering	312,236	106,882	16,759		16,080	
100	398.00	Miscellaneous Equipment	2,850,542	1,192,768	121,768		286,710	
101	399.00	Other Tangible Property	40,867	39,927	5,319		5,319	
102	399.01	Other Tangible Property - Servers - H/W	1,255,886	852,243	73,192		150,492	
103	399.02	Other Tangible Property - Servers - S/W	603,296	573,183	19,468		69,549	
104	399.03	Other Tangible Property - Network - H/W	724,910	680,115	24,059		30,315	
105	399.04	Other Tangible Property - CPU	56,964	83,539	0		0	
106	399.05	Other Tangible Property - MF Hardware	60,318	77,441	0		0	
107	399.06	Other Tangible Property - PC Hardware	4,538,528	3,909,152	177,992		827,720	
108	399.07	Other Tang. Property - PC Software	515,241	447,639	21,295		41,858	
109	399.08	Other Tang. Property - Application Software	7,610,511	4,689,742	845,902		623,587	
110	399.09	Other Tang. Property - Mainframe S/W	133,816	191,807	0		0	
111	399.24	Other Tang. Property - General Startup Costs	1,297,650	964,881	206,197		108,094	
112								
113		Total General Plant	30,993,244	18,043,895	2,500,626		2,705,767	
114								
115		Total Plant	321,881,192	149,560,075	11,604,713		13,109,989	

*** Note: Includes allocations from Shared Services and Mid States General office. Snavely King has proposed no change in Shared Services rates.**
Column G and I Note: Depreciation rates are specific to Kentucky, Shared Services amd Mid States General office and can be found on schedules AG DR15 series of schedules. Snavely King rates shown on pages 3-4 of this exhibit

1/ Company workpaper "wpB 3.1 F09" (forecasted reserves) updated for Snavely King rates.
2/ Cushion gas (acct. 352.3) plant balance updated to reflect Atmos response to AG DR 2-52.
Reserves adjusted to reflect 60% of plant transferred to acct. 117.

Source: Original document provided in response to AG DR15 and also AG DR 2-46.

Atmos Energy Corporation, KY
Case No. 2006-00464
Workpaper Computation of Depreciation Expense - Div. 09 KY Only
Forecast Period Ending 6-30-2008 - Reflecting Snavely King Rates

Line No.	Acct No.	Account Titles	DIVISION 09 13 Month Avg. Investment	DIVISION 09 13 Month Avg. Reserve 1/	Annual Accrual Rate SK 2/	Reserve Computation	12 Month Expense 98.85%	Annual Accrual Rate Current	Reserve Computation	12 Month Expense 98.85%
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
1		Intangible Plant								
2	301.00	Organization	8,330	8,330	0.00%	0	0	0.00%	0	0
3	302.00	Franchises & Consents	119,853	119,853	0.00%	0	0	0.00%	0	0
4	303.00	Misc. Intangible Plant	0	0	0.00%	0	0	0.00%	0	0
5										
6		Total Intangible Plant	128,182	128,182		0	0		0	0
7										
8		Natural Gas Production Plant								
9	325.20	Producing Leaseholds	2,353	69	5.89%	139	137	0.00%	0	0
10	325.40	Rights of Ways	83,422	955	2.29%	1,910	1,888	0.00%	0	0
11	331.00	Production Gas Wells Equipment	3,492	3,492	0.00%	0	0	0.00%	0	0
12	332.01	Field Lines	47,163	47,163	0.00%	0	0	0.00%	0	0
13	332.02	Tributary Lines	528,218	529,956	0.00%	0	0	0.00%	0	0
14	334.00	Field Meas. & Reg. Sta. Equip	198,469	198,469	0.00%	0	0	0.00%	0	0
15	336.00	Purification Equipment	44,369	1,145	5.16%	2,289	2,263	0.00%	0	0
16										
17		Total Natural Gas Production Plant	907,486	781,249		4,338	4,288		0	0
18										
19		Storage Plant								
20	350.10	Land	261,127	0	0.00%	0	0	0.00%	0	0
21	350.20	Rights of Way	4,682	4,757	0.92%	0	0	0.92%	0	0
22	351.00	Structures & Improvements	4,700	2,503	0.60%	28	28	1.93%	91	90
23	351.02	Compression Station Equipment	159,811	118,199	0.60%	959	948	1.93%	3,084	3,049
24	351.03	Meas. & Reg. Sta. Structues	23,138	24,976	0.60%	0	0	1.93%	0	0
25	351.04	Other Structures	144,554	132,962	0.60%	867	857	1.93%	2,790	2,758
26	352.00	Wells \ Rights of Way	62,814	51,214	1.31%	823	813	2.71%	1,702	1,683
27	352.01	Well Construction	2,113,527	1,786,598	1.31%	27,687	27,368	2.71%	57,277	56,616
28	352.02	Well Equipment	531,954	579,757	1.31%	0	0	2.71%	0	0
29	352.03	Cushion Gas **3/**	677,933	17,389	2.38%	16,135	15,949	0.00%	0	0
[illegible]	352.10	Leaseholds	178,530	179,464	0.30%	0	0	0.30%	0	0
	352.11	Storage Rights	54,614	52,586	0.44%	240	238	1.83%	999	988
[illegible]	353.01	Field Lines	178,501	186,188	1.35%	0	0	1.35%	0	0
33	353.02	Tributary Lines	209,458	219,495	1.35%	0	0	1.35%	0	0
34	354.00	Compressor Station Equipment	546,780	481,599	0.60%	3,281	3,243	1.51%	8,256	8,161
35	355.00	Meas & Reg. Equipment	288,851	290,474	0.12%	0	0	2.06%	0	0
36	356.00	Purification Equipment	243,119	248,386	1.30%	0	0	1.30%	0	0
37										
38		Total Storage Plant	5,684,093	4,376,545		50,020	49,444		74,200	73,344
39										
40		Transmission Plant								
41	365.10	Land	26,970	16	0.00%	0	0	0.00%	0	0
42	365.20	Rights of Way	838,245	342,444	1.65%	13,831	13,672	0.89%	7,460	7,374
43	366.02	Structures & Improvements	214,065	17,431	2.05%	4,388	4,338	1.39%	2,976	2,941
44	366.03	Other Structues	69,172	63,126	2.05%	1,418	1,402	1.39%	961	950
45	367.00	Mains - Cathodic Protection	406,111	337,167	1.42%	5,767	5,700	1.27%	5,158	5,098
46	367.01	Mains - Steel	23,217,765	15,580,995	1.42%	329,692	325,892	1.27%	294,866	291,467
47	369.00	Meas. & Reg. Equipment	185,854	60,644	1.44%	2,676	2,645	2.28%	4,237	4,189
48	369.01	Meas. & Reg. Equipment	2,968,370	1,961,127	1.44%	42,745	42,252	2.28%	67,679	66,899
49										
50		Total Transmission Plant	27,926,553	18,362,950		400,517	395,901		383,337	378,918
51										

Atmos Energy Corporation, KY
Case No. 2006-00464
Workpaper Computation of Depreciation Expense - Div. 09 KY Only
Forecast Period Ending 6-30-2008 - Reflecting Snavely King Rates

Line No.	Acct. No.	Account Titles	DIVISION 09 13 Month Avg. Investment	DIVISION 09 13 Month Avg. Reserve 1/	Annual Accrual Rate SK 2/	Reserve Computation	12 Month Expense 98.85%	Annual Accrual Rate Current	Reserve Computation	12 Month Expense 98.85%
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
52		Distribution Plant								
53	374.00	Land & Land Rights	98,315	57,145	0.00%	0	0	0.00%	0	0
54	374.01	Land	51,571	0	0.00%	0	0	0.00%	0	0
55	374.02	Land Rights	244,565	26,362	1.86%	4,549	4,496	1.68%	4,109	4,061
56	374.03	Land Other	2,784	0	0.00%	0	0	0.00%	0	0
57	375.00	Structures & Improvements	312,033	33,961	2.98%	9,299	9,191	1.95%	6,085	6,015
58	375.01	Structures & Improvements T.B.	105,699	81,973	2.98%	3,150	3,114	1.95%	2,061	2,037
59	375.02	Land Rights	46,591	38,779	2.98%	1,388	1,372	1.95%	909	898
60	375.03	Improvements	4,005	51,327	2.98%	0	0	1.95%	0	0
61	376.00	Mains Cathodic Protection	10,874,159	2,470,479	2.03%	220,745	218,201	2.39%	259,892	256,897
62	376.01	Mains - Steel	68,360,296	39,694,946	2.03%	1,387,714	1,371,718	2.39%	1,633,811	1,614,978
63	376.02	Mains - Plastic	27,804,905	8,562,599	2.03%	564,440	557,933	2.39%	664,537	656,877
64	378.00	Meas. & Reg. Sta. Equipment General	3,132,686	1,440,773	1.82%	57,015	56,358	2.49%	78,004	77,105
65	379.00	Meas. & Reg. Sta. Equipment - City Gate	1,277,515	166,911	2.13%	27,211	26,897	2.57%	32,832	32,454
66	379.05	Meas & Reg. Sta. Equipment T.B.	1,636,212	1,727,745	2.13%	0	0	2.57%	0	0
67	380.00	Services	79,748,813	39,058,865	3.95%	3,150,078	3,113,767	6.86%	5,470,769	5,407,707
68	381.00	Meters	14,802,451	2,453,491	7.06%	1,045,053	1,033,007	3.35%	495,882	490,166
69	382.00	Meter Installations	36,781,828	7,005,807	5.48%	2,015,644	1,992,410	3.06%	1,125,524	1,112,550
70	383.00	House Regulators	5,400,323	2,713,334	2.90%	156,609	154,804	2.85%	153,909	152,135
71	384.00	House Reg. Installations	154,276	140,951	2.02%	3,116	3,080	3.37%	5,199	5,139
72	385.00	Ind. Meas. & Reg. Sta. Equipment	4,926,403	2,139,293	2.22%	109,366	108,105	2.73%	134,491	132,941
73	386.00	Other Property on Cust Prem	0	2,511	3.00%	0	0	3.00%	0	0
74										
75		Total Plant Distribution	255,765,430	107,867,253		8,755,378	8,654,454		10,068,013	9,951,959
76										
77		General Plant								
78	389.00	Land & Land Rights	71,393	28,459	0.00%	0	0	0.00%	0	0
79	390.01	Structures Frame	0	0		0	0	0.00%	0	0
80	390.02	Structures & Improvements	193,598	109,629	9.91%	19,186	18,964	2.12%	4,104	4,057
1	390.03	Improvements	774,269	134,945	9.91%	76,730	75,846	2.12%	16,414	16,225
	390.04	Air Conditioning Equipment	12,129	5,868	9.91%	1,202	1,188	2.12%	257	254
	390.09	Improvement to Leased Premises	1,382,343	1,166,083	2.36%	32,623	32,247	5.00%	69,117	68,320
84	391.00	Office Furniture & Equipment	1,560,722	603,410	6.22%	97,077	95,958	7.05%	110,031	108,763
85	391.02	Remittance Processing Equip	0	0		0	0	0.00%	0	0
86	391.03	Office Machines	94,911	(20,448)	6.22%	5,903	5,835	7.05%	6,691	6,614
87	392.00	Transportation Equipment	514,843	(507,279)	59.91%	308,442	304,887	8.92%	45,924	45,395
88	392.01	Trucks	16,597	25,470	8.92%	0	0	8.92%	0	0
89	392.02	Trailers	111,671	154,739	59.91%	0	0	8.92%	0	0
90	393.00	Stores Equipment	0	0		0	0	0.00%	0	0
91	394.00	Tools, Shop & Garage Equip	1,404,373	63,134	6.63%	93,110	92,037	3.28%	46,063	45,532
92	396.00	Power Operated Equipment	0	0		0	0	0.00%	0	0
93	396.03	Ditchers	223,756	(133,021)	20.76%	46,452	45,916	2.79%	6,243	6,171
94	396.04	Backhoes	267,602	38,654	20.76%	55,554	54,914	2.79%	7,466	7,380
95	396.05	Welders	33,959	(1,713)	20.76%	7,050	6,969	2.79%	947	937
96	397.00	Communication Equipment	1,141,094	703,626	5.43%	61,961	61,247	5.21%	59,451	58,766
97	397.01	Communication Equip. - Mobile Radios	3,338	(18,709)	5.43%	181	179	5.21%	174	172
98	397.02	Communication Equip. - Fixed Radios	41,432	8,828	5.43%	2,250	2,224	5.21%	2,159	2,134
99	397.05	Communication Equip. - Telemetering	312,236	106,882	5.43%	16,954	16,759	5.21%	16,267	16,080
100	398.00	Miscellaneous Equipment	2,511,890	1,107,139	4.26%	107,006	105,773	10.94%	274,801	271,633
101	399.00	Other Tangible Property	0	0		0	0	0.00%	0	0
102	399.01	Other Tangible Property - Servers - H/W	175,990	205,672	2.71%	0	0	14.29%	0	0
103	399.02	Other Tangible Property - Servers - S/W	113,473	146,838	14.29%	0	0	14.29%	0	0
104	399.03	Other Tangible Property - Network - H/W	511,781	545,999	5.22%	0	0	14.29%	0	0
105	399.04	Other Tangible Property - CPU	0	0		0	0	0.00%	0	0
106	399.05	Other Tangible Property - MF Hardware	0	0		0	0	0.00%	0	0
107	399.06	Other Tangible Property - PC Hardware	3,631,797	3,410,816	0.61%	22,154	21,899	18.51%	672,246	664,497
108	399.07	Other Tang. Property - PC Software	242,979	249,794	19.16%	0	0	15.85%	0	0
109	399.08	Other Tang. Property - Application Software	522,254	459,904	17.49%	91,342	90,289	12.50%	65,282	64,529
110	399.09	Other Tangible Property - Mainframe - S/W	0	0	0.00%	0	0	0.00%	0	0
111	399.24	Other Tang. Property - General Startup Costs	0	0	0.00%	0	0	0.00%	0	0
112										
113		Total General Plant	15,870,429	8,594,718		1,045,179	1,033,131		1,403,638	1,387,458
114										
115		Total Plant	306,282,174	140,110,898		10,255,433	10,137,218		11,929,188	11,791,680

1/ Company workpaper "wpB 3.1 F09" (forecasted reserves) updated for SK rates.
See Exhibit___(MJM-4).
'ushion gas (acct. 352.3) balance updated to reflect Atmos response to AG DR 2-52. Reserves adjusted to reflect the 60% of plant transferred to acct. 117.

Michael J. Majoros, Jr.

Experience

Snavely King Majoros O'Connor & Lee, Inc.

Vice President and Treasurer (1988 to Present)
Senior Consultant (1981-1987)

Mr. Majoros provides consultation specializing in accounting, financial, and management issues. He has testified as an expert witness or negotiated on behalf of clients in more than one hundred thirty regulatory federal and state regulatory proceedings involving telephone, electric, gas, water, and sewerage companies. His testimony has encompassed a wide array of complex issues including taxation, divestiture accounting, revenue requirements, rate base, nuclear decommissioning, plant lives, and capital recovery. Mr. Majoros has also provided consultation to the U.S. Department of Justice and appeared before the U.S. EPA and the Maryland State Legislature on matters regarding the accounting and plant life effects of electric plant modifications and the financial capacity of public utilities to finance environmental controls. He has estimated economic damages suffered by black farmers in discrimination suits.

Van Scoyoc & Wiskup, Inc., *Consultant (1978-1981)*

Mr. Majoros conducted and assisted in various management and regulatory consulting projects in the public utility field, including preparation of electric system load projections for a group of municipally and cooperatively owned electric systems; preparation of a system of accounts and reporting of gas and oil pipelines to be used by a state regulatory commission; accounting system analysis and design for rate proceedings involving electric, gas, and telephone utilities. Mr. Majoros provided onsite management accounting and controllership assistance to a municipal electric and water utility. Mr. Majoros also assisted in an antitrust proceeding involving a major electric utility. He submitted expert testimony in FERC Docket No. RP79-12 (El Paso Natural Gas Company), and he co-authored a study entitled Analysis of Staff Study on Comprehensive Tax Normalization that was submitted to FERC in Docket No. RM 80-42.

Handling Equipment Sales Company, Inc.

Controller/Treasurer (1976-1978)

Mr. Majoros' responsibilities included financial management, general accounting and reporting, and income taxes.

Ernst & Ernst, *Auditor (1973-1976)*

Mr. Majoros was a member of the audit staff where his responsibilities included auditing, supervision, business systems analysis, report preparation, and corporate income taxes.

University of Baltimore - *(1971-1973)*

Mr. Majoros was a full-time student in the School of Business.

During this period Mr. Majoros worked consistently on a part-time basis in the following positions: Assistant Legislative Auditor – State of Maryland, Staff Accountant – Robert M. Carney & Co., CPA's, Staff Accountant – Naron & Wegad, CPA's, Credit Clerk – Montgomery Wards.

Central Savings Bank, *(1969-1971)*

Mr. Majoros was an Assistant Branch Manager at the time he left the bank to attend college as a full-time student. During his tenure at the bank, Mr. Majoros gained experience in each department of the bank. In addition, he attended night school at the University of Baltimore.

Education

University of Baltimore, School of Business, B.S. –
Concentration in Accounting

Professional Affiliations

American Institute of Certified Public Accountants
Maryland Association of C.P.A.s
Society of Depreciation Professionals

Publications, Papers, and Panels

"Analysis of Staff Study on Comprehensive Tax Normalization," FERC Docket No. RM 80-42, 1980.

"Telephone Company Deferred Taxes and Investment Tax Credits – A Capital Loss for Ratepayers," Public Utility Fortnightly, September 27, 1984.

"The Use of Customer Discount Rates in Revenue Requirement Comparisons," Proceedings of the 25th Annual Iowa State Regulatory Conference, 1986

"The Regulatory Dilemma Created By Emerging Revenue Streams of Independent Telephone Companies," Proceedings of NARUC 101st Annual Convention and Regulatory Symposium, 1989.

"BOC Depreciation Issues in the States," National Association of State Utility Consumer Advocates, 1990 Mid-Year Meeting, 1990.

"Current Issues in Capital Recovery" 30th Annual Iowa State Regulatory Conference, 1991.

"Impaired Assets Under SFAS No. 121," National Association of State Utility consumer Advocates, 1996 Mid-Year Meeting, 1996.

"What's 'Sunk' Ain't Stranded: Why Excessive Utility Depreciation is Avoidable," with James Campbell, Public Utilities Fortnightly, April 1, 1999.

"Local Exchange Carrier Depreciation Reserve Percents," with Richard B. Lee, Journal of the Society of Depreciation Professionals, Volume 10, Number 1, 2000-2001

"Rolling Over Ratepayers," Public Utilities Fortnightly, Volume 143, Number 11, November, 2005.

Michael J. Majoros, Jr.

Date	Jurisdiction / Agency	Docket	Utility

Federal Courts

2005	US District Court, Northern District of AL, Northwestern Division 55/56/57/	CV 01-B-403-NW	Tennessee Valley Authority

State Legislatures

2006	Maryland General Assembly 61/	SB154	Maryland Healthy Air Act
2006	Maryland House of Delegates 62/	HB189	Maryland Healthy Air Act

Federal Regulatory Agencies

1979	FERC-US 19/	RP79-12	El Paso Natural Gas Co.
1980	FERC-US 19/	RM80-42	Generic Tax Normalization
1996	CRTC-Canada 30/	97-9	All Canadian Telecoms
1997	CRTC-Canada 31/	97-11	All Canadian Telecoms
1999	FCC 32/	98-137 (Ex Parte)	All LECs
1999	FCC 32/	98-91 (Ex Parte)	All LECs
1999	FCC 32/	98-177 (Ex Parte)	All LECs
1999	FCC 32/	98-45 (Ex Parte)	All LECs
2000	EPA 35/	CAA-00-6	Tennessee Valley Authority
2003	FERC 48/	RM02-7	All Utilities
2003	FCC 52/	03-173	All LECs
2003	FERC 53/	ER03-409-000, ER03-666-000	Pacific Gas and Electric Co.

State Regulatory Agencies

1982	Massachusetts 17/	DPU 557/558	Western Mass Elec. Co.
1982	Illinois 16/	ICC81-8115	Illinois Bell Telephone Co.
1983	Maryland 8/	7574-Direct	Baltimore Gas & Electric Co.
1983	Maryland 8/	7574-Surrebuttal	Baltimore Gas & Electric Co.
1983	Connecticut 15/	810911	Woodlake Water Co.
1983	New Jersey 1/	815-458	New Jersey Bell Tel. Co.
1983	New Jersey 14/	8011-827	Atlantic City Sewerage Co.
1984	Dist. Of Columbia 7/	785	Potomac Electric Power Co.
1984	Maryland 8/	7689	Washington Gas Light Co.
1984	Dist. Of Columbia 7/	798	C&P Tel. Co.
1984	Pennsylvania 13/	R-832316	Bell Telephone Co. of PA
1984	New Mexico 12/	1032	Mt. States Tel. & Telegraph
1984	Idaho 18/	U-1000-70	Mt. States Tel. & Telegraph
1984	Colorado 11/	1655	Mt. States Tel. & Telegraph

Michael J. Majoros, Jr.

1984	Dist. Of Columbia 7/	813	Potomac Electric Power Co.
1984	Pennsylvania 3/	R842621-R842625	Western Pa. Water Co.
1985	Maryland 8/	7743	Potomac Edison Co.
1985	New Jersey 1/	848-856	New Jersey Bell Tel. Co.
1985	Maryland 8/	7851	C&P Tel. Co.
1985	California 10/	I-85-03-78	Pacific Bell Telephone Co.
1985	Pennsylvania 3/	R-850174	Phila. Suburban Water Co.
1985	Pennsylvania 3/	R850178	Pennsylvania Gas & Water Co.
1985	Pennsylvania 3/	R-850299	General Tel. Co. of PA
1986	Maryland 8/	7899	Delmarva Power & Light Co.
1986	Maryland 8/	7754	Chesapeake Utilities Corp.
1986	Pennsylvania 3/	R-850268	York Water Co.
1986	Maryland 8/	7953	Southern Md. Electric Corp.
1986	Idaho 9/	U-1002-59	General Tel. Of the Northwest
1986	Maryland 8/	7973	Baltimore Gas & Electric Co.
1987	Pennsylvania 3/	R-860350	Dauphin Cons. Water Supply
1987	Pennsylvania 3/	C-860923	Bell Telephone Co. of PA
1987	Iowa 6/	DPU-86-2	Northwestern Bell Tel. Co.
1987	Dist. Of Columbia 7/	842	Washington Gas Light Co.
1988	Florida 4/	880069-TL	Southern Bell Telephone
1988	Iowa 6/	RPU-87-3	Iowa Public Service Company
1988	Iowa 6/	RPU-87-6	Northwestern Bell Tel. Co.
1988	Dist. Of Columbia 7/	869	Potomac Electric Power Co.
1989	Iowa 6/	RPU-88-6	Northwestern Bell Tel. Co.
1990	New Jersey 1/	1487-88	Morris City Transfer Station
1990	New Jersey 5/	WR 88-80967	Toms River Water Company
1990	Florida 4/	890256-TL	Southern Bell Company
1990	New Jersey 1/	ER89110912J	Jersey Central Power & Light
1990	New Jersey 1/	WR90050497J	Elizabethtown Water Co.
1991	Pennsylvania 3/	P900465	United Tel. Co. of Pa.
1991	West Virginia 2/	90-564-T-D	C&P Telephone Co.
1991	New Jersey 1/	90080792J	Hackensack Water Co.
1991	New Jersey 1/	WR90080884J	Middlesex Water Co.
1991	Pennsylvania 3/	R-911892	Phil. Suburban Water Co.
1991	Kansas 20/	176, 716-U	Kansas Power & Light Co.
1991	Indiana 29/	39017	Indiana Bell Telephone
1991	Nevada 21/	91-5054	Central Tele. Co. – Nevada
1992	New Jersey 1/	EE91081428	Public Service Electric & Gas
1992	Maryland 8/	8462	C&P Telephone Co.
1992	West Virginia 2/	91-1037-E-D	Appalachian Power Co.
1993	Maryland 8/	8464	Potomac Electric Power Co.
1993	South Carolina 22/	92-227-C	Southern Bell Telephone
1993	Maryland 8/	8485	Baltimore Gas & Electric Co.
1993	Georgia 23/	4451-U	Atlanta Gas Light Co.
1993	New Jersey 1/	GR93040114	New Jersey Natural Gas. Co.

Michael J. Majoros, Jr.

1994	Iowa 6/	RPU-93-9	U.S. West -- Iowa
1994	Iowa 6/	RPU-94-3	Midwest Gas
1995	Delaware 24/	94-149	Wilm. Suburban Water Corp.
1995	Connecticut 25/	94-10-03	So. New England Telephone
1995	Connecticut 25/	95-03-01	So. New England Telephone
1995	Pennsylvania 3/	R-00953300	Citizens Utilities Company
1995	Georgia 23/	5503-0	Southern Bell
1996	Maryland 8/	8715	Bell Atlantic
1996	Arizona 26/	E-1032-95-417	Citizens Utilities Company
1996	New Hampshire 27/	DE 96-252	New England Telephone
1997	Iowa 6/	DPU-96-1	U S West – Iowa
1997	Ohio 28/	96-922-TP-UNC	Ameritech – Ohio
1997	Michigan 28/	U-11280	Ameritech – Michigan
1997	Michigan 28/	U-112 81	GTE North
1997	Wyoming 27/	7000-ztr-96-323	US West – Wyoming
1997	Iowa 6/	RPU-96-9	US West – Iowa
1997	Illinois 28/	96-0486-0569	Ameritech – Illinois
1997	Indiana 28/	40611	Ameritech – Indiana
1997	Indiana 27/	40734	GTE North
1997	Utah 27/	97-049-08	US West – Utah
1997	Georgia 28/	7061-U	BellSouth – Georgia
1997	Connecticut 25/	96-04-07	So. New England Telephone
1998	Florida 28/	960833-TP et. al.	BellSouth – Florida
1998	Illinois 27/	97-0355	GTE North/South
1998	Michigan 33/	U-11726	Detroit Edison
1999	Maryland 8/	8794	Baltimore Gas & Electric Co.
1999	Maryland 8/	8795	Delmarva Power & Light Co.
1999	Maryland 8/	8797	Potomac Edison Company
1999	West Virginia 2/	98-0452-E-GI	Electric Restructuring
1999	Delaware 24/	98-98	United Water Company
1999	Pennsylvania 3/	R-00994638	Pennsylvania American Water
1999	West Virginia 2/	98-0985-W-D	West Virginia American Water
1999	Michigan 33/	U-11495	Detroit Edison
2000	Delaware 24/	99-466	Tidewater Utilities
2000	New Mexico 34/	3008	US WEST Communications, Inc.
2000	Florida 28/	990649-TP	BellSouth -Florida
2000	New Jersey 1/	WR30174	Consumer New Jersey Water
2000	Pennsylvania 3/	R-00994868	Philadelphia Suburban Water
2000	Pennsylvania 3/	R-0005212	Pennsylvania American Sewerage
2000	Connecticut 25/	00-07-17	Southern New England Telephone
2001	Kentucky 36/	2000-373	Jackson Energy Cooperative
2001	Kansas 38/39/40/	01-WSRE-436-RTS	Western Resources
2001	South Carolina 22/	2001-93-E	Carolina Power & Light Co.
2001	North Dakota 37/	PU-400-00-521	Northern States Power/Xcel Energy
2001	Indiana 29/41/	41746	Northern Indiana Power Company

Michael J. Majoros, Jr.

2001	New Jersey 1/	GR01050328	Public Service Electric and Gas
2001	Pennsylvania 3/	R-00016236	York Water Company
2001	Pennsylvania 3/	R-00016339	Pennsylvania America Water
2001	Pennsylvania 3/	R-00016356	Wellsboro Electric Coop.
2001	Florida 4/	010949-EL	Gulf Power Company
2001	Hawaii 42/	00-309	The Gas Company
2002	Pennsylvania 3/	R-00016750	Philadelphia Suburban
2002	Nevada 43/	01-10001 &10002	Nevada Power Company
2002	Kentucky 36/	2001-244	Fleming Mason Electric Coop.
2002	Nevada 43/	01-11031	Sierra Pacific Power Company
2002	Georgia 27/	14361-U	BellSouth-Georgia
2002	Alaska 44/	U-01-34,82-87,66	Alaska Communications Systems
2002	Wisconsin 45/	2055-TR-102	CenturyTel
2002	Wisconsin 45/	5846-TR-102	TelUSA
2002	Vermont 46/	6596	Citizen's Energy Services
2002	North Dakota 37/	PU-399-02-183	Montana Dakota Utilities
2002	Kansas 40/	02-MDWG-922-RTS	Midwest Energy
2002	Kentucky 36/	2002-00145	Columbia Gas
2002	Oklahoma 47/	200200166	Reliant Energy ARKLA
2002	New Jersey 1/	GR02040245	Elizabethtown Gas Company
2003	New Jersey 1/	ER02050303	Public Service Electric and Gas Co.
2003	Hawaii 42/	01-0255	Young Brothers Tug & Barge
2003	New Jersey 1/	ER02080506	Jersey Central Power & Light
2003	New Jersey 1/	ER02100724	Rockland Electric Co.
2003	Pennsylvania 3/	R-00027975	The York Water Co.
2003	Pennsylvania /3	R-00038304	Pennsylvania-American Water Co.
2003	Kansas 20/ 40/	03-KGSG-602-RTS	Kansas Gas Service
2003	Nova Scotia, CN 49/	EMO NSPI	Nova Scotia Power, Inc.
2003	Kentucky 36/	2003-00252	Union Light Heat & Power
2003	Alaska 44/	U-96-89	ACS Communications, Inc.
2003	Indiana 29/	42359	PSI Energy, Inc.
2003	Kansas 20/ 40/	03-ATMG-1036-RTS	Atmos Energy
2003	Florida 50/	030001-E1	Tampa Electric Company
2003	Maryland 51/	8960	Washington Gas Light
2003	Hawaii 42/	02-0391	Hawaiian Electric Company
2003	Illinois 28/	02-0864	SBC Illinois
2003	Indiana 28/	42393	SBC Indiana
2004	New Jersey 1/	ER03020110	Atlantic City Electric Co.
2004	Arizona 26/	E-01345A-03-0437	Arizona Public Service Company
2004	Michigan 27/	U-13531	SBC Michigan
2004	New Jersey 1/	GR03080683	South Jersey Gas Company
2004	Kentucky 36/	2003-00434,00433	Kentucky Utilities, Louisville Gas & Electric
2004	Florida 50/ 54/	031033-EI	Tampa Electric Company
2004	Kentucky 36/	2004-00067	Delta Natural Gas Company

Michael J. Majoros, Jr.

2004	Georgia 23/	18300, 15392, 15393	Georgia Power Company
2004	Vermont 46/	6946, 6988	Central Vermont Public Service Corporation
2004	Delaware 24/	04-288	Delaware Electric Cooperative
2004	Missouri 58/	ER-2004-0570	Empire District Electric Company
2005	Florida 50/	041272-EI	Progress Energy Florida, Inc.
2005	Florida 50/	041291-EI	Florida Power & Light Company
2005	California 59/	A.04-12-014	Southern California Edison Co.
2005	Kentucky 36/	2005-00042	Union Light Heat & Power
2005	Florida 50/	050045 & 050188-EI	Florida Power & Light Co.
2005	Kansas 38/ 40/	05-WSEE-981-RTS	Westar Energy, Inc.
2006	Delaware 24/	05-304	Delmarva Power & Light Company
2006	California 59/	A.05-12-002	Pacific Gas & Electric Co.
2006	New Jersey 1/	GR05100845	Public Service Electric and Gas Co.
2006	West Virginia 2/	06-0960-E-42T, 06-1426-E-D	Allegheny Power

Michael J. Majoros, Jr.

PARTICIPATION AS NEGOTIATOR IN FCC TELEPHONE DEPRECIATION RATE REPRESCRIPTION CONFERENCES

COMPANY	YEARS	CLIENT
Diamond State Telephone Co. 24/	1985 + 1988	Delaware Public Service Comm
Bell Telephone of Pennsylvania 3/	1986 + 1989	PA Consumer Advocate
Chesapeake & Potomac Telephone Co. - Md. 8/	1986	Maryland People's Counsel
Southwestern Bell Telephone – Kansas 20/	1986	Kansas Corp. Commission
Southern Bell – Florida 4/	1986	Florida Consumer Advocate
Chesapeake & Potomac Telephone Co.-W.Va. 2/	1987 + 1990	West VA Consumer Advocate
New Jersey Bell Telephone Co. 1/	1985 + 1988	New Jersey Rate Counsel
Southern Bell - South Carolina 22/	1986 + 1989 + 1992	S. Carolina Consumer Advocate
GTE-North – Pennsylvania 3/	1989	PA Consumer Advocate

Michael J. Majoros, Jr.

PARTICIPATION IN PROCEEDINGS WHICH WERE SETTLED BEFORE TESTIMONY WAS SUBMITTED

STATE	DOCKET NO.	UTILITY
Maryland 8/	7878	Potomac Edison
Nevada 21/	88-728	Southwest Gas
New Jersey 1/	WR90090950J	New Jersey American Water
New Jersey 1/	WR900050497J	Elizabethtown Water
New Jersey 1/	WR91091483	Garden State Water
West Virginia 2/	91-1037-E	Appalachian Power Co.
Nevada 21/	92-7002	Central Telephone - Nevada
Pennsylvania 3/	R-00932873	Blue Mountain Water
West Virginia 2/	93-1165-E-D	Potomac Edison
West Virginia 2/	94-0013-E-D	Monongahela Power
New Jersey 1/	WR94030059	New Jersey American Water
New Jersey 1/	WR95080346	Elizabethtown Water
New Jersey 1/	WR95050219	Toms River Water Co.
Maryland 8/	8796	Potomac Electric Power Co.
South Carolina 22/	1999-077-E	Carolina Power & Light Co.
South Carolina 22/	1999-072-E	Carolina Power & Light Co.
Kentucky 36/	2001-104 & 141	Kentucky Utilities, Louisville Gas and Electric
Kentucky 36/	2002-485	Jackson Purchase Energy Corporation
Florida 50/ 54/	030157-EI	Progress Energy Florida
Colorado 60/	06S-234EG	Public Service Co. of Colorado
Kentucky 36/	2006-00172	Union Light, Heat & Power
Kansas 40/	06-KGSG-1209-RTS	Kansas Gas Service
Delaware 24/	06-284	Delmarva Power & Light Co.

Michael J. Majoros, Jr.

Clients

1/ New Jersey Rate Counsel/Advocate	33/ Michigan Attorney General
2/ West Virginia Consumer Advocate	34/ New Mexico Attorney General
3/ Pennsylvania OCA	35/ Environmental Protection Agency Enforcement Staff
4/ Florida Office of Public Advocate	36/ Kentucky Attorney General
5/ Toms River Fire Commissioner's	37/ North Dakota Public Service Commission
6/ Iowa Office of Consumer Advocate	38/ Kansas Industrial Group
7/ D.C. People's Counsel	39/ City of Witchita
8/ Maryland's People's Counsel	40/ Kansas Citizens' Utility Rate Board
9/ Idaho Public Service Commission	41/ NIPSCO Industrial Group
10/ Western Burglar and Fire Alarm	42/ Hawaii Division of Consumer Advocacy
11/ U.S. Dept. of Defense	43/ Nevada Bureau of Consumer Protection
12/ N.M. State Corporation Comm.	44/ GCI
13/ City of Philadelphia	45/ Wisc. Citizens' Utility Rate Board
14/ Resorts International	46/ Vermont Department of Public Service
15/ Woodlake Condominium Association	47/ Oklahoma Corporation Commission
16/ Illinois Attorney General	48/ National Assn. of State Utility Consumer Advocates
17/ Mass Coalition of Municipalities	49/ Nova Scotia Utility and Review Board
18/ U.S. Department of Energy	50/ Florida Office of Public Counsel
19/ Arizona Electric Power Corp.	51/ Maryland Public Service Commission
20/ Kansas Corporation Commission	52/ MCI
21/ Public Service Comm. – Nevada	53/ Transmission Agency of Northern California
22/ SC Dept. of Consumer Affairs	54/ Florida Industrial Power Users Group
23/ Georgia Public Service Comm.	55/ Sierra Club
24/ Delaware Public Service Comm.	56/ Our Children's Earth Foundation
25/ Conn. Ofc. Of Consumer Counsel	57/ National Parks Conservation Association, Inc.
26/ Arizona Corp. Commission	58/ Missouri Office of the Public Counsel
27/ AT&T	59/ The Utility Reform Network
28/ AT&T/MCI	60/ Colorado Office of Consumer Counsel
29/ IN Office of Utility Consumer Counselor	61/ MD State Senator Paul G. Pinsky
30/ Unitel (AT&T – Canada)	62/ MD Speaker of the House Michael Busch
31/ Public Interest Advocacy Centre	
32/ U.S. General Services Administration	

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF GAS RATES) CASE NO. 2006-00464

AFFIDAVIT OF MICHAEL MAJOROS

District of Columbia)
)
)

Michael Majoros, being first duly sworn, states the following: The prepared Pre-Filed Direct Testimony, and the Schedules and Appendix attached thereto constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the Pre-Filed Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further affiant saith not.

Michael Majoros

SUBSCRIBED AND SWORN to before me this 23rd day of April, 2007.

Angel L. Finch
NOTARY PUBLIC

My Commission Expires: March 14, 2011

original

BEFORE THE

KENTUCKY PUBLIC SERVICE COMMISSION

IN THE MATTER OF:	)	
	)	
THE APPLICATION OF THE	)	
ATMOS ENERGY CORPORATION	)	**CASE NO. 2006-00464**
TO INCREASE ITS GAS SERVICE RATES	)	

DIRECT TESTIMONY

OF

DR. J. RANDALL WOOLRIDGE

April 27, 2007

Atmos Energy Corporation
Kentucky Division

Direct Testimony of
Dr. J. Randall Woolridge

TABLE OF CONTENTS

LIST OF EXHIBIT

Q. PLEASE STATE YOUR FULL NAME, ADDRESS, AND OCCUPATION.

A. My name is J. Randall Woolridge and my business address is 120 Haymaker Circle, State College, PA 16801. I am a Professor of Finance and the Goldman, Sachs & Co. and Frank P. Smeal Endowed University Fellow in Business Administration at the University Park Campus of the Pennsylvania State University. I am also the Director of the Smeal College Trading Room and President of the Nittany Lion Fund, LLC. A summary of my educational background, research, and related business experience is provided in Appendix A.

I. SUBJECT OF TESTIMONY AND SUMMARY OF RECOMMENDATIONS

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

A. I have been asked by the Office of Attorney General (OAG) to provide an opinion as to the overall fair rate of return or cost of capital for the Kentucky Division of Atmos Energy Corp. ("Atmos" or "Company").

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND FINDINGS CONCERNING THE RATE OF RETURN THAT SHOULD BE UTILIZED IN SETTING RATES FOR ATMOS IN THIS PROCEEDING.

A. To arrive at an equity cost rate for the Company, I have applied the Discounted Cash Flow Model ("DCF") and the Capital Asset Pricing Model ("CAPM") to a group of publicly-held gas distribution companies as well as Atmos Energy Corp. My analysis indicates an equity cost rate of 9.00% for the Company. Using my capital structure ratios and senior capital cost rates, I am recommending an overall fair rate of return of 7.47% for Atmos. This recommendation is summarized in Exhibit_(JRW-1).

As discussed in my testimony, my recommendation is consistent with the current economic environment. Long-term capital costs are at historical low levels. The yields on long-term Treasury bonds have been in the 4-5 percent range for several years. Prior to this cyclical decline in rates, these yields had not been this low over an extended period of time since the 1960s. Long-term capital costs are also low due to the decline in the equity risk premium and the *Jobs and Growth Tax Relief Reconciliation Act of 2003* which reduced the tax rates on dividend income and capital gains.

In developing my recommendation, I have reviewed the testimony and recommendations of Atmos witness Dr. Donald A. Murry. I have adjusted the Company's proposed capital structure to include short-term debt since the Company uses short-term debt to finance its gas purchases and the monthly fluctuations in its Gas Stored Underground balances. Dr. Murry's equity cost rate estimate is 11.75%, while my analysis indicates an equity cost rate of 9.00% is appropriate for Atmos. We have both used DCF and CAPM approaches to estimating an equity cost rate for the Company. Dr. Murry and

I have applied these approaches to a proxy group of gas distribution companies as well as Atmos Energy. My recommendation presumes that the Kentucky Commission does not adopt the Company's Formula Based Rate (FBR) tariff plan.

In terms of the DCF approaches, the two major areas of disagreement are (1) the relevance of DCF equity cost rate results and (2) the estimation of the expected growth rate. With respect to (1), Dr Murry argues that the DCF model produces unreliable results in estimating an equity cost rate for a public utility. As a result, he ignores the vast majority of his own DCF results for the proxy group and Atmos Energy in estimating a DCF equity cost rate range of 10.87% to 12.39%. With respect to (2), Dr. Murry has relied exclusively on the forecasted EPS growth rates of Wall Street analysts and *Value Line* in estimating a DCF equity cost rate. I have used both historic and projected growth rate measures, and have evaluated growth in dividends, book value, and earnings per share. One important factor that I consider and highlight is the upwardly-biased expected earnings growth rates of Wall Street analysts and *Value Line*.

The CAPM approach requires an estimate of the risk-free interest rate, beta, and the equity risk premium. Whereas there is general agreement on the beta and risk-free interest rate, we have significantly different views on the alternative approaches to measuring the equity risk premium as well as the magnitude of equity risk premium. We also disagree on the need for a size premium adjustment to the CAPM. As I highlight in my testimony, there are three procedures for estimating an equity risk premium – historic returns, surveys, and expected return models. Dr. Murry relies solely on historic measures of the equity risk premium and has used equity risk premiums of 7.10% and 8.65% in his two versions of the CAPM. I provide evidence that risk premiums based on historic returns series are upwardly biased measures of expected risk premiums. I use an equity risk premium of 4.16% which (1) uses all three approaches to estimating an equity premium and (2) employs the results of many studies of the equity risk premium. As I note, my equity risk premium is consistent with the equity risk premiums (1) discovered in recent academic studies by leading finance scholars, (2) employed by leading investment banks and management consulting firms, and (3) found in surveys of financial forecasters and corporate CFOs.

Dr. Murry and I also disagree on the need for a size premium adjustment to the CAPM. The size premium is based on historical stock returns and, as discussed in my testimony, there are a number of errors in using historical market returns to compute risk premiums. In addition, I argue that any equity cost rate adjustment based on the relative size of a public utility is inappropriate. One study noted in my testimony tested for a size premium in utilities and concluded that, unlike industrial stocks, utility stocks do not exhibit a significant size premium. The primary reason that a size premium is not required for utilities is that utilities are regulated closely by state and federal agencies and commissions and hence their financial performance is monitored on an on-going basis by agencies of both the state and federal governments.

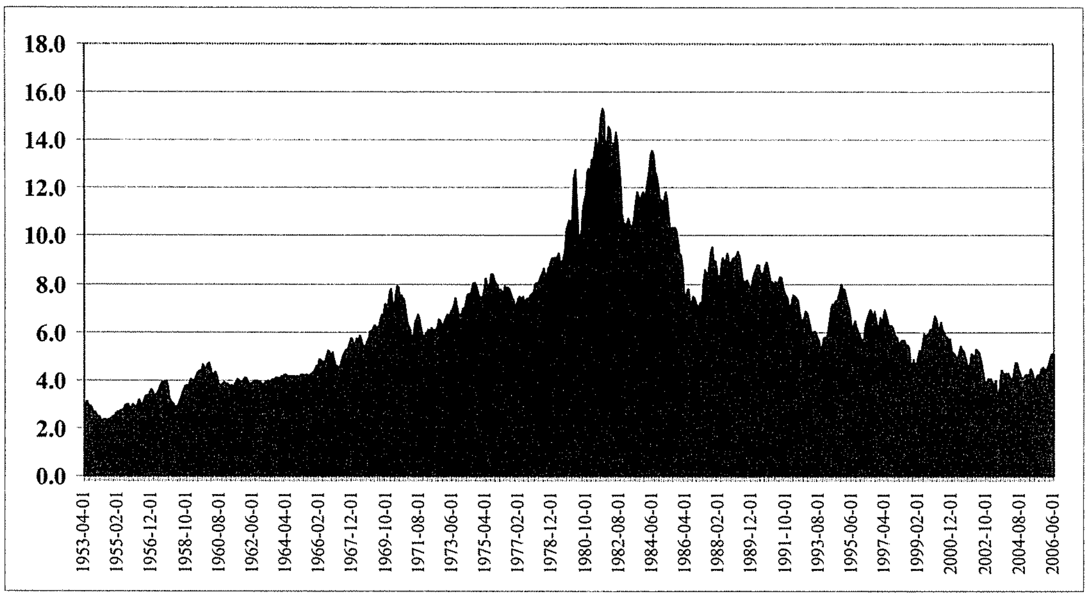
In the end, the most significant areas of disagreement between Dr. Murry and me with respect to the cost of equity are (1) the relevance of the DCF model and its results in determining an equity cost rate for the Company, and (2) the measurement and magnitude of the equity risk premium. Dr. Murry believes that the DCF model produces equity cost rate results that are too low and so he has ignored the DCF results for the vast majority of the companies in his gas distribution company group. On the other hand, I believe that the DCF model provides a good indication of equity cost rates for public utilities and have placed heavy reliance on these results in this proceeding. With respect to the measurement of an equity risk premium, Dr. Murry has relied exclusively on historical stock and bond returns. On the contrary, I have employed the results from twenty equity risk premium studies which employ the three alternative approaches for estimating an equity risk premium – averages of historical returns, surveys of market professionals, and models of expected market returns.

II. CAPITAL COSTS IN TODAY'S MARKETS

Q. PLEASE DISCUSS CAPITAL COSTS IN TODAY'S MARKETS.

A. Long-term capital cost rates for U.S. corporations are currently at their lowest levels in more than four decades. Corporate capital cost rates are determined by the level of interest rates and the risk premium demanded by investors to buy the debt and equity capital of corporate issuers. The base level of interest rates in the US economy is indicated by the rates on ten-year U.S. Treasury bonds. The rates are provided in the graph below from 1953 to the present. As indicated, prior to the decline in rates that began in the year 2000, the 10-year Treasury had not been in the 4-5 percent range since the 1960s.

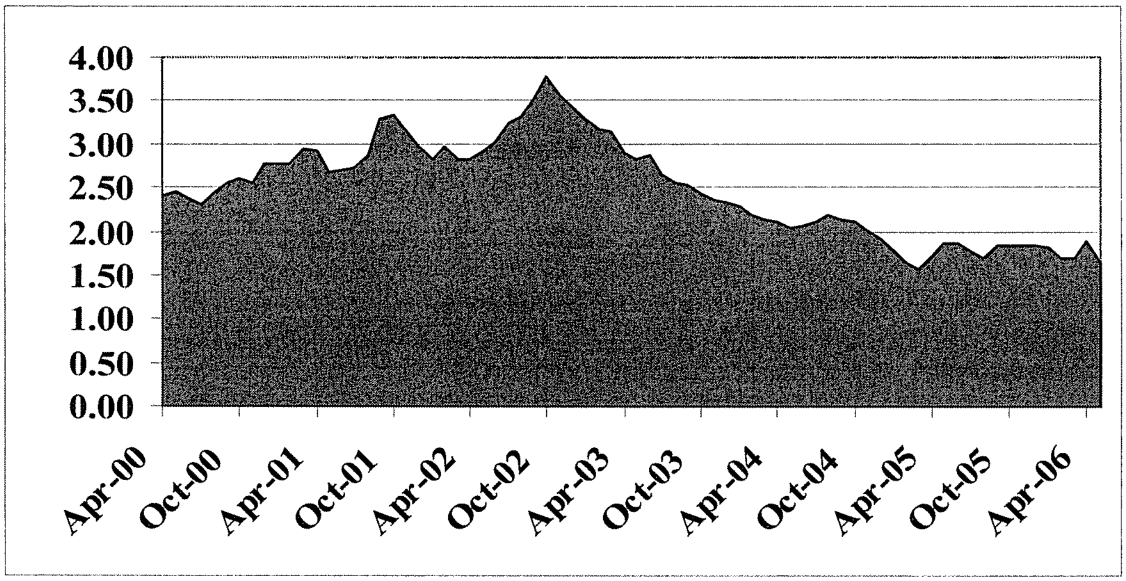
Yields on Ten-Year Treasury Bonds
1953-Present



Source: http://research.stlouisfed.org/fred2/data/GS10.txt

The second base component of the corporate capital cost rates is the risk premium. The risk premium is the return premium required by investors to purchase riskier securities. Risk premiums for bonds are the yield differentials between different bond classes as rated by agencies such as Moody's, and Standard and Poor's. The graph below provides the yield differential between Baa-rate corporate bonds and 10-year Treasuries. This yield differential peaked at 350 basis points (BPs) in 2002 and has declined significantly since that time. This is an indication that the market price of risk has declined and therefore the risk premium has declined in recent years.

Corporate Bond Yield Spreads
Baa-Rated Corporate Bond Yield Minus Ten-Year Treasury Bond Yield



Source: http://www.treas.gov/offices/domestic-finance/debt-management/interest-rate/index.html

The equity risk premium is the return premium required to purchase stocks as opposed to bonds. Since the equity risk premium is not readily observable in the markets (as are bond risk premiums), and there are alternative approaches to estimating the equity premium, it is the subject of much debate. One way to estimate the equity risk premium is to compare the mean returns on bonds and stocks over long historical periods. Measured in this manner, the equity risk premium has been in the 5-7 percent range. But recent studies by leading academics indicate the forward-looking equity risk premium is in the 3-4 percent range. These authors indicate that historical equity risk premiums are upwardly biased measures of expected equity risk premiums. Jeremy Siegel, a Wharton finance professor and author of the book *Stocks for the Long Term*, published a study entitled "The Shrinking Equity Risk Premium."[1] He concludes:

> The degree of the equity risk premium calculated from data estimated from 1926 is unlikely to persist in the future. The real return on fixed-income assets is likely to be significantly higher than estimated on earlier data. This is confirmed by the yields available on Treasury index-linked securities, which currently exceed 4%. Furthermore, despite the acceleration in earnings growth, the return on equities is likely to fall from its historical level due to the very high level of equity prices relative to fundamentals.

Even Alan Greenspan, the former Chairman of the Federal Reserve Board, indicated in an October 14, 1999, speech on financial risk that the fact that equity risk premiums have declined during the past decade is "not in dispute." His assessment focused on the relationship between information availability and equity risk premiums.

> There can be little doubt that the dramatic improvements in information technology in recent years have altered our approach to risk. Some analysts perceive that information technology has permanently lowered equity premiums and, hence, permanently raised the prices of the collateral that underlies all financial assets.
>
> The reason, of course, is that information is critical to the evaluation of risk. The less that is known about the current state of a market or a venture, the less the ability to project future outcomes

[1] Jeremy J. Siegel, "The Shrinking Equity Risk Premium," *The Journal of Portfolio Management* (Fall, 1999), p.15.

> and, hence, the more those potential outcomes will be discounted.
>
> The rise in the availability of real-time information has reduced the uncertainties and thereby lowered the variances that we employ to guide portfolio decisions. At least part of the observed fall in equity premiums in our economy and others over the past five years does not appear to be the result of ephemeral changes in perceptions. It is presumably the result of a permanent technology-driven increase in information availability, which by definition reduces uncertainty and therefore risk premiums. This decline is most evident in equity risk premiums. It is less clear in the corporate bond market, where relative supplies of corporate and Treasury bonds and other factors we cannot easily identify have outweighed the effects of more readily available information about borrowers.[2]

In sum, the relatively low interest rates in today's markets as well as the lower risk premiums required by investors indicate that capital costs for U.S. companies are the lowest in decades. In addition, the 2003 tax law further lowered capital cost rates for companies.

Q. HOW DID THE *JOBS AND GROWTH TAX RELIEF RECONCILIATION ACT OF 2003* REDUCE THE COST OF CAPITAL FOR COMPANIES?

A. On May 28th of 2003, President Bush signed the *Jobs and Growth Tax Relief Reconciliation Act of 2003*. The primary purpose of this legislation was to reduce taxes to enhance economic growth. A primary component of the new tax law was a significant

[2] Alan Greenspan, "Measuring Financial Risk in the Twenty-First Century," Office of the Comptroller of the Currency Conference, October 14, 1999.

reduction in the taxation of corporate dividends for individuals. Dividends have been described as "double-taxed." First, corporations pay taxes on the income they earn before they pay dividends to investors, then investors pay taxes on the dividends that they receive from corporations. One of the implications of the double taxation of dividends is that, all else equal, it results in a higher cost of raising capital for corporations. The tax legislation reduced the effect of double taxation of dividends by lowering the tax rate on dividends from the 30 percent range (the average tax bracket for individuals) to 15 percent.

Overall, the 2003 tax law reduced the pre-tax return requirements of investors, thereby reducing corporations' cost of equity capital. This is because the reduction in the taxation of dividends for individuals enhances their after-tax returns and thereby reduces their pre-tax required returns. This reduction in pre-tax required returns (due to the lower tax on dividends) effectively reduces the cost of equity capital for companies. The 2003 tax law also reduced the tax rate on long-term capital gains from 20% to 15%. The magnitude of the reduction in corporate equity cost rates is debatable, but my assessment indicates that it could be as large as 100 basis points.

III. COMPARISON GROUP SELECTION

Q. PLEASE DESCRIBE YOUR APPROACH TO DEVELOPING A FAIR RATE OF RETURN RECOMMENDATION FOR ATMOS.

A. To develop a fair rate of return recommendation for Atmos, I evaluated the return requirements of investors on the common stock of a group of publicly-held natural gas distribution companies as well as Atmos Energy Corporation.

Q. PLEASE DESCRIBE YOUR GROUP OF GAS DISTRIBUTION COMPANIES.

A. I initially reviewed the natural gas distribution companies followed by both *AUS Utility Reports* and the *Value Line Investment Survey* – Standard edition. I then applied four screens to these companies: (1) regulated gas revenues must be at least 25% of total revenues, (2) an investment grade bond rating by S&P, (3) must pay a cash dividend, (4) not currently the target of an acquisition. As shown on page 2 of Exhibit_(JRW-2), applying these screens provided a group of nine natural gas distribution companies: AGL Resources, Laclede Group, New Jersey Resources, NICOR, Northwest Natural Gas, Piedmont Natural Gas Company, South Jersey Industries, Southwest Gas, and WGL Holdings. Atmos Energy also meets these criteria, and I have separately evaluated the return requirements on the stock of Atmos Energy.

Summary financial statistics for the group are provided on page 1 of Exhibit_(JRW-2). On average, the group has average revenues and net plant of

$2,073.8M and $1,889.1M, respectively. The group has an average common equity ratio of 48.1%, and the current average earned return on common equity of 12.3%. Atmos Energy has revenues and net plant of $5,471.2M and $3,667.9M, with a common equity ratio of 45.0% and an earned return on common equity of 8.9%.

IV. CAPITAL STRUCTURE RATIOS AND DEBT COST RATES

Q. WHAT CAPITAL STRUCTURE RATIOS HAVE BEEN PROPOSED BY ATMOS?

A. As shown in Panel A of Exhibit_(JRW-3), Atmos' rate of return witness Dr. Donald A. Murry has proposed a capital structure consisting of 51.85% long-debt and 48.15% common equity.

Q. PLEASE DISCUSS THE CAPITAL STRUCTURE RATIOS OF ATMOS ENERGY AND THE PROXY GROUP OF GAS DISTRIBUTION COMPANIES.

A. Panel B of Exhibit_(JRW-3), provides the average capitalization ratios for Atmos Energy over the past year. The average common equity ratio over this time is 41.37%. Hence, it is clear that a common equity ratio of 48.15% significantly exceeds the amount of equity capital employed by the Company over the past year. Furthermore, the figures in Panel B indicate that the Company has consistently used short-term debt as a source of capital.

Panel C of Exhibit_(JRW-3) provides the average capitalization ratios for my proxy group of nine gas distribution companies. Like Atmos Energy, these companies have consistently used short-term debt as a source of capital. The average common equity ratio over the past year for this group is 49.74%.

Q. WHAT CAPITAL STRUCTURE RATIOS AND SENIOR CAPITAL COST RATES ARE YOU USING TO ESTIMATE AN OVERALL RATE OF RETURN FOR ATMOS?

A. As discussed above, both Atmos Energy and the group of gas companies consistently use short-term debt as a source of capital. In addition, in its responses to AG-1-3 and AG-1-5, the Company confirms that it uses short term debt to finance its gas purchases and the monthly fluctuations in its Gas Stored Underground balances. The purchased gas expenses are included in the test period operating expenses and the average Gas Stored Underground balance is included in the requested test period rate base. For consistency purposes, a representative average balance of short term debt should therefore be included in the capital structure. In AG-1-1, the Company estimates a projected Forecasted Test Period daily average short-term debt balance of $123,886,000. The projected average short term debt cost rate for the Forecasted Test Period is 6.58%. I will use this short-term debt amount and cost rate, in addition to the Company's projected amounts of debt and equity capital. My proposed capital structure and senior capital cost rates, as developed in Exhibit_(JRW-3), are summarized below.

Proposed Capital Structure and Senior Capital Cost Rates

Source of Capital	Capitalization Ratio	Cost Rate
Short-Term Debt	**2.86%**	**6.58%**
Long-Term Debt	**50.36%**	**6.10%**
Common Equity	**46.78%**	

V. THE COST OF COMMON EQUITY CAPITAL

A. Overview

Q. WHY MUST AN OVERALL COST OF CAPITAL OR FAIR RATE OF RETURN BE ESTABLISHED FOR A PUBLIC UTILITY?

A. In a competitive industry, the return on a firm's common equity capital is determined through the competitive market for its goods and services. Due to the capital requirements needed to provide utility services, however, and to the economic benefit to society from avoiding duplication of these services, some public utilities are monopolies. It is not appropriate to permit monopoly utilities to set their own prices because of the lack of competition and the essential nature of the services. Thus, regulation seeks to establish prices which are fair to consumers and at the same time are sufficient to meet the operating and capital costs of the utility, i.e., provide an adequate return on capital to attract investors.

Q. PLEASE PROVIDE AN OVERVIEW OF THE COST OF CAPITAL IN THE CONTEXT OF THE THEORY OF THE FIRM.

A. The total cost of operating a business includes the cost of capital. The cost of common equity capital is the expected return on a firm's common stock that the marginal investor would deem sufficient to compensate for risk and the time value of money. In equilibrium, the expected and required rates of return on a company's common stock are equal.

Normative economic models of the firm, developed under very restrictive assumptions, provide insight into the relationship between firm performance or profitability, capital costs, and the value of the firm. Under the economist's ideal model of perfect competition where entry and exit is costless, products are undifferentiated, and there are increasing marginal costs of production, firms produce up to the point where price equals marginal cost. Over time, a long-run equilibrium is established where price equals average cost, including the firm's capital costs. In equilibrium, total revenues equal total costs, and because capital costs represent investors' required return on the firm's capital, actual returns equal required returns and the market value and the book value of the firm's securities must be equal.

In the real world, firms can achieve competitive advantage due to product market imperfections. Most notably, companies can gain competitive advantage through product differentiation (adding real or perceived value to products) and by achieving economies of scale (decreasing marginal costs of production). Competitive advantage allows firms to price products above average cost and thereby earn accounting profits greater than those required to cover capital costs. When these profits are in excess of that required by investors, or when a firm earns a return on equity in excess of its cost of equity, investors respond by valuing the firm's equity in excess of its book value.

James M. McTaggart, founder of the international management consulting firm Marakon Associates, has described this essential relationship between the return on equity, the cost of equity, and the market-to-book ratio in the following manner:[3]

> Fundamentally, the value of a company is determined by the cash flow it generates over time for its owners, and the minimum acceptable rate of return required by capital investors. This "cost of equity capital" is used to discount the expected equity cash flow, converting it to a present value. The cash flow is, in turn, produced by the interaction of a company's return on equity and the annual rate of equity growth. High return on equity (ROE) companies in low-growth markets, such as Kellogg, are prodigious generators of cash flow, while low ROE companies in high-growth markets, such as Texas Instruments, barely generate enough cash flow to finance growth.
>
> A company's ROE over time, relative to its cost of equity, also determines whether it is worth more or less than its book value. If its ROE is consistently greater than the cost of equity capital (the investor's minimum acceptable return), the business is economically profitable and its market value will exceed book value. If, however, the business earns an ROE consistently less than its cost of equity, it is economically unprofitable and its market value will be less than book value.

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[3] James M. McTaggart, "The Ultimate Poison Pill: Closing the Value Gap," *Commentary* (Spring 1988), p. 2.

As such, the relationship between a firm's return on equity, cost of equity, and market-to-book ratio is relatively straightforward. A firm which earns a return on equity above its cost of equity will see its common stock sell at a price above its book value. Conversely, a firm which earns a return on equity below its cost of equity will see its common stock sell at a price below its book value.

Q. PLEASE PROVIDE ADDITIONAL INSIGHTS INTO THE RELATIONSHIP BETWEEN RETURN ON EQUITY AND MARKET-TO-BOOK RATIOS?

A. This relationship is discussed in a classic Harvard Business School case study entitled "A Note on Value Drivers." On page 2 of that case study, the author describes the relationship very succinctly:[4]

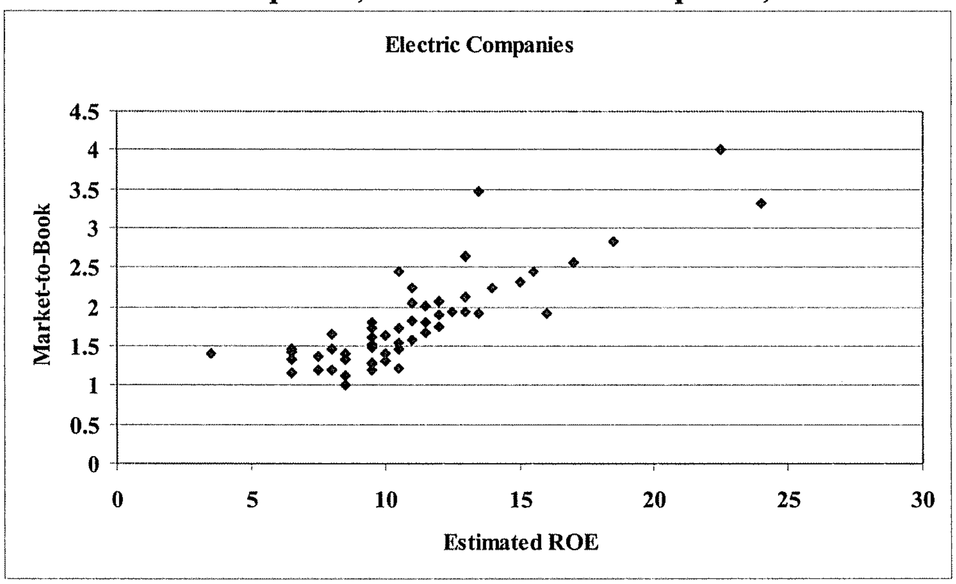
> For a given industry, more profitable firms – those able to generate higher returns per dollar of equity – should have higher market-to-book ratios. Conversely, firms which are unable to generate returns in excess of their cost of equity should sell for less than book value.

Profitability	*Value*
If ROE > K	*then Market/Book > 1*
If ROE = K	*then Market/Book =1*
If ROE < K	*then Market/Book < 1*

[4] Benjamin Esty, "A Note on Value Drivers," Harvard Business School, Case No. 9-297-082, April 7, 1997.

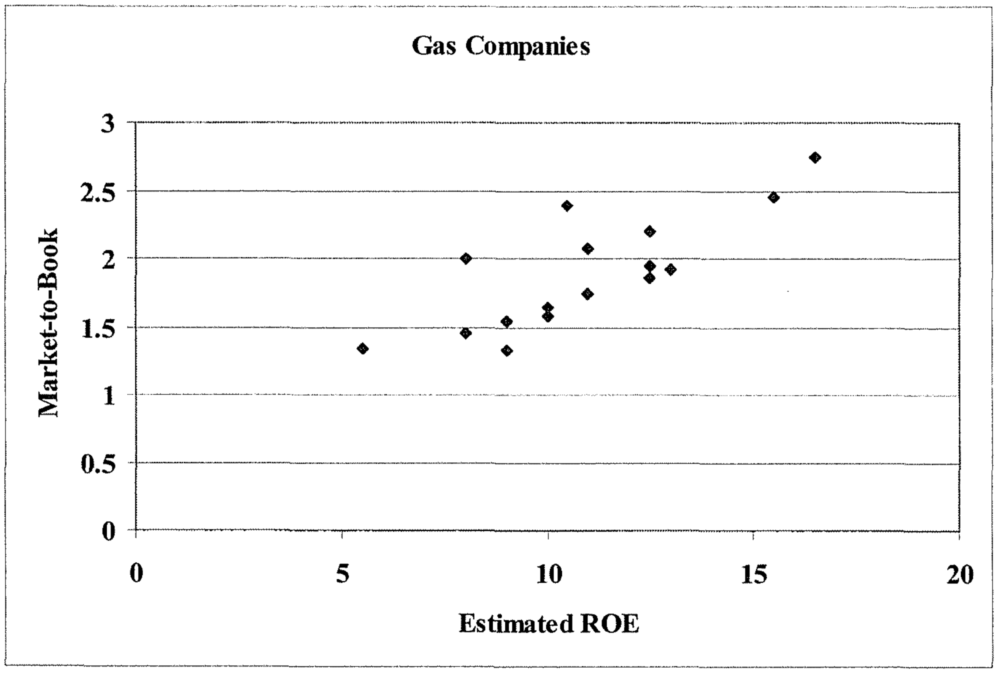
To assess the relationship by industry, as suggested above, I have performed a regression study between estimated return on equity and market-to-book ratios using natural gas distribution, electric utility and water utility companies. I used all companies in these three industries which are covered by *Value Line* and who have estimated return on equity and market-to-book ratio data. The results are presented below.

The Relationship Between Estimated ROE and Market-to-Book Ratios
Value Line Electrics Companies, Gas Distribution Companies, and Water Utilities

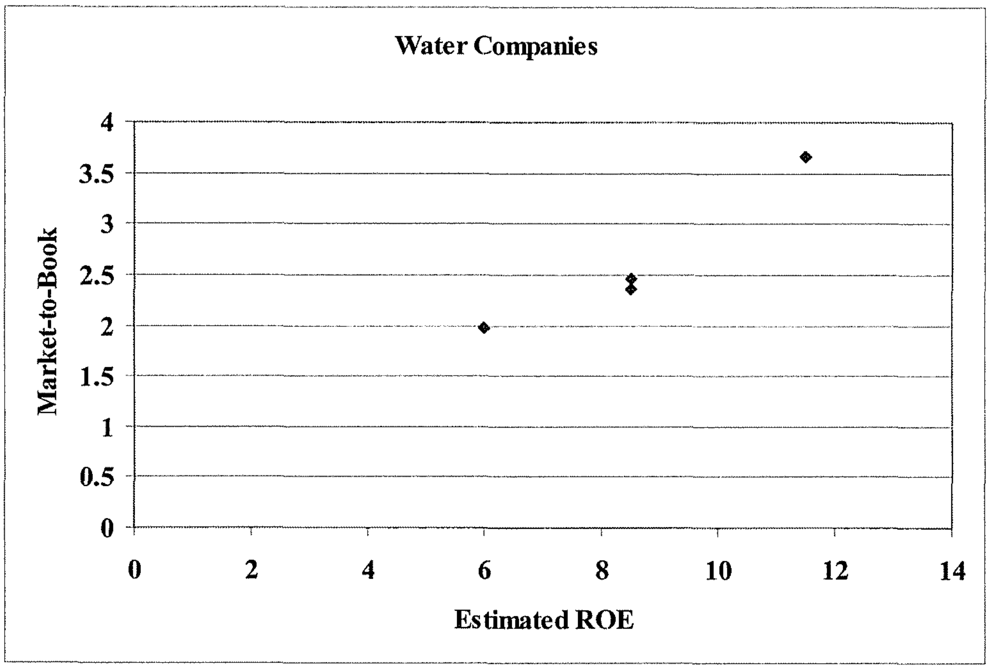


R-Square = .70

N=58



R-Square = .64
N=16



R-Square = .93
N=4

The average R-squares for the electric, gas, and water companies are 0.70, 0.64, and 0.93. This demonstrates the strong positive relationship between ROEs and market-to-book ratios for public utilities.[5]

Q. WHAT ECONOMIC FACTORS HAVE AFFECTED THE COST OF EQUITY CAPITAL FOR PUBLIC UTILITIES?

A. Exhibit_JRW-4 provides indicators of public utility equity cost rates over the past decade. Page 1 shows the yields on 10-year, 'A' rated public utility bonds. These yields peaked in the 1990s at 10%, and have generally declined since that time. They hovered in the 4.5 to 5.0 percent range between 2003 and 2005, and have since increased to 5.75%. Page 2 provides the dividend yields for the fifteen utilities in the Dow Jones Utilities Average over the past decade. These yields peaked in 1994 at 7.2%. Since that time they have declined and were below 4.0% as of 2005.

Average earned returns on common equity and market-to-book ratios are given on page 3 of Exhibit_JRW-4. Over the past decade, earned returns on common equity have consistently been in the 10.0-13.0 percent range. The high point was 13.45% in 2001, and they have decreased since that time. As of 2005, the average was 11.75%. Over the past decade, market-to-book ratios for this group have increased gradually, but with

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[5] R-square measures the percent of variation in one variable (e.g., market-to-book ratios) explained by another variable (e.g., expected return on equity). R-squares vary between zero and 1.0, with values closer to 1.0 indicating a higher relationship between two variables.

several ups and downs. The market-to-book average was 1.75 as of 2001, declined to 1.45 in 2003, and increased to 1.95 as of 2005.

The indicators in Exhibit_JRW-4, coupled with the overall decrease in interest rates, suggest that capital costs for the Dow Jones Utilities have decreased over the past decade. Specifically for the equity cost rate, the increase in the market-to-book ratios, coupled with a slightly lower average return on equity, suggests a decline in the overall equity cost rate.

Q. WHAT FACTORS DETERMINE INVESTORS' EXPECTED OR REQUIRED RATE OF RETURN ON EQUITY?

A. The expected or required rate of return on common stock is a function of market-wide, as well as company-specific, factors. The most important market factor is the time value of money as indicated by the level of interest rates in the economy. Common stock investor requirements generally increase and decrease with like changes in interest rates. The perceived risk of a firm is the predominant factor that influences investor return requirements on a company-specific basis. A firm's investment risk is often separated into business and financial risk. Business risk encompasses all factors that affect a firm's operating revenues and expenses. Financial risk results from incurring fixed obligations in the form of debt in financing its assets.

Q. HOW DOES THE INVESTMENT RISK OF NATURAL GAS DISTRIBUTION COMPANIES COMPARE WITH THAT OF OTHER INDUSTRIES?

A. Due to the essential nature of their service as well as their regulated status, public utilities are exposed to a lesser degree of business risk than other, non-regulated businesses. The relatively low level of business risk allows public utilities to meet much of their capital requirements through borrowing in the financial markets, thereby incurring greater than average financial risk. Nonetheless, the overall investment risk of public utilities is below most other industries. Exhibit_(JRW-5) provides an assessment of investment risk for 100 industries as measured by beta, which according to modern capital market theory is the only relevant measure of investment risk that need be of concern for investors. These betas come from the *Value Line Investment Survey* and are compiled by Aswath Damodoran of New York University. They may be found on the Internet at http://www.stern.nyu.edu/~adamodar/. The study shows that the investment risk of public utilities is relatively low. The average beta for natural gas distribution companies of 0.73 is in the bottom 10% of the 100 industries in terms of beta. As such, the cost of equity for the natural gas distribution industry is among the lowest of all industries in the U.S.

Q. HOW CAN THE EXPECTED OR REQUIRED RATE OF RETURN ON COMMON EQUITY CAPITAL BE DETERMINED?

A. The costs of debt and preferred stock are normally based on historical or book values and can be determined with a great degree of accuracy. The cost of common equity capital, however, cannot be determined precisely and must instead be estimated from market data and informed judgment. This return to the stockholder should be commensurate with returns on investments in other enterprises having comparable risks.

According to valuation principles, the present value of an asset equals the discounted value of its expected future cash flows. Investors discount these expected cash flows at their required rate of return that, as noted above, reflects the time value of money and the perceived riskiness of the expected future cash flows. As such, the cost of common equity is the rate at which investors discount expected cash flows associated with common stock ownership.

Models have been developed to ascertain the cost of common equity capital for a firm. Each model, however, has been developed using restrictive economic assumptions. Consequently, judgment is required in selecting appropriate financial valuation models to estimate a firm's cost of common equity capital, in determining the data inputs for these models, and in interpreting the models' results. All of these decisions must take into consideration the firm involved as well as conditions in the economy and the financial markets.

Q. HOW DO YOU PLAN TO ESTIMATE THE COST OF EQUITY CAPITAL FOR THE COMPANY?

A. I rely primarily on the DCF model to estimate the cost of equity capital. Given the investment valuation process and the relative stability of the utility business, I believe that the DCF model provides the best measure of equity cost rates for public utilities. I have also performed a CAPM study, but I give these results less weight because I believe that risk premium studies, of which the CAPM is one form, provide a less reliable indication of equity cost rates for public utilities.

B. Discounted Cash Flow Analysis

Q. BRIEFLY DESCRIBE THE THEORY BEHIND THE TRADITIONAL DCF MODEL.

A. According to the discounted cash flow model, the current stock price is equal to the discounted value of all future dividends that investors expect to receive from investment in the firm. As such, stockholders' returns ultimately result from current as well as future dividends. As owners of a corporation, common stockholders are entitled to a pro-rata share of the firm's earnings. The DCF model presumes that earnings that are not paid out in the form of dividends are reinvested in the firm so as to provide for future growth in earnings and dividends. The rate at which investors discount future dividends, which reflects the timing and riskiness of the expected cash flows, is interpreted as the market's expected or required return on the common stock. Therefore this discount rate represents the cost of common equity. Algebraically, the DCF model can be expressed as:

$$P = \frac{D_1}{(1+k)^1} + \frac{D_2}{(1+k)^2} + \ldots \frac{D_n}{(1+k)^n}$$

where P is the current stock price, D_n is the dividend in year n, and k is the cost of common equity.

Q. IS THE DCF MODEL CONSISTENT WITH VALUATION TECHNIQUES EMPLOYED BY INVESTMENT FIRMS?

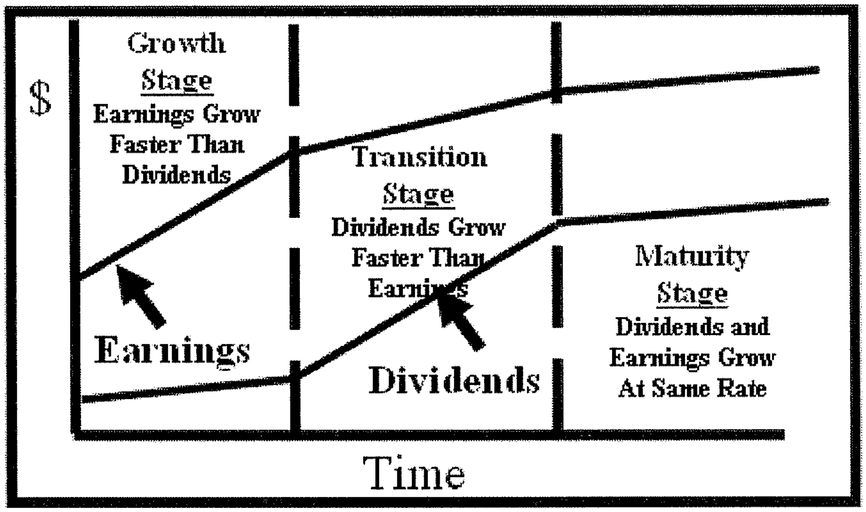
A. Yes. Virtually all investment firms use some form of the DCF model as a valuation technique. One common application for investment firms is called the three-stage DCF or dividend discount model ("DDM"). The stages in a three-stage DCF model are discussed below. This model presumes that a company's dividend payout progresses initially through a growth stage, then proceeds through a transition stage, and finally assumes a steady-state stage. The dividend-payment stage of a firm depends on the profitability of its internal investments, which, in turn, is largely a function of the life cycle of the product or service. These stages are depicted in the graphic below labeled the Three-Stage DCF Model.[6]

[6] This description comes from William F. Sharp, Gordon J. Alexander, and Jeffrey V. Bailey, *Investments* (Prentice-Hall, 1995), pp. 590-91.

1. Growth stage: Characterized by rapidly expanding sales, high profit margins, and abnormally high growth in earnings per share. Because of highly profitable expected investment opportunities, the payout ratio is low. Competitors are attracted by the unusually high earnings, leading to a decline in the growth rate.
2. Transition stage: In later years, increased competition reduces profit margins and earnings growth slows. With fewer new investment opportunities, the company begins to pay out a larger percentage of earnings.
3. Maturity (steady-state) stage: Eventually the company reaches a position where its new investment opportunities offer, on average, only slightly attractive returns on equity. At that time its earnings growth rate, payout ratio, and return on equity stabilize for the remainder of its life. The constant-growth DCF model is appropriate when a firm is in the maturity stage of the life cycle.

In using this model to estimate a firm's cost of equity capital, dividends are projected into the future using the different growth rates in the alternative stages, and then the equity cost rate is the discount rate that equates the present value of the future dividends to the current stock price.

Three-Stage DCF Model



Q. HOW DO YOU ESTIMATE STOCKHOLDERS' EXPECTED OR REQUIRED RATE OF RETURN USING THE DCF MODEL?

A. Under certain assumptions, including a constant and infinite expected growth rate, and constant dividend/earnings and price/earnings ratios, the DCF model can be simplified to the following:

$$P = \frac{D_1}{k - g}$$

where D_1 represents the expected dividend over the coming year and g is the expected growth rate of dividends. This is known as the constant-growth version of the DCF model. To use the constant-growth DCF model to estimate a firm's cost of equity, one solves for k in the above expression to obtain the following:

$$k = \frac{D_1}{P} + g$$

The economics of the public utility business indicate that the industry is in the steady-state or constant-growth stage of a three-stage DCF. The economics include the relative stability of the utility business, the maturity of the demand for public utility services, and the regulated status of public utilities (especially the fact that their returns on investment are effectively set through the ratemaking process). The DCF valuation procedure for companies in this stage is the constant-growth DCF. In the constant-growth version of the DCF model, the current dividend payment and stock price are directly observable. Therefore, the primary problem and controversy in applying the DCF model to estimate equity cost rates entails estimating investors' expected dividend growth rate.

Q. WHAT FACTORS SHOULD ONE CONSIDER WHEN APPLYING THE DCF METHODOLOGY?

A. One should be sensitive to several factors when using the DCF model to estimate a firm's cost of equity capital. In general, one must recognize the assumptions under which the DCF model was developed in estimating its components (the dividend yield and expected growth rate). The dividend yield can be measured precisely at any point in time, but tends to vary somewhat over time. Estimation of expected growth is considerably more difficult. One must consider recent firm performance, in conjunction with current economic developments and other information available to investors, to accurately estimate investors' expectations.

Q. PLEASE DISCUSS EXHIBIT_JRW-6.

A. My DCF analysis is provided in Exhibit_JRW-6. The DCF summary is on page 1 of this Exhibit and the supporting data and analysis for the dividend yield and expected growth rate are provided on the following pages.

Q. WHAT DIVIDEND YIELDS ARE YOU EMPLOYING IN YOUR DCF ANALYSIS FOR YOUR GROUP OF NATURAL GAS DISTRIBUTION COMPANIES AND ATMOS?

A. The dividend yields on the common stock for the companies in the group and Atmos are provided on page 2 of Exhibit_(JRW-6) for the six-month period ending April, 2007. Over this period, the average monthly dividend yields for the group of gas companies was 3.5%. As of April, 2007, the mean dividend yields for the group was 3.6%. For the DCF dividend yields for the group, I use the average of the six month and April, 2007 dividend yields. Hence, I am employing a DCF dividend yield of 3.6%. For Atmos Energy, the average of the six month and April, 2007 dividend yields is 4.0%.

Q. PLEASE DISCUSS THE APPROPRIATE ADJUSTMENT TO THE SPOT DIVIDEND YIELD.

A. According to the traditional DCF model, the dividend yield term relates to the dividend yield over the coming period. As indicated by Professor Myron Gordon, who is commonly associated with the development of the DCF model for popular use, this is obtained by (1) multiplying the expected dividend over the coming quarter by 4, and (2) dividing this dividend by the current stock price to determine the appropriate dividend yield for a firm, which pays dividends on a quarterly basis.[7]

In applying the DCF model, some analysts adjust the current dividend for growth over the coming year as opposed to the coming quarter. This can be complicated because firms tend to announce changes in dividends at different times during the year. As such, the dividend yield computed based on presumed growth over the coming quarter as opposed to the coming year can be quite different. Consequently, it is common for analysts to adjust the dividend yield by some fraction of the long-term expected growth rate.

The appropriate adjustment to the dividend yield is further complicated in the regulatory process when the overall cost of capital is applied to a projected or end-of-future-test-year rate base. The net effect of this application is an overstatement of the equity cost rate estimate derived from the DCF model. In the context of the constant-

[7] *Petition for Modification of Prescribed Rate of Return*, Federal Communications Commission, Docket No. 79-05,

growth DCF model, both the adjusted dividend yield and the growth component are overstated. The overstatement results from applying an equity cost rate computed using current market data to a future or test-year-end rate base which includes growth associated with the retention of earnings during the year. In other words, an equity cost rate times a future, yet to be achieved rate base, results in an inflated dividend yield and growth rate.

Q. GIVEN THIS DISCUSSION, WHAT ADJUSTMENT FACTOR WILL YOU USE FOR YOUR DIVIDEND YIELD?

A. I will adjust the dividend yield by 1/2 the expected growth so as to reflect growth over the coming year.

Q. PLEASE DISCUSS THE GROWTH RATE COMPONENT OF THE DCF MODEL.

A. There is much debate as to the proper methodology to employ in estimating the growth component of the DCF model. By definition, this component is investors' expectation of the long-term dividend growth rate. Presumably, investors use some combination of historical and/or projected growth rates for earnings and dividends per share and for internal or book value growth to assess long-term potential.

Direct Testimony of Myron J. Gordon and Lawrence I. Gould at 62 (April 1980).

Q. WHAT GROWTH DATA HAVE YOU REVIEWED FOR THE GROUP OF NATURAL GAS DISTRIBUTION COMPANIES?

A. I have analyzed a number of measures of growth for the gas distribution companies. I have reviewed *Value Line's* historical and projected growth rate estimates for earnings per share (EPS), dividends per share (DPS), and book value per share (BVPS). In addition, I have utilized the average EPS growth rate forecasts of Wall Street analysts as provided by Zacks, Reuters, and First Call. These services solicit five-year earning growth rate projections from securities analysts and compile and publish the averages of these forecasts on the Internet. Finally, I have also assessed prospective growth as measured by prospective earnings retention rates and earned returns on common equity.

Q. PLEASE DISCUSS HISTORICAL GROWTH IN EARNINGS AND DIVIDENDS AS WELL AS INTERNAL GROWTH.

A. Historical growth rates for sales, EPS, DPS, and BVPS are readily available to virtually all investors and presumably an important ingredient in forming expectations concerning future growth. However, one must use historical growth numbers as measures of investors' expectations with caution. In some cases, past growth may not reflect future growth potential. Also, employing a single growth rate number (for example, for five or ten years), is unlikely to accurately measure investors' expectations due to the sensitivity of a single growth rate figure to fluctuations in individual firm performance as well as overall economic fluctuations (i.e., business cycles). However, one must appraise the context in which the growth rate is being employed. According to the conventional DCF model, the expected return on a security is equal to the sum of the dividend yield and the expected long-term growth in dividends. Therefore, to best estimate the cost of common equity capital using the conventional DCF model, one must look to long-term growth rate expectations.

Internally generated growth is a function of the percentage of earnings retained within the firm (the earnings retention rate) and the rate of return earned on those earnings (the return on equity). The internal growth rate is computed as the retention rate times the return on equity. Internal growth is significant in determining long-run earnings and, therefore, dividends. Investors recognize the importance of internally generated growth and pay premiums for stocks of companies that retain earnings and earn high returns on internal investments.

Q. PLEASE DISCUSS THE HISTORICAL GROWTH OF THE COMPANIES IN THE GROUP AND ATMOS AS PROVIDED IN THE *VALUE LINE INVESTMENT SURVEY.*

A. Historic growth rates for the companies in the group, as published in the *Value Line Investment Survey*, are provided on page 3 of Exhibit_(JRW-6). Due to the presence of outliers among the historic growth rate figures, both the mean and medians are used in the analysis. The historical growth measures in EPS, DPS, and BVPS for the group, as measured by the means and medians, range from 1.5% to 5.7%, with an average of 4.1%. The average of these historic measures for Atmos Energy is 5.6%.

Q. PLEASE SUMMARIZE *VALUE LINE'S* PROJECTED GROWTH RATES FOR THE GROUP OF NATURAL GAS DISTRIBUTION COMPANIES AND ATMOS?

A. *Value Line's* projections of EPS, DPS, and BVPS growth for the group are shown on page 4 of Exhibit_(JRW-6). As above, due to the presence of outliers, both the mean and medians are used in the analysis. For the group, the central tendency measures range from 3.0% to 4.5%, with an average of 3.7%. The average of these projected measures for Atmos Energy is 3.5%.

Also provided on page 4 of Exhibit_(JRW-6) is prospective internal growth for the group as measured by *Value Line*'s average projected retention rate and return on shareholders' equity. The average prospective internal growth rate for the group is 5.0%. The prospective internal growth for Atmos Energy is 4.6% based on a projected retention rate of 46.0% and return on shareholders' equity of 10.0%.

Q. PLEASE ASSESS GROWTH FOR THE GROUP AND ATMOS AS MEASURED BY ANALYSTS' FORECASTS OF EXPECTED 5-YEAR GROWTH IN EPS.

A. Zacks, First Call, and Reuters collect, summarize, and publish Wall Street analysts' five-year EPS growth rate forecasts for companies. These forecasts are provided for the companies in the group of natural gas distribution companies on page 5 of Exhibit_(JRW-6). The mean/median of the analysts' projected EPS growth rates for the group are 4.5%/5.0%.[8] For Atmos Energy, the average of the analysts' projected EPS growth rate is 5.5%.

Q. PLEASE SUMMARIZE YOUR ANALYSIS OF THE HISTORICAL AND PROSPECTIVE GROWTH OF THE GAS COMPANY GROUP.

A. The table below shows the summary DCF growth rate indicators for the group of gas distribution companies. For the group, the average of *Value Line*'s historical mean and median growth rate measures in EPS, DPS, and BVPS is 4.1%. *Value Line*'s average projected growth rate for EPS, DPS, and BVPS is 3.7%. The average internal growth rate is 5.0%, and the mean/median of the projected EPS growth rate for companies in the group are 4.5%/5.0%. Given these results, an expected DCF growth rate of 5.0 percent range would appear to be at the upper end the range of expectations for the group.

For Atmos, the averages of *Value Line*'s historical and projected EPS, DPS, and BVPS growth rates are 5.6% and 3.5%, respectively. Prospective internal growth for

[8] Since there is considerable overlap in analyst coverage between the three services, and not all of the companies have forecasts from the different services, I have averaged the expected five-year EPS growth rates from the three services for each company to arrive at an expected EPS growth rate by company.

Atmos Energy is 4.6%, and the average projected EPS growth rate is 5.5%. Given the figures, an expected growth rate in the 5.0-5.5 percent range would appear to be reasonable. I will use the mid-point of this range - 5.25% - as my DCF growth rate for Atmos Energy.

DCF Growth Rate Indicators

Growth Rate Indicator	**Proxy Group**	**Atmos Energy**
Historic *Value Line* Growth in EPS, DPS, and BVPS	4.1%	5.6%
Projected *Value Line* Growth in EPS, DPS, and BVPS	3.7%	3.5%
Internal Growth ROE * Retention rate	5.0%	4.6%
Projected EPS Growth from First Call, Reuters, and Zacks	5.0%	5.5%

Q. BASED ON THE ABOVE ANALYSIS, WHAT ARE YOUR INDICATED COMMON EQUITY COST RATES FROM THE DCF MODEL FOR THE GROUP?

A. My DCF-derived equity cost rate for the group are:

$$\text{DCF Equity Cost Rate (k)} = \frac{D}{P} + g$$

	Dividend Yield	1+ ½ (Growth Adjustment)	DCF Growth Rate	Equity Cost Rate
Gas Group	3.6%	1.0250	5.00%	8.6%
Atmos Energy	4.0%	1.0265	5.25%	9.4%

These results are summarized on page 1 of Exhibit_(JRW-6).

C. Capital Asset Pricing Model

Q. PLEASE DISCUSS THE CAPITAL ASSET PRICING MODEL (CAPM).

A. The CAPM is a risk premium approach to gauging a firm's cost of equity capital. According to the risk premium approach, the cost of equity is the sum of the interest rate on a risk-free bond (R_f) and a risk premium (RP), as in the following:

$$k = R_f + RP$$

The yield on long-term Treasury securities is normally used as R_f. Risk premiums are measured in different ways. The CAPM is a theory of the risk and expected returns of common stocks. In the CAPM, two types of risk are associated with a stock: firm-specific risk or unsystematic risk; and market or systematic risk, which is measured by a firm's beta. The only risk that investors receive a return for bearing is systematic risk.

According to the CAPM, the expected return on a company's stock, which is also the equity cost rate (K), is equal to:

$$K = (R_f) + \beta_i * [E(R_m) - (R_f)]$$

Where:

- K represents the estimated rate of return on the stock;
- $E(R_m)$ represents the expected return on the overall stock market. Frequently, the 'market' refers to the S&P 500;
- (R_f) represents the risk-free rate of interest;
- $[E(R_m) - (R_f)]$ represents the expected equity or market risk premium—the excess return that an investor expects to receive above the risk-free rate for investing in risky stocks; and
- *Beta*—($ß_i$) is a measure of the systematic risk of an asset.

To estimate the required return or cost of equity using the CAPM requires three inputs: the risk-free rate of interest (R_f), the beta ($ß_i$), and the expected equity or market risk premium, $[E(R_m) - (R_f)]$. R_f is the easiest of the inputs to measure – it is the yield on long-term Treasury bonds. $ß_i$, the measure of systematic risk, is a little more difficult to measure because there are different opinions about what adjustments, if any, should be made to historical betas due to their tendency to regress to 1.0 over time. And finally, an even more difficult input to measure is the expected equity or market risk premium, $[E(R_m) - (R_f)]$. I will discuss each of these inputs, with most of the discussion focusing on the expected equity risk premium.

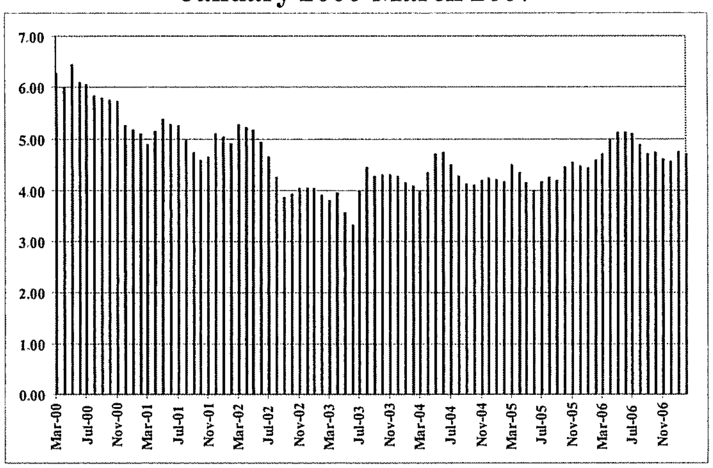
Q. PLEASE DISCUSS EXHIBIT_JRW-7.

A. Exhibit_JRW-7 provides the summary results for my CAPM study. Page 1 shows the results, and the pages following it, contain the supporting data.

Q. PLEASE DISCUSS THE RISK-FREE INTEREST RATE.

A. The yield on long-term Treasury bonds has usually been viewed as the risk-free rate of interest in the CAPM. The yield on long-term Treasury bonds, in turn, has been considered to be the yield on Treasury bonds with 30-year maturities. However, when the Treasury's issuance of 30-year bonds was interrupted for a period of time in recent years, the yield on 10-year Treasury bonds replaced the yield on 30-year Treasury bonds as the benchmark long-term Treasury rate. The 10-year Treasury yields over the past five years are shown in the chart below. These rates hit a 60-year low in the summer of 2003 at 3.33%. They increased with the rebounding economy and fluctuated in the 4.0-4.50 percent range over the past three years until advancing to 5.0% in early 2006 in response to a strong economy and increases in energy, commodity, and consumer prices. Beginning in the fourth quarter of 2006, however, long-term interest rates have retreated to below 5.0 percent as inflationary pressures have subsided.

Ten-Year U.S. Treasury Yields
January 2000-March 2007



Source: http://www.federalreserve.gov/releases/h15/current/h15.pdf

Q. WHAT RISK-FREE INTEREST RATE ARE YOU USING IN YOUR CAPM?

A. With the growing budget deficit, the U.S. Treasury has decided to again begin issuing a 30-year bond. As such, the market may again begin to focus on its yield as the benchmark for long-term capital costs in the U.S. In recent months, the yields on the 10- and 30- year Treasuries have increased and have been in the 4.75%-5.25% range. As of April 23, 2007, as shown in the table below, the rates on 10- and 30- Treasuries were 4.64% and 4.82%, respectively. Given this recent range and recent movement, I will use 5.00% as the risk-free rate, or R_f, in my CAPM.

U.S. Treasury Yields
April 23, 2007

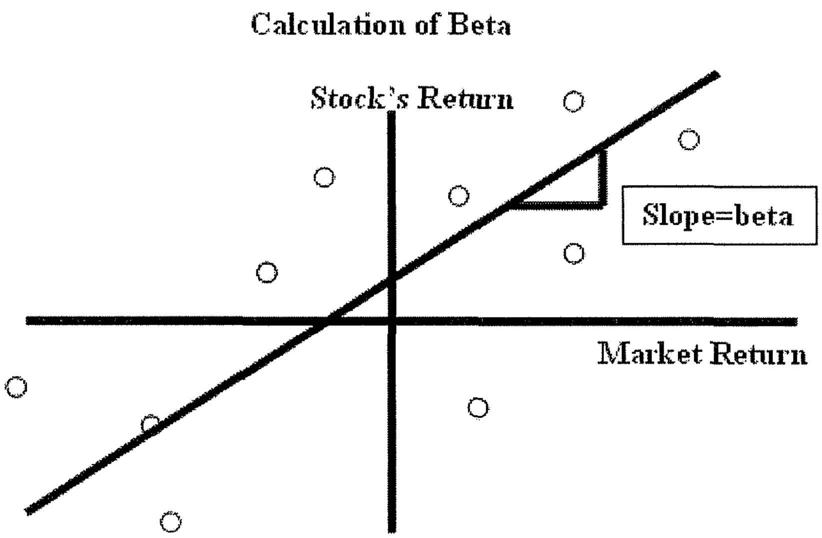
NOTES/BONDS	COUPON	MATURITY DATE	CURRENT PRICE/YIELD
2-YEAR	4.500	03/31/2009	99-24+ / 4.62
3-YEAR	4.750	02/15/2010	100-16+ / 4.55
5-YEAR	4.500	03/31/2012	99-27 / 4.54
10-YEAR	4.625	02/15/2017	99-27¾ / 4.64
30-YEAR	4.750	02/15/2037	98-27 / 4.82

Source: www.bloomberg.com

Q. WHAT BETAS ARE YOU EMPLOYING IN YOUR CAPM?

A. Beta (ß) is a measure of the systematic risk of a stock. The market, usually taken to be the S&P 500, has a beta of 1.0. The beta of a stock with the same price movement as the market also has a beta of 1.0. A stock whose price movement is greater than that of the market, such as a technology stock, is riskier than the market and has a beta greater than

1.0. A stock with below average price movement, such as that of a regulated public utility, is less risky than the market and has a beta less than 1.0. Estimating a stock's beta involves running a linear regression of a stock's return on the market return as in the following:



The slope of the regression line is the stock's ß. A steeper line indicates the stock is more sensitive to the return on the overall market. This means that the stock has a higher ß and greater than average market risk. A less steep line indicates a lower ß and less market risk.

Numerous online investment information services, such as Yahoo and Reuters, provide estimates of stock betas. Usually these services report different betas for the same stock. The differences are usually due to (1) the time period over which the ß is measured and (2) any adjustments that are made to reflect the fact that betas tend to regress to 1.0 over time. In estimating an equity cost rate for the group of gas distribution companies, I am using the betas for the companies as provided in the *Value Line Investment Survey*. As shown on page 2 of Exhibit_JRW-7, the average betas for the gas group and Atmos Energy are 0.87 and 0.80.

Q. PLEASE DISCUSS THE EQUITY RISK PREMIUM.

A. The equity or market risk premium—$[E(R_m) - R_f]$: is equal to the expected return on the stock market (e.g., the expected return on the S&P 500 ($E(R_m)$) minus the risk-free rate of interest (R_f). The equity premium is the difference in the expected total return between investing in equities and investing in "safe" fixed-income assets, such as long-term government bonds. However, while the equity risk premium is easy to define conceptually, it is difficult to measure because it requires an estimate of the expected return on the market.

Q. PLEASE DISCUSS THE ALTERNATIVE APPROACHES TO ESTIMATING THE EQUITY RISK PREMIUM.

A. The table below highlights the primary approaches to, and issues in, estimating the expected equity risk premium. The traditional way to measure the equity risk premium was to use the difference between historical average stock and bond returns. In this case, historical stock and bond returns, also called ex post returns, were used as the measures of the market's expected return (known as the ex ante or forward-looking expected return). This type of historical evaluation of stock and bond returns is often called the "Ibbotson approach" after Professor Roger Ibbotson who popularized this method of using historical financial market returns as measures of expected returns. Most historical assessments of the equity risk premium suggest an equity risk premium of 5-7 percent above the rate on long-term Treasury bonds. However, this can be a problem because (1) ex post returns are not the same as ex ante expectations, (2) market risk premiums can change over time, increasing when investors become more risk-averse, and decreasing when investors become less risk-averse, and (3) market conditions can change such that ex post historical returns are poor estimates of ex ante expectations.

Risk Premium Approaches

	Historical Ex Post Excess Returns	Surveys	Ex Ante Models and Market Data
Means of Assessing the Equity-Bond Risk Premium	Historical average is a popular proxy for the ex ante premium – but likely to be misleading	Investor and expert surveys can provide direct estimates of prevailing expected returns/premiums	Current financial market prices (simple valuation ratios or DCF-based measures) can give most objective estimates of feasible ex ante equity-bond risk premium
Problems/Debated Issues	Time variation in required returns and systematic selection and other biases have boosted valuations over time, and have exaggerated realized excess equity returns compared with ex ante expected premiums	Limited survey histories and questions of survey representativeness. Surveys may tell more about hoped-for expected returns than about objective required premiums due to irrational biases such as extrapolation.	Assumptions needed for DCF inputs, notably the trend earnings growth rate, make even these models' outputs subjective. The range of views on the growth rate, as well as the debate on the relevant stock and bond yields, leads to a range of premium estimates.

Source: Antti Ilmanen, Expected Returns on Stocks and Bonds," *Journal of Portfolio Management*, (Winter 2003).

The use of historical returns as market expectations has been criticized in numerous academic studies.[9] The general theme of these studies is that the large equity risk premium discovered in historical stock and bond returns cannot be justified by the fundamental data. These studies, which fall under the category "Ex Ante Models and Market Data," compute ex ante expected returns using market data to arrive at an expected equity risk premium. These studies have also been called "Puzzle Research" after the famous study by Mehra and Prescott in which the authors first questioned the magnitude of historical equity risk premiums relative to fundamentals.[10]

Q. PLEASE BRIEFLY SUMMARIZE SOME OF THE ACADEMIC STUDIES THAT DEVELOP EX ANTE EQUITY RISK PREMIUMS.

A. Two of the most prominent studies of ex ante expected equity risk premiums were by Eugene Fama and Ken French (2002) and James Claus and Jacob Thomas (2001). The primary debate in these studies revolves around two related issues: (1) the size of expected equity risk premium, which is the return equity investors require above the yield on bonds; and (2) the fact that estimates of the ex ante expected equity risk premium using fundamental firm data (earnings and dividends) are much lower than estimates using historical stock and bond return data. Fama and French (2002), two of the most

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[9] The problems with using ex post historical returns as measures of ex ante expectations will be discussed at length later in my testimony.

[10] Rahnish Mehra and Edward Prescott, "The Equity Premium: A Puzzle," *Journal of Monetary Economics* (1985).

preeminent scholars in finance, use dividend and earnings growth models to estimate expected stock returns and ex ante expected equity risk premiums.[11] They compare these results to actual stock returns over the period 1951-2000. Fama and French estimate that the expected equity risk premium from DCF models using dividend and earnings growth to be between 2.55% and 4.32%. These figures are much lower than the ex post historical equity risk premium produced from the average stock and bond return over the same period, which is 7.40%.

Fama and French conclude that the ex ante equity risk premium estimates using DCF models and fundamental data are superior to those using ex post historical stock returns for three reasons: (1) the estimates are more precise (a lower standard error); (2) the Sharpe ratio, which is measured as the [(expected stock return – risk-free rate)/standard deviation], is constant over time for the DCF models but varies considerably over time and more than doubles for the average stock-bond return model; and (3) valuation theory specifies relationships between the market-to-book ratio, return on investment, and cost of equity capital that favor estimates from fundamentals. They also conclude that the high average stock returns over the past 50 years were the result of low expected returns and that the average equity risk premium has been in the 3-4 percent range.

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[11] Eugene F. Fama and Kenneth R. French, "The Equity Premium," *The Journal of Finance*, (April 2002).

The study by Claus and Thomas of Columbia University provides direct support for the findings of Fama and French.[12] These authors compute ex ante expected equity risk premiums over the 1985-1998 period by (1) computing the discount rate that equates market values with the present value of expected future cash flows, and (2) then subtracting the risk-free interest rate. The expected cash flows are developed using analysts' earnings forecasts. The authors conclude that over this period the ex ante expected equity risk premium is in the range of 3.0%. Claus and Thomas note that, over this period, ex post historical stock returns overstate the ex ante expected equity risk premium because, as the expected equity risk premium has declined, stock prices have risen. In other words, from a valuation perspective, the present value of expected future returns increase when the required rate of return decreases. The higher stock prices have produced stock returns that have exceeded investors' expectations and therefore ex post historical equity risk premium estimates are biased upwards as measures of ex ante expected equity risk premiums.

Q. PLEASE PROVIDE A SUMMARY OF THE EX ANTE EQUITY RISK PREMIUM STUDIES.

[12] James Claus and Jacob Thomas, "Equity Risk Premia as Low as Three Percent? Empirical Evidence from Analysts' Earnings Forecasts for Domestic and International Stock Market," *Journal of Finance*. (October 2001).

A. Richard Derrig and Elisha Orr (2003) completed the most comprehensive paper to date which summarizes and assesses the many risk premium studies.[13] These authors reviewed the various approaches to estimating the equity risk premium, and the overall results. Page 3 of Exhibit_JRW-7 provides a summary of the results of the primary risk premium studies reviewed by Derrig and Orr. In developing page 3 of Exhibit_JRW-7, I have (1) updated the results of the studies that have been updated by the various authors, (2) included the results of several additional studies and surveys, and (3) included the results of the "Building Blocks" approach to estimating the equity risk premium, including a study I performed which is presented below.

On page 3, the risk premium studies listed under the 'Social Security' and 'Puzzle Research' sections are primarily ex ante expected equity risk premium studies (as discussed above). Most of these studies are performed by leading academic scholars in finance and economics. Also provided are the results of studies by Ibbotson and Chen and myself which use the Building Blocks approach.

Q. PLEASE DISCUSS YOUR DEVELOPMENT OF AN EX ANTE EXPECTED EQUITY RISK PREMIUM COMPUTED USING THE BUILDING BLOCKS METHODOLOGY.

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[13] Richard Derrig and Elisha Orr, "Equity Risk Premium: Expectations Great and Small," Working Paper (version 3.0), Automobile Insurers Bureau of Massachusetts, August 28, 2003.

A. Ibbotson and Chen (2002) evaluate the ex post historical mean stock and bond returns in what is called the Building Blocks approach.[14] They use 75 years of data and relate the compounded historical returns to the different fundamental variables employed by different researchers in building ex ante expected equity risk premiums. Among the variables included were inflation, real EPS and DPS growth, ROE and book value growth, and P/E ratios. By relating the fundamental factors to the ex post historical returns, the methodology bridges the gap between the ex post and ex ante equity risk premiums. Ilmanen (2003) illustrates this approach using the geometric returns and five fundamental variables – inflation (CPI), dividend yield (D/P), real earnings growth (RG), repricing gains (PEGAIN) and return interaction/reinvestment (INT).[15] This is shown in the graph below. The first column breaks the 1926-2000 geometric mean stock return of 10.7% into the different return components demanded by investors: the historical Treasury bond return (5.2%), the excess equity return (5.2%), and a small interaction term (0.3%). This 10.7% annual stock return over the 1926-2000 period can then be broken down into the following fundamental elements: inflation (3.1%), dividend yield (4.3%), real earnings growth (1.8%), repricing gains (1.3%) associated with higher P/E ratios, and a small interaction term (0.2%).

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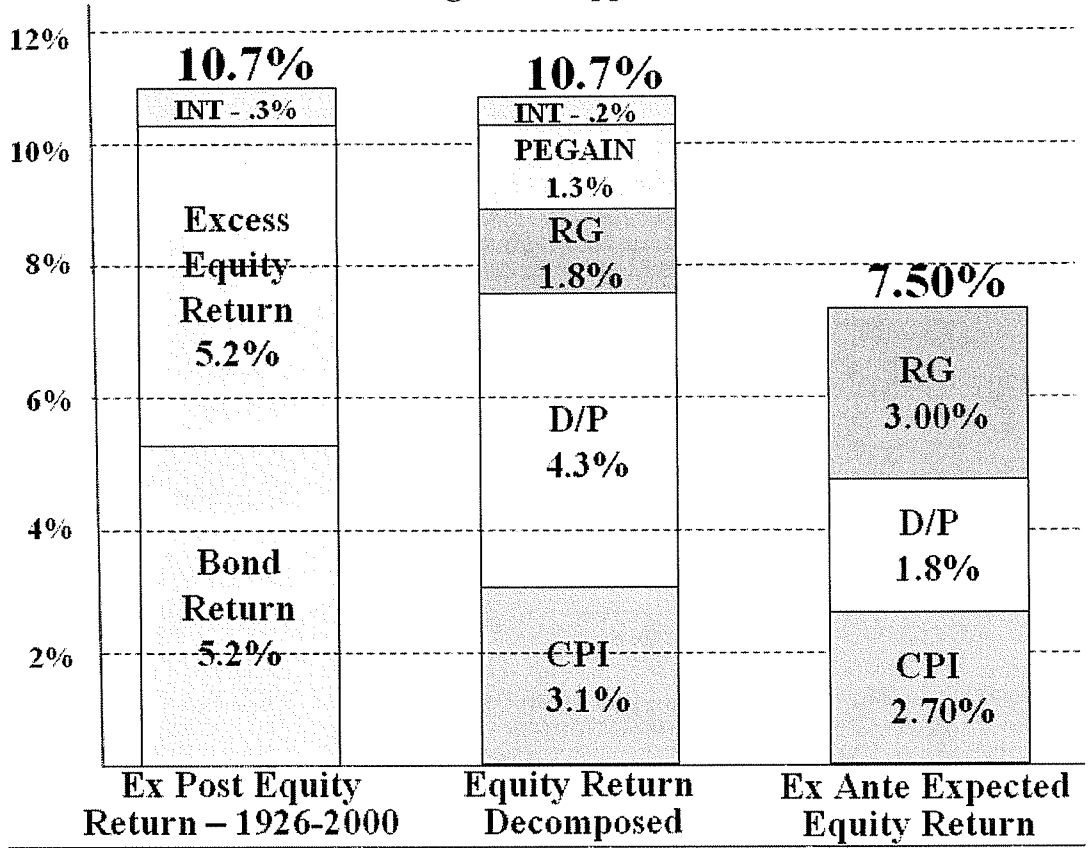
[14] Roger Ibbotson and Peng Chen, "Long Run Returns: Participating in the Real Economy," *Financial Analysts Journal*, January 2003.

[15] Antti Ilmanen, Expected Returns on Stocks and Bonds," *Journal of Portfolio Management*, (Winter 2003), p. 11.

Decomposing Equity Market Returns
The Building Blocks Approach

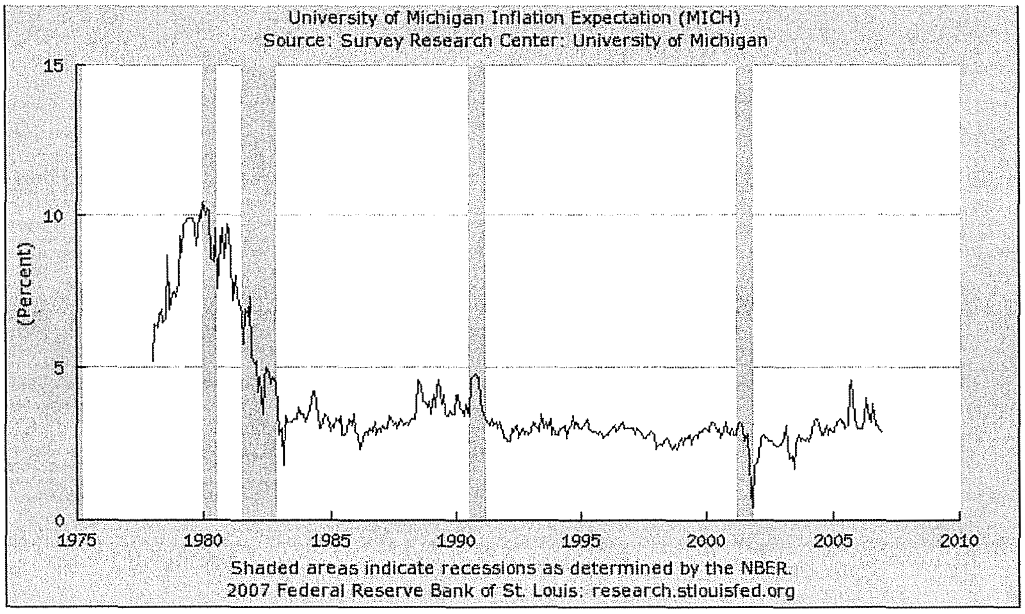


Q. HOW ARE YOU USING THIS METHODOLOGY TO DERIVE AN EX ANTE EXPECTED EQUITY RISK PREMIUM?

A. The third column in the graph above shows current inputs to estimate an ex ante expected market return. These inputs include the following:

CPI – To assess expected inflation, I have employed expectations of the short-term and long-term inflation rate. The graph below shows the expected annual inflation rate according to consumers, as measured by the CPI, over the coming year. This survey is published monthly by the University of Michigan Survey Research Center. In the most recent report, the expected one-year inflation rate was 3.0%.

Expected Inflation Rate
University of Michigan Consumer Research
(Data Source: http://research.stlouisfed.org/fred2/series/MICH/98)



Longer term inflation forecasts are available in the Federal Reserve Bank of Philadelphia's publication entitled *Survey of Professional Forecasters*.[16] This survey of professional economists has been published for almost 50 years. While this survey is published quarterly, only the first quarter survey includes long-term forecasts of GDP growth, inflation, and market returns. In the first quarter, 2007 survey, published on

[16] Federal Reserve Bank of Philadelphia, *Survey of Professional Forecasters,* February 13, 2007. The *Survey of Professional Forecasters* was formerly conducted by the American Statistical Association (ASA) and the National Bureau of Economic Research (NBER) and was known as the ASA/NBER survey. The survey, which began in 1968, is conducted each quarter. The Federal Reserve Bank of Philadelphia, in cooperation with the NBER,

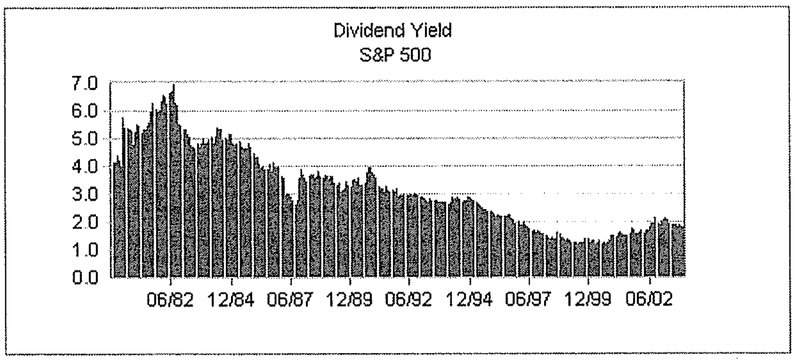
February 13, 2007, the median long-term (10-year) expected inflation rate as measured by the CPI was 2.35% (see page 4 of Exhibit_JRW-7).

Given these results, I will use the average of the University of Michigan and Philadelphia Federal Reserve's surveys (3.0% and 2.35%), or 2.7%.

D/P – As shown in the graph below, the dividend yield on the S&P 500 has decreased gradually over the past decade. Today, it is far below its average of 4.3% over the 1926-2000 time period. Whereas the S&P dividend yield bottomed out at less than 1.4% in 2000, it is currently at 1.8% which I use in the ex ante risk premium analysis.

S&P 500 Dividend Yield

(Data Source: http://www.barra.com/Research/fund_charts.asp)



RG – To measure expected real growth in earnings, I use (1) the historical real earnings growth rate for the S&P 500, and (2) expected real GDP growth. The S&P 500 was created in 1960. It includes 500 companies which come from ten different sectors of the economy. Over the 1960-2005 period, nominal growth in EPS for the S&P 500 was

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assumed responsibility for the survey in June 1990.

7.11%. On page 5 of Exhibit_JRW-7, real EPS growth is computed using the CPI as a measure of inflation. As indicated by Ibbotson and Chen, real earnings growth over the 1926-2000 period was 1.8%. The real growth figure over 1960-2006 period for the S&P 500 is 3.0 %.

The second input for expected real earnings growth is expected real GDP growth. The rationale is that over the long-term, corporate profits have averaged a relatively consistent 5.50% of US GDP.[17] Real GDP growth, according to McKinsey, has averaged 3.5% over the past 80 years. Expected GDP growth, according to the Federal Reserve Bank of Philadelphia's *Survey of Professional Forecasters,* is 3.0% (see page 4 of Exhibit_JRW-7).

Given these results, I will use the average of the historical S&P EPS real growth and the projected real GDP growth (as reported by the Philadelphia Federal Reserve Survey) -- 3.0% and 3.0% -- or 3.0%, for real earnings growth.

PEGAIN – PEGAIN is the repricing gain associated with an increase in the P/E ratio. It accounted for 1.3% of the 10.7% annual stock return in the 1926-2000 period. In estimating an ex ante expected stock market return, one issue is whether investors expect P/E ratios to increase from their current levels. The graph below shows the P/E ratios for the S&P 500 over the past 25 years. The run-up and eventual peak in P/Es is most notable in the chart. The relatively low P/E ratios (in the range of 10) over two

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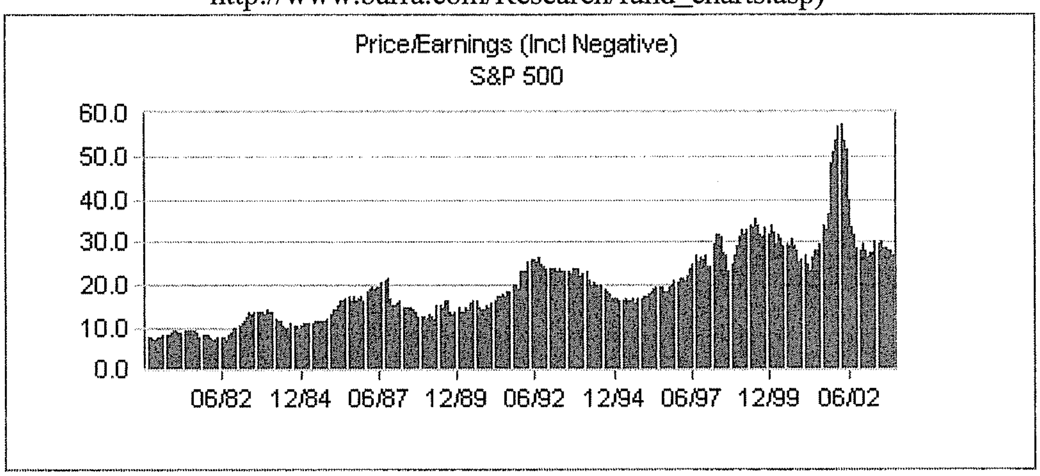
[17] Marc. H. Goedhart, et al, "The Real Cost of Equity," *McKinsey on Finance* (Autumn 2002), p.14.

decades ago are also quite notable. As of April, 2007 the average P/E for the S&P 500, using the trailing 12 months EPS, is 20.7 according to www.investor.reuters.com.

Given the current economic and capital markets environment, I do not believe that investors expect even higher P/E ratios. Therefore, a PEGAIN would not be appropriate in estimating an ex ante expected stock market return. There are two primary reasons for this. First, the average historical S&P 500 P/E ratio is 15 – thus the current P/E exceeds this figure. Second, as previously noted, interest rates are at a cyclical low not seen in almost 50 years. This is a primary reason for the high current P/Es. Given the current market environment with relatively high P/E ratios and low relative interest rates, investors are not likely to expect to get stock market gains from lower interest rates and higher P/E ratios.

S&P 500 P/E Ratios
(DataSource:
http://www.barra.com/Research/fund_charts.asp)



Q. GIVEN THIS DISCUSSION, WHAT IS YOUR EX ANTE EXPECTED MARKET RETURN AND EQUITY RISK PREMIUM USING THE "BUILDING BLOCKS APPROACH"?

A. My expected market return is represented by the last column on the right in the graph entitled "Decomposing Equity Market Returns: The Building Blocks Approach" set forth on page 49 of my testimony. The current expected market return is 7.50% which is composed of 3.00% expected inflation, 1.80% dividend yield, and 3.00% real earnings growth rate.

Expected Market Return	=	Expected Inflation	+	Dividend Yield	+	Real Earnings Growth
Expected Market Return	=	2.70%	+	1.80%	+	3.0%
Expected Market Return	=	7.5%				

Q. GIVEN THAT THE HISTORICAL COMPOUNDED ANNUAL MARKET RETURN IS IN EXCESS OF 10%, WHY DO YOU BELIEVE THAT YOUR EXPECTED MARKET RETURN OF 7.5% IS REASONABLE?

A. As discussed above in the development of the expected market return, stock prices are relatively high at the present time in relation to earnings and dividends and interest rates are relatively low. Hence, it is unlikely that investors are going to experience high stock market returns due to higher P/E ratios and/or lower interest rates. In addition, as shown in the decomposition of equity market returns, whereas the dividend portion of the return was historically 4.3%, the current dividend yield is only 1.8%. Due to these reasons, lower market returns are expected for the future.

Q. IS YOUR EXPECTED MARKET RETURN OF 7.5% CONSISTENT WITH THE FORECASTS OF MARKET PROFESSIONALS?

A. Yes. In the first quarter 2007 survey, published on February 13, 2007, the median long-term expected return on the S&P 500 was 7.50% (see page 4 of Exhibit_JRW-7). This is consistent with my expected market return of 7.50%.

Q. IS YOUR EXPECTED MARKET RETURN CONSISTENT WITH THE EXPECTED MARKET RETURNS OF CORPORATE CHIEF FINANCIAL OFFICERS (CFOS)?

A. Yes. John Graham and Campbell Harvey of Duke University conduct a semi-annual survey of corporate CFOs. The survey is a joint project of Duke University and *CFO Magazine*. In the March, 2007 survey, the mean expected return on the S&P 500 over the next ten years is 8.12%.[18]

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[18] The survey results are available at www.cfosurvey.org.

Q. GIVEN THIS EXPECTED MARKET RETURN, WHAT IS YOUR EX ANTE EQUITY RISK PREMIUM USING THE BUILDING BLOCKS METHODOLOGY?

A. As shown in the April 23rd U. S. Treasury Yield Chart on page 40, the current 30-year treasury yield is 4.82%. My ex ante equity risk premium is simply the expected market return from the Building Blocks methodology minus this risk-free rate:

Ex Ante Equity Risk Premium = 7.50% - 4.82% = 2.68%

Q. GIVEN THIS DISCUSSION, HOW ARE YOU MEASURING AN EXPECTED EQUITY RISK PREMIUM IN THIS PROCEEDING?

A. As discussed above, page 3 of Exhibit_JRW-7 provides a summary of the results of a variety of the equity risk premium studies. These include the results of (1) the study of historical risk premiums as provided by Ibbotson, (2) ex ante equity risk premium studies (studies commissioned by the Social Security Administration as well as those labeled 'Puzzle Research'), (3) equity risk premium surveys of CFOs, Financial Forecasters, as well as academics, (4) Building Block approaches to the equity risk premium, and (5) other miscellaneous studies. The overall average equity risk premium of these studies is 4.16%, which I will use as the equity risk premium in my CAPM study.

Q. IS YOUR EX ANTE EQUITY RISK PREMIUM CONSISTENT WITH THE EQUITY RISK PREMIUMS OF LEADING INVESTMENT FIRMS?

A. Yes. One of the first studies in this area was by Stephen Einhorn, one of Wall Street's leading investment strategists.[19] His study showed that the market or equity risk premium had declined to the 2.0 to 3.0 percent range by the early 1990s. Among the evidence he provided in support of a lower equity risk premium is the inverse relationship between real interest rates (observed interest rates minus inflation) and stock prices. He noted that the decline in the market risk premium has led to a significant change in the relationship between interest rates and stock prices. One implication of this development was that stock prices had increased higher than would be suggested by the historical relationship between valuation levels and interest rates.

The equity risk premiums of some of the other leading investment firms today support the result of the academic studies. An article in *The Economist* indicated that some other firms like J.P. Morgan are estimating an equity risk premium for an average risk stock in the 2.0 to 3.0 percent range above the interest rate on U.S. Treasury Bonds.[20]

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[19] Steven G. Einhorn, "The Perplexing Issue of Valuation: Will the Real Value Please Stand Up?" *Financial Analysts Journal* (July-August 1990), pp. 11-16.

[20] For example, see "Welcome to Bull Country," *The Economist* (July 18, 1998), pp. 21-3, and "Choosing the Right Mixture," *The Economist* (February 27, 1999), pp. 71-2.

Q. IS YOUR EX ANTE EQUITY RISK PREMIUM CONSISTENT WITH THE EQUITY RISK PREMIUMS USED BY CORPORATE CHIEF FINANCIAL OFFICERS (CFOS)?

A. Yes. In the previously-referenced March, 2007 CFO – Duke University CFO survey conducted by John Graham and Campbell Harvey, the average ex ante 10-year equity risk premium was 3.42% (8.12% - 4.7%).

Q. IS YOUR EX ANTE EQUITY RISK PREMIUM CONSISTENT WITH THE EX ANTE EQUITY RISK PREMIUMS OF PROFESSIONAL FORECASTERS?

A. Yes. The financial forecasters in the previously-referenced Federal Reserve Bank of Philadelphia survey project both stock and bond returns. As shown on page 4 of Exhibit_JRW-7, the median long-term expected stock and bond returns were 7.50% and 5.00%, respectively. This provides an ex ante equity risk premium of 2.50%.

Q. IS YOUR EX ANTE EQUITY RISK PREMIUM CONSISTENT WITH THE EQUITY RISK PREMIUMS USED BY THE LEADING CONSULTING FIRMS?

A. Yes. McKinsey & Co. is widely recognized as the leading management consulting firm in the world. They recently published a study entitled "The Real Cost of Equity" in which they developed an ex ante equity risk premium for the US. In reference to the decline in the equity risk premium, as well as what is the appropriate equity risk premium to employ for corporate valuation purposes, the McKinsey authors concluded the following:

> We attribute this decline not to equities becoming less risky (the inflation-adjusted cost of equity has not changed) but to investors demanding higher returns in real terms on government bonds after the inflation shocks of the late 1970s and early 1980s. We believe that using an equity risk premium of 3.5 to 4 percent in the current environment better reflects the true long-term opportunity cost of equity capital and hence will yield more accurate valuations for companies.[21]

Q. WHAT EQUITY COST RATE IS INDICATED BY YOUR CAPM ANALYSIS?

A. The results of my CAPM studies for the group of gas distribution companies and Atmos Energy are provided below:

$$K = (R_f) + \beta i * [E(R_m) - (R_f)]$$

	Risk-Free Rate	Beta	Equity Risk Premium	Equity Cost Rate
Gas Distribution Group	5.0%	0.87	4.16%	8.6%
Atmos Energy	5.0%	0.80	4.16%	8.3%

D. Equity Cost Rate Summary

Q. PLEASE SUMMARIZE YOUR EQUITY COST RATE STUDY.

A. The results for my DCF and CAPM analyses for the group of gas distribution companies are indicated below:

	DCF	CAPM
Gas Distribution Group	8.6%	8.6%
Atmos Energy	9.4%	8.3%

Q. GIVEN THESE RESULTS, WHAT IS YOUR ESTIMATED EQUITY COST RATE FOR THE COMPANY?

A. These results suggest that the equity cost rate for the group of gas distribution companies and Atmos Energy is in the 8.3-9.4 percent range. Giving primary weight to the DCF model and the results for the proxy group of gas distribution companies, an equity cost rate of 8.6% would be appropriate. However, the DCF results for Atmos Energy suggests that the equity cost rate for Atmos Energy is higher than that of the proxy group. This is consistent with the lower bond ratings for Atmos Energy vis-à-vis the gas distribution group average. Hence, I will use 9.00% as an equity cost rate for Atmos. This represents the average of the DCF results for the gas distribution group and Atmos Energy. This 9.0% figure provides the Company with a return premium of forty basis points relative to the group. This return premium represents the return premium which is slightly larger

[21] Marc H. Goedhart, et al, "The Real Cost of Equity," *McKinsey on Finance* (Autumn 2002), p. 15.

than that required by investors for one full bond rating differential (e.g., the yields on A versus BBB bond ratings).

Q. DOES YOUR RECOMMENDATION PRESUME THAT THE COMMISSION ADOPTS THE COMPANY'S FORMULA BASED RATE TARIFF?

A. No. If the Kentucky Commission does adopt the Company's Formula Based Rate (FBR) tariff plan, my recommendation would decline to the bottom of my range – 8.3%-8.6% because, in my opinion, the FBR plan would reduce the risk of the Company by reducing the volatility of earnings.

Q. ISN'T YOUR RECOMMENDED RATE OF RETURN LOW BY HISTORICAL STANDARDS?

A. Yes it is, and appropriately so. My rate of return is low by historical standards for three reasons. First, as discussed above, current capital costs are very low by historical standards, with interest rates at a cyclical low not seen since the 1960s. Second, the 2003 tax law, which reduces the tax rates on dividend income and capital gains, lowers the pre-tax return required by investors. And third, as discussed below, the equity or market risk premium has declined.

Q. FINALLY, PLEASE DISCUSS YOUR RATE OF RETURN IN LIGHT OF RECENT YIELDS ON 'A' RATED PUBLIC UTILITY BONDS.

A. In recent months the yields on long-term public utility bonds have been in the 6.00 percent range. My rate of return may appear to be too low given these yields. However, as previously noted, my recommendation must be viewed in the context of the significant decline in the market or equity risk premium. As a result, the return premium that equity investors require over bond yields is much lower than today. This decline was previously reviewed in my discussion of capital costs in today's markets.

Q. HOW DO YOU TEST THE REASONABLENESS OF YOUR COST OF EQUITY AND OVERALL RATE OF RETURN RECOMMENDATION?

A. To test the reasonableness of my 9.00% equity cost rate recommendation, I examine the relationship between the return on common equity and the market-to-book ratios for the companies in the group of gas distribution companies and for Atmos Energy.

Q. WHAT DO THE RETURNS ON COMMON EQUITY AND MARKET-TO-BOOK RATIOS FOR THE GROUP OF GAS COMPANIES AND ATMOS INDICATE ABOUT THE REASONABLENESS OF YOUR 9.00% RECOMMENDATION?

A. Exhibit_(JRW-2) provides financial performance and market valuation statistics for the group of gas distribution companies. The average current return on equity and market-to-book ratios for the group are summarized below:

	Current ROE	Market-to-Book Ratio
Gas Group	12.3%	2.00
Atmos Energy	8.9%	1.46

Source: Exhibit_(JRW-2)

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These results clearly indicate that, on average, these companies and Atmos Energy are earning returns on equity above their equity cost rates. As such, this observation provides evidence that my recommended equity cost rate of 9.00% is reasonable and fully consistent with the financial performance and market valuation of the group of gas distribution companies.

V. CRITIQUE OF ATMOS RATE OF RETURN TESTIMONY

Q. WHAT ISSUES ARE YOU ADDRESSING IN YOUR REBUTTAL TESTIMONY?

A. The Company's rate of return testimony is provided by Dr. Donald A. Murry. My rebuttal testimony focuses on Dr. Murry's recommended capital structure and equity cost rate approaches and results.

Q. PLEASE DISCUSS THE CAPITAL STRUCTURE ISSUE IN THIS CASE.

A. As shown in Panel A of Exhibit_(JRW-3), Atmos has proposed a capital structure consisting of 51.85% long-debt and 48.15% common equity. Panel B of Exhibit_(JRW-3), provides the average capitalization ratios for Atmos Energy over the past year. The average common equity ratio, including short-term debt, was only 41.37%. The figures in Panel B indicate that the Company has consistently used short-term debt as a source of capital, and that a common equity ratio of 48.15% significantly exceeds the amount of equity capital employed by the Company. Panel C of Exhibit_(JRW-3), provides the average capitalization ratios for proxy group of nine gas distribution companies. Like Atmos Energy, these companies have consistently used short-term debt as a source of capital. Indeed, in its responses to AG-1-3 and AG-1-5, the Company confirms that it uses short term debt to finance its gas purchases and the monthly fluctuations in its Gas Stored Underground balances. The purchased gas expenses are included in the test period operating expenses and the average Gas Stored Underground balance is included in the requested test period rate base. For consistency purposes, a representative average balance of short term debt should therefore be included in the capital structure. The Company has failed to do so in its proposed capital structure.

Q. PLEASE REVIEW DR. MURRY'S EQUITY COST RATE APPROACHES.

A. Dr. Murry uses a comparable group gas companies as well as Atmos Energy and employs DCF and CAPM equity cost rate approaches. Dr. Murry's comparable group of gas companies includes AGL Resources, New Jersey Resources, Nicor, Northwest natural Gas, Piedmont Natural Gas Company, Southwest Gas, and WGL Holdings.

Q. BEFORE ADDRESSING DR. MURRY'S EQUITY COST RATE APPROACHES, PLEASE COMMENT ON DR. MURRY'S PROXY GROUP OF GAS COMPANIES.

A. My only concern with Dr. Murry's is that, without explanation, he has excluded Laclede Group and South Jersey Industries.

Q. PLEASE SUMMARIZE DR. MURRY'S EQUITY COST RATE RESULTS.

A. Dr. Murry's equity cost rate estimates for Atmos Energy and the comparable group are summarized in the table below. Based on these figures, he concludes that the appropriate equity cost rate for the Company to be 11.75%.

<u>Summary of Equity Cost Rate Approaches and Results</u>

	Comparable Gas Companies		**Atmos Energy**	
Approach	**Low**	**High**	**Low**	**High**
52 Week DCF				
Using EPS Growth	9.55%	10.44%	11.25%	12.39%
Using Projected Growth	7.10%	9.81%	10.87%	12.01%
Current DCF				
Using EPS Growth	9.61%	9.66%	11.31%	11.36%
Using Projected Growth	7.16%	9.00%	10.93%	10.98%
CAPM				
Size-Adjusted CAPM		12.49%		11.13%
Historic CAPM		12.93%		11.82%

Equity Cost Rate Recommendation 11.75%

Q. PLEASE DISCUSS YOUR ISSUES WITH DR. MURRY'S RECOMMENDED EQUITY COST RATE.

A. There are a number of problems with Dr. Murry's equity cost rate studies. With respect to his specific approaches, he arrives at an excessive estimate of Atmos' cost of equity capital primarily due to (1) his highly selective use of his DCF results which produces an upwardly-biased DCF equity cost rate; and (2) excessive risk premium estimates in his CAPM approaches. In addition, his CAPM equity cost rate estimates include inappropriate premium for size.

Q. PLEASE SUMMARIZE DR. MURRY'S DCF ESTIMATES.

A. On pages 22-32 of his testimony, and in Schedules DAM-16-DAM-23, Dr. Murry develops an equity cost rate by applying a DCF model to Atmos Energy and his comparable gas group. In the traditional DCF approach, the equity cost rate is the sum of the dividend yield and expected growth. For Atmos Energy and the comparable group, he performs two DCF analyses – a 52-week DCF using stock prices over the past year, and a Current DCF using stock prices over the past two weeks. For each of these DCFs, he computes equity cost rates using (1) projected DPS growth rates, (2) *Value Line* projected EPS over the 2000-02 to the 2009-11 time period, and (3) projected EPS growth rates estimates from *Value Line* (from 2003-05 to 2009-11) and from analysts as compiled by S&P.

	Atmos Energy		Comparable Gas Companies	
Approach	**Low**	**High**	**Low**	**High**
52 Week DCF				
Using DPS Growth	5.57%	6.71%	6.46%	7.38%
Using VL EPS Growth	**11.25%**	**12.39%**	8.66%	9.57%
Using VL-S&P Growth	**10.87%**	**12.01%**	7.10%	9.81%
Current DCF				
Using DPS Growth	5.63%	5.68%	6.52%	6.57%
Using VL EPS Growth	**11.31%**	**11.36%**	8.71%	8.76%
Using VL-S&P Growth	**10.93%**	**10.98%**	7.16%	9.00%

Data Source: Exhibits DAM-17—DAM 23.

Based on these figures, Dr. Murry claims that the relevant DCF results for Atmos Energy are in the range of 10.87% to 12.39%. These figures are bolded in the table above.

Q. PLEASE EXPRESS YOUR CONCERNS WITH DR. MURRY'S DCF STUDY.

A. Beyond my previously-discussed concerns on the composition of his proxy group, I have several major concerns with Dr. Murry's DCF analyses. These are: (1) he has ignored results using projected DPS growth rates for both Atmos Energy and the comparable gas company group; (2) he has totally ignored the DCF results for his comparable group of gas companies and relied on selected results for Atmos Energy; and (3) the selected DCF results employed by Dr. Murry in arriving at his DCF conclusion are for Atmos Energy and rely primarily on the projected EPS growth rate estimates of *Value Line* (as projected over the 2000-02 to 2009-11 and the 2003-05 to 2009-11 time periods).

Q. BEFORE ADDRESSING THESE ISSUES, PLEASE REVIEW DR. MURRY'S DCF GROWTH RATES.

A. In Schedule DAM-17 Dr. Murry provides the growth rates that he claims to have used in his DCF equity cost rate study. As discussed below, whereas Dr. Murry has presented these as his DCF growth rates, he has very selectively used these in developing his equity cost rate for Atmos. Note that the averages of the growth rates for Atmos Energy and for the gas group are 5.31% and 4.18%, respectively.

Atmos Energy and Comparable Gas Companies
Discounted Cash Flow Growth Rate Summary

	Value Line						Projections			
	2001 TO 2010 Estimate			Five Year Historical			Value Line		S & P	
	EPS	DPS	Book Value	EPS	DPS	Book Value	EPS	DPS	EPS	Average
Atmos Energy Corp.	7.38%	1.70%	6.70%	6.5%	2.0%	8.5%	7.0%	2.0%	6.0%	5.31%
Comparable Companies' Averages	5.27%	3.07%	4.79%	4.86%	2.29%	4.71%	5.21%	3.43%	4.00%	4.18%

Q. PLEASE ADDRESS YOUR FIRST ISSUE.

A. Dr. Murry has ignored the DCF results for both Atmos Energy and the comparable group using projected DCF growth rates. In the DCF model, the cash flows that investors receive are in the form of dividends. The average projected DPS growth for Atmos Energy and the comparable gas group are in the 2.0% and 3.0% range, respectively. Ignoring the DCF results which use projected DPS growth rates leads to an upwardly biased estimate of a DCF equity cost rate.

Q. YOU CLAIM THAT DR. MURRY HAS ALSO IGNORED THE DCF RESULTS FOR HIS COMPARABLE GROUP. PLEASE EXPLAIN.

A. Dr. Murry's summary results are provided in Schedule DAM-25. First, it should be noted that his comparison group DCF summary results are misstated because he has omitted low DCF results for NICOR. Second, and most importantly, on page 39 of his testimony, Dr. Murry claims that the relevant DCF results are from 10.87% to 12.39%. However, these are the range of DCF figures for Atmos Energy using (a) 2000-02 to 2009-11 EPS growth rates and (b) analysts' projected EPS growth rates from Value Line and S&P. This relevant range totally ignores the results for the comparable group. Hence, Dr. Murry has employed a sample size of one -- Atmos Energy – in arriving at a DCF equity cost rate for the Company and he has totally ignored the results for his comparable gas companies. In each and every case, these figures were ignored because they provided low equity cost rate results. From the table on page 66, the average of the low – high DCF equity cost rate DCF results for the comparable companies is 7.4% and 8.5%. The averages, excluding the projected DPS growth rate results as Dr. Murry has done, are 7.9% and 9.3%. Therefore, by ignoring these results, he is recommending a DCF equity cost rate using the results for one company which is 300-400 basis points higher than that of his comparable gas company group.

Q. YOU ALSO CLAIM THAT DR. MURRY'S DCF GROWTH RATE HAS BEEN VERY SELECTIVELY CHOSEN. PLEASE ELABORATE.

A. Not only has Dr. Murry employed a sample size of one (Atmos Energy) by ignoring the results for the comparison gas company group, he has also been very selective in which growth rates he considers. As shown on page 67, the average of the growth rates listed by Dr. Murry for Atmos Energy is 5.13%. Is his alternative DCF models for Atmos, he has used growth rates of 7.38% (*Value Line*'s projected EPS growth - 2000-02 to 2009-11), 7.00% (*Value Line*'s projected EPS growth - 2003-05 to 2009-11), and 6.00% (Analysts' projected 5-year EPS growth rate). *Value Line's* projected growth rate figures (7.38% and 7.00%) are above the consensus of current projections of Wall Street analysts (6.00%). He certainly has put no weight whatsoever on a number of the growth rate indicators listed on Schedule DAM-17. Instead, he has relied exclusively on the EPS growth rate projections of Wall Street analysts and *Value Line* results in upwardly biased DCF equity cost rate estimates.

Q. PLEASE REVIEW DR. MURRY'S RELIANCE ON ANALYSTS' AND *VALUE LINE*'S PROJECTED EPS GROWTH RATE ESTIMATES.

A. In the two DCF results that Dr. Murry deems relevant, he has relied excessively on the EPS forecasts of Wall Street analysts and *Value Line*'s average projected EPS growth rate to gauge growth for his DCF model. It seems highly unlikely that investors today would rely excessively on the forecasts of securities analysts and *Value Line*, and ignore historical growth, in arriving at expected growth. In the academic world, the fact that

EPS forecasts of securities analysts are overly optimistic and biased upwards has been known for years. In addition, as I show below, *Value Line's* EPS forecasts are excessive and unrealistic.

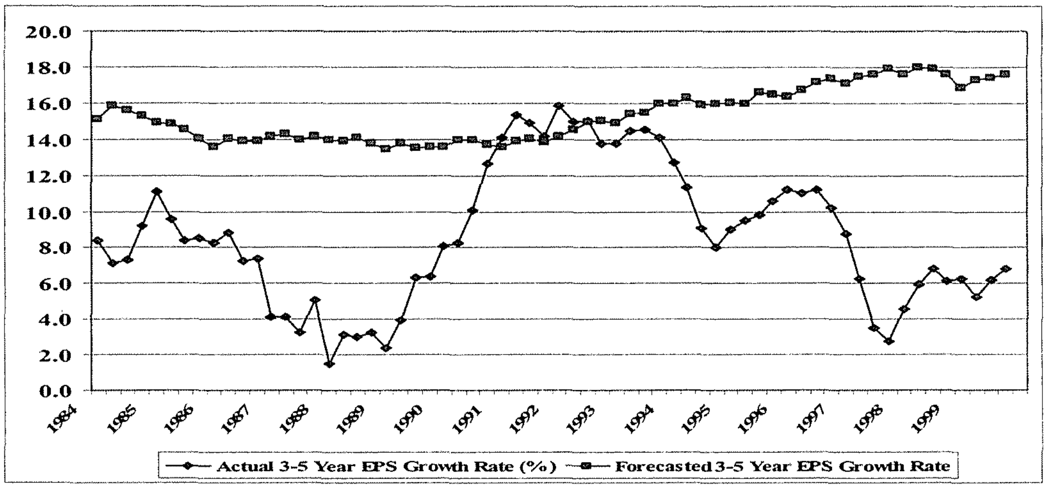
Q. PLEASE REVIEW THE BIAS IN ANALYSTS' GROWTH RATE FORECASTS.

A. Analysts' growth rate forecasts are collected and published by Zacks, First Call, I/B/E/S, and Reuters. These services retrieve and compile EPS forecasts from Wall Street Analysts. These analysts come from both the sell side (Merrill Lynch, Paine Webber) and the buy side (Prudential Insurance, Fidelity).

The problem with using these forecasts to estimate a DCF growth rate is that the objectivity of Wall Street research has been challenged, and many have argued that analysts' EPS forecasts are overly optimistic and biased upwards. To evaluate the accuracy of analysts' EPS forecasts, I have compared actual 3-5 year EPS growth rates with forecasted EPS growth rates on a quarterly basis over the past 20 years for all companies covered by the I/B/E/S data base. In the graph below, I show the average analysts' forecasted 3-5 year EPS growth rate with the average actual 3-5 year EPS growth rate. Because of the necessary 3-5 year follow-up period to measure actual growth, the analysis in this graph (1) only covers forecasted and actual EPS growth rates through 1999, and (2) includes only companies that have 3-5 years of actual EPS data following the forecast period.

The following example shows how the results can be interpreted. As of the first quarter of 1995, analysts were projecting an average 3-5-year annual EPS growth rate of 15.98%, but companies only generated an average annual EPS growth rate over the next 3-5 years of 8.14%. This 15.98% figure represented the average projected growth rate for 1,115 companies, with an average of 4.70 analysts' forecasts per company over the 20 year period covered by the study. The only periods when firms met or exceeded analysts' EPS growth rate expectations were for six consecutive quarters in 1991-92 following the one-year economic downturn at the turn of the decade.

Analysts' Forecasted 3-5-Year Forecasted Versus Actual EPS Growth Rates 1984-1999



Source: J. Randall Woolridge.

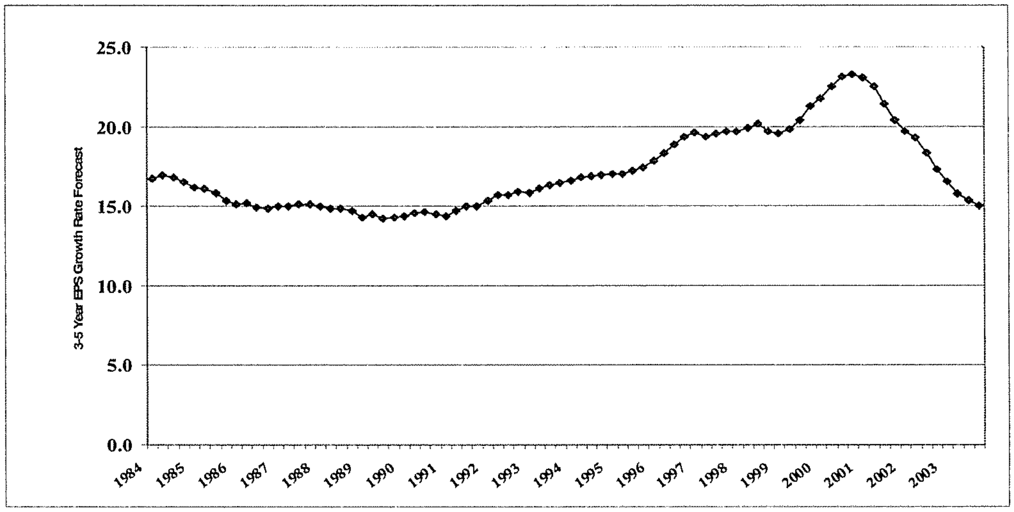
Over the entire time period, Wall Street analysts have continually forecasted 3-5-year EPS growth rates in the 14-18 percent range (mean = 15.32%), but these firms have only delivered an average EPS growth rate of 8.75%.

The post-1999 period has seen the boom and then the bust in the stock market, an economic recession, 9/11, and the Iraq war. Furthermore, and highly significant in the context of this study, we have also had the Elliott Spitzer investigation of Wall Street firms and the subsequent Global Securities Settlement in which nine major brokerage firms paid a fine of $1.5B for their biased investment research.

To evaluate the impact of these events on analysts' forecasts, the graph below provides the average 3-5-year EPS growth rate projections for all companies provided in the I/B/E/S database on a quarterly basis from 1985 to 2004. In this graph, no comparison to actual EPS growth rates is made and hence there is no follow-up period. Therefore, 3-5 year growth rate forecasts are shown until 2004 and, since companies are dropped from the study due to a lack of follow-up EPS data, these results are for a larger sample of firms.[22] Analysts' forecasts for EPS growth were higher for this larger sample of firms, with a more pronounced run-up and then decline around the stock market peak in 2000. The average projected growth rate hovered in the 14.5%-17.5% range until 1995, and then increased dramatically over the next five years to 23.3% in the fourth quarter of the year 2000. Forecasted growth has since declined to the 15.0% range.

[22] The number of companies in the sample grows from 2,220 in 1984, peaks at 4,610 in 1998, and then declines to 3,351 in 2004. The number of analysts' forecasts per company averages between 3.75 to 5.10, with an overall mean of 4.37.

Mean Analysts' 3-5-Year Forecasted EPS Growth Rates
1985-2004



Source: J. Randall Woolridge.

While analysts' EPS growth rate forecasts have subsided since 2000, these results suggest that, despite the Elliot Spitzer investigation and the Global Securities Settlement, analysts' EPS forecasts are still upwardly biased. The actual 3-5 year EPS growth rate over time has been about one half the projected 3-5 year growth rate forecast of approximately 15.0%. Furthermore, as discussed later in my testimony, historic growth in GNP and corporate earnings has been in the 7% range. This observation is supported by a *Wall Street Journal* article entitled "Analysts Still Coming Up Rosy – Over-Optimism on Growth Rates is Rampant – and the Estimates Help to Buoy the Market's Valuation." The following quote provides insight into the continuing bias in analysts' forecasts:

> Hope springs eternal, says Mark Donovan, who manages Boston Partners Large Cap Value Fund. 'You would have thought that, given what happened in the last three years, people would have given up the ghost. But in large measure they have not.'
>
> These overly optimistic growth estimates also show that, even with all the regulatory focus on too-bullish analysts allegedly influenced by their firms' investment-banking relationships, a lot of things haven't changed: Research remains rosy and many believe it always will.[23]

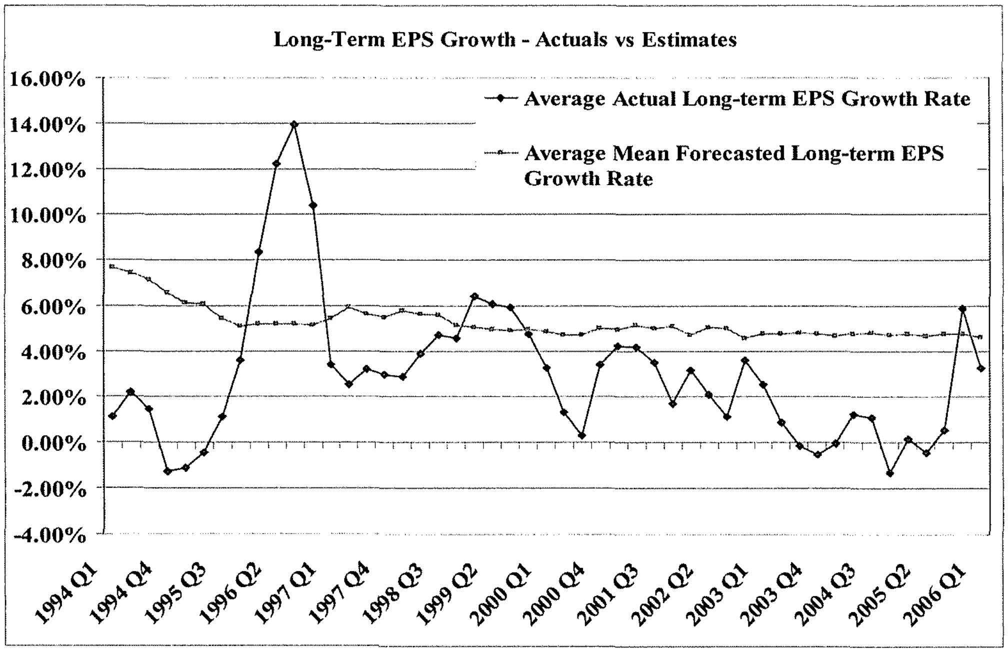
Q. ARE ANALYSTS' EPS GROWTH RATE FORECASTS LIKEWISE UPWARDLY BIASED FOR NATURAL GAS DISTRIBUTION COMPANIES?

A. Yes. To evaluate whether analysts' EPS growth rate forecasts are upwardly biased for a group of natural gas distribution companies, I conducted a study similar to the one described above using a group of gas distribution companies.[24] The projected EPS growth rates, which were in the 7-8 percent range in the early 1990s, have steadily declined over the past decade to the 4 percent range today. Actual EPS growth has been volatile, and pretty consistently below projected EPS growth rates. Over the entire period, the average quarterly projected and actual EPS growth rates are 5.25% and 3.01%, respectively. Hence, analysts' projected EPS growth rate forecasts are likewise upwardly biased for natural gas distribution companies.

[23] Ken Brown, "Analysts Still Coming Up Rosy – Over-Optimism on Growth Rates is Rampant – and the Estimates Help to Buoy the Market's Valuation." *Wall Street Journal*, (January 27, 2003), p. C1.

[24] The companies include Cascade Natural Gas, Laclede, Nicor, Northwest Natural Gas, Piedmont, and WGL Holdings.

Analysts' Forecasted 3-5-Year Forecasted Versus Actual EPS Growth Rates
Natural Gas Distribution Companies
1990-2006



Q. ARE *VALUE LINE*'S GROWTH RATE FORECASTS SIMILARILY UPWARDLY BIASED?

A. Yes. *Value Line* has a decidedly positive bias to its earnings growth rate forecasts as well. To assess *Value Line*'s earnings growth rate forecasts, I used the *Value Line Investment Analyzer*. The results are summarized in the table below. I initially filtered the database and found that *Value Line* has 3-5 year EPS growth rate forecasts for 2,611 firms. The average projected EPS growth rate was 16.1%. This is incredibly high given that the average historical EPS growth rate in the US is about seven percent! Equally incredible is that *Value Line* only predicts negative EPS growth for thirty companies. That is one percent of the companies covered by *Value Line*. Given the ups and downs of corporate earnings, this is unreasonable.

***Value Line* 3-5 year EPS Growth Rate Forecasts**

	Average Projected EPS Growth rate	**Number of Negative EPS Growth Projections**	**Percent of Negative EPS Growth Projections**
2,611 Firms	**16.1%**	**30**	**1.1%**

To put this figure in perspective, I screened the 2,611 firms with 3-5 year growth rate forecasts to see what percent had experienced negative EPS growth rates over the past five years. *Value Line* reported a five-year historic growth rate for 1,613 of the 2,613 companies. It should be noted that the past five years have been a period of rapidly rising corporate earnings as the economy and businesses have rebounded from the recession of 2001. These results, shown in the table below, indicate that the average historic growth was 9.40% and *Value Line* reported negative historic growth for 405 firms which represents 25.1% of these companies.

Historical Five-Year EPS Growth Rates for Companies with *Value Line* 3-5 year EPS Growth Rate Forecasts

	Average Historical EPS Growth rate	**Number with Negative Historical EPS Growth**	**Percent with Negative Historical EPS Growth**
1,613 Firms	**9.40%**	**405**	**25.1%**

These results indicate that *Value Line*'s EPS forecasts are excessive and unrealistic. It appears that analysts at *Value Line* are similar to the analysts at Wall Street firms and view future earnings through 'rose-colored' glasses and provide overly-optimistic forecasts of future growth.

Q. FINALLY, IN LIGHT OF THE DISCUSSION ABOVE, PLEASE COMMENT ON DR. MURRY'S REFERENCES TO STUDIES THAT DEMONSTRATE THE IMPORTANCE OF ANALYSTS' EPS FORECASTS.

A. Dr. Murry has highlighted studies by Carleton and Vander Weide and by Timme and Eisemann to support his exclusive reliance on Wall Street analysts' EPS forecasts. While these studies indicate that analysts' EPS forecasts are superior to historic growth rate measures, there are numerous errors in the studies that make their relevance in this proceeding insignificant.

First, it is important to note that these studies were published nearly twenty years ago, using relatively small samples of companies. Since that time, many more exhaustive studies have been performed using significantly larger data bases and, from these studies, much has been learned about Wall Street analysts and their stock recommendations and earnings forecasts. Nonetheless, there are several errors in the studies that invalidate the results. Most significantly, the regression models in the studies are mis-specified. This results because the authors used a "linear approximation" of the DCF model. They used the approximation so that they did not have to measure k, investors' required return, directly, but instead they used proxy variables for risk. The error in this approach is there can be an interaction between growth (g) and investors' required return (k) which could lead him to conclude that one growth rate measure is superior to others. Furthermore, due to this problem, analysts' EPS forecasts could be upwardly biased and still appear to provide better measures of expected growth. As a result, the authors of the studies cannot conclude whether one growth rate measure is better than the other.

Q. FINALLY, ON PAGE 28 OF HIS TESTIMONY, DR. MURRY HAS ARGUED THAT HE HAS FOCUSED ON THE HIGHER DCF RESULTS AS AN ALTERNATIVE TO MAKING AN ADJUSTMENT FOR FLOTATION COSTS OR MARKET PRESSURE. PLEASE RESPOND.

A. Dr. Murry's argument for using the higher end DCF results to account for flotation costs or market pressure is in error. There is no need for such an adjustment. Usually it is argued that a flotation cost adjustment is necessary to prevent the dilution of the existing shareholders. Such an adjustment is commonly justified by reference to bonds and the manner in which issuance costs are recovered by including the amortization of bond flotation costs in annual financing costs. However, this is incorrect for several reasons:

(1) If an equity flotation cost adjustment is similar to a debt flotation cost adjustment, the fact that the market-to-book ratios for gas distribution companies are nearly 2.0 actually suggests that there should be a flotation cost reduction (and not increase) to the equity cost rate. This is because when (a) a bond is issued at a price in excess of face or book value, and (b) the difference between market price

and the book value is greater than the flotation or issuance costs, the cost of that debt lower than the coupon rate of the debt. The amount by which market values of gas distribution companies are in excess of book values is much greater than flotation costs. Hence, if common stock flotation costs were exactly like bond flotation costs, and one was making an explicit flotation cost adjustment to the cost of common equity, the adjustment would be downward;

(2) It is commonly argued that a flotation cost adjustment is needed to prevent dilution of existing stockholders' investment. However, the reduction of the book value of stockholder investment associated with flotation costs can occur only when a company's stock is selling at a market price at/or below its book value. As noted above, gas distribution companies are selling at market prices well in excess of book value. Hence, when new shares are sold, existing shareholders realize an increase in the book value per share of their investment, not a decrease;

(3) Flotation costs consist primarily of the underwriting spread or fee and not out-of-pocket expenses. On a per share basis, the underwriting spread is the difference between the price the investment banker receives from investors and the price the investment banker pays to the company. Hence, these are not expenses that must be recovered through the regulatory process. Furthermore, the

underwriting spread is known to the investors who are buying the new issue of stock, who are well aware of the difference between the price they are paying to buy the stock and the price that the Company is receiving. The offering price which they pay is what matters when investors decide to buy a stock based on its expected return and risk prospects. Therefore, the company is not entitled to an adjustment to the allowed return to account for those costs; and

(4) Flotation costs, in the form of the underwriting spread, are a form of a transaction cost in the market. They represent the difference between the price paid by investors and the amount received by the issuing company. Whereas Dr. Murry believes that the Company should be compensated for these transactions costs by using the high-end DCF results, neither he or I have accounted for other market transaction costs in determining a cost of equity for the Company. Most notably, brokerage fees that investors pay when they buy shares in the open market are another market transaction cost. Brokerage fees increase the effective stock price paid by investors to buy shares. If Dr. Murry and I had included these brokerage fees or transaction costs in our DCF analyses, the higher effective stock prices paid for stocks would lead to lower dividend yields and equity cost rates. To be fair then, if Dr. Murry is to make an upward adjustment for transaction costs in the form of using the high-end DCF results, he also should have made a

downward adjustment for transaction costs in the form of brokerage fees.

Q. PLEASE DISCUSS DR. MURRY'S USE OF THE CAPM.

A. On pages 33-39, in Schedules DAM-24 and DAM-25, Dr. Murry applies the CAPM to Atmos Energy and the comparison group of gas companies. The first CAPM, which he calls the size-adjusted CAPM, is a traditional CAPM with an incremental 1.02%-1.81% adjustment to account for the relative size of Atmos and the comparable gas companies. The second CAPM, which Dr. Murry calls a historical CAPM, is based strictly on historical stock and bond returns. Dr. Murry's historical CAPM is very untraditional in three ways: (1) the market total return is the average of the historical returns for large and small stocks as reported by Ibbotson Associates, (2) the historic bond return of 6.20% is for long-term corporate bonds, and (3) the risk-free rate Dr. Murry uses is the historic Aaa corporate bond return. The results of Dr. Murry's CAPM analyses are summarized below.

CAPM Equity Cost Rate
Size Adjusted CAPM

	Atmos Energy	**Comparable Gas Companies**
Risk-Free Rate	4.78%	4.78%
Beta	.75	.88
Risk-Adjusted Market Premium	7.10%	7.10%
CAPM Equity Cost Rate	10.11%	11.03%
Size Adjustment Premium	1.02%	1.47%
CAPM Equity Cost Rate	**11.13%**	**12.49%**

CAPM Equity Cost Rate
Historical CAPM

	Atmos Energy	Comparable Gas Companies
Market Return	14.85%	14.85%
L-T Bond Return	6.20%	6.20%
Risk Premium	8.65%	8.65%
Weighting	.75	.88
Adjusted Risk Premium	6.49%	7.60%
Aaa Corporate Bond Return	5.33%	5.33%
CAPM Equity Cost Rate	11.82%	12.93%

Q. PLEASE SUMMARIZE YOUR ASSESSMENT OF DR. MURRY'S CAPM ANALYSES.

A. There are two primary flaws with Dr. Murry's CAPM analyses: (1) his explicit size adjustment of 1.02% for Atmos and 1.47% for the comparison gas group in his size-adjusted CAPM and an implicit size premium in his historical CAPM; and (2) most significantly, his equity risk premium of 7.10% in his size-adjusted CAPM and his risk premium of 8.65% in his historical CAPM.

Q. PLEASE DISCUSS DR. MURRY'S EXPLICIT AND IMPLICIT SIZE ADJUSTEMENTS.

A. As noted above, Dr. Murry uses explicit size adjustment of 1.02% for Atmos and 1.47% for the comparison gas group in his size-adjusted CAPM and uses an implicit size premium in his historical CAPM. The implicit size premium in his historical CAPM results from the fact that his market total return of 14.85% is the average of the arithmetic mean stock returns for large stocks of 12.3% and for small stocks of 17.4%. Dr. Murry supports the need for a size premium by citing the work of Ibbotson Associates.

There are several flaws in this analysis. First, as discussed later in my testimony, there are a number of errors in using historical market returns to compute risk premiums. Second, the Ibbotson study used for the explicit size premium is based on the stock returns for companies in the 10^{th} decile. However, a review of Tables 7-5 and 7-7 in the Ibbotson document indicates that these companies have betas that are much larger than the betas of gas distribution companies. Hence, these size premiums are not associated with the gas distribution industry.

Finally, and most importantly, any equity cost rate adjustment based on the relative size of a public utility is inappropriate. Professor Annie Wong has tested for a size premium in utilities and concluded that, unlike industrial stocks, utility stocks do not exhibit a significant size premium.[25] As explained by Professor Wong, there are several reasons why such a size premium would not be attributable to utilities. Utilities are regulated closely by state and federal agencies and commissions and hence their financial performance is monitored on an on-going basis by both the state and federal governments. In addition, public utilities must gain approval from government entities for common

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[25] Annie Wong, "Utility Stocks and the Size Effect: An Empirical Analysis", *Journal of the Midwest Finance Association*, 1993, PP. 95-101.

financial transactions such as the sale of securities. Furthermore, unlike their industrial counterparts, accounting standards and reporting are fairly standardized for public utilities. Finally, a utility's earnings are predetermined to a certain degree through the ratemaking process in which performance is reviewed by state commissions and other interested parties. Overall, in terms of regulation, government oversight, performance review, accounting standards, and information disclose, utilities are much different than industrials which could account for the lack of a size premium.

Q. PLEASE REVIEW THE ERRORS IN DR. MURRY'S EQUITY OR RISK PREMIUM IN HIS TWO CAPM APPROACHES.

A. The primary problem with Dr. Murry's two CAPM analyses is the size of the market or equity risk premium. Dr. Murry uses a risk premium of 7.10% in his size-adjusted CAPM. This is the arithmetic average risk premium of the 1926-2005 results from the Ibbotson study. He uses a risk premium of 8.65% in his historical CAPM which is the difference between his historic market return of 14.85% (the average of the arithmetic mean stock returns for large stocks of 12.3% and for small stocks of 17.4%) and 6.10% which is the historic long-term corporate bond return. Both of these risk premiums are based solely on the difference in the arithmetic mean stock and bond returns over the 1926-2005 period.

Q. PLEASE ADDRESS THE ISSUE INVOLVING THE USE OF HISTORIC STOCK AND BOND RETURNS TO COMPUTE A FORWARD-LOOKING OR EX ANTE RISK PREMIUM.

A. Using the historic relationship between stock and bond returns to measure an ex ante equity risk premium is erroneous and, especially in this case, overstates the true market equity risk premium. The equity risk premium is based on expectations of the future and when past market conditions vary significantly from the present, historic data does not provide a realistic or accurate barometer of expectations of the future. At the present time, using historic returns to measure the ex ante equity risk premium ignores current market conditions and masks the dramatic change in the risk and return relationship between stocks and bonds. This change suggests that the equity risk premium has declined.

Q. PLEASE DISCUSS THE ERRORS IN USING HISTORICAL STOCK AND BOND RETURNS TO ESTIMATE AN EQUITY RISK PREMIUM.

A. There are a number of flaws in using historical returns over long time periods to estimate expected equity risk premiums. These issues include:

(A) Biased historical bond returns;

(B) The arithmetic versus the geometric mean return;

(C) Unattainable and biased historical stock returns;

(D) Survivorship bias;

(E) The "Peso Problem;"

(F) Market conditions today are significantly different than the past; and

(G) Changes in risk and return in the markets.

These issues will be addressed in order.

Biased Historical Bond Returns

Q. HOW ARE HISTORICAL BOND RETURNS BIASED?

A. An essential assumption of these studies is that over long periods of time investors' expectations are realized. However, the experienced returns of bondholders in the past violate this critical assumption. Historic bond returns are biased downward as a measure of expectancy because of capital losses suffered by bondholders in the past. As such, risk premiums derived from this data are biased upwards.

The Arithmetic Versus the Geometric Mean Return

Q. PLEASE DISCUSS THE ISSUE RELATING TO THE USE OF THE ARITHMETIC VERSUS THE GEOMETRIC MEAN RETURNS IN THE IBBOTSON METHODOLOGY.

A. The measure of investment return has a significant effect on the interpretation of the risk premium results. When analyzing a single security price series over time (i.e., a time series), the best measure of investment performance is the geometric mean return. Using the arithmetic mean overstates the return experienced by investors. In a study entitled "Risk and Return on Equity: The Use and Misuse of Historical Estimates," Carleton and Lakonishok make the following observation: "The geometric mean measures the changes in wealth over more than one period on a buy and hold (with dividends invested) strategy."[26] Since Dr. Murry's study covers more than one period (and he assumes that dividends are reinvested), he should be employing the geometric mean and not the arithmetic mean.

Q. PLEASE PROVIDE AN EXAMPLE DEMONSTRATING THE PROBLEM WITH USING THE ARITHMETIC MEAN RETURN.

A. To demonstrate the upward bias of the arithmetic mean, consider the following example. Assume that you have a stock (that pays no dividend) that is selling for $100 today, increases to $200 in one year, and then falls back to $100 in two years. The table below shows the prices and returns.

Time Period	Stock Price	Annual Return
0	$100	
1	$200	100%
2	$100	-50%

[26] Willard T. Carleton and Josef Lakonishok, "Risk and Return on Equity: The Use and Misuse of Historical Estimates," *Financial Analysts Journal* (January-February, 1985), pp. 38-47.

The arithmetic mean return is simply (100% + (-50%))/2 = 25% per year. The geometric mean return is $((2 * .50)^{(1/2)}) - 1 = 0\%$ per year. Therefore, the arithmetic mean return suggests that your stock has appreciated at an annual rate of 25%, while the geometric mean return indicates an annual return of 0%. Since after two years, your stock is still only worth $100, the geometric mean return is the appropriate return measure. For this reason, when stock returns and earnings growth rates are reported in the financial press, they are generally reported using the geometric mean. This is because of the upward bias of the arithmetic mean. As further evidence as to the appropriate mean return measure, the U.S. Securities and Exchange Commission requires equity mutual funds to report historical return performance using geometric mean and not arithmetic mean returns.[27] In sum, Dr. Murry's arithmetic mean return measures are biased and should be disregarded.

Unattainable and Biased Historic Stock Returns

Q. YOU NOTE THAT HISTORIC STOCK RETURNS ARE BIASED USING THE IBBOTSON METHODOLOGY. PLEASE ELABORATE.

A. Returns developed using Ibbotson's methodology are computed on stock indexes and therefore (1) cannot be reflective of expectations because these returns are unattainable to investors, and (2) produce biased results. This methodology assumes (a) monthly portfolio rebalancing and (b) reinvestment of interest and dividends. Monthly portfolio rebalancing

[27] U.S. Securities and Exchange Commission, Form N-1A.

presumes that investors rebalance their portfolios at the end of each month in order to have an equal dollar amount invested in each security at the beginning of each month. The assumption would obviously generate extremely high transaction costs and thereby render these returns unattainable to investors. In addition, an academic study demonstrates that the monthly portfolio rebalancing assumption produces biased estimates of stock returns.[28]

Transaction costs themselves provide another bias in historic versus expected returns. The observed stock returns of the past were not the realized returns of investors due to the much higher transaction costs of previous decades. These higher transaction costs are reflected through the higher commissions on stock trades, and the lack of low cost mutual funds like index funds.

<u>Survivorship Bias</u>

Q. HOW DOES SURVIVORSHIP BIAS AFFECT DR. MURRY'S HISTORIC EQUITY RISK PREMIUM?

A. Using historic data to estimate an equity risk premium suffers from survivorship bias. Survivorship bias results when using returns from indexes like the S&P 500. The S&P 500 includes only companies that have survived. The fact that returns of firms that did not perform so well were dropped from these indexes is not reflected. Therefore these

[28] See Richard Roll, "On Computing Mean Returns and the Small Firm Premium," *Journal of Financial Economics* (1983), pp. 371-86.

stock returns are upwardly biased because they only reflect the returns from more successful companies.

The "Peso Problem"

Q. WHAT IS THE "PESO PROBLEM" AND HOW DOES IT AFFECT HISTORIC RETURNS AND EQUITY RISK PREMIUMS?

A. Dr. Murry's use of historic return data also suffers from the so-called "peso problem." The "peso problem" issue was first highlighted by the Nobel laureate, Milton Friedman, and gets its name from conditions related to the Mexican peso market in the early 1970s. This issue involves the fact that past stock market returns were higher than were expected at the time because despite war, depression, and other social, political, and economic events, the US economy survived and did not suffer hyperinflation, invasion, and the calamities of other countries. As such, highly improbable events, which may or may not occur in the future, are factored into stock prices, leading to seemingly low valuations. Higher than expected stock returns are then earned when these events do not subsequently occur. Therefore, the "peso problem" indicates that historical stock returns are overstated as measures of expected returns.

Market Conditions Today are Significantly Different than in the Past

Q. FROM AN EQUITY RISK PREMIUM PERSPECTIVE, PLEASE DISCUSS HOW MARKET CONDITIONS ARE DIFFERENT TODAY.

A. The equity risk premium is based on expectations of the future. When past market conditions vary significantly from the present, historic data does not provide a realistic or accurate barometer of expectations of the future. As noted previously, stock valuations (as measured by P/E) are relatively high and interest rates are relatively low, on a historic basis. Therefore, given the high stock prices and low interest rates, expected returns are likely to be lower on a going forward basis.

Changes in Risk and Return in the Markets

Q. PLEASE DISCUSS THE NOTION THAT HISTORIC EQUITY RISK PREMIUM STUDIES DO NOT REFLECT THE CHANGE IN RISK AND RETURN IN TODAY'S FINANCIAL MARKETS.

A. The historic equity risk premium methodology is unrealistic in that it makes the explicit assumption that risk premiums do not change over time based on market conditions such as inflation, interest rates, and expected economic growth. Furthermore, using historic returns to measure the equity risk premium masks the dramatic change in the risk and return relationship between stocks and bonds. The nature of the change, as I will discuss below, is that bonds have increased in risk relative to stocks. This change suggests that the equity risk premium has declined in recent years.

Page 1 of Exhibit_(JRW-8) provides the yields on long-term U.S. Treasury bonds from 1926 to 2006. One very obvious observation from this graph is that interest rates increase dramatically from the mid-1960s until the early 1980s, and since have returned to their 1960 levels. The annual market risk premiums for the 1926 to 2006 period are provided on page 2 of Exhibit_(JRW-8). The annual market risk premium is defined as the return on common stock minus the return on long-term Treasury Bonds. There is considerable variability in this series and a clear decline in recent decades. The high was 54% in 1933 and the low was -38% in 1931. Evidence of a change in the relative riskiness of bonds and stocks is provided on page 3 of Exhibit_(JRW-8) which plots the standard deviation of monthly stock and bond returns since 1930. The plot shows that, whereas stock returns were much more volatile than bond returns from the 1930s to the 1970s, bond returns became more variable than stock returns during the 1980s. In recent years stocks and bonds have become much more similar in terms of volatility, but stocks are still a little more volatile. The decrease in the volatility of stocks relative to bonds over time has been attributed to several stock related factors: the impact of technology on productivity and the new economy; the role of information (see former Federal Reserve Chairman Greenspan's comments referred to earlier in this testimony) on the economy and markets; better cost and risk management by businesses; capital losses suffered bond investors during periods of increasing interest rates; deregulation of the financial system; inflation fears and interest rates; and the increase in the use of debt financing. Further evidence of the greater relative riskiness of bonds is shown on page 4 of Exhibit_(JRW-8), which plots real interest rates (the nominal interest rate minus inflation) from 1926 to 2006. Real rates have been well above historic norms during the past 10-15 years. These high real interest rates reflect the fact that investors view bonds as riskier investments.

The net effect of the change in risk and return has been a significant decrease in the return premium that stock investors require over bond yields. In short, the equity or market risk premium has declined in recent years. This decline has been discovered in studies by leading academic scholars and investment firms, and has been acknowledged by government regulators. As such, using a historic equity risk premium analysis is simply outdated and not reflective of current investor expectations and investment fundamentals.

Q. DO YOU HAVE ANY OTHER THOUGHTS ON THE USE OF HISTORICAL RETURN DATA TO ESTIMATE AN EQUITY RISK PREMIUM?

A. Yes. Jay Ritter, a Professor of Finance at the University of Florida, identified the use of historical stock and bond return data to estimate a forward-looking equity risk premium as one of the "Biggest Mistakes" taught by the finance profession.[29] His argument is based on the theory behind the equity risk premium, the excessive results produced by

[29] Jay Ritter, "The Biggest Mistakes We Teach," *Journal of Financial Research* (Summer 2002).

historical returns, and the previously-discussed errors of such as survivorship bias in historical data.

Q. PLEASE ADDRESS DR. MURRY'S ASSERTION ON PAGE 39 OF HIS TESTIMONY THAT HIS RECOMMENDATION IS INFLUENCED BY HIGHER FORECASTED INTEREST RATES.

A. Dr. Murry's testimony indicates that higher forecasted interest rates have influenced his estimate of the appropriate rate of return in this case. Whereas interest rates have been forecasted to increase over the past year, they have not moved much. Forecasts of market-determined rates like interest and exchange rates, in my opinion, are not reliable, credible, or accurate. I am not aware of any empirical studies that indicate forecasted interest rates are better measures of future interest rates than today's interest rates. The investors in fixed income securities like Treasury Bonds are primarily sophisticated financial institutions. These institutional investors are not going to buy bonds at today's interest rates if they believe that interest rates are going to increase in the near future and leave them with a capital loss associated with the decline in the bond price. Hence, Dr. Murry's presumption of higher interest rates in gauging an appropriate rate of return for the Company is incorrect.

Q. TO CONCLUDE THIS DISCUSSION, PLEASE SUMMARIZE DR. MURRY'S CAPM RESULTS IN LIGHT OF THE EVIDENCE ON RISK PREMIUMS IN TODAY'S MARKETS.

A. Dr. Murry employs equity risk premiums of 7.10% and 8.65% in his two CAPM approaches. These risk premiums are well in excess of the equity risk premium estimates (a) discovered in recent academic studies by leading finance scholars and (b) employed by leading investment banks, management consulting firms, financial forecasters and corporate CFOs. These later sources – investment banks, consulting firms, and CFOs - use the equity risk premium concept every day in making financing, investment, and valuation decisions. Their results, which reflect the level of the equity risk premium as it is applied in the real world of finance, indicate an equity risk premium in the 3-4 percent range and not in the 7-8 percent range. Hence, Dr. Murry's equity risk premiums are not reflective of the equity risk premiums used by financial professionals in the real world of finance.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes it does.

Exhibit_(JRW-1)

Atmos Energy Corporation
Cost of Capital and Fair Rate of Return

Rate of Return Applicable to Original Cost Rate Base

Capital Source			Capitalization Ratio*	Cost Rate	Weighted Cost Rate
Short-Term Debt		123,886	2.86%	6.58%	0.19%
Long-Term Debt	$	2,179,529	50.36%	6.10%	3.07%
Common Equity		2,024,314	46.78%	9.00%	4.21%
Total	$	4,327,729	100.00%		7.47%

* See Exhibit_(JRW-3) for capitalization ratios.

Exhibit_(JRW-2)

Atmos Energy Corporation

Summary Financial Statistics

Nine-Company Natural Gas Distribution Group and Atmos Energy

Company		S&P Bond Rating	Operating Revenue ($mil)	Percent Gas Revenue	Net Plant ($mil)	Pre-Tax Interest Coverage	Primary Service Area	Common Equity Ratio*	Return on Equity	Price/ Earnings Ratio	Market to Book Ratio
AGL Resources	**ATG**	A-	2624.0	62%	3436.0	5.0	GA,VA,TN	42.0%	13.6%	14.8	195
Laclede Group, Inc.	**LG**	A	1847.9	58%	769.0	3.1	MO	58.0%	10.3%	15.2	153
New Jersey Resources	**NJR**	AA-	2876.5	34%	942.3	6.0	NJ, Canada	51.0%	12.4%	18.9	210
Nicor	**GAS**	AA	2960.0	83%	2714.7	4.0	IL	51.0%	15.2%	16.5	242
Northwest Natural Gas Company	**NWN**	AA-	1013.2	99%	1389.4	3.4	OR, WA	48.0%	10.7%	19.4	203
Piedmont Natural Gas, Inc.	**PNY**	A	1924.6	82%	2075.3	4.0	NC, SC, TN	47.0%	11.0%	20.7	225
South Jersey Industries	**SJI**	A	931.4	65%	920.0	5.4	NJ	44.0%	17.3%	14.6	238
Southwest Gas	**SWX**	BBB-	2024.8	85%	2668.1	2.4	AZ,NV,CA	41.0%	10.1%	18.3	171
WGL Holdings, Inc.	**WGL**	AA-	2461.5	59%	2087.3	4.2	VA, MD	51.0%	9.9%	16.5	160
Mean			**2073.8**	**70%**	**1889.1**	**4.2**		**48.1%**	**12.3%**	**17.2**	**200**
Median			**2024.8**	**65%**	**2075.3**	**4.0**		**48.0%**	**11.0%**	**16.5**	**203**
Atmos Energy	**ATO**	**BBB**	**5471.2**	**59%**	**3667.9**	**2.8**	LA,TX,CO,KS,KY	**45%**	**8.9%**	**16.6**	**146**

Data Source: *AUS Utility Reports*, April, 2007, *Value Line Investment Survey*, March 16, 2007.

Exhibit_(JRW-2)
Atmos Energy Corporation
Natural Gas Distribution Group and Atmos Energy

Company Name	M&A	Dividend	% Reg. Gas	Ticker
AGL Resources				ATG
Cascade Natural Gas	X			
KeySpan Corp.	X			
Laclede Group				LG
New Jersey Resources				NJR
Nicor Inc.				GAS
Northwest Nat. Gas				NWN
Piedmont Natural Gas				PNY
SEMCO Energy		X		
South Jersey Inds.				SJI
Southern Union		X		
Southwest Gas				SWX
UGI Corp.			X	
WGL Holdings Inc.				WGL

Atmos Energy	ATO

Data Source: *AUS Utility Reports*, April, 2007, *Value Line Investment Survey*, March 16, 2007.

Exhibit_(JRW-3)
Atmos Energy Corporation
Capital Structure Ratios

Panel A - Atmos Energy Capitalization Ratios for Ratemaking Purposes

	Capitalization Amounts	Capitalization Ratios
Short-Term Debt		0.00%
Long-Term Debt	$ 2,179,529	51.85%
Common Equity	2,024,314	48.15%
Total Capital	4,203,843	100.00%

Panel B - Atmos Energy Capitalization Ratios

	Quarter Ended 12/06	Quarter Ended 09/06	Quarter Ended 06/06	Quarter Ended 03/06	4 QUARTER AVERAGE
Short-Term Debt	10.75%	9.15%	7.25%	6.40%	8.39%
Long-Term Debt	44.13%	51.74%	52.60%	52.52%	50.25%
Common Equity	45.11%	39.11%	40.15%	41.09%	41.37%
Total Capital	100.00%	100.00%	100.00%	100.00%	100.00%

Panel C - Proxy Group Quarterly Capitalization Ratios

Proxy Group 9 Gas Distribution Companies	Quarter Ended 12/06	Quarter Ended 09/06	Quarter Ended 06/06	Quarter Ended 03/06	4 QUARTER AVERAGE
Short/Current Long-Term Debt	9.25%	7.72%	5.63%	6.51%	7.28%
Long-Term Debt	41.61%	43.21%	43.71%	43.37%	42.98%
Common Equity	49.14%	49.07%	50.66%	50.12%	49.74%
Total Capital	100.00%	100.00%	100.00%	100.00%	100.00%

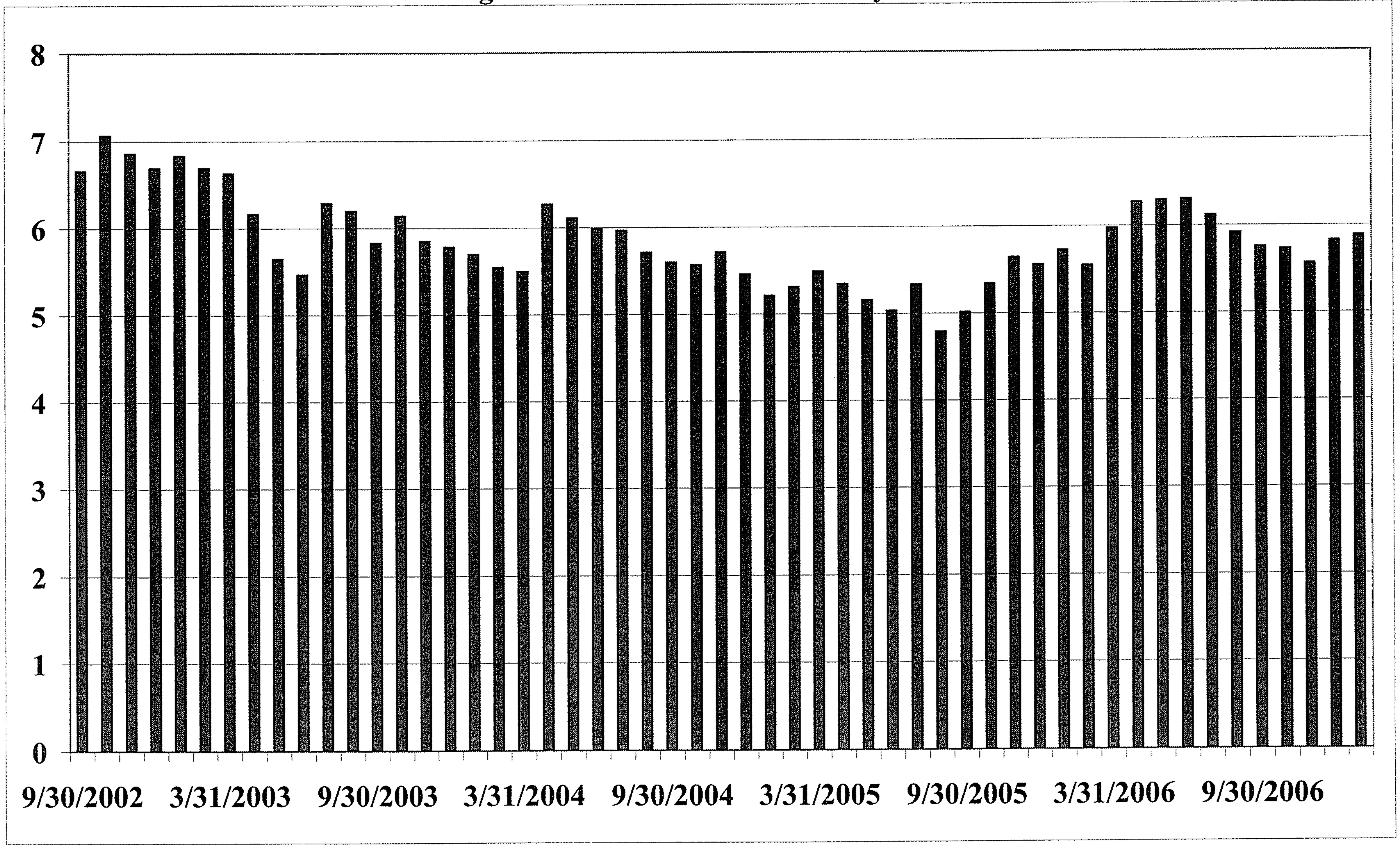
Data Source: Bloomberg

Panel D - OAG's Capitalization Ratios for Ratemaking Purposes

Atmos	Capitalization Amounts	Capitalization Ratios
Short-Term Debt	123,886	2.86%
Long-Term Debt	2,179,529	50.36%
Common Equity	2,024,314	46.78%
Total Capital	4,327,729	100.00%

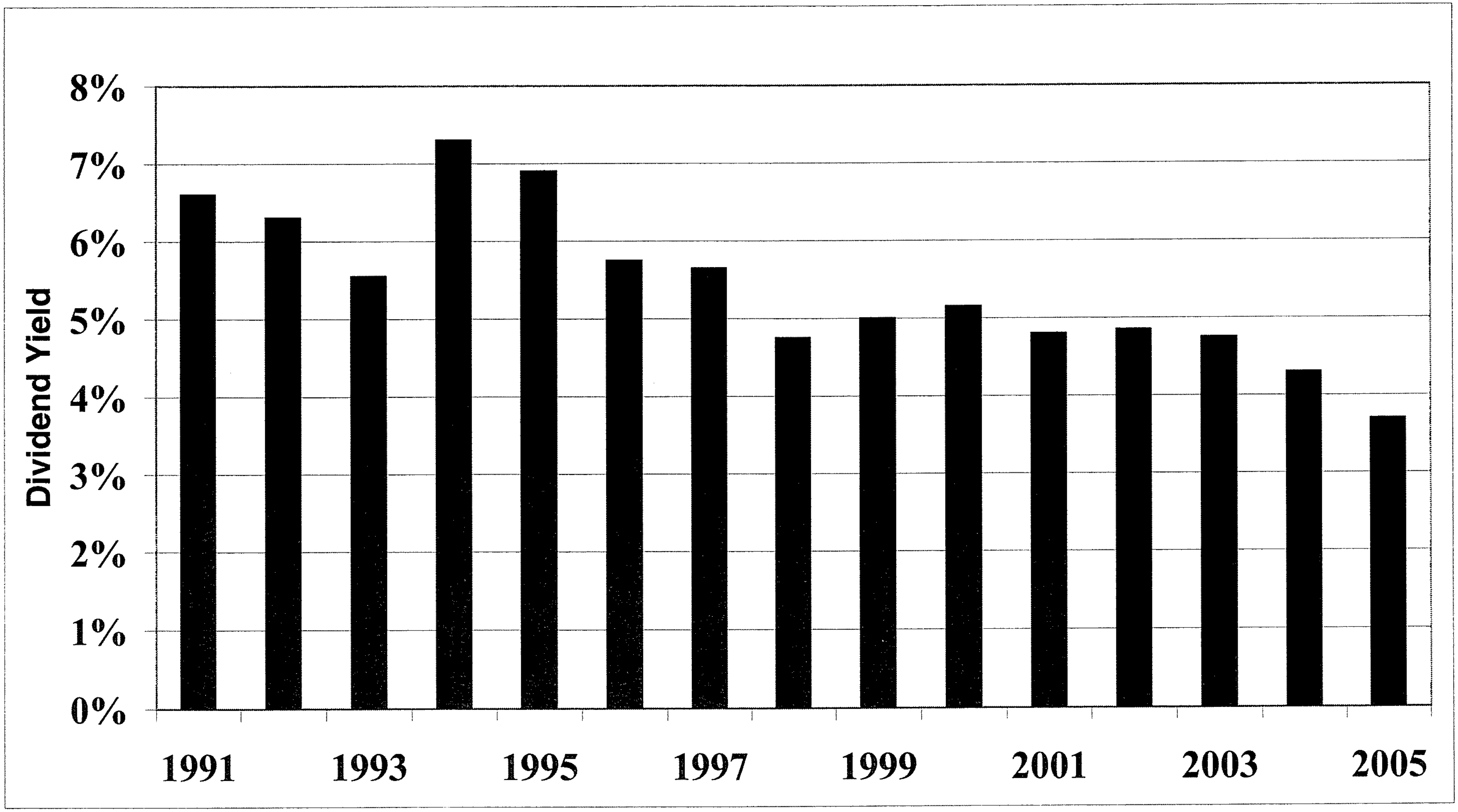
Exhibit_(JRW-4)

Long-Term 'A' Rated Public Utility Bonds



Data Source: Bloomberg (FMCI Function).

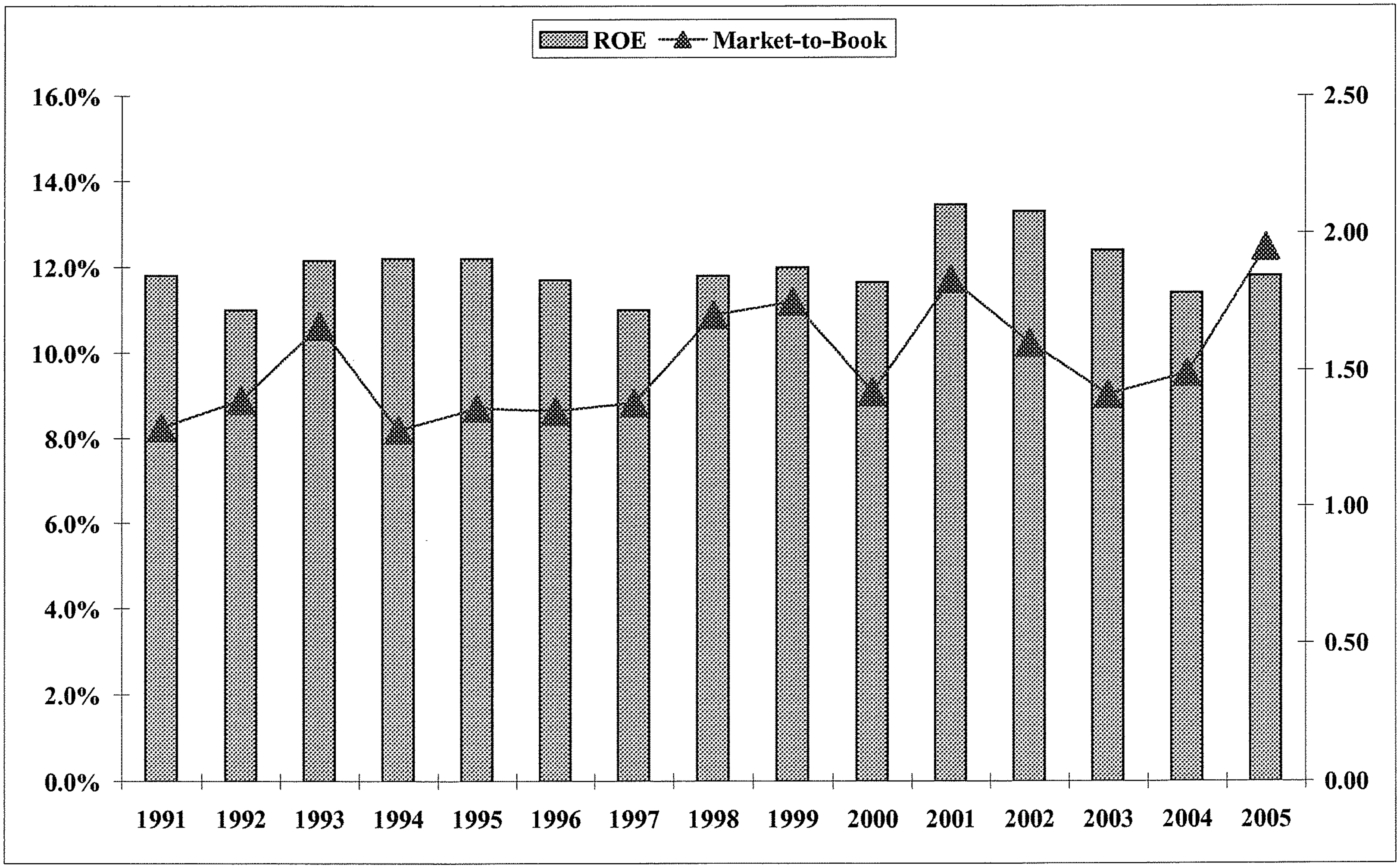
Exhibit_(JRW-4)
Dow Jones Utilities Dividend Yield



Data Source: Value Line Investment Survey

Exhibit_(JRW-4)

Dow Jones Utilities - Market to Book and ROE



Data Source: Value Line Investment Survey

Exhibit_(JRW-5)

Industry Average Betas

Industry Name	Number of Firms	Beta	Industry Name	Number of Firms	Beta	Industry Name	Number of Firms	Beta
Semiconductor Equip	14	2.95	Retail Automotive	15	1.04	Publishing	50	0.89
Semiconductor	124	2.92	Grocery	19	1.04	Petroleum (Producing)	178	0.88
Wireless Networking	73	2.41	Foreign Electronics	10	1.03	Diversified Co.	134	0.87
Power	41	2.39	Office Equip/Supplies	26	1.02	Electric Utility (East)	29	0.87
Telecom. Equipment	136	2.35	Cement & Aggregates	13	1.02	Furn/Home Furnishings	38	0.87
Internet	329	2.30	Information Services	41	1.02	Environmental	96	0.87
E-Commerce	60	2.23	Metal Fabricating	37	1.01	Packaging & Container	36	0.87
Entertainment Tech	31	2.18	Natural Gas (Div.)	34	1.01	Maritime	46	0.86
Computers/Peripherals	148	1.99	Industrial Services	230	1.01	Home Appliance	14	0.84
Computer Software/Svcs	425	1.84	Machinery	139	1.01	Paper/Forest Products	42	0.84
Bank (Foreign)	4	1.78	Utility (Foreign)	6	1.00	Toiletries/Cosmetics	21	0.83
Cable TV	23	1.76	Auto Parts	64	0.99	Insurance (Prop/Cas.)	97	0.83
Coal	16	1.75	Advertising	36	0.99	Restaurant	81	0.80
Precision Instrument	104	1.71	Manuf. Housing/RV	19	0.99	Bank (Midwest)	37	0.79
Drug	334	1.59	Homebuilding	41	0.98	Tobacco	11	0.79
Biotechnology	105	1.56	Chemical (Specialty)	94	0.98	Household Products	31	0.79
Electrical Equipment	94	1.52	Trucking	38	0.98	R.E.I.T.	143	0.77
Steel (Integrated)	16	1.50	Retail (Special Lines)	164	0.98	Hotel/Gaming	84	0.77
Electronics	186	1.49	Building Materials	47	0.98	Newspaper	18	0.76
Telecom. Services	173	1.43	Chemical (Basic)	24	0.98	Investment Co.	20	0.75
Air Transport	56	1.38	Electric Utility (West)	16	0.97	Canadian Energy	14	0.73
Entertainment	101	1.30	Chemical (Diversified)	36	0.97	Natural Gas (Distrib.)	30	0.73
Securities Brokerage	32	1.29	Tire & Rubber	10	0.96	Water Utility	16	0.73
Auto & Truck	31	1.29	Railroad	20	0.96	Food Processing	123	0.72
Human Resources	35	1.22	Petroleum (Integrated)	30	0.96	Bank (Canadian)	7	0.72
Healthcare Information	34	1.22	Retail Building Supply	9	0.95	Food Wholesalers	21	0.72
Investment Co.(Foreign)	15	1.21	Medical Services	186	0.94	Beverage (Soft Drink)	21	0.71
Steel (General)	30	1.16	Retail Store	51	0.94	Beverage (Alcoholic)	27	0.66
Recreation	84	1.12	Electric Util. (Central)	24	0.94	Bank	550	0.59
Medical Supplies	279	1.11	Pharmacy Services	20	0.93	Thrift	248	0.56
Educational Services	37	1.09	Insurance (Life)	40	0.93	**Market**	**7661**	**1.14**
Shoe	24	1.08	Apparel	64	0.93			
Other	1	1.06	Aerospace/Defense	73	0.92			
Oilfield Svcs/Equip.	110	1.05	Precious Metals	67	0.90			
Metals & Mining (Div.)	82	1.04	Financial Svcs. (Div.)	269	0.89			

Data Source: http://pages.stern.nyu.edu/~adamodar/

Exhibit_(JRW-6)

Atmos Energy Corporation
DCF Equity Cost Rate

Nine-Company Natural Gas Distribution Group

Dividend Yield*	3.6%
Adjustment Factor	1.025
Adjusted Dividend Yield	3.64%
Growth Rate**	5.00%
Equity Cost Rate	8.6%

Atmos Energy Corporation

Dividend Yield*	4.0%
Adjustment Factor	1.02625
Adjusted Dividend Yield	4.11%
Growth Rate**	5.25%
Equity Cost Rate	9.4%

* Page 2 of Exhibit_(JRW-6)

** Based on data provided on pages 3-4, Exhibit_(JRW-6)

Exhibit_(JRW-6)

Atmos Energy Corporation
Monthly Dividend Yields
November 2006 - April 2007

Nine-Company Natural Gas Distribution Group and Atmos Energy

Company	Nov	Dec	Jan	Feb	Mar	Apr	Mean
AGL	4.0%	3.9%	3.8%	3.8%	3.9%	4.1%	**3.9%**
Laclede Group, Inc.	4.2%	3.9%	4.2%	4.3%	4.6%	4.9%	**4.4%**
New Jersey Resources	2.8%	2.8%	3.1%	3.2%	3.1%	3.1%	**3.0%**
Nicor	4.1%	3.8%	3.9%	4.2%	4.0%	3.9%	**4.0%**
Northwest Natural Gas Company	3.5%	3.5%	3.4%	3.5%	3.3%	3.2%	**3.4%**
Piedmont Natural Gas, Inc.	3.6%	3.4%	3.5%	3.7%	3.6%	3.8%	**3.6%**
South Jersey Industries	2.9%	2.8%	3.0%	3.0%	2.8%	2.7%	**2.9%**
Southwest Gas	2.3%	2.2%	2.2%	2.2%	2.1%	2.3%	**2.2%**
WGL Holdings, Inc.	4.2%	4.1%	4.1%	4.3%	4.2%	4.4%	**4.2%**
Mean	**3.5%**	**3.4%**	**3.5%**	**3.6%**	**3.5%**	**3.6%**	**3.5%**
Atmos Energy	**4.2%**	**3.9%**	**4.0%**	**4.1%**	**3.9%**	**4.0%**	**4.0%**

Data Source: AUS Utility Reports, monthly issues.

Exhibit_(JRW-6)

Atmos Energy Corporation
DCF Equity Cost Growth Rate Measures
Value Line Historic Growth Rates

Nine-Company Natural Gas Distribution Group and Atmos Energy

Company	Sym	*Value Line* Historic Growth					
		Past 10 Years			Past 5 Years		
		Earnings	Dividends	Book Value	Earnings	Dividends	Book Value
AGL Resources	ATG	6.5%	1.5%	5.5%	13.5%	2.0%	8.5%
Laclede Group, Inc.	LG	3.0%	1.0%	3.0%	6.5%	0.5%	3.5%
New Jersey Resources	NJR	7.5%	3.0%	6.5%	8.0%	3.5%	8.5%
Nicor	GAS	1.0%	4.0%	3.0%	-3.5%	3.5%	1.5%
Northwest Natural Gas Company	NWN	1.5%	1.0%	4.0%	5.0%	1.0%	3.5%
Piedmont Natural Gas, Inc.	PNY	5.5%	5.5%	6.5%	5.0%	5.0%	6.5%
South Jersey Industries	SJI	8.0%	1.5%	5.5%	11.5%	2.5%	13.0%
Southwest Gas	SWX	7.5%	0.5%	2.0%	-0.5%	0.0%	3.0%
WGL Holdings, Inc.	WGL	4.5%	1.5%	4.0%	6.0%	1.5%	3.0%
Mean		**5.0%**	**2.2%**	**4.4%**	**5.7%**	**2.2%**	**5.7%**
Median		**5.3%**	**1.5%**	**4.2%**	**5.9%**	**2.1%**	**4.6%**
		Average of Mean and Median Figures =			**4.1%**		

Atmos Energy	**ATO**	**3.5%**	**3.0%**	**6.5%**	**10.0%**	**2.0%**	**8.5%**
		Average =			**5.6%**		

Data Source: ***Value Line Investment Survey, March 16, 2007.***

Exhibit_(JRW-6)

Atmos Energy Corporation
DCF Equity Cost Growth Rate Measures
***Value Line* Projected Growth Rates**

Nine-Company Natural Gas Distribution Group and Atmos Energy

Company	Sym	*Value Line* Projected Growth Est'd. '03-'05 to '09-'11			*Value Line* Internal Growth		
		Earnings	Dividends	Book Value	Return on Equity	Retention Rate	Internal Growth
AGL Resources	ATG	3.5%	5.5%	2.5%	14.0%	42.0%	5.9%
Laclede Group, Inc.	LG	2.0%	2.5%	5.0%	10.0%	33.0%	3.3%
New Jersey Resources	NJR	2.5%	3.0%	8.0%	11.0%	50.0%	5.5%
Nicor	GAS	4.0%	1.0%	4.5%	12.0%	31.0%	3.7%
Northwest Natural Gas Company	NWN	7.0%	4.0%	3.5%	12.0%	40.0%	4.8%
Piedmont Natural Gas, Inc.	PNY	3.0%	4.0%	2.5%	11.5%	26.0%	3.0%
South Jersey Industries	SJI	9.5%	5.5%	5.0%	17.5%	63.0%	11.0%
Southwest Gas	SWX	8.0%	1.5%	4.0%	10.0%	66.0%	6.6%
WGL Holdings, Inc.	WGL	1.0%	1.5%	3.0%	10.5%	35.0%	3.7%
Mean		4.5%	3.2%	4.2%	12.1%	42.9%	5.3%
Median		3.5%	3.0%	4.0%	11.5%	40.0%	4.8%
Average of Mean and Median Figures =			3.7%	Average of Mean and Median Figures =			5.0%
Atmos Energy	ATO	5.0%	1.5%	4.0%	10.0%	46.0%	4.6%
			Average =	3.5%			

Data Source: ***Value Line Investment Survey, March 16, 2007.***

Exhibit_(JRW-6)

Atmos Energy Corporation

DCF Equity Cost Growth Rate Measures
Analysts Projected EPS Growth Rate Estimates

Nine-Company Natural Gas Distribution Group and Atmos Energy

Company	Sym	Yahoo First Call	Reuters	Zack's	Average
AGL Resources	ATG	4.0%	4.7%	5.0%	4.6%
Laclede Group, Inc.	LG	3.0%	3.0%	--	3.0%
New Jersey Resources	NJR	5.0%	5.2%	6.0%	5.4%
Nicor	GAS	1.5%	3.3%	2.0%	2.3%
Northwest Natural Gas Company	NWN	5.0%	5.3%	5.3%	5.2%
Piedmont Natural Gas, Inc.	PNY	5.1%	4.6%	5.5%	5.1%
South Jersey Industries	SJI	6.5%	6.3%	6.5%	6.4%
Southwest Gas	SWX	--	5.0%	5.0%	5.0%
WGL Holdings, Inc.	WGL	3.5%	3.3%	3.0%	3.3%
Mean		**4.2%**	**4.5%**	**4.8%**	**4.5%**
Median		**4.5%**	**4.7%**	**5.2%**	**5.0%**

Atmos Energy	ATO	**6.0%**	**5.2%**	**5.3%**	**5.5%**

Data Sources: www.zacks.com, www.investor.reuters.com, http://quote.yahoo.com, *2007.*

Exhibit_(JRW-7)
Atmos Energy Corporation
CAPM Equity Cost Rate

Nine-Company Natural Gas Distribution Group

Risk-Free Interest Rate	5.00%
Beta**	0.87
Ex Ante Equity Risk Premium***	4.16%
CAPM Cost of Equity	8.6%

Atmos Energy Corporation

Risk-Free Interest Rate	5.00%
Beta**	0.80
Ex Ante Equity Risk Premium***	4.16%
CAPM Cost of Equity	8.3%

** See page 2 of Exhibit_(JRW-7)
*** See page 3 of Exhibit_(JRW-7)

Exhibit_(JRW-7)

Atmos Energy Corporation
CAPM
Beta

Nine-Company Natural Gas Distribution Group and Atmos Energy

Company	Ticker	Beta
AGL Resources	ATG	0.95
Laclede Group, Inc.	LG	0.85
New Jersey Resources	NJR	0.80
Nicor	GAS	1.30
Northwest Natural Gas Company	NWN	0.75
Piedmont Natural Gas, Inc.	PNY	0.80
South Jersey Industries	SJI	0.70
Southwest Gas	SWX	0.85
WGL Holdings, Inc.	WGL	0.85
Mean		0.87
Median		0.85
Atmos Energy	ATO	0.80

Data Source: *Value Line Investment Survey, March 16, 2007.*

Exhibit_(JRW-7)

Atmos Energy Corporation
Capital Asset Pricing Model
Equity Risk Premium

Category	Study Authors		Range Low	Range High	Mean of Range	Mean	Category Average
Historic							
	Ibbotson	Arithmetic			6.50%	5.75%	
		Geometric			5.00%		
	AVERAGE						5.75%
Puzzle Research							
	Claus Thomas					3.00%	
	Arnott and Bernstein					2.40%	
	Constantinides					6.90%	
	Cornell		3.50%	7.00%	5.25%		
	Dimson, Marsh, and Staunton	Arithmetic	2.50%	4.00%	3.81%	4.35%	
		Geometric	3.50%	5.25%			
	Fama French		2.55%	4.32%		3.44%	
	Harris & Marston					7.14%	
	Siegel	Geometric				2.50%	
	AVERAGE						4.25%
Surveys							
	Survey of Financial Forecasters					2.50%	
	Duke - CFO Magazine CFO Survey					3.42%	
	Welch - Academics		5.00%	5.50%		5.25%	
	AVERAGE						3.72%
Social Security							
	Office of Chief Actuary		4.00%	4.70%			
	John Campbell		2.00%	3.50%			
	Peter Diamond		3.00%	4.80%			
	John Shoven		3.00%	3.50%		3.56%	
	AVERAGE						3.56%
Building Block							
	Ibbotson and Peng						
		Arithmetic			6.00%	5.00%	
		Geometric			4.00%		
	Woolridge					2.84%	
	AVERAGE						3.92%
Other Studies							
	McKinsey		3.50%	4.00%		3.75%	
	AVERAGE						3.75%
OVERALL AVERAGE							**4.16%**

Sources:

Ibbotson Associates, SBBI Yearbook, 2007.
Duke University - CFO Magazine Survey of CFOs, March 2007.
James Claus and Jacob Thomas, "Equity Risk Premia as Low as Three Percent? Empirical Evidence from Analysts' Earnings Forecasts for Domestic and International Stock Market," *Journal of Finance*. (October 2001).
Eugene F. Fama and Kenneth R. French, "The Equity Premium," *The Journal of Finance*, April 2002.
Elroy Dimson, Paul Marsh, and Mike Staunton, "New Evidence puts Risk Premium in Context," *Corporate Finance* (March 2003)
Ivo Welch, "The Equity Risk Premium Consensus Forecast Revisited," (September 2001). Cowles Foundation Discussion Paper No. 1325.
Federal Reserve Bank of Philadelphia, *Survey of Professional Forecasters*, February 13, 2007.
Marc H. Goedhart, Timothy M. Koller, and Zane D. Williams, "The Real Cost of Equity," *McKinsey on Finance* (Autumn 2002), p.14.
Roger Ibbotson and Peng Chen, "Long Run Returns: Participating in the Real Economy," *Financial Analysts Journal*, January 2003

Exhibit_(JRW-7)

Survey of Professional Forecasters
Philadelphia Federal Reserve Bank
Long-Term Forecasts

TABLE FIVE
LONG-TERM (10 YEAR) FORECASTS

SERIES: CPI INFLATION RATE		SERIES: REAL GDP GROWTH RATE	
STATISTIC		STATISTIC	
MINIMUM	1.690	MINIMUM	2.500
LOWER QUARTILE	2.200	LOWER QUARTILE	2.810
MEDIAN	2.350	MEDIAN	3.000
UPPER QUARTILE	2.600	UPPER QUARTILE	3.200
MAXIMUM	4.000	MAXIMUM	3.500
MEAN	2.410	MEAN	3.010
STD. DEV.	0.400	STD. DEV.	0.220
N	46	N	44
MISSING	3	MISSING	5

SERIES: PRODUCTIVITY GROWTH		SERIES: STOCK RETURNS (S&P 500)	
STATISTIC		STATISTIC	
MINIMUM	1.200	MINIMUM	5.000
LOWER QUARTILE	2.000	LOWER QUARTILE	6.400
MEDIAN	2.200	MEDIAN	7.500
UPPER QUARTILE	2.300	UPPER QUARTILE	8.130
MAXIMUM	3.000	MAXIMUM	15.000
MEAN	2.150	MEAN	7.680
STD. DEV.	0.320	STD. DEV.	2.050
N	0	N	32
MISSING	11	MISSING	17

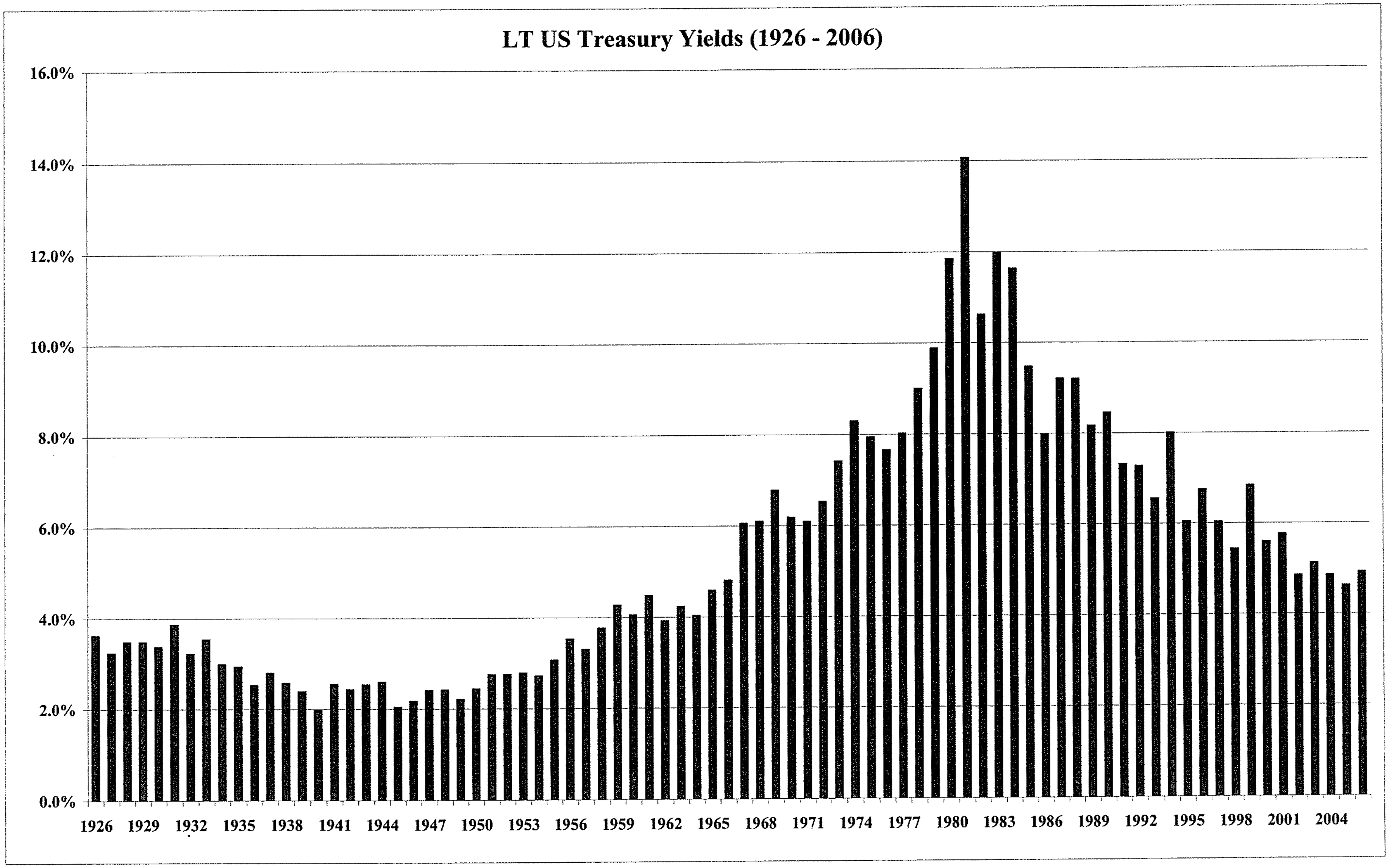
SERIES: BOND RETURNS (10-YEAR)		SERIES: BILL RETURNS (3-MONTH)	
STATISTIC		STATISTIC	
MINIMUM	2.000	MINIMUM	3.000
LOWER QUARTILE	5.000	LOWER QUARTILE	4.000
MEDIAN	5.000	MEDIAN	4.500
UPPER QUARTILE	5.200	UPPER QUARTILE	4.680
MAXIMUM	6.000	MAXIMUM	6.000
MEAN	5.000	MEAN	4.330
STD. DEV.	0.600	STD. DEV.	0.670
N	39	N	39
MISSING	10	MISSING	10

Source: Philadelphia Federal Researve Bank, Survey of Professional Forecasters, February 13, 2007.
http://www.phil.frb.org/files/spf/spfq107.pdf

Exhibit_(JRW-7)

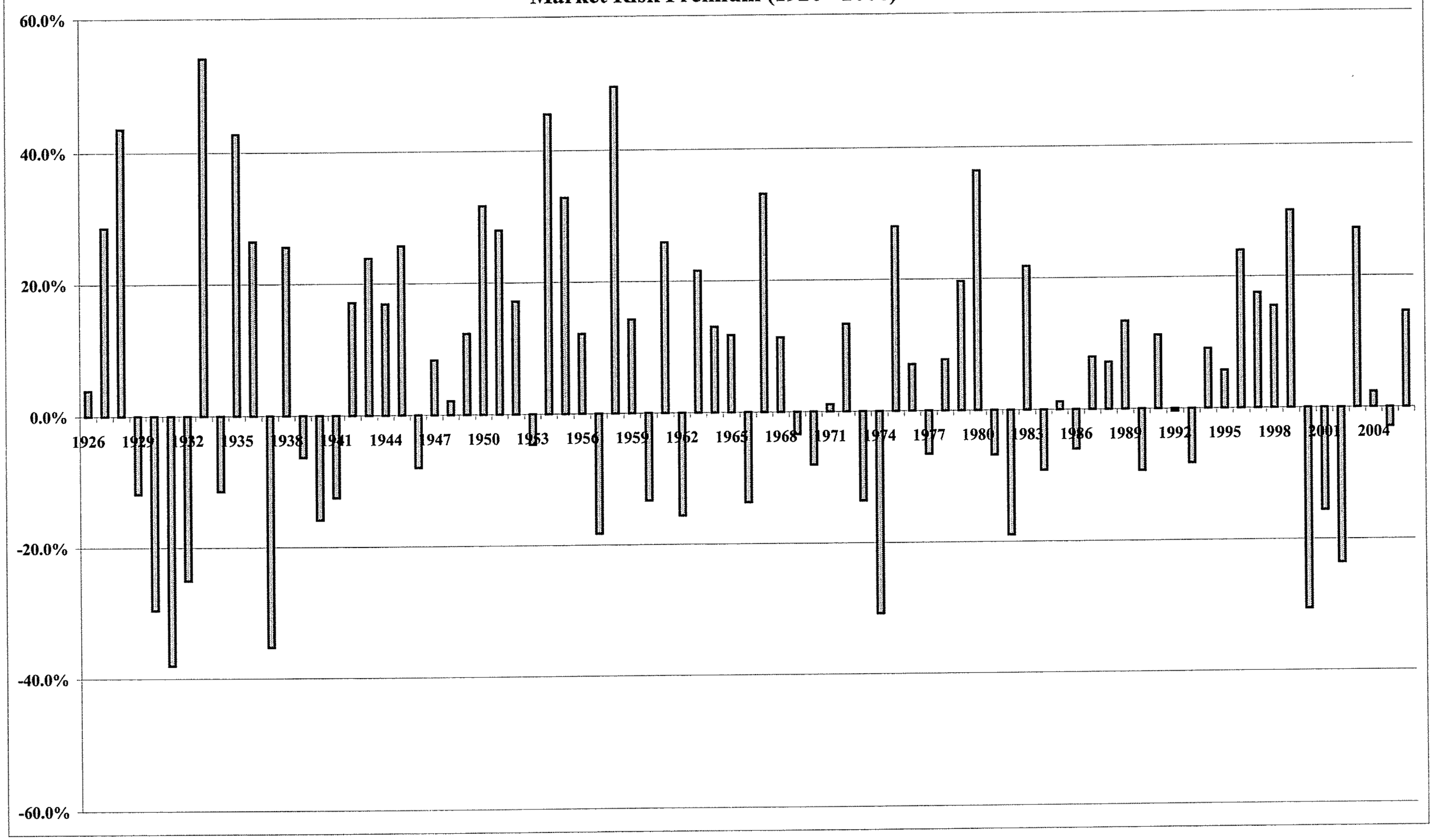
Atmos Energy Corporation
CAPM
Real S&P 500 EPS Growth Rate

Year	S&P 500 EPS	Annual Inflatior CPI	Inflation Adjustment Factor	Real S&P 500 EPS	
1960	3.10	1.40		3.10	
1961	3.37	0.70	1.01	3.35	
1962	3.67	1.30	1.02	3.59	
1963	4.13	1.60	1.04	3.99	
1964	4.76	1.00	1.05	4.55	
1965	5.30	1.90	1.07	4.97	
1966	5.41	3.50	1.10	4.90	
1967	5.46	3.00	1.14	4.80	
1968	5.72	4.70	1.19	4.81	
1969	6.10	6.20	1.26	4.83	10-Year
1970	5.51	5.60	1.34	4.13	2.89%
1971	5.57	3.30	1.38	4.04	
1972	6.17	3.40	1.43	4.33	
1973	7.96	8.70	1.55	5.13	
1974	9.35	12.30	1.74	5.37	
1975	7.71	6.90	1.86	4.14	
1976	9.75	4.90	1.95	4.99	
1977	10.87	6.70	2.08	5.22	
1978	11.64	9.00	2.27	5.13	
1979	14.55	13.30	2.57	5.66	10-Year
1980	14.99	12.50	2.89	5.18	2.30%
1981	15.18	8.90	3.15	4.82	
1982	13.82	3.80	3.27	4.23	
1983	13.29	3.80	3.40	3.91	
1984	16.84	3.90	3.53	4.77	
1985	15.68	3.80	3.66	4.28	
1986	14.43	1.10	3.70	3.90	
1987	16.04	4.40	3.87	4.15	
1988	22.77	4.40	4.04	5.64	
1989	24.03	4.60	4.22	5.69	10-Year
1990	21.73	6.10	4.48	4.85	-0.65%
1991	19.10	3.10	4.62	4.14	
1992	18.13	2.90	4.75	3.81	
1993	19.82	2.70	4.88	4.06	
1994	27.05	2.70	5.01	5.40	
1995	35.35	2.50	5.14	6.88	
1996	35.78	3.30	5.31	6.74	
1997	39.56	1.70	5.40	7.33	
1998	38.23	1.60	5.48	6.97	
1999	45.17	2.70	5.63	8.02	10-Year
2000	52.00	3.40	5.82	8.93	6.29%
2001	44.23	1.60	5.92	7.48	
2002	47.24	2.40	6.06	7.80	
2003	54.15	1.90	6.17	8.77	
2004	67.01	3.26	6.37	10.51	5-Year
2005	68.32	3.52	6.60	10.35	3.00%
2006	81.96	2.50	6.76	12.12	
Data Source: http://pages.stern.nyu.edu/~adamodar/				Real EPS Growth	**3.0%**

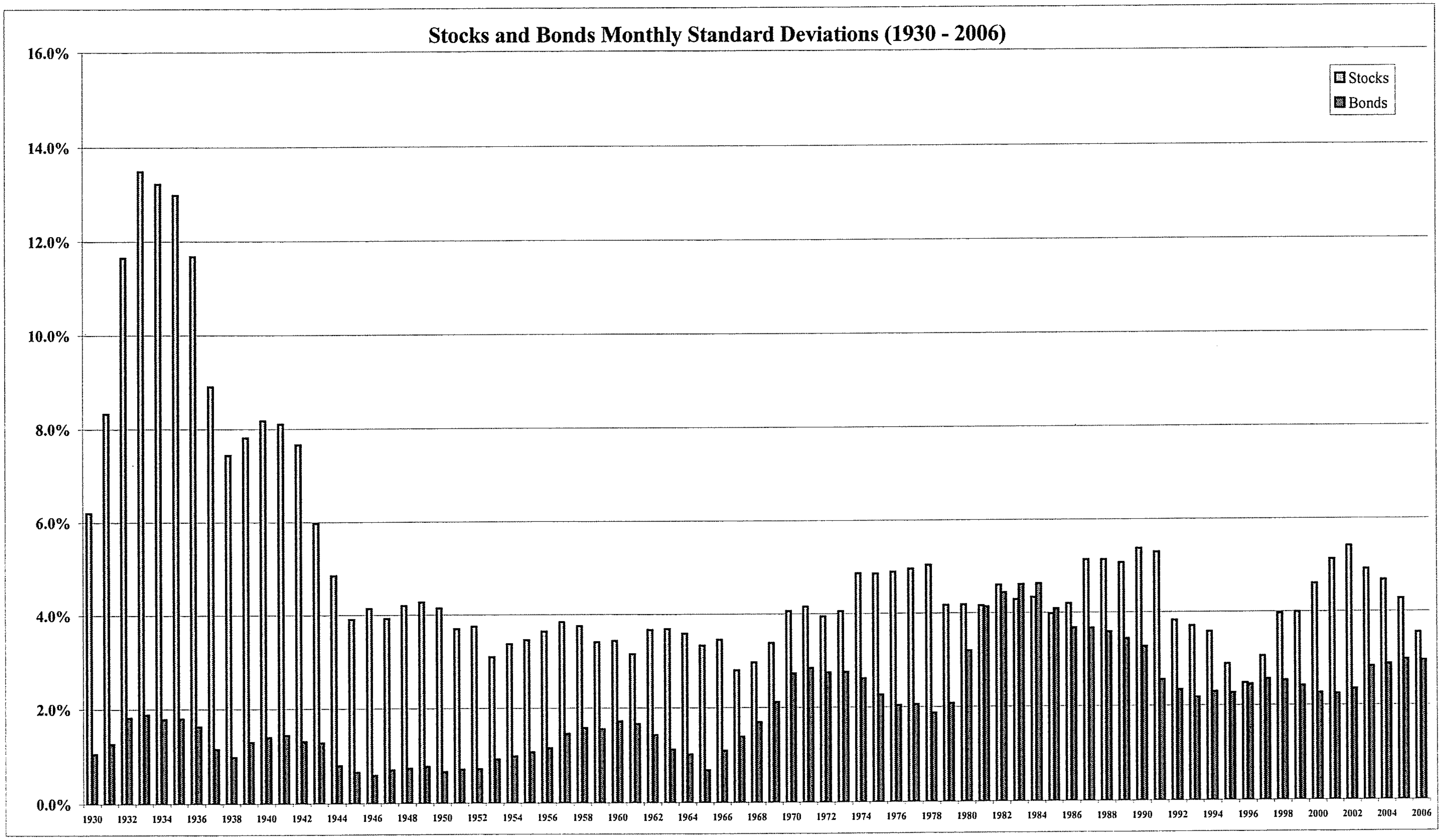


Data Source: Ibbotson Associates, *SBBI Yearbook*, 2007.

Market Risk Premium (1926 - 2006)

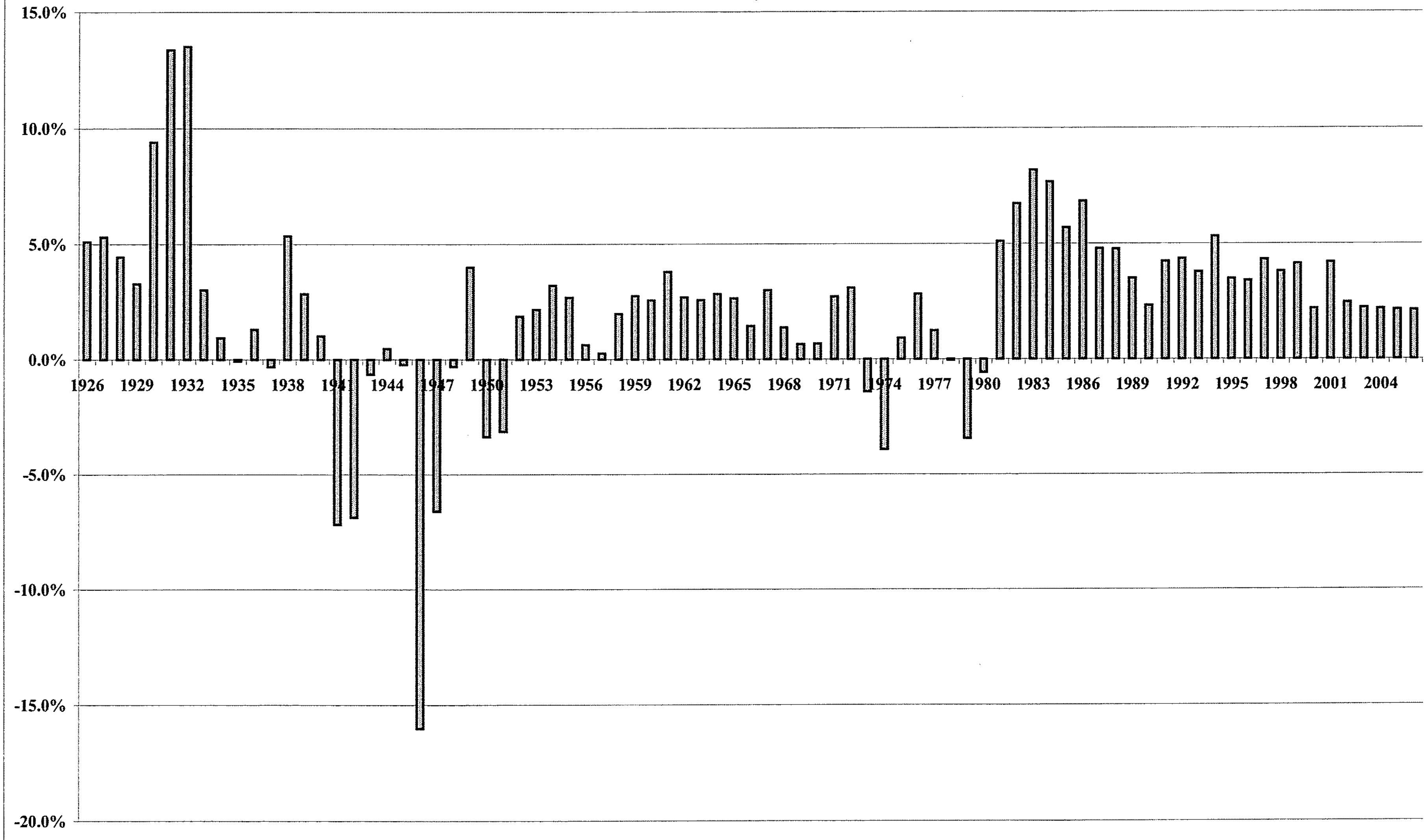


Data Source: Ibbotson Associates, *SBBI Yearbook*, 2007.



Data Source: Ibbotson Associates, *SBBI Yearbook*, 2007.

Real Interest Rates (1926 - 2006)



Data Source: Ibbotson Associates, *SBBI Yearbook*, 2007.

APPENDIX A

EDUCATIONAL BACKGROUND, RESEARCH, AND RELATED BUSINESS EXPERIENCE

J. RANDALL WOOLRIDGE

J. Randall Woolridge is a Professor of Finance and the Goldman, Sachs & Co. and Frank P. Smeal Endowed Faculty Fellow in Business Administration in the College of Business Administration of the Pennsylvania State University in University Park, PA. In addition, Professor Woolridge is Director of the Smeal College Trading Room and President and CEO of the Nittany Lion Fund, LLC.

Professor Woolridge received a Bachelor of Arts degree in Economics from the University of North Carolina, a Master of Business Administration degree from the Pennsylvania State University, and a Doctor of Philosophy degree in Business Administration (major area-finance, minor area-statistics) from the University of Iowa. At Iowa he received a Graduate Fellowship and was awarded membership in Beta Gamma Sigma, a national business honorary society. He has taught Finance courses at the University of Iowa, Cornell College, and the University of Pittsburgh, as well as the Pennsylvania State University. These courses include corporation finance, commercial and investment banking, and investments at the undergraduate, graduate, and executive MBA levels.

Professor Woolridge's research has centered on the theoretical and empirical foundations of corporation finance and financial markets and institutions. He has published over 35 articles in the best academic and professional journals in the field, including the *Journal of Finance,* the *Journal of Financial Economics,* and the *Harvard Business Review.* His research has been cited extensively in the business press. His work has been featured in the *New York Times*, *Forbes, Fortune, The Economist*, *Financial World*, *Barron's*, *Wall Street Journal*, *Business Week*, *Washington Post*, *Investors' Business Daily*, *Worth Magazine*, *USA Today*, and other publications. In addition, Dr. Woolridge has appeared as a guest on CNN's *Money Line* and CNBC's *Morning Call* and *Business Today*.

The second edition of Professor Woolridge's popular stock valuation book, *The StreetSmart Guide to Valuing a Stock* (McGraw-Hill, 2003), was released in its second edition. He has also co-authored *Spinoffs and Equity Carve-Outs: Achieving Faster Growth and Better Performance* (Financial Executives Research Foundation, 1999) as well as a new textbook entitled Applied Principles of *Finance* (Kendall Hunt, 2006). Dr. Woolridge is a founder and a managing director of www.valuepro.net - a stock valuation website.

Professor Woolridge has also consulted with and prepared research reports for major corporations, financial institutions, and investment banking firms, and government agencies. In addition, he has directed and participated in over 500 university- and company- sponsored professional development programs for executives in 25 countries in North and South America, Europe, Asia, and Africa.

Dr. Woolridge has prepared testimony and/or provided consultation services in the following cases:

Pennsylvania: Dr. Woolridge has prepared testimony on behalf of the Pennsylvania Office of Consumer Advocate in the following cases before the Pennsylvania Public Utility Commission: Bell Telephone Company (R-811819), Peoples Natural Gas Company (R-832315), Pennsylvania Power Company (R-832409), Western Pennsylvania Water Company (R-832381), Pennsylvania Power Company (R-842740), Pennsylvania Gas and Water Company (R-850178), Metropolitan Edison Company (R-860384), Pennsylvania Electric Company (R-860413), North Penn Gas Company (R-860535), Philadelphia Electric Company (R-870629), Western Pennsylvania Water Company (R-

870825), York Water Company (R-870749), Pennsylvania-American Water Company (R-880916), Equitable Gas Company (R-880971), the Bloomsburg Water Co. (R-891494), Columbia Gas of Pennsylvania, Inc. (R-891468), Pennsylvania-American Water Company (R-90562), Breezewood Telephone Company (R-901666), York Water Company (R-901813), Columbia Gas of Pennsylvania, Inc. (R-901873), National Fuel Electric utility Company (R-911912), Pennsylvania-American Water Company (R-911909), Borough of Media Water Fund (R-912150), UGI Utilities, Inc. - Electric Utility Division (R-922195), Dauphin Consolidated Water Supply Company - General Waterworks of Pennsylvania, Inc, (R-932604), National Fuel Electric utility Company (R-932548), Commonwealth Telephone Company (I-920020), Conestoga Telephone and Telegraph Company (I-920015), Peoples Natural Gas Company (R-932866), Blue Mountain Consolidated Water Company (R-932873), National Fuel Gas Company (R-942991), UGI - Gas Division (R-953297), UGI - Electric Division (R-953534), Pennsylvania-American Water Company (R-973944), Pennsylvania-American Water Company (R-994638), Philadelphia Suburban Water Company (R-994868;R-994877;R-994878; R-9948790), Philadelphia Suburban Water Company (R-994868), Wellsboro Electric Company (R-00016356), Philadelphia Suburban Water Company (R-00016750), National Fuel Electric utility Company (R-00038168), Pennsylvania-American Water Company (R-00038304), York Water Company (R-00049165), Valley Energy Company (R-00049345), Wellsboro Electric Company (R-00049313), National Fuel Gas Utility Corporation (R-00049656), T.W. Phillips Gas and Oil Co. (R-00051178), PG Energy (R-00061365), City of Dubois Water Company (Docket No. R-00050671), R-00049165), York Water Company (R-00061322), and Emporium Water Company (R-00061297).

New Jersey: Dr. Woolridge prepared testimony for the New Jersey Department of the Public Advocate, Division of Rate Counsel: New Jersey-American Water Company (R-91081399J), New Jersey-American Water Company (R-92090908J), and Environmental Disposal Corp (R-94070319).

Alaska: Dr. Woolridge prepared testimony for Attorney General's Office of Alaska: Golden Heart Utilities, Inc. and College Utilities Corp. (Water Public Utility Service TA-29-118 and Sewer Public Utility Service TA-82-97).

Arizona: Dr. Woolridge prepared testimony for Utility Division Staff of the Arizona Corporation Commission, Arizona Public Service Company (Docket No. E-01345A-06-0009).

Hawaii: Dr. Woolridge prepared testimony for the Hawaii Office of the Consumer Advocate: East Honolulu Community Services, Inc. (Docket No. 7718).

Delaware: Dr. Woolridge prepared testimony for the Delaware Division of Public Advocate: Artesian Water Company (R-00-649). Dr. Woolridge prepared testimony for the Staff of the Public Service Commission: Artesian Water Company (R-06-158).

Ohio: Dr. Woolridge prepared testimony for the Ohio Office of Consumers' Council: SBC Ohio (Case No. 02-1280-TP-UNC R-00-649), and Cincinnati Gas & Electric Company (Case No. 05-0059-EL-AIR).

Texas: Dr. Woolridge prepared testimony for the Atmos Cities Steering Committee: Mid-Texas Division of Atmos Energy Corp. (Docket No. 9670).

New York: Dr. Woolridge prepared testimony for the County of Nassau in New York State: Long Island Lighting Company (PSC Case No. 942354).

Florida: Dr. Woolridge prepared testimony for the Office of Peoples Counsel in Florida: Florida Power & Light Co. (Docket No. 050045-EL).

Connecticut: Dr. Woolridge prepared testimony for the Office of Consumer Counsel in Connecticut: United Illuminating (Docket No. 96-03-29), Yankee Gas Company (Docket No. 04-06-01), Southern Connecticut Gas Company (Docket No. 03-03-17), the United Illuminating Company (Docket No. 05-06-04), Connecticut Light and Power Company (Docket No. 05-07-18), Birmingham Utilities, Inc. (Docket No. 06-05-10), Connecticut Water Company (Docket No. 06-07-08), and Connecticut Natural Gas Corp. (Docket No. 06-03-04).

California: Dr. Woolridge prepared testimony for the Office of Ratepayer Advocate in California: San Gabriel Valley Water Company (Docket No. 05-08-021).

South Carolina: Dr. Woolridge prepared testimony for the Office of Regulatory Staff in South Carolina: South Carolina Electric and Gas Company (Docket No. 2005-113-G), Carolina Water Service Co. (Docket No. 2006-87-WS), Tega Cay Water Company (Docket No. 2006-97-WS), United Utilities Companies, Inc. Company (Docket No. 2006-107-WS).

Missouri: Dr. Woolridge prepared testimony for the Department of Energy in Missouri: Kansas City Power & Light Company (CASE NO. ER-2006-0314).

Kentucky: Dr. Woolridge prepared testimony for the Office of Attorney General in Kentucky: Kentucky-American Water Company (Case No. 2004-00103), Union Heat, Light, and Power Company (Case No. 2004-00042), Kentucky Power Company (Case No. 2005-00341), Union Heat, Light, and Power Company (Case No. 2006-00172),

Washington, D.C.: Dr. Woolridge prepared testimony for the Office of the People's Counsel in the District of Columbia: Potomac Electric Power Company (Formal Case No. 939).

Washington: Dr. Woolridge consulted with trial staff of the Washington Utilities and Transportation Commission on the following cases: Puget Energy Corp. (Docket Nos. UE-011570 and UG-011571); and Avista Corporation (Docket No. UE-011514).

Kansas: Dr. Woolridge prepared testimony on behalf of the Kansas Citizens' Utility Ratepayer Board Utilities in the following cases: Western Resources Inc. (Docket No. 01-WSRE-949-GIE), UtiliCorp (Docket No. 02-UTCG701-CIG), and Westar Energy, Inc. (Docket No. 05-WSEE-981-RTS).

FERC: Dr. Woolridge has prepared testimony on behalf of the Pennsylvania Office of Consumer Advocate in the following cases before the Federal Energy Regulatory Commission: National Fuel Gas Supply Corporation (RP-92-73-000) and Columbia Gulf Transmission Company (RP97-52-000).

Vermont: Dr. Woolridge prepared testimony for the Department of Public Service in the Central Vermont Public Service (Docket No. 6988) and Vermont Gas Systems, Inc. (Docket No. 7160).

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF ATMOS ENERGY)
CORPORATION FOR AN ADJUSTMENT) CASE NO. 2006-00464
OF GAS RATES)

AFFIDAVIT OF DR. J. RANDALL WOOLRIDGE

Commonwealth of Pennsylvania)
County of Centre)

Dr. J. Randall Woolridge, being first duly sworn, states the following: The prepared Pre-Filed Direct Testimony, and the Exhibits and Appendix attached thereto constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the Pre-Filed Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further affiant saith not.

Dr. J. Randall Woolridge

Dr. J. Randall Woolridge

SUBSCRIBED AND SWORN to before me this 26 day of April, 2007.

Mary L. Hart

NOTARY PUBLIC

My Commission Expires:

~~NOTARIAL SEAL~~
Mary L. Hart, Notary Public
State College Boro., Centre County
My commission expires August 25, 2009

DIRECT TESTIMONY

OF

CHARLES W. KING

Submitted on Behalf of
the Attorney General of Kentucky

ATMOS ENERGY CORPORATION
Kentucky P.S.C. Case No. 2006-00464

April 27, 2007

Witness: Charles W. King
Type of Exhibit: Direct Testimony
Sponsoring Party: Kentucky Attorney General
Case No.: 2006-00464
Date: April 27, 2007

DIRECT TESTIMONY OF

CHARLES W. KING

QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Charles W. King. I am President of the economic consulting firm of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"). My business address is 1111 14th Street, N.W., Suite 300, Washington, D.C. 20005.

Q. PLEASE DESCRIBE SNAVELY KING.

A. Snavely King, formerly Snavely, King & Associates, Inc., was founded by the late Carl M. Snavely and myself in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated firms and industries. The firm has a professional staff of 12 economists, accountants, engineers and cost analysts. Most of its work involves the development, preparation and presentation of expert witness testimony before federal and state regulatory agencies. Over the course of its 37-year history, members of the firm have participated in over 1000 proceedings before almost all of the state commissions and all Federal commissions that regulate utilities or transportation industries.

Q. HAVE YOU PREPARED A SUMMARY OF YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. Attachment A is a summary of my qualifications and experience.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN REGULATORY PROCEEDINGS?

A. Yes. Attachment B is a tabulation of my appearances as an expert witness before state and federal regulatory agencies

Q. FOR WHOM ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Kentucky Attorney General.

Q. WHAT IS THE OBJECTIVE OF YOUR TESTIMONY?

A. The objective of this testimony is to briefly present the Attorney General's position with regard to the Experimental Customer Rate Stabilization ("CRS") mechanism that has been proposed by Atmos Energy Corporation ("Atmos," or "the Company") in this case. I will also comment on the rate design changes that Atmos has requested, and I will make an alternative recommendation.

CUSTOMER RATE STABILIZATION MECHANISM

Q. PLEASE DESCRIBE THE CRS MECHANISM THAT ATMOS HAS PROPOSED.

A. Atmos proposes that beginning in March of 2008 and continuing for each of the subsequent five years, it would submit an annual filing that would present the financial results for the previous calendar year (the "Evaluation Period") and forecast financial results for the 12 months beginning May 1 through April 30 of the following year (the "Rate Effective Period"). The forecast for the Rate Effective Period would include Commission-approved pro forma adjustments; known and measurable changes; and the budgeted capital additions, depreciation accruals and deferred taxes for the first six months of the period.

The Commission and the Attorney General's office would have 45 days, from March 31 to April 15, to review this filing, submit data requests, and determine the propriety of the Company's forecasts. If the approved forecast indicates that the Company will earn more or less than the most recently approved rate of return on equity, the Company's rates will be adjusted upward or downward on May 1 to correct for the deficiency or excess in earnings. Beginning in the second year of the program, the annual rate adjustment will also reflect a true up between the previously forecast results and the actual results during the historical Evaluation Period.

If the Commission has not determined the propriety of the Rate Effective Period forecast by May 1, the Company's proposed rate adjustment would go into effect subject to refund until the Commission formally approves the forecast.

Q. WHAT JUSTIFICATION DOES ATMOS OFFER FOR THIS MECHANISM?

A. Atmos witness Gary Smith claims that the CRS would "provide assurance to the customers, Commission, Attorney General's office and the Company that the rates in place are appropriate, or that those rates would be decreased or increased to the correct amount, assuring that the customer only pays the most current and appropriate rate." Mr. Smith also argues that this mechanism would avoid the costly and resource-intensive traditional rate cast process. He believes that the CRS would substitute the rate case procedure with "a simple, straightforward and financially transparent process that would ensure that the customer pays only the appropriate rate." This process, argues Mr. Smith, would eliminate suspicions that the Company's earnings are too high.

Q. IS THIS A VALID JUSTIFICATION FOR THE CRS?

A. No. The mechanism would not provide assurance that rates are appropriate because it would remove the incentive for Atmos to control its costs. It would not be a simple, straightforward process because it would not reduce the complexity or controversy associated with establishing the Company's revenue requirement. Its schedule is totally infeasible. It would not be transparent because it would be conducted entirely within the confines of the Commission and Attorney General staffs with no public record of the proceedings or of the basis for the ratemaking decisions.

Q. WHY DO YOU SAY THAT THE CRS WOULD REMOVE THE INCENTIVE FOR ATMOS TO CONTROL ITS COSTS?

A. The major problem with cost-plus utility rate regulation is that it deprives the regulated company of the incentive to control costs. If all costs are automatically passed through to monopoly service ratepayers, then the utility experiences minimal, if any, risks. If approved, the CRS would be a disincentive for utilities like Atmos to pursue yet further improvements in operating efficiency or technological enhancement. In the end, any promise to control costs and maximize efficiency is only as good as the incentives a company has to hold up to those promises. This is why the traditional rate-making processes and procedures were invented in the first place – to shed light on complex decision making processes and provide adequate time for regulators to conduct thorough discovery and evaluate findings with the assistance of experts. The CRS would constitute a step backwards in this regard, because it would not provide enough time to conduct discovery and evaluate company-supplied data.

Q. WOULD THE CRS BE A SIMPLE, STRAIGHTFORWARD PROCESS, AS ATMOS CONTENDS?

A. No. The only rate case issue that would be avoided under the CRS would be rate of return to equity. Atmos has left open all of the other revenue requirements issues to be resolved in the CRS review. It would allow the utility, the staff and the Attorney General to suggest pro forma adjustments to the prospective year's financial results. It would employ forecasts of capital expenditures and plant retirements. Even the capital structure into which the return on equity is inserted would be subject to adjustment.

Nor would issues of rate design be avoided. The CRS tariff calls for adjustments in "rates" without specifying which rates. Would the CRS adjustment be a percentage surcharge, a mcf surcharge, or a per-customer surcharge? Would it be a surcharge at all, or would it call for annual adjustments in base rates? These issues would presumably be decided in the course of the "simple straightforward" CRS process.

Q. WOULD THE CRS BE ADMINISTRATIVELY FEASIBLE?

A. As proposed by Atmos, it would not be. Atmos's plan is to allow 45 days from submission of its CRS data to Commission decision. In response to data requests, Atmos has suggested that this would allow for two rounds of data requests, with the requests prepared in five days and the responses in 10 days. The discovery period would last 42 days, leaving three days for a Commission decision.[1] As noted in response to the last question, virtually all rate case issues other than return on equity would be under consideration. Moreover, in the second year forward, the review would include a retrospective examination of the past year's results, something that does not have to happen in a rate case.

It is inconceivable that this schedule can be met. If it is met, it would only be because the Commission staff and Attorney General's Office gave the filing a very perfunctory review, and the Commission gave it no review at all.

[1] Atmos response to KPSC data request 2-58.

Q. WOULD THE CRS BE FINANCIALLY TRANSPARENT, AS ATMOS CONTENDS?

A. No. To the contrary, it appears that the CRS review process would be conducted through three-way negotiations among the Company, the Commission Staff and the Attorney General's Office with no public record and little opportunity for individual consumers or consumer groups to participate. Given the compressed schedule, it is doubtful that the Commission itself would have much involvement. Its only role would be to vote up or down the recommendations of its staff. To the general public, the CRS would appear as a "black box" process that each year would increase their gas rates.

Q. ATMOS STATES THAT MISSISSIPPI AND LOUISIANA HAVE PROGRAMS IN PLACE SIMILAR TO THE CRS THAT ATMOS IS PROPOSING IN KENTUCKY – HOW DO THEY COMPARE?

A. Each of these programs involves a "dead band" range of rates of return around an approved level of return. Within that dead band, there are no adjustments in rates. In Mississippi, the dead band is 100 basis points higher or lower than a "Performance Based Benchmark Return" which reflects a comparison of the Company's rates against the rates of a comparison group of gas companies. In

Louisiana, the approved range is 10.0 to 10.8 percent, and rate adjustments are designed only to reach the bottom or the top of that range.

These programs thus retain some level of incentive to maintain cost controls so as to enhance its earnings, albeit within the dead band. The programs are also based on historical, recorded costs and revenues, not forecasts. They thus involve one year's regulatory lag as a further incentive toward efficiency and cost containment.

However, even in these states, Atmos reports that the Mississippi Stable Rate mechanism has resulted in rate increases of 37.833 percent since its inception in 1992. The Louisiana clause adjustments have resulted in nothing but repeated rate increases.[2]

[2] Atmos response to KPSC data request 3-21.

Q. DOES ATMOS NEED A CRS?

A. No. Atmos already has an array of risk-reducing rate mechanisms:

- The Gas Cost Adjustment protects the Company from fluctuations in the cost of gas, gas transportation and gas storage.

- The Weather Normalization Adjustment protects the Company from fluctuations in revenues due to variations in winter weather.

- The Experimental Performance Based Rate Mechanism allows the Company to receive added compensation if it can improve on the market prices for purchased gas.

- The Margin Loss Recovery Rider partially protects the Company from revenue losses due to alternate fuel price competition, special contracts, and bypass of the Company's distribution system.

- The Demand Side Management Rider allows the Company to pass through the costs of DSM programs, dollar for dollar.

- The Research & Development Rider allows the Company to pass through, dollar for dollar, its contribution to the Gas Technology Institute.

Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE CRS?

A. I recommend that the CRS be rejected.

RATE DESIGN

Q. WHAT CHANGES DOES THE COMPANY PROPOSE IN ITS RATE DESIGN?

A. Atmos proposes to increase sharply the "base" charges, that is, the flat monthly charges per customer that do not vary with consumption. The Company partially offsets these customer charge increases with reductions in the first (under 300 mcf) block of the commodity charge. The "tail blocks" of the commodity charge that are paid only by larger commercial and industrial customers are increased. A summary of these changes is as follows:

	Present Rate	Proposed Rate
Customer Charge - Res	$ 7.50	$ 13.00
Customer Charge - Non-Res	$ 20.00	$ 35.00
Commodity Charge[3]		
1st 300 mcf	$ 9.9769	$ 9.6969
Next 14,700 mcf	$ 9.4459	$ 9.5519
Over 15,000 mcf.	$ 9.2169	$ 9.2868
Excluding Purchased Gas:[4]		
1st 300 mcf	$ 1.1900	$ 0.9100
Next 14,700 mcf	$ 0.6590	$ 0.7650
Over 15,000 mcf.	$ 0.4300	$ 0.4999

Q. WHAT REASONS DOES ATMOS PROVIDE FOR THESE RATE CHANGES?

A. Atmos witness Gary Smith argues that most of the Company's distribution costs are fixed, that is, they do not vary with the volume of gas flowing through the distribution system. He concludes that it is therefore inappropriate to recover these costs on a volumetric basis through a per-mcf charge. The company's position is that: (a) such a charge gives the wrong price signal to the customer because it conveys the impression that the volume of gas is a major driver of distribution

[3] Applies to all firm sales service classes.
[4] Applies to firm transportation service classes.

costs; and (b) when customers conserve, it exposes the Company to revenue losses that are not offset with cost savings.

Q. DO YOU AGREE WITH THE COMPANY'S RATIONALE?

A. To a certain extent, yes, but with major, important qualifications. First of all, the Company's rationale would be much more persuasive if it did not have the risk-reducing rate features that I have listed earlier in this testimony. As it is, the Company is already protected from the principal source of risk, weather, by the Weather Normalization Adjustment.

Moreover, the cost of the distribution system in the long run does in fact vary to some extent with the volume of gas distributed, particularly the volume of gas distributed during the peak months of the year. The cost allocations in Mr. Uffelman's cost of service study attest to this relationship.

From the consumers' perspective, a rate design that concentrates pricing in the volumetric portion of the charge gives ratepayers choices as to how to control their costs. On the other hand, a design in which pricing concentrates on the customer charge does not give a price signal to ratepayers, and thus is not consumer friendly. From the public interest standpoint, a rate design that concentrates pricing on the volumetric component encourages conservation of what is rapidly becoming a scarce resource: natural gas. For these reasons, I have reservations regarding Atmos' rationale.

Based on these reservations, I strongly object to the Company's proposal to reduce the under 300 mcf rate when it is increasing rates overall. The actual effect of this rate adjustment is to award rate reductions to commercial and industrial customers whose monthly consumption is close to the 300 mcf threshold. It is unreasonable to grant rate reductions to some customers when most customers are experiencing rate increases. For this reason, I recommend holding the under 300 mcf commodity rate at its present level.

With this adjustment, I recommend that in this case, the residential increase be flowed into the customer charge, but at a much lower level than the Company has proposed. The company's proposal to nearly double the residential customer charge is altogether excessive.

Q. <u>HOW WOULD INCREASED CUSTOMER CHARGES AFFECT THE VARIOUS CLASSES?</u>

A. For the large commercial, industrial and public authority classes, the customer charge has relatively little impact, so the mcf charges necessarily must be increased for these customers. Since only these large customers pay the tail blocks (over 300 mcf) of the rate schedule, these block rates should be increased.

As between the residential and commercial classes, a proposal to flow increases into the customer charge disproportionately increases the burden on the residential class. That is because of the much smaller size of the average residential customer relative to the average commercial customer. For this reason, it is necessary to examine the distribution of costs among the classes, analyzed by Atmos witness Uffelman, and then revisit the level of the customer charges.

Q. WHAT DOES MR. UFFELMAN'S CLASS COST OF SERVICE STUDY SHOW?

A. Based on actual revenues and costs for the year ending August 31, 2006, Mr. Uffelman's study finds the following class rates of return:

Firm Residential	6.24%
Firm Commercial	5.08%
Firm Industrial	6.01%
Small Interruptible & Carriage	25.92%
Large Interruptible & Carriage	3.68%

Q. WHAT DO THESE RESULTS SUGGEST?

A. They suggest that rates should be increased by a common percentage among the firm customer classes, but that the small interruptible and carriage class should be increased less than the large interruptible and carriage class.

Q. DO THE COMPANY'S PROPOSED RATE INCREASES CONFORM TO THIS PATTERN?

A. No. In Exhibit CWK-1, I multiply the present and the Company's proposed rates by the July 2006 – June 2007 billing units that Mr. Smith lists in his Exhibit GLS-7. I derive the following percentage rate changes for the firm sales service classes:

Residential	6.41%
Commercial	4.14%
Industrial	-0.16%
Public Authority	0.32%

The results for the interruptible and carriage classes are obscured by the fact that Mr. Uffelman's categorization of customers does not appear to match the listing of the rate schedules.

Q. IS IT POSSIBLE TO EQUALIZE THE RATE INCREASE AMONG THESE CLASSES?

A. It is possible to equalize the rate increase as between the residential and the combined commercial, industrial, and public authority classes. That is because the residential class has a different customer charge from the other classes. However, as long as all firm service customers pay a common schedule of mcf commodity rates, it is not possible to ensure that the three non-residential classes experience the same rate increase. That is because these classes contain customers of significantly different sizes, so that the impact of different increases in the customer charges and the block commodity rates varies among them.

Q. IF YOU WERE TO ACCEPT THE COMPANY'S OVERALL TARGET FOR REVENUE RECOVERY FROM FIRM SERVICE SALES CUSTOMERS, WHAT PERCENTAGE INCREASE WOULD EQUALIZE THE IMPACT ON RESIDENTIAL AND NON-RESIDENTIAL CUSTOMERS?

A. On page 1 of Exhibit CWK-1, I calculate that increase as 5.14 percent.

Q. HAVE YOU DEVELOPED RATES THAT IMPLEMENT YOUR RECOMMENDATIONS?

A. Yes. In Exhibit CWK-1, I develop rates that (1) hold the under 300 mcf commodity charge at its present level, (2) accept the Company's proposed increases in the tail block mcf rates for the industrial and public authority classes, and (3) equalize the rate increase as between the residential and non-residential classes at 5.14 percent. The equalization is accomplished by adjusting the customer charges to recover the needed revenue. The resultant rate schedule is as follows:

	Present Rate	Recommended Rate
Customer Charge - Res	$ 7.50	$ 10.68
Customer Charge - Non-Res	$ 20.00	$ 34.75
Commodity Charge[5]		
1st 300 mcf	$ 9.9769	$ 9.9769
Next 14,700 mcf	$ 9.4459	$ 9.5519
Over 15,000 mcf.	$ 9.2169	$ 9.2868

Q. WHAT ARE THE CLASS RATE INCREASES UNDER THIS RECOMMENDED SCHEDULE?

A. As I mentioned earlier, it is impossible to adjust the commercial, industrial, and public authority rates to yield the same increase, but I have equalized the overall increase as between the residential and the non-residential classes, as follows:

Residential 5.14%

[5] Applies to all firm sales service classes.

Commercial	6.33%
Industrial	1.18%
Public Authority	2.45%
Combined Commercial, Industrial and Public Authority	5.14%

Q. HOW SHOULD RATES BE ADJUSTED IF ATMOS RECEIVES LESS REVENUE THAN IT IS REQUESTING?

A. If Atmos receives less revenue than it is requesting, the reduction should come out of the customer charges, both residential and non-residential. This adjustment would reduce the disproportionate increase being borne by commercial customers within the non-residential customer classes. It would also reduce the disparity in the increase among individual residential customers.

Q. WHAT RECOMMENDATIONS CAN YOU OFFER WITH RESPECT TO THE INTERRUPTIBLE, TRANSPORTATION AND CARRIAGE RATES?

A. As with the firm sales service rates, I recommend that the initial block commodity rates not be reduced. Again, this is to prevent some customers from receiving rate reductions when most customers are experiencing rate increases. The added revenue from the initial block adjustment will have to be offset by reductions in the tail blocks. Most customers in these classes are too large for the customer charge to have much of an impact.

Q. CAN YOU OFFER ANY SUGGESTIONS WITH RESPECT TO MR. UFFELMAN'S COST OF SERVICE STUDY?

A. Yes. His study would be much more useful if it clearly identified customer classes by rate schedule. In particular, the study should separate costs and revenues for (1) firm transportation, (2) carriage and (3) interruptible sales customers. It would then be possible to adjust the changes in the respective rate schedules according to their relative cost responsibility.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Atmos Energy Corp.
Analysis of Gas Rate Increase by Class

		Source	A Present Rate	B Proposed Rate	C
1	Customer Charge - Res	Tariff St 4	$ 7.50	$ 13.00	
2	1st 300 mcf	Tariff St 4	$ 9.9769	$ 9.6969	
			Bills	Mcf	
3	Residential Billing Units	GLS - 5	1,845,778	10,075,514	
	Company Proposed:		Present	Proposed	% Increase
4	Total Revenue Customer Chg	Ln 1 * Cell 3A	13,843,335	23,995,114	
5	Total Revenue mcf Charge	Ln 2 * Cell 3B	100,522,396	97,701,252	
6	Total Residential Revenue	Ln 4 + Ln 5	114,365,731	121,696,366	6.41%
7	Total C&I Revenue	Page 2	$ 69,292,446	$ 71,396,043	3.04%
8	Total Revenue	Ln 6 + Ln 7	183,658,176	193,092,409	5.14%
9	At Equalized Rate Increase:				
10	Residential Revenue	6A *1.0514		120,240,519	
11	Mcf Charge Revenue @ Present Rate	Cell 5A		100,522,396	
12	Customer Charge Revenue	Ln 10 - Ln 11		19,718,123	
13	Residential Customer Charge	Ln 12/Cell 3A		$ 10.68	
14	C&I Revenue	Cell 7A*1.0514		72,851,890	
15	Total Revenue	Ln 10 - Ln 14		193,092,409	

Atmos Energy Corp.
Analysis of Gas Rate Increase by Class

		Source	A Present Rate	B Proposed Rate	C	D	E
1	Customer Charge - Non-Res	Tariff Sheet 4	$ 20.00	$ 35.00			
2	1st 300 mcf	Tariff Sheet 4	$ 9.9769	$ 9.6969			
3	Next 14,700 mcf	Tariff Sheet 4	$ 9.4459	$ 9.5519			
4	Over 15,000 mcf.	Tariff Sheet 4	$ 9.2169	$ 9.2868			
	Billing Units		Bills	mcf <300	mcf>300	Total	% Change
5	Firm Commercial	GLS - 5	211,033	4,100,564	517,951		
6	Firm Industrial	GLS - 5	2,585	305,053	346,714		
7	Firm Public Authority	GLS - 5	19,508	999,432	268,556		
8	Total		233,126	5,405,049	1,133,221		
	At Present Rates:						
9	Firm Commercial	Col A, Lns 1-3 * Ln 5	$ 4,220,660	40,910,917	4,892,513	50,024,090	
10	Firm Industrial	Col A, Lns 1-3 * Ln 6	$ 51,700	3,043,483	3,275,026	6,370,209	
11	Firm Public Authority	Col A, Lns 1-3 * Ln 7	$ 390,160	9,971,233	2,536,753	12,898,146	
12	Total	Ln 9 + Ln 10 + Ln 11	$ 4,662,520	$ 53,925,633	$ 10,704,292	69,292,446	
	At Proposed Rates						
13	Firm Commercial	Col B, Lns 1-3 * Ln 5	$ 7,386,155	39,762,759	4,947,416	52,096,330	4.14%
14	Firm Industrial	Col B, Lns 1-3 * Ln 6	$ 90,475	2,958,068	3,311,777	6,360,321	-0.16%
15	Firm Public Authority	Col B, Lns 1-3 * Ln 7	$ 682,780	9,691,392	2,565,220	12,939,392	0.32%
16	Total		$ 8,159,410	$ 52,412,220	$ 10,824,414	71,396,043	3.04%
	Recommended Rates:						
17	Total C&I Revenue	Note 1	8,101,843	$ 53,925,633	$ 10,824,414	72,851,890	
18	C&L Customer Charge	Cell 17A/Cell 8A	$ 34.75				
19	Firm Commercial	Note 2	7,334,043	$ 40,910,917	4,947,416	53,192,377	6.33%
20	Firm Industrial	Note 2	89,837	$ 3,043,483	3,311,777	6,445,097	1.18%
21	Firm Public Authority	Note 2	677,963	$ 9,971,233	2,565,220	13,214,416	2.45%
22	Total	Ln 19 + Ln 20 + Ln 21	8,101,843	$ 53,925,633	$ 10,824,414	72,851,890	5.14%

Note 1: Column D from page 1, cell 14A; column C from Cell 16C; column B from Cell 12B; column A computed as Col D - Cols B & C
Note 2: Column A Cell 18A * Cells A5,A6,A7; column B from Cells B9,B10, B11; column C from Cells C13, C14, C15; column D sum cols A,B,C

Experience

Snavely King Majoros O'Connor & Lee, Inc. Washington, DC

President (1989 to Present)
Vice President (1970 - 1989)

Mr. King, a founder of the firm and acknowledged authority on regulatory economics, brings over thirty years of experience in economic consulting to his direction of the firm's work in transportation, utility and telecommunications economics.

Mr. King has appeared as an expert witness on over 300 separate occasions before more than thirty state and nine U.S. and Canadian federal regulatory agencies, presenting testimony on rate base calculations, rate of return, rate design, costing methodology, depreciation market forecasting, and ratemaking principles. Mr. King has also testified before House and Senate Committees on energy and telecommunications legislation pending before the U.S. Congress.

In telecommunications, Mr. King has testified before the Federal Communications Commission on a number of policy issues, service authorization, competitive impacts, video dialtone, and prescription of interstate depreciation rates. Before state regulatory bodies, he has presented testimony in proceedings on intrastate rates, costs earnings and depreciation.

Mr. King has testified in electric, gas and water utility cases on virtually every aspect of regulation, including cost of capital, revenue requirements, depreciation, cost allocation and rate design. Mr. King is one of the nation's leading authorities on utility depreciation practices, having testified on this subject in several dozen cases before state regulatory bodies.

In addition to his appearances as a witness in judicial and administrative proceedings, Mr. King has negotiated settlements among private parties and between private parties and regulatory offices. Mr. King also has directed depreciation studies, investment cost benefit analyses, demand forecasts, cost allocation studies and antitrust damage calculations. Mr. King directed analyses of the prices of services under Federal Government's FTS2000 long distance system.

In Canada, Mr. King designed and directed an extended inquiry into the principles and procedures for regulating the telecommunication carriers subject to the jurisdiction of the Canadian Transport Commission. He also was the principal investigator in the Canadian Transport Commission's comprehensive review of rail costing procedures.

EBS Management Consultants, Inc., Washington, DC

Director, Economic Development Department (1968-1970)

Mr. King organized and directed a five-person staff of economists performing research, evaluation, and planning relating to economic development of depressed areas and communities within the U.S. Most of this work was on behalf of federal, state, and municipal agencies responsible for community or regional economic development.

Principal Consultant (1966-1968)

Mr. King conducted research on a broad range of economic topics, including transportation, regional economic development, communications, and physical distribution.

W.B. Saunders & Company, Inc., Washington, DC

Staff Economist (1962-1966)

For this economic consulting firm, which later merged with EBS Management Consultants, Inc., Mr. King engaged in numerous research efforts relating primarily to economic development and transportation.

U.S. Bureau of the Budget, Office of Statistical Standards

Analytical Statistician (1961-1962)

Mr. King was responsible for the review of all federal statistical and data-gathering programs relating to transportation.

Education

Washington & Lee University, B.A. in Economics

The George Washington University, M.A. in Government Economic Policy

CHARLES W. KING
Appearances before State Regulatory Agencies

State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
MI (Cont'd)	Michigan Attorney General	U-12999	Consumers Energy Company	March 10, 2004
	Michigan Attorney General	U-13898,9	Michigan Consolidated Gas Co.	August 23, 2004
	Michigan Attorney General	U-14201	Detroit Edison Company	Filed December 5, 2004'
	Michigan Attorney General	U-14274	Consumers Energy Company	Filed February 15, 2005
	Michigan Attorney General	U-14148	Consumers Energy Company	Filed March 2, 25, 2005
	Michigan Attorney General	U-14399	Detroit Edison Company	July 29, 2005
	Michigan Attorney General	U-14428	Detroit Edison Company	September 7, 2005
	Michigan Attorney General	U-14292	All Michigan Utilities	September 27, 2005
	Michigan Attorney General	U-13808-R	Detroit Edison Company	November 7, 2005
	Michigan Attorney General	U-14547	Consumers Energy Company	Nov.7, 2005; Mar. 22, 2006
	Michigan Attorney General	U-14701	Consumers Energy Company	March 21, 2006
	Michigan Attorney General	U-14526	Consumers Energy Company	April 11.2006
	Michigan Attorney General	U-14561	All Gas Distribution Utilities	June 1, 2006
	Michigan Attorney General	U-15002	Detroit Edison Company	December 8, 2006
MN	Minnesota Retail Federation	EOO2/6R-77-611	Northern States Power	1979
MO	Missouri Retailers Association	EO-78-161	Kansas City Power & Light Company	February 19, 1981
	Missouri Public Counsel	ER-2006-0315	Empire District Electric Company	September 14, 2006
	Missouri Public Counsel	GR-2007-0003	Ameren UE (Gas)	Filed December 15, 2006
	Missouri Public Counsel	ER-2007-0002	Ameren UE (Electric)	March 22, 2007
NC	North Carolina Merchants Association	E-100	All Electric Utilities	December 18, 1975
ND	North Dakota Public Service Commission	PU-400-00-521	Xcel Energy, Inc.	April 20, 2001
	North Dakota Public Service Commission	PU-399-01-186	Montana-Dakota Utilities (Electric)	February 25, 2002
	North Dakota Public Service Commission	PU-399-02-183	Montana-Dakota Utilities (Gas)	October 7, 2002
	North Dakota Public Service Commission	PU-399-02-183	Montana-Dakota Utilities (Gas Depr.)	Filed April 7, 2003
	North Dakota Public Service Commission	PU-399-03-296	Montana-Dakota Utilities (Electric)	Filed October 15, 2003
	North Dakota Public Service Commission	PU-04-97	Montana-Dakota Utilities (Gas)	Filed July 6, 2004
NH	Business & Industry Association of N.H.	79-187-II	Public Service of N.H.	February 6, 1981
	Business & Industry Association of N.H.	80-260	Public Service of N.H.	February 5, 1981
	Business & Industry Association of N.H.	82-333	Public Service of N.H.	November 2, 1983
NJ	N.J. Retail Merchants Association	803-151	All New Jersey Utilities	March 31, 1981
	Department of Public Advocate	815-459	N.J. Natural Gas Company	(none)
	Resorts International Hotel, Inc.	8011-827	Atlantic City Sewerage Co.	(none)
	Dept. of Public Advocate	822-116	Atlantic City Electric Co.	August 11, 1982
	Dept. of Public Advocate	355-87	Elizabethtown Gas	June 9, 1987
	Dover Township Fire Chiefs	88-080967	Tom's River Water Company	February 22, 1989

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF GAS RATES	**) CASE NO. 2006-00464**

AFFIDAVIT OF CHARLES W. KING

District of Columbia)
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)

Charles W. King, being first duly sworn, states the following: The prepared Pre-Filed Direct Testimony, and the Schedules and Appendix attached thereto constitute the direct supplemental testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the Pre-Filed Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further affiant saith not.

Charles W. King

SUBSCRIBED AND SWORN to before me this 23rd day of April, 2007.

Angel L. Finch
NOTARY PUBLIC

My Commission Expires: March 14, 2011