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September 21, 2007

Sharla Dillon, Docket Manager
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, TN 37238

VIA HAND DELIVERY

RE: Petition of Atmos Energy Corporation for Approval of Adjustment of its Rates and Revised Tariff, TRA Docket No. 07-00105

Dear Ms. Dillon:

Enclosed for filing in the above-referenced matter are the originals and four copies each of the rebuttal testimony of the following witnesses:

1. Danny P. Bertotti;
2. Patricia Childers;
3. Christopher Forsythe;
4. Dr. Donald A. Murry;
5. Thomas H. Petersen;
6. Donald S. Roff;
7. Laurie M. Sherwood; and
8. Gary L. Smith.

Also enclosed is a CD ROM containing the referenced testimony.

Best regards.

Sincerely,

A. Scott Ross

ASR:prd

xc: Vance Broemel (Via Hand Delivery w/ CD ROM)
Timothy C. Phillips (Via Hand Delivery w/ CD ROM)
Henry M. Walker (Via Hand Delivery w/ CD ROM)
D. Billye Sanders (Via Hand Delivery w/ CD ROM)
John M. Dosker (Via U. S. Mail w/ CD ROM)

**BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE**

IN RE:

PETITION OF ATMOS ENERGY CORPORATION FOR APPROVAL OF ADJUSTMENT OF ITS RATES AND REVISED TARIFF	))))	**DOCKET NO. 07-00105**

**REBUTTAL TESTIMONY OF DANNY P. BERTOTTI
ON BEHALF OF ATMOS ENERGY CORPORATION**

I. NAME AND POSITION

Q. PLEASE INTRODUCE YOURSELF.

A. My name is Danny P. Bertotti. I am a Sales Representative for Atmos in Tennessee and the Kentucky/Mid-States region. My business address is 200 Noah Drive, Franklin, Tennessee 37064.

II. SUMMARY OF TESTIMONY

Q. DID YOU FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. No, I did not.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my testimony is to respond to the rate design proposals set forth in this case by the Atmos Intervention Group's witness Mr. Hal Novak. Although Mr. Novak advances several proposed tariff changes, I will only be addressing three general areas in my testimony. It is my understanding that pursuant to the TRA's September 13, 2007 Order in this docket, the transportation tariff and related issues, asset management issues, and capacity release issues have all been severed from this proceeding. In light of the TRA's Order, I will not address the remaining proposals that were outlined by Mr. Novak, with the exception of the proposed change to Rate Schedule 260 since that would impact sales customers.

III. BACKGROUND AND EDUCATION

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES, AND PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. I am a 1994 graduate of the University of Tennessee, with a Bachelor of Science Degree in Mechanical Engineering. I have been employed by Atmos full time since 1994. Currently, I am responsible for initiating, developing and maintaining relationships with Atmos' industrial and large volume commercial customers to promote business development and the continued use of the company's products and services that add value for those customers. I routinely conduct on-site visits to become and remain knowledgeable about customer operations.

Q. HAVE YOU EVER SUBMITTED TESTIMONY BEFORE THE TENNESSEE REGULATORY AUTHORITY ("TRA")?

A. Yes. I submitted rebuttal testimony in TRA Docket No. 05-00258.

III. RATE SCHEDULES 220 AND 230

Q. WHAT IS MR. NOVAK PROPOSING WITH RESPECT TO RATE SCHEDULES 220 AND 230?

A. Mr. Novak proposes that Rate Schedule 220 only be available to smaller commercial and industrial customers who consume less than 4,000 Ccf per year. He also proposes the addition of a three tiered declining block rate structure to Rate Schedule 230, with the third block set at a rate that is half that of the first block.

Q. DO YOU AGREE WITH THESE PROPOSED CHANGES?

A. No, for a number of reasons. First, it appears that Mr. Novak designed this rate structure with the intention to mirror the rate structure at Chattanooga Gas Company ("Chattanooga"). Secondly, the proposal does not accurately reflect rate design at Chattanooga. Finally, and maybe most importantly, none of the parties to this case has adequately studied the impact of shifting costs from this

Company's larger commercial and industrial customers on the rate 230 schedule to the smaller commercial and industrial customers on the 220 rate schedule.

Q. DID CHATTANOOGA BASE ITS RATES ON A COST OF SERVICE STUDY?

A. No. As more fully explained in the rebuttal testimony of Mrs. Patricia Childers, Mr. Novak is incorrect when he testifies on page 3, lines 14 and 15 that Chattanooga's rates were based on its cost of service study.

Q. IS THE RATE STRUCTURE PROPOSED BY MR. NOVAK CONSISTENT WITH CHATTANOOGA'S RATE STRUCTURE?

A. No. Again, Mr. Novak is misleading when he testifies on lines 10 and 11 of page that his rate design structure is consistent with the structure approved for Chattanooga. The structure that this Authority approved for Chattanooga consists of four tiers, not three. This is significant because Mr. Novak's three tiered proposal would put more volumes in the 50% block as compared to Chattanooga's four tiered rate design. For example, a Chattanooga customer must use over 15,000 Ccf per month in order to reach the 50% rate. Mr. Novak's proposal would have an Atmos customer reach the 50% rate at a mere 5,000 Ccf per month, only one-third of the level of consumption required in the Chattanooga structure. The table below more clearly shows the difference between Mr. Novak's proposal and the rates approved for Chattanooga.

Novak's Proposal for Atmos	**Chattanooga Gas' C-2 Rate**
1st 3000 Ccf per month $<<xxx>> per Ccf	1st 3000 therms per month $<<xxx>>
Next 2000 Ccf per month $<<xxx>> per Ccf	Next 2000 therms per month $<<xxx>> **minus 8.7%**
Over 5000 Ccf per month $<<xxx>> per Ccf **minus 50%**	Next 10,000 therms per month $<<xxx>> **minus 11.1%**
	Over 15,000 therms per month <<xxx>> **minus 54%**

IV. RATE SCHEDULES 240 AND 250

Q. WHAT IS MR. NOVAK PROPOSING WITH RESPECT TO RATE SCHEDULE 240 AND 250?

A. Mr. Novak is proposing that customers in Rate Schedules 240 and 250 be combined into a single rate.

Q. ARE YOU AWARE OF ANY CUSTOMERS WHO ARE INTERESTED IN SEEING THIS CHANGE OCCUR?

A. No. To my knowledge, no customers have inquired about or discussed the possibility of eliminating the distinction between the Rate 240 and Rate 250 customers.

Q. WHY IS THE COMPANY OPPOSED TO THIS CHANGE?

A. Rate Schedules 240 and 250 offer two very distinct services and the rates should remain separate. Rate Schedule 240 was designed with a demand/commodity rate structure in order to give larger firm customers with a relatively flat load profile the option of remaining a firm customer without the need to arrange for an alternative fuel source, while at the same time having the ability to realize some savings when compared to smaller customers on the firm Rate Schedule 230. Rate Schedule 250, on the other hand, gives the industrial customer with an alternative fuel source a rate that is even further reduced. In exchange for that savings, the Company has the ability to curtail that customer with a 30 minute notice.

Q. WHAT ABOUT MR. NOVAK'S CONTENTION THAT RATE 250 CUSTOMERS RECEIVE A HIGHER VALUE OF SERVICE?

A. This is simply not the case. Rate 250 customers must maintain back up fuel systems and be prepared to accept curtailments on extremely short notice.

Q. ARE THESE CUSTOMERS CURRENTLY ABLE TO CHANGE BETWEEN SALES AND TRANSPORTATION RATES WITHOUT NOTICE?

A. No. The statement made by Mr. Novak at lines 21-24 on page 4 of his testimony regarding the "no notice" provisions is misleading. Atmos requires a customer who selects transportation service to stay on that rate for twelve months. They are not free to "swing" back and forth between rates as Mr. Novak testified.

Q. DO RATE 250 CUSTOMERS PRESENT A HIGHER CREDIT RISK?

A. No, Mr. Novak is again incorrect when he makes the wholly unsupported statement at lines 24-25 on page 4 of his testimony that Rate 250 customers present a significantly greater credit risk to the Company. In fact, Rate 250 customers actually represent a lower credit risk because, on average, their bills are lower and Atmos has the ability to require these customers to use their back up fuel system if they fail to timely pay their bills.

RATE SCHEDULE 260

Q. DOES MR. NOVAK PROPOSE CHANGES TO THE TRANSPORTATION RATE SCHEDULE 260?

A. Yes, Mr. Novak proposes changes to Rate Schedule 260 which would result in these customers paying a lower base rate than the sales customers in Rate Schedule 250.

Q. **DO YOU AGREE WITH MR. NOVAK'S PROPOSAL?**

A. No. Even though transportation issues have been severed from this docket, it is necessary to point out in this docket that Mr. Novak is proposing a transportation rate structure that will result in a margin loss for the company as sales customers switch to transportation service.

Q. DO YOU AGREE WITH MR. NOVAK THAT THE COST OF PROVIDING SERVICE TO THESE CUSTOMERS IS LESS THAN IT IS FOR SALES CUSTOMERS?

A. No, the cost of service to transportation customers is actually higher. Transportation customers require Electronic Flow Measurement ("EFM") technology, which typically requires more maintenance. Also, additional administrative costs are required for transportation customers such as handling nominations, scheduling gas, reviewing allocations, and calculating monthly cash outs. In addition, many transportation accounts are required to be billed by hand, rather than using the Company's billing system.

V. MISCELLANEOUS RATES

Q. DOES MR. NOVAK MAKE ANY FURTHER RECOMMENDATIONS WITH RESPECT TO OTHER RATE SCHEDULES?

A. Yes. Mr. Novak would like to eliminate several service rates including Experimental School Service, Economic Development Gas Service, Negotiated Gas Service, Cogeneration Service and Large Tonnage Air Conditioning Service.

Q. DOES THE COMPANY AGREE WITH THE ELIMINATION OF THESE SERVICES?

A. No. Although these particular services are used sparingly, they are an important part of economic development in Tennessee. These services support economic growth as well as development of new technologies such as cogeneration and gas powered air conditioning. Although the Experimental School Service is no longer available to new schools, some existing schools have already invested in gas technology because of the rate and it is important to keep this rate in place for those schools.

Q. DOES THIS COMPLETE YOUR REBUTTAL TESTIMONY?

A. Yes.

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:	)	
	)	
PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	
ADJUSTMENT OF ITS RATES AND	)	
REVISED TARIFF	)	**DOCKET NO. 07-00105**

VERIFICATION

STATE OF TENNESSEE)
)
COUNTY OF WILLIAMSON)

I, Danny Bertotti, being first duly sworn, state that I am a Sales Representative for Atmos Energy Corporation, that I am authorized to testify on behalf of Atmos Energy Corporation in the above referenced docket, that the Rebuttal Testimony of Danny Bertotti pre-filed in this docket on the date of filing herein is true and correct to the best of my knowledge, information and belief.

Daniel P Bertotti
Danny Bertotti

Sworn and subscribed before me this 20th day of September, 2007.

Pamela Todd
Notary Public

My Commission Expires: May 2008

PAMELA TODD
STATE OF TENNESSEE NOTARY PUBLIC
DAVIDSON COUNTY, TENN.
My Commission Expires 05-24-08

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:

PETITION OF ATMOS ENERGY CORPORATION FOR APPROVAL OF ADJUSTMENT OF ITS RATES AND REFISED TARIFF	))))	**DOCKET NO. 07-00105**

REBUTTAL TESTIMONY OF PATRICIA CHILDERS
ON BEHALF OF ATMOS ENERGY CORPORATION

Q. PLEASE STATE YOUR NAME AND BUSINESS AFFILIATION.

A. My name is Patricia Childers. I am the Vice President, Rates and Regulatory Affairs, of the Kentucky/Mid-States Division of Atmos Energy Corporation ("Atmos", "Atmos Energy" or "the Company").

Q. DID YOU FILE DIRECT TESTIMONY ON BEHALF OF THE COMPANY IN THIS PROCEEDING?

A. Yes. In my direct testimony, I primarily addressed rate design, including the apportionment of any rate increase approved by the Tennessee Regulatory Authority (the "Authority") equally across the Company's existing customer classes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I am providing this testimony in rebuttal to specific issues raised in the direct testimony of William H. Novak, a witness for the Atmos Intervention Group ("AIG"). In his direct testimony, Mr. Novak proposes an alternative rate design within the Company's classes of customers receiving service under the Company's Rate Schedules 220, 230, 240, 250 and 260. These changes are addressed more specifically in the rebuttal testimony of Mr. Daniel Bertotti. Mr. Novak also proposes other changes to the Company's transportation service rate schedules, but these issues have been severed from this case by the Authority into another pending docket. Mr. Novak further proposes that the Company file a class cost of service study (a "CCOS") in its next general rate case. He also indicates that the commercial and industrial tariff sheets he has proposed in this proceeding were based on the results of a CCOS performed by Chattanooga Gas Company in its most recent rate case. My rebuttal testimony addresses the issues concerning a CCOS raised in Mr. Novak's testimony.

Q. WHAT IS A CCOS?

A. A CCOS examines cost responsibility of customer rate classes based on principles of cost-causation. A CCOS generally begins with cost data grouped into functional categories including gas production, storage, transmission, distribution and administrative and general. The costs for each functional group are then reviewed with regard to whether the cost is more related to the number of customers served, the amount of commodity used, the peak use demand placed on the system or a combination of these items. The customers are then grouped into customer classes considering the amount and pattern of gas use. Factors are developed to allocate each cost category among the customer classes. Finally, the allocated costs are compared to current and proposed revenues for each customer class with the result of the comparison expressed as a rate of return on rate base for each class. It generally provides a benchmark for allocating a utility's cost of service among the customer classes and can be a useful tool in designing base rates.

Q. ARE THERE DIFFERING CCOS METHODOLOGIES?

A. Yes. Some of these methodologies are known as minimum system, zero intercept and Seaboard, with the latter being somewhat rarely used anymore. Methodologies may vary from jurisdiction to jurisdiction with some recognizing minimum system as the preferred approach while others have sanctioned the use of zero intercept.

Q. IS A CCOS USED TO ALLOCATE COSTS BETWEEN CUSTOMERS WITHIN THE SAME CLASS?

A. I am not sure how a CCOS could be used in this manner. If there is a significant disparity between groups of customers within a class, then it seems that, for purposes of truly determining cost causation, that a new class would need to be formed. For example, if multi-family was included within the general residential class, then there might, depending on a particular utility's system, be sufficient disparity to justify the creation of a large-volume residential class or multi-family class.

Q. IS A CCOS UNIQUE TO A SPECIFIC UTILITY'S SYSTEM?

A. Yes. A CCOS, irrespective of the methodology used, examines the specific utility's system and attempts to allocate that utility's cost of service across that specific utility's customer classes. Not all gas utilities have the same types of systems, the same costs or the same customer classes. Accordingly, a class cost of service study prepared for another gas utility, such as Piedmont Natural Gas or Chattanooga Gas Company, cannot be legitimately used as a ratemaking tool for the Company.

Q. HAS THE AUTHORITY SANCTIONED ANY PARTICULAR METHODOLOGY?

A. Not to my knowledge. I am unaware of any utility rate case decided by the Authority within the last 15 years where it has relied upon any particular class cost of service or associated methodology for purposes of approving a utility's rate design. This does not necessarily mean that a stipulated settlement in a rate case, which may have included a rate design based upon a study presented by or agreed to by the case participants, did not receive approval from the Authority. I am just unaware of any actual decision by the Authority on this subject matter.

Q. DID THE COMPANY FILE A CCOS IN THIS PROCEEDING?

A. No. Such studies can be expensive and, inasmuch as the Authority has generally taken the approach of equal apportionment of a utility's increased or decreased revenue requirement across the respective rate classes in prior cases, then that is the approach that the Company has proposed in this rate case.

Q. WHAT PRIOR CASES DO YOU REFER TO?

A. The rate proceeding involving the Company last year and the Company's 1995 general rate proceeding before the Authority. No class cost of service studies were filed in those proceedings.

Q. DID ANY OTHER PARTY TO THIS PROCEEDING FILE A CCOS?

A. No.

Q. DID ANY PARTY TO THIS PROCEEDING REQUEST THE COMPANY TO PERFORM A CCOS?

A. No.

Q. DID ANY PARTY TO THIS PROCEEDING CONDUCT ANY DISCOVERY TO OBTAIN INFORMATION THAT WOULD BE USED TO PERFORM A CCOS?

A. Not to my knowledge. AIG might claim that it sent discovery to the Company that the Authority determined did not have to be answered in this docket. However, almost all of that information pertained to AIG's complaints regarding the Company's proposed transportation tariff changes, which are pending in another docket.

Q. WHEN WAS THE FIRST TIME THAT THE POSSIBILITY OF A CCOS WAS RAISED IN THIS PROCEEDING?

A. It was raised for the first time by AIG on August 21 when it filed the pre-filed direct testimony of Mr. Novak.

Q. WHAT DOES MR. NOVAK STATE REGARDING A CCOS?

A. Mr. Novak, on behalf of AIG, states that the proposed commercial and industrial tariff sheets that he has attached to his testimony, and which prescribe no specific rates, were based on the results of a CCOS prepared by Chattanooga Gas Company in its 2006 rate case before the authority in Docket No. 06-00175.

Q. IS THIS A CORRECT STATEMENT?

A. Not entirely. Although Mr. Novak is correct that Chattanooga prepared and filed a CCOS in that docket, Chattanooga's rate increase was applied as an equal percentage to each customer class, which is what the Company has requested in this rate proceeding. There was actually no revenue shift in Chattanooga's revenue requirement as a result of its CCOS. Even if there had been, that study and any attendant rate design based upon that study, would have been unique to Chattanooga and would be inapplicable to the Company.

Q. WHAT ARE MR. NOVAK'S RECOMMENDATIONS REGARDING THE APPORTIONMENT OF ANY INCREASE IN THE COMPANY'S REVENUE REQUIREMENT IN THIS PROCEEDING?

A. He recommends that the Authority apportion any rate change evenly across-the-board to all customer classes and then, through supplemental testimony or post-hearing briefs, to provide the Authority with specific rate recommendations that will produce the new level of revenue for those customer classes that he has addressed within his testimony.

Q. IS THERE ANYTHING WRONG WITH THIS PROPOSAL?

A. Yes. It unduly complicates this proceeding by extending ratemaking issues beyond the Authority's decision on any appropriate rate increase. If AIG wanted to truly address rate design within the procedural schedule and hearing dates for this proceeding set by the Authority, it could have done so by performing its own CCOS. Although Mr. Novak suggests that the Company be required to file a CCOS in its next general rate case, and which the Company would be willing to do if it deems such a study necessary, this does not lend any support to his current proposals.

Q. ARE THERE ANY OTHER ATTENDANT PROBLEMS WITH MR. NOVAK'S PROPOSALS?

A. Yes, based upon my understanding of his rate design proposals set out in his testimony. Although Mr. Novak advocates an equal apportionment of any revenue increase across all customer classes, it appears that his proposed rate design would actually unravel the Authority's decision on the apportionment of the authorized revenue requirement. For example, if you accept Mr. Novak's position regarding a rate decrease for Rate Schedule 260 customers, then where does the revenue shortfall come from? The answer is that it will come from customers within other classes. As a result, his proposal, contrary to what he has stated in his testimony about equal apportionment, ultimately will result in shifting a portion of the revenue requirement onto other customers. Inasmuch as the Company would not agree to any such result, the entire issue of the apportionment of the total revenue requirement would have to be revisited by the Authority within this docket.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:	)	
	)	
PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	
ADJUSTMENT OF ITS RATES AND	)	
REVISED TARIFF	)	**DOCKET NO. 07-00105**

VERIFICATION

STATE OF TENNESSEE)
)
COUNTY OF WILLIAMSON)

I, Patricia Childers, being first duly sworn, state that I am the Vice President, Rates and Regulatory Affairs of the Kentucky/Mid-States Division of Atmos Energy Corporation, that I am authorized to testify on behalf of Atmos Energy Corporation in the above referenced docket, that the Rebuttal Testimony of Patricia Childers pre-filed in this docket on the date of filing herein is true and correct to the best of my knowledge, information and belief.

Patricia Childers

Patricia Childers

Sworn and subscribed before me this 21 day of October, 2007.

PHYLLIS R. DICKENS STATE OF TENNESSEE NOTARY PUBLIC DAVIDSON COUNTY, TENN.

Phyllis R. Dickens

Notary Public

My Commission Expires: ____________ My Commission Expires JAN. 3, 2011

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:

PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	
ADJUSTMENT OF ITS RATES AND	)	
REFISED TARIFF	)	**DOCKET NO. 07-00105**

REBUTTAL TESTIMONY OF CHRISTOPHER FORSYTHE
ON BEHALF OF ATMOS ENERGY CORPORATION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Christopher Forsythe. My business address is 5430 LBJ Freeway, Suite 600, Dallas, Texas 75240.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the Director of Financial Reporting for Atmos Energy Corporation ("Atmos" or the "Company").

Q. WHAT ARE YOUR JOB RESPONSIBILITIES?

A. As Director of Financial Reporting, I am primarily responsible for planning, organizing, coordinating and directing the timely and accurate preparation of financial, regulatory and benefits accounting reports to ensure compliance with regulatory requirements. This includes, but is not limited to, timely preparation and filing of quarterly and annual reports with the Securities and Exchange Commission ("SEC") in accordance with applicable federal securities laws and regulations. I am also responsible for oversight of the Company's annual filings made with the various state commissions that regulate the Company's local gas distribution operations, including the Tennessee Regulatory Authority ("TRA").

Q. PLEASE OUTLINE YOUR EDUCATIONAL AND PROFESSIONAL QUALIFICATIONS.

A. I received Bachelor of Business Administration degrees in Accounting and Management Information Systems from Baylor University in 1993. I am a licensed certified public accountant in the State of Texas.

From September 1993 to June 2003, I worked for the public accounting firm of PricewaterhouseCoopers LLP and its predecessor firm, Price Waterhouse LLP, as an auditor and was ultimately promoted to senior manager. During my public accounting career, my client base was comprised predominantly of publicly traded companies in the energy and manufacturing sectors. In June 2003, I joined Atmos as Manager, Financial Reporting and was promoted to Director, Financial Reporting in September 2003.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE TRA OR OTHER REGULATORY ENTITIES?

A. I have never testified before the TRA. I have testified before the Railroad Commission of Texas and the Mississippi Public Service Commission.

Q. DID YOU FILE DIRECT TESTIMONY ON BEHALF OF THE COMPANY IN THIS PROCEEDING?

A. No. My direct testimony was not required for the Company's initial rate filing with the TRA in this docket.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. Dr. Steve Brown, a witness for the Consumer Advocate and Protection Division ("CAPD") of the Tennessee Attorney General's Office, has raised certain issues regarding financial information filed with the Securities and Exchange Commission ("SEC") by publicly traded companies, including Atmos Energy. Specifically, Dr. Brown has stated that, for purposes of addressing capital structure issues in this rate proceeding, the only reliable source of information filed with the SEC is the Company's Form 10-K. My testimony addresses this subject matter and rebuts Dr. Brown's position.

In addition to my testimony on this discrete issue, Dr. Donald Murry and Ms. Laurie Sherwood have provided rebuttal testimony on behalf of the Company regarding capital structure and cost of debt issues in response to Dr. Brown's direct testimony.

II. CAPITAL STRUCTURE DATA SOURCES

Q. WHAT CAPITAL STRUCTURE DOES THE CAPD RECOMMEND FOR THE COMPANY IN THIS PROCEEDING?

A. The capital structure recommended by Dr. Brown on behalf of the CAPD is reflected on page 2 of his cost of capital testimony. His capital structure components are 11.3% short-term debt, 1.7% for current maturities of long-term debt, 46.3% long-term debt and 40.7% equity. Although current maturities of long-term debt are reported in the Company's financial statements filed with the SEC, they are not considered to be a separate capital structure component and are instead considered to be part of long-term debt.

Q. HOW DID DR. BROWN DERIVE HIS CAPITAL STRUCTURE?

A. Dr. Brown derives his recommended capital structure on a 10-year average of the Company's historical capital structures reported in its annual report on Form 10-K filed with the SEC. For purposes of his averaging, he states that he has omitted the Company's fiscal year 2004 as the year in which the Company's acquisition of TXU Gas occurred. However, the acquisition actually closed on October 1, 2004, which was the beginning of the Company's 2005 fiscal year, and affected debt levels reported during fiscal 2005.

Q. DID DR. BROWN USE ANY OTHER HISTORICAL REPORTS FILED WITH THE SEC BY THE COMPANY IN ARRIVING AT HIS CAPITAL STRUCTURE?

A. No. Dr. Brown has apparently concluded that the only reliable source for determining a publicly traded company's capital structure is its 10-K reports. The rationale he provides for this is that 10-Ks are audited by independent registered public accountants. The last Form 10-K filed by the Company and included in Dr. Brown's analysis was for the Company's fiscal year ended September 30, 2006. He apparently did not consider the interim reports on Form 10-Q filed with the SEC since September 30 of last year which report important changes affecting the Company's capital structure and which are discussed in Ms. Sherwood's rebuttal testimony.

Q. DO YOU AGREE WITH DR. BROWN'S CONCLUSION THAT 10-Ks ARE THE ONLY RELIABLE SOURCE OF DATA?

A. No. More frequent and more current data is available in the form of quarterly reports on Form 10-Q, which are also filed by the Company with the SEC.

Q. MUST 10-Qs BE REVIEWED BY AN INDEPENDENT PUBLIC ACCOUNTANT?

A. Yes. In December of 1999[1], the SEC strengthened its rules regarding the filing of interim financial information by publicly traded companies to require the pre-filing review of Forms 10-Q by an independent public accountant.[2] The SEC's stated purpose for the new requirements was as follows:

> *We believe that the reviews required will facilitate early identification and resolution of material accounting and reporting issues because the auditors will be involved earlier in the year. Early involvement of the auditors should reduce the likelihood of restatements or other year-end adjustments and enhance the reliability of financial information. In addition, as a result of changes in the markets, companies may be experiencing pressure to "manage" interim financial results. Inappropriate earnings management could be deterred by imposing more discipline on the process of preparing interim financial information before filing such information with the Commission.*[3]

The SEC then went on to say:

> *We believe that companies are under increasing pressure to meet financial analysts' expectations, and that pressure can be even more acute in the context of reports on quarterly earnings. We believe that the participation of auditors in the financial reporting process at interim dates will help to counterbalance that pressure and impose increased discipline on the process of preparing interim financial information. Auditor involvement in the financial reporting process earlier in the year should facilitate timely identification and resolution of significant and sensitive issues and result in fewer year-end adjustments, which should reduce the cost of annual audits. The increased focus and discipline imposed on the preparation of interim financial statements should enhance the efficiency of the capital markets by improving the reliability of*

[1] 64 Fed.Reg. 73,389 (Dec. 30, 1999).
[2] 17 CFR §210.10-1(d).
[3] 64 Fed.Reg. at 73,392.

quarterly financial statements, although these benefits are difficult to quantify.[4]

The SEC's rulemaking clearly enunciates the importance of quarterly reports for financial transparency and the investing community. Further, the SEC's rulemaking suggests that quarterly reports can be more important to the investment community than annual reports. Although Dr. Brown is correct that 10-Ks are the only audited financials that are filed with the SEC by the Company, the year-around involvement by the Company's independent registered public accountants through the pre-filing review of quarterly financials is beneficial to both the Company and investors. In other words, annual reports cannot be read in isolation because market conditions continually change and material transactions and events often occur subsequent to the release of the annual reports that can impact a company. Therefore, relying strictly upon the annual report prevents a financial statement user from obtaining a current and comprehensive view of a company's financial position and results of operations.

A review of the Company's quarterly reports on Form 10-Q shows that they comply with the pre-filing requirements of the SEC's rules in that they have been reviewed by the Company's independent public accounting firm of Ernst & Young, LLP.[5] Therefore, Dr. Brown's conclusion that annual reports on Form 10-K are the only reliable source of investor data for a publicly traded company is simply erroneous.

Q. SUBSEQUENT TO 1999, WERE THERE ANY OTHER CHANGES IN LAW THAT AFFECTED THE COMPANY'S QUARTERLY AND ANNUAL FINANCIAL DISCLOSURE OBLIGATIONS UNDER THE FEDERAL SECURITIES LAWS?

A. Yes. On July 30, 2002, Congress enacted the Sarbanes-Oxley Act of 2002 ("SOX"), which was designed to prevent future corporate abuses involving public companies, such as the Enron and WorldCom debacles, and to restore investor confidence in the securities markets. SOX is an expansive piece of legislation

[4] 64 Fed.Reg. at 73,397.

[5] *See* Exhibit CF-R-1, p. 22, Exhibit CF-R-2, p. 26 and Exhibit CF-R-3, p. 26.

that touches upon numerous topics regarding corporate governance, but some of the key requirements of the act affecting the Company's disclosure obligations include:

- Requiring the Company's officers and directors to implement policies and procedures that result in improved corporate governance and to report on those controls on a quarterly basis
- Requiring increased disclosure of material information to the investing public
- Providing for enhanced enforcement penalties and powers to the SEC and prosecutors to ensure that officers and directors fulfill their responsibilities

For all periodic reports (including Forms 10-Q) SOX now requires the Company's chief executive officer and chief financial officer to sign certifications with prescribed language (with potential civil and criminal penalties) of annual and quarterly financial statements, disclosure controls and internal controls that contain materiality qualifiers.[6] These certifications are filed or furnished as exhibits to the periodic SEC reports on Forms 10-K and 10-Q.

Q. ARE THE COMPANY'S FORMS 10-Q A RELIABLE DATA SOURCE THAT DR. BROWN SHOULD HAVE CONSIDERED?

A. Yes. Aside from the fact that they are reports that are required to be filed with the SEC, reviewed by the Company's independent registered public accountants before they are filed, and certified by the Company through processes and controls prescribed by SEC regulations and SOX, they are also relied upon heavily by investors.

Q. WHY IS THAT?

A. Although a publicly traded company's annual report on Form 10-K is a key piece of information for making an investment decision, an astute investor wants to evaluate the most current data available when making a decision whether to buy the Company's stock. It is unrealistic to conclude, as Dr. Brown has concluded,

[6] Required by Sections 302, 404(a) and 906 of SOX as well as SEC Release No. 33-8124 and SEC Proposing Release No. 33-8212.

that investors rely only on annual reports. Would an investor that is evaluating whether to buy Atmos stock in August of 2007 want to rely entirely upon information in a Form 10-K for a fiscal year ended almost 12 months prior and a SEC report that, by that time, has been on file with the SEC for almost 9 months? The answer is a resounding no. That particular investor would want to see both the last annual report as well as all intervening quarterly reports filed with the SEC. Moreover, he would probably also want to review any filings made on Form 8-K since the annual report. Perhaps the reasoning is best summed up by the SEC itself when it stated "...interim financial reporting, as reflected in quarterly reports on Form 10-Q, is an important part of the full disclosure principle underlying the federal securities laws because investors rely on, and react quickly to, quarterly reports."[7]

Q. HAS THE COMPANY FILED ANY INTERIM REPORTS WITH THE SEC SINCE THE 10-K FOR THE FISCAL YEAR ENDING SEPTEMBER 30, 2006?

A. Yes, the Company has since filed 3 quarterly reports on Form 10-Q filed with the SEC. The quarterly report for the period ending December 31, 2006 is attached hereto as Exhibit CF-R-1, the quarterly report for the period ending March 31, 2007 is attached hereto as Exhibit CF-R-2 and the quarterly report for the period ending June 30, 2007 is attached hereto as Exhibit CF-R-3. All of these reports are publicly available and can be accessed on-line through the SEC's EDGAR database at www.sec.gov as well as the Company's website at www.atmosenergy.com.

Q. DID YOU OVERSEE THE PREPARATION OF THE QUARTERLY REPORTS AND THE FILING THEREOF WITH THE SEC?

A. Yes. As I stated previously, I have oversight of all of the Company's external reports filed with the SEC, including Forms 10-K and 10-Q.

Q. WERE THE QUARTERLY REPORTS YOU HAVE ATTACHED AS EXHIBITS TO YOUR REBUTTAL TESTIMONY PUBLICLY AVAILABLE WHEN DR. BROWN FILED HIS DIRECT TESTIMONY?

[7] SEC Securities Exchange Act of 1934 Release No. 42587 (Mar. 29, 2000).

A. Yes. Dr. Brown's direct testimony and accompanying verification are dated August 21, 2007. The Forms 10-Q attached hereto as Exhibit CF-R-1 and CF-R-2 were filed with the SEC and publicly available several months before the filing of Dr. Brown's testimony. The Company's most recent Form 10-Q attached hereto as Exhibit CF-R-3 was filed with the SEC on August 8, 2007, or two weeks before the filing of Dr. Brown's testimony. Because filings are made with the SEC electronically, they are typically available for review through the SEC's on-line EDGAR database by the next business day.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

EXHIBIT CF-R-1

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

(Mark One)

☑ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended December 31, 2006

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number 1-10042

Atmos Energy Corporation
(Exact name of registrant as specified in its charter)

Texas and Virginia *(State or other jurisdiction of incorporation or organization)*	**75-1743247** *(IRS employer identification no.)*
Three Lincoln Centre, Suite 1800 **5430 LBJ Freeway, Dallas, Texas** *(Address of principal executive offices)*	**75240** *(Zip code)*

(972) 934-9227
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "Accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer ☑ Accelerated Filer ☐ Non-Accelerated Filer ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act) Yes ☐ No ☑

Number of shares outstanding of each of the issuer's classes of common stock, as of January 31, 2007.

Class	Shares Outstanding
No Par Value	88,577,022

GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
AES	Atmos Energy Services, LLC
APS	Atmos Pipeline and Storage, LLC
Bcf	Billion cubic feet
EITF	Emerging Issues Task Force
FASB	Financial Accounting Standards Board
FIN	FASB Interpretation
Fitch	Fitch Ratings, Ltd.
GRIP	Gas Reliability Infrastructure Program
KPSC	Kentucky Public Service Commission
LGS	Louisiana Gas Service Company and LGS Natural Gas Company, which were acquired July 1, 2001
LPSC	Louisiana Public Service Commission
Mcf	Thousand cubic feet
MMcf	Million cubic feet
Moody's	Moody's Investors Services, Inc.
NYMEX	New York Mercantile Exchange, Inc.
RRC	Railroad Commission of Texas
RSC	Rate Stabilization Clause
S&P	Standard & Poor's Corporation
SEC	United States Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
TRA	Tennessee Regulatory Authority
WNA	Weather Normalization Adjustment

PART I. FINANCIAL INFORMATION

Item 1. ***Financial Statements***

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

	December 31, 2006	September 30, 2006
	(Unaudited)	
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$5,162,006	$5,101,308
Less accumulated depreciation and amortization	1,494,091	1,472,152
Net property, plant and equipment	3,667,915	3,629,156
Current assets		
Cash and cash equivalents	94,406	75,815
Cash held on deposit in margin account	—	35,647
Accounts receivable, net	766,632	374,629
Gas stored underground	520,034	461,502
Other current assets	194,566	169,952
Total current assets	1,575,638	1,117,545
Goodwill and intangible assets	738,369	738,521
Deferred charges and other assets	234,473	234,325
	$6,216,395	$5,719,547
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: December 31, 2006 — 88,504,847 shares; September 30, 2006 — 81,739,516 shares	$ 442	$ 409
Additional paid-in capital	1,670,487	1,467,240
Retained earnings	279,299	224,299
Accumulated other comprehensive loss	(29,771)	(43,850)
Shareholders' equity	1,920,457	1,648,098
Long-term debt	1,878,733	2,180,362
Total capitalization	3,799,190	3,828,460
Current liabilities		
Accounts payable and accrued liabilities	762,487	345,108
Other current liabilities	407,351	388,451
Short-term debt	154,471	382,416
Current maturities of long-term debt	303,209	3,186
Total current liabilities	1,627,518	1,119,161
Deferred income taxes	324,296	306,172
Regulatory cost of removal obligation	255,321	261,376
Deferred credits and other liabilities	210,070	204,378
	$6,216,395	$5,719,547

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended December 31	
	2006	2005
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Utility segment	$ 964,244	$1,405,010
Natural gas marketing segment	711,694	1,101,845
Pipeline and storage segment	49,852	39,712
Other nonutility segment	1,353	1,492
Intersegment eliminations	(124,510)	(264,239)
	1,602,633	2,283,820
Purchased gas cost		
Utility segment	701,676	1,124,829
Natural gas marketing segment	648,560	1,075,526
Pipeline and storage segment	225	—
Other nonutility segment	—	—
Intersegment eliminations	(123,420)	(263,125)
	1,227,041	1,937,230
Gross profit	375,592	346,590
Operating expenses		
Operation and maintenance	115,370	108,217
Depreciation and amortization	48,995	43,260
Taxes, other than income	40,067	45,416
Total operating expenses	204,432	196,893
Operating income	171,160	149,697
Miscellaneous income	1,579	448
Interest charges	39,532	36,189
Income before income taxes	133,207	113,956
Income tax expense	51,946	42,929
Net income	$ 81,261	$ 71,027
Basic net income per share	$ 0.98	$ 0.88
Diluted net income per share	$ 0.97	$ 0.88
Cash dividends per share	$ 0.320	$ 0.315
Weighted average shares outstanding:		
Basic	82,726	80,259
Diluted	83,350	80,722

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended December 31	
	2006	2005
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	$ 81,261	$ 71,027
Adjustments to reconcile net income to net cash provided by (used in) operating activities:		
Depreciation and amortization:		
Charged to depreciation and amortization	48,995	43,260
Charged to other accounts	83	147
Deferred income taxes	13,869	20,448
Other	4,718	3,680
Net assets / liabilities from risk management activities	(34,857)	13,695
Net change in operating assets and liabilities	50,900	(347,626)
Net cash provided by (used in) operating activities	164,969	(195,369)
Cash Flows From Investing Activities		
Capital expenditures	(86,986)	(102,465)
Other, net	(1,324)	(1,121)
Net cash used in investing activities	(88,310)	(103,586)
Cash Flows From Financing Activities		
Net increase (decrease) in short-term debt	(227,945)	329,250
Repayment of long-term debt	(1,717)	(1,695)
Cash dividends paid	(26,261)	(25,429)
Issuance of common stock	5,594	6,164
Net proceeds from equity offering	192,261	—
Net cash provided by (used in) financing activities	(58,068)	308,290
Net increase in cash and cash equivalents	18,591	9,335
Cash and cash equivalents at beginning of period	75,815	40,116
Cash and cash equivalents at end of period	$ 94,406	$ 49,451

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
December 31, 2006

1. Nature of Business

Atmos Energy Corporation ("Atmos" or "the Company") and our subsidiaries are engaged primarily in the natural gas utility business as well as other natural gas nonutility businesses. Our natural gas utility business distributes natural gas through sales and transportation arrangements to approximately 3.2 million residential, commercial, public authority and industrial customers throughout our six regulated natural gas utility divisions, in the service areas described below:

Division	Service Area
Atmos Energy Colorado-Kansas Division	Colorado, Kansas, Missouri(2)
Atmos Energy Kentucky/Mid-States Division(1)	Georgia(2), Illinois(2), Iowa(2), Kentucky, Missouri(2), Tennessee, Virginia(2)
Atmos Energy Louisiana Division	Louisiana
Atmos Energy Mid-Tex Division	Texas, including the Dallas/Fort Worth Metroplex
Atmos Energy Mississippi Division	Mississippi
Atmos Energy West Texas Division	West Texas

(1) Effective October 1, 2006, the Kentucky and Mid-States Divisions were combined.

(2) Denotes locations where we have more limited service areas.

In addition, we transport natural gas for others through our distribution system. Our utility business is subject to federal and state regulation and/or regulation by local authorities in each of the states in which the utility divisions operate. Our shared services division is located in Dallas, Texas, and our customer support centers are located in Amarillo and Waco, Texas.

Our nonutility businesses operate in 22 states and include our natural gas marketing operations, pipeline and storage operations and other nonutility operations. These operations are either organized under or managed by Atmos Energy Holdings, Inc. (AEH), which is wholly-owned by the Company.

Our natural gas marketing operations are managed by Atmos Energy Marketing, LLC (AEM), which is wholly-owned by AEH. AEM provides a variety of natural gas management services to municipalities, natural gas utility systems and industrial natural gas customers, primarily in the southeastern and midwestern states and to our Louisiana and Kentucky/Mid-States utility divisions. These services consist primarily of furnishing natural gas supplies at fixed and market-based prices, contract negotiation and administration, load forecasting, gas storage acquisition and management services, transportation services, peaking sales and balancing services, capacity utilization strategies and gas price hedging through the use of derivative instruments.

Our pipeline and storage business includes the regulated operations of our Atmos Pipeline — Texas Division, a division of Atmos Energy Corporation, and the nonregulated operations of Atmos Pipeline and Storage, LLC (APS), which is wholly-owned by AEH. The Atmos Pipeline — Texas Division transports natural gas to our Atmos Energy Mid-Tex Division and to third parties, as well as manages five underground storage reservoirs in Texas. Through APS, we own or have an interest in underground storage fields in Kentucky and Louisiana. We also use these storage facilities to reduce the need to contract for additional pipeline capacity to meet customer demand during peak periods.

Our other nonutility businesses consist primarily of the operations of Atmos Energy Services, LLC (AES) and Atmos Power Systems, Inc., which are each wholly-owned by AEH. Through AES, we have provided natural gas management services to our utility operations, other than the Mid-Tex Division. These services included aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering the gas to our utility service areas at competitive prices. The revenues of AES represent charges to our utility divisions equal to the costs incurred to provide those services. Effective January 1, 2007, our shared services division began providing these services to our utility operations, which were formerly provided by AES. Through Atmos Power Systems, Inc., we have constructed electric peaking power-generating plants and associated facilities and lease these plants through sales-type lease agreements.

2. Unaudited Interim Financial Information

In the opinion of management, all material adjustments (consisting of normal recurring accruals) necessary for a fair presentation have been made to the unaudited consolidated interim-period financial statements. These consolidated interim-period financial statements are condensed as permitted by the instructions to Form 10-Q and should be read in conjunction with the audited consolidated financial statements of Atmos Energy Corporation included in its Annual Report on Form 10-K for the fiscal year ended September 30, 2006. Because of seasonal and other factors, the results of operations for the three-month period ended December 31, 2006 are not indicative of expected results of operations for the full 2007 fiscal year, which ends September 30, 2007.

Significant accounting policies

Our accounting policies are described in Note 2 to our Annual Report on Form 10-K for the year ended September 30, 2006. There were no significant changes to those accounting policies during the three months ended December 31, 2006.

Regulatory assets and liabilities

We record certain costs as regulatory assets in accordance with Statement of Financial Accounting Standards (SFAS) 71, *Accounting for the Effects of Certain Types of Regulation*, when future recovery through customer rates is considered probable. Regulatory liabilities are recorded when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. Substantially all of our regulatory assets are recorded as a component of deferred charges and other assets and substantially all of our regulatory liabilities are recorded as a component of deferred credits and other liabilities. Deferred gas costs are recorded either in other current assets or liabilities and the regulatory cost of removal obligation is separately reported.

Significant regulatory assets and liabilities as of December 31, 2006 and September 30, 2006 included the following:

	December 31, 2006	September 30, 2006
	(In thousands)	
Regulatory assets:		
Merger and integration costs, net	$ 8,541	$ 8,644
Deferred gas cost	86,024	44,992
Environmental costs	1,234	1,234
Rate case costs	11,318	10,579
Deferred franchise fees	1,004	1,311
Other	8,065	9,055
	$116,186	$ 75,815
Regulatory liabilities:		
Deferred gas cost	$ 15,498	$ 68,959
Regulatory cost of removal obligation	276,300	276,490
Deferred income taxes, net	235	235
Other	10,320	10,825
	$302,353	$356,509

Currently, our authorized rates do not include a return on certain of our merger and integration costs; however, we recover the amortization of these costs. Merger and integration costs, net, are generally amortized on a straight-line basis over estimated useful lives ranging up to 20 years. Environmental costs have been deferred to be included in future rate filings in accordance with rulings received from various state regulatory commissions.

Comprehensive income

The following table presents the components of comprehensive income, net of related tax, for the three-month periods ended December 31, 2006 and 2005:

	Three Months Ended December 31	
	2006	2005
	(In thousands)	
Net income	$81,261	$ 71,027
Unrealized holding gains on investments, net of tax expense of $883 and $248	1,441	405
Amortization of interest rate hedging transactions, net of tax expense of $528 and $528	860	860
Net unrealized gains (losses) on commodity hedging transactions, net of tax expense (benefit) of $7,219 and $(14,749)	11,778	(24,063)
Comprehensive income	$95,340	$ 48,229

Accumulated other comprehensive loss, net of tax, as of December 31, 2006 and September 30, 2006 consisted of the following unrealized gains (losses):

	December 31, 2006	September 30, 2006
	(In thousands)	
Accumulated other comprehensive loss:		
Unrealized holding gains on investments	$ 3,007	$ 1,566
Treasury lock agreements	(19,680)	(20,540)
Cash flow hedges	(13,098)	(24,876)
	$(29,771)	$(43,850)

Recent accounting pronouncements

In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R).* The new standard makes a significant change to the existing rules by requiring recognition in the balance sheet of the overfunded or underfunded positions of defined benefit pension and other postretirement plans, along with a corresponding noncash, after-tax adjustment to stockholders' equity. Additionally, this standard requires that the measurement date must correspond to the fiscal year end balance sheet date. This standard does not change how net periodic pension and postretirement cost or the projected benefit obligation is determined. The balance sheet recognition guidance of this standard will be effective as of September 30, 2007 and the measurement date provisions of this guidance can be adopted as late as fiscal 2008 for our company.

In June 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109* (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes by establishing standards for measurement and recognition in financial statements of positions taken by an entity in its income tax returns. This interpretation also provides guidance on derecognition of income tax assets and liabilities, classification of current and deferred income tax assets and liabilities, accounting for interest and penalties, accounting for income taxes in interim periods and income tax disclosures. We will be required to apply the provisions of FIN 48 beginning October 1, 2007. We are currently evaluating the impact this standard may have on our financial position, results of operations and cash flows.

3. Derivative Instruments and Hedging Activities

We conduct risk management activities through both our utility and natural gas marketing segments. We record our derivatives as a component of risk management assets and liabilities, which are classified as current or noncurrent other assets or liabilities based upon the anticipated settlement date of the underlying derivative. Our determination of the fair value of these derivative financial instruments reflects the estimated amounts that we would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains and losses on open contracts. In our determination of fair value, we consider various factors, including closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts. These risk management assets and liabilities are subject to continuing market risk until the underlying derivative contracts are settled.

The following table shows the fair values of our risk management assets and liabilities by segment at December 31, 2006 and September 30, 2006:

	Utility	Natural Gas Marketing	Total
		(In thousands)	
December 31, 2006:			
Assets from risk management activities, current	$ 241	$68,170	$ 68,411
Assets from risk management activities, noncurrent	—	8,344	8,344
Liabilities from risk management activities, current	(33,556)	(1,274)	(34,830)
Liabilities from risk management activities, noncurrent	—	(277)	(277)
Net assets (liabilities)	$(33,315)	$74,963	$ 41,648
September 30, 2006:			
Assets from risk management activities, current	$ —	$12,553	$ 12,553
Assets from risk management activities, noncurrent	—	6,186	6,186
Liabilities from risk management activities, current	(27,209)	(3,460)	(30,669)
Liabilities from risk management activities, noncurrent	—	(276)	(276)
Net assets (liabilities)	$(27,209)	$15,003	$(12,206)

Utility Hedging Activities

We use a combination of storage, fixed physical contracts and fixed financial contracts to partially insulate us and our customers against gas price volatility during the winter heating season. Because the gains or losses of financial derivatives used in our utility segment ultimately will be recovered through our rates, current period changes in the assets and liabilities from these risk management activities are recorded as a component of deferred gas costs in accordance with SFAS 71, *Accounting for the Effects of Certain Types of Regulation.* Accordingly, there is no earnings impact to our utility segment as a result of the use of financial derivatives.

Nonutility Hedging Activities

AEM manages its exposure to the risk of natural gas price changes through a combination of storage and financial derivatives, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. Our financial derivative activities include fair value hedges to offset changes in the fair value of our natural gas inventory and cash flow hedges to offset anticipated purchases and sales of gas in the future. AEM also utilizes basis swaps and other non-hedge derivative instruments to manage its exposure to market volatility.

For the three-month period ended December 31, 2006, the change in the deferred hedging position in accumulated other comprehensive loss was attributable to decreases in future commodity prices relative to the commodity prices stipulated in the derivative contracts, and the recognition for the three months ended December 31, 2006 of $21.0 million in net deferred hedging losses in net income when the derivative contracts matured according to their terms. The net deferred hedging loss associated with open cash flow hedges remains subject to market price fluctuations until the positions are either settled under the terms of the hedge contracts or terminated prior to settlement. The majority of the deferred hedging balance as of December 31, 2006 is expected to be recognized in net income in fiscal 2007 along with the corresponding hedged purchases and sales of natural gas. The remainder of the deferred hedging balance is expected to be recognized in net income in fiscal 2008 and beyond.

Our hedge ineffectiveness primarily results from differences in the location and timing of the derivative hedging instrument and the hedged item and could materially affect our results as ineffectiveness is recognized in the income statement. Fair value and cash flow hedge ineffectiveness arising from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the hedge instruments is referred to as basis ineffectiveness. Fair value hedge ineffectiveness arising from the timing of the settlement of physical contracts and the settlement of the related fair value hedge is referred to as timing ineffectiveness. Gains and losses arising from basis and timing ineffectiveness for the three months ended December 31, 2006 and 2005 is as follows:

	Three Months Ended December 31	
	2006	2005
	(In thousands)	
Basis ineffectiveness:		
Fair value basis ineffectiveness	$ (646)	$8,114
Cash flow basis ineffectiveness	124	982
Total basis ineffectiveness	(522)	9,096
Timing ineffectiveness:		
Fair value timing ineffectiveness	(1,284)	(439)
Total hedge ineffectiveness	$(1,806)	$8,657

Under our risk management policies, we seek to match our financial derivative positions to our physical storage positions as well as our expected current and future sales and purchase obligations to maintain no open positions at the end of each trading day. The determination of our net open position as of any day, however, requires us to make assumptions as to future circumstances, including the use of gas by our customers in relation to our anticipated storage and market positions. Because the price risk associated with any net open position at the end of each day may increase if the assumptions are not realized, we review these assumptions as part of our daily monitoring activities. We may also be affected by intraday fluctuations of gas prices, since the price of natural gas purchased or sold for future delivery earlier in the day may not be hedged until later in the day. At times, limited net open positions related to our existing and anticipated commitments may occur. At the close of business on December 31, 2006, AEH had a net open position (including existing storage) of less than 0.1 Bcf.

4. Debt

Long-term debt

Long-term debt at December 31, 2006 and September 30, 2006 consisted of the following:

	December 31, 2006	September 30, 2006
	(In thousands)	
Unsecured floating rate Senior Notes, due October 2007	$ 300,000	$ 300,000
Unsecured 4.00% Senior Notes, due 2009	400,000	400,000
Unsecured 7.375% Senior Notes, due 2011	350,000	350,000
Unsecured 10% Notes, due 2011	2,303	2,303
Unsecured 5.125% Senior Notes, due 2013	250,000	250,000
Unsecured 4.95% Senior Notes, due 2014	500,000	500,000
Unsecured 5.95% Senior Notes, due 2034	200,000	200,000
Medium term notes		
Series A, 1995-2, 6.27%, due 2010	10,000	10,000
Series A, 1995-1, 6.67%, due 2025	10,000	10,000
Unsecured 6.75% Debentures, due 2028	150,000	150,000
First Mortgage Bonds		
Series P, 10.43% due 2013	7,500	8,750
Other term notes due in installments through 2013	5,358	5,825
Total long-term debt	2,185,161	2,186,878
Less:		
Original issue discount on unsecured senior notes and debentures	(3,219)	(3,330)
Current maturities	(303,209)	(3,186)
	$1,878,733	$2,180,362

Our unsecured floating rate debt bears interest at a rate equal to the three-month LIBOR rate plus 0.375 percent per year. At December 31, 2006, the interest rate on our floating rate debt was 5.749 percent.

Short-term debt

At December 31, 2006 and September 30, 2006, there was $154.5 million and $382.4 million outstanding under our commercial paper program and bank credit facilities.

Shelf Registration

On December 4, 2006, we filed a registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to $900 million in new common stock and/or debt securities available for issuance, including approximately $401.5 million of capacity carried over from our prior shelf registration statement filed with the SEC in August 2004. As discussed in Note 5, in December 2006, we sold 6.3 million shares of common stock under the new registration statement, the net proceeds of which were used to reduce short-term debt. As of December 31, 2006, we have approximately $701 million of availability remaining under the registration statement.

Credit facilities

We maintain both committed and uncommitted credit facilities. Borrowings under our uncommitted credit facilities are made on a when-and-as-needed basis at the discretion of the banks. Our credit capacity and the amount of unused borrowing capacity are affected by the seasonal nature of the natural gas business and our short-term borrowing requirements, which are typically highest during colder winter months. Our working capital needs can vary significantly due to changes in the price of natural gas and the increased gas supplies required to meet customers' needs during periods of cold weather.

Committed credit facilities

As of December 31, 2006, we had three short-term committed revolving credit facilities totaling $918 million. The first facility is a five-year unsecured facility for $600 million that we entered into in December 2006. This credit facility replaced our $600 million three-year revolving credit facility entered into in October 2005. The new facility, expiring December 2011, bears interest at a base rate or at the LIBOR rate plus from 0.30 percent to 0.75 percent, based on the Company's credit ratings, and serves as a backup liquidity facility for our $600 million commercial paper program. At December 31, 2006, there was $154.5 million outstanding under our commercial paper program.

We have a second unsecured facility in place which is a 364-day facility expiring November 2007, for $300 million that bears interest at a base rate or at the LIBOR rate plus from 0.30 percent to 0.75 percent, based on the Company's credit ratings. At December 31, 2006, there were no borrowings under this facility.

We have a third unsecured facility in place for $18 million that bears interest at the Federal Funds rate plus 0.5 percent. This facility expires in March 2007. At December 31, 2006, there were no borrowings under this facility.

The availability of funds under our credit facilities is subject to conditions specified in the respective credit agreements, all of which we currently satisfy. These conditions include our compliance with financial covenants and the continued accuracy of representations and warranties contained in these agreements. We are required by the financial covenants in both our $600 million five-year credit facility and $300 million 364-day credit facility to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At December 31, 2006, our total-debt-to-total-capitalization ratio, as defined, was 58 percent. In addition, the fees that we pay on unused amounts under both the $600 million and $300 million credit facilities are subject to adjustment depending upon our credit ratings.

Uncommitted credit facilities

AEM has a $580 million uncommitted demand working capital credit facility that expires in March 2007. Borrowings under the credit facility can be made either as revolving loans or offshore rate loans. Revolving loan borrowings will bear interest at a floating rate equal to a base rate (defined as the higher of 0.50 percent per annum above the Federal Funds rate or the lender's prime rate) plus 0.25 percent. Offshore rate loan borrowings will bear interest at a floating rate equal to a base rate based upon LIBOR plus an applicable margin, ranging from 1.25 percent to 1.625 percent per annum, depending on the excess tangible net worth of AEM, as defined in the credit facility. Borrowings drawn down under letters of credit issued by the banks will bear interest at a floating rate equal to the base rate, as defined above, plus an applicable margin, which will range from 1.00 percent to 1.875 percent per annum, depending on the excess tangible net worth of AEM and whether the letters of credit are swap-related standby letters of credit.

AEM is required by the financial covenants in the credit facility to maintain a maximum ratio of total liabilities to tangible net worth of 5 to 1, along with minimum levels of net working capital ranging from $20 million to $120 million. Additionally, AEM must maintain a minimum tangible net worth ranging from $21 million to $121 million, and must not have a maximum cumulative loss from March 30, 2005 exceeding $4 million to $23 million, depending on the total amount of borrowing elected from time to time by AEM. At December 31, 2006, AEM's ratio of total liabilities to tangible net worth, as defined, was 1.61 to 1.

At December 31, 2006, there were no borrowings outstanding under this credit facility. However, at December 31, 2006, AEM letters of credit totaling $153.9 million had been issued under the facility, which reduced the amount available by a corresponding amount. The amount available under this credit facility is also limited by various covenants, including covenants based on working capital. Under the most restrictive covenant, the amount available to AEM under this credit facility was $21.1 million at December 31, 2006. This line of credit is collateralized by substantially all of the assets of AEM and is guaranteed by AEH.

The Company also has an unsecured short-term uncommitted credit line of $25 million that is used for working-capital and letter-of-credit purposes. There were no borrowings under this uncommitted credit facility at December 31, 2006, but letters of credit reduced the amount available by $5.4 million. This uncommitted line is renewed or renegotiated at least annually with varying terms, and we pay no fee for the availability of the line. Borrowings under this line are made on a when-and-as-available basis at the discretion of the bank.

AEH, the parent company of AEM, has a $100 million intercompany uncommitted demand credit facility with the Company which bears interest at LIBOR plus 2.75 percent. State regulators have approved this facility through December 31, 2007 and have authorized an increase in the intercompany facility to $200 million. At December 31, 2006, there were no borrowings under this facility.

In addition, AEM has a $120 million intercompany uncommitted demand credit facility with AEH for its nonutility business which bears interest at LIBOR plus 2.75 percent. Any outstanding amounts under this facility are subordinated to AEM's $580 million uncommitted demand credit facility described above. This facility is used to supplement AEM's $580 million credit facility. At December 31, 2006, there were no borrowings under this facility.

Debt Covenants

We have other covenants in addition to those described above. Our Series P First Mortgage Bonds contain provisions that allow us to prepay the outstanding balance in whole at any time, after November 2007, subject to a prepayment premium. The First Mortgage Bonds provide for certain cash flow requirements and restrictions on additional indebtedness, sale of assets and payment of dividends. Under the most restrictive of such covenants, cumulative cash dividends paid after December 31, 1985 may not exceed the sum of accumulated net income for periods after December 31, 1985 plus $9 million. At December 31, 2006 approximately $258.3 million of retained earnings was unrestricted with respect to the payment of dividends.

We were in compliance with all of our debt covenants as of December 31, 2006. If we were unable to comply with our debt covenants, we could be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions. Our two public debt indentures relating to our senior notes and debentures, as well as our $600 million and $300 million revolving credit agreements, each contain a default provision that is triggered if outstanding indebtedness arising out of any other credit agreements in amounts ranging from in excess of $15 million to in excess of $100 million becomes due by acceleration or is not paid at maturity. In addition, AEM's credit agreement contains a cross-default provision whereby AEM would be in default if it defaults on other indebtedness, as defined, by at least $250 thousand in the aggregate. Additionally, this agreement contains a provision that would limit the amount of credit available if Atmos were downgraded below an S&P rating of BBB and a Moody's rating of Baa2.

Except as described above, we have no triggering events in our debt instruments that are tied to changes in specified credit ratings or stock price, nor have we entered into any transactions that would require us to issue equity, based on our credit rating or other triggering events.

5. Public Offering

On December 13, 2006, we completed the public offering of 6,325,000 shares of our common stock including the underwriters' exercise of their overallotment option of 825,000 shares. The offering was priced at $31.50 and generated net proceeds of approximately $192 million. We used the net proceeds from this offering to reduce short-term debt.

6. Earnings Per Share

Basic and diluted earnings per share for the three months ended December 31, 2006 and 2005 are calculated as follows:

	Three Months Ended December 31	
	2006	2005
	(In thousands, except per share amounts)	
Net income	$81,261	$71,027
Denominator for basic income per share — weighted average common shares	82,726	80,259
Effect of dilutive securities:		
Restricted and other shares	453	365
Stock options	171	98
Denominator for diluted income per share — weighted average common shares	83,350	80,722
Income per share — basic	$ 0.98	$ 0.88
Income per share — diluted	$ 0.97	$ 0.88

There were no out-of-the-money options excluded from the computation of diluted earnings per share for the three months ended December 31, 2006 and 2005 as their exercise price was less than the average market price of the common stock during that period.

7. Interim Pension and Other Postretirement Benefit Plan Information

The components of our net periodic pension cost for our pension and other postretirement benefit plans for the three months ended December 31, 2006 and 2005 are presented in the following table. All of these costs are recoverable through our gas utility rates; however, a portion of these costs is capitalized into our utility rate base. The remaining costs are recorded as a component of operation and maintenance expense.

	Three Months Ended December 31			
	Pension Benefits		Other Benefits	
	2006	2005	2006	2005
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 4,018	$ 4,117	$2,807	$3,271
Interest cost	6,495	5,722	2,640	2,210
Expected return on assets	(6,089)	(6,400)	(597)	(547)
Amortization of transition asset	—	—	378	378
Amortization of prior service cost	45	16	8	90
Amortization of actuarial loss	2,434	3,299	—	320
Net periodic pension cost	$ 6,903	$ 6,754	$5,236	$5,722

The assumptions used to develop our net periodic pension cost for the three months ended December 31, 2006 and 2005 are as follows:

	Pension Benefits		Other Benefits	
	2006	2005	2006	2005
Discount rate	6.30%	5.00%	6.30%	5.00%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Expected return on plan assets	8.25%	8.50%	5.20%	5.30%

The discount rate used to compute the present value of a plan's liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid. Generally, our funding policy is to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974. However, additional voluntary contributions are made to satisfy regulatory requirements in certain of our jurisdictions. During the three months ended December 31, 2006, we contributed $2.8 million to our other postretirement plans, and we expect to contribute a total of approximately $11 million to these plans during fiscal 2007.

8. Commitments and Contingencies

Litigation and Environmental Matters

With respect to the specific litigation and environmental-related matters or claims that were disclosed in Note 13 to our annual report on Form 10-K for the year ended September 30, 2006, there were no material changes in the status of such litigation and environmental-related matters or claims during the three months ended December 31, 2006. We continue to believe that the final outcome of such litigation and environmental-related matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

In addition, we are involved in other litigation and environmental-related matters or claims that arise in the ordinary course of our business. While the ultimate results of such litigation and response actions to such environmental-related matters or claims cannot be predicted with certainty, we believe the final outcome of such litigation and response actions will not have a material adverse effect on our financial condition, results of operations or cash flows.

Purchase Commitments

AEM has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At December 31, 2006, AEM was committed to purchase 89.5 Bcf within one year and 56.7 Bcf within one to three years under indexed contracts. AEM is committed to purchase 1.6 Bcf within one year and 0.1 Bcf within one to three years under fixed price contracts with prices ranging from $5.26 to $12.00. Purchases under these contracts totaled $420.4 million and $787.7 million for the three months ended December 31, 2006 and 2005.

Our utility operations, other than the Mid-Tex Division, maintain supply contracts with several vendors that generally cover a period of up to one year. Commitments for estimated base gas volumes are established under these contracts on a monthly basis at contractually negotiated prices. Commitments for incremental daily purchases are made as necessary during the month in accordance with the terms of the individual contract.

Our Mid-Tex Division maintains long-term supply contracts to ensure a reliable source of gas for our customers in its service area which obligate it to purchase specified volumes at market prices. The estimated fiscal year commitments under these contracts as of December 31, 2006 are as follows (in thousands):

2007	$332,401
2008	109,656
2009	9,588
2010	9,189
2011	8,589
Thereafter	19,418
	$488,841

Regulatory Matters

In February 2005, the Attorney General of the State of Kentucky filed a complaint with the Kentucky Public Service Commission (KPSC) alleging that our rates were producing revenues in excess of reasonable levels. We answered the complaint and filed a Motion to Dismiss with the KPSC. In February 2006, the KPSC issued an Order denying our Motion to Dismiss but stated that the Attorney General had not met his burden of proof concerning his complaint. In November 2006, we requested dismissal of the case through our filing of a notice of intent to file a general rate case in December 2006. Upon receipt of the notice of intent, the KPSC suspended the procedural schedule until it issues a decision regarding the motion for dismissal. A hearing should be scheduled for early 2007. We believe that the Attorney General will not be able to demonstrate that our present rates are in excess of reasonable levels.

In December 2006, the Company filed a rate application for an increase in base rates of $10.4 million in Kentucky. Additionally, we proposed to implement a process to review our rates annually and to collect the bad debt portion of gas costs directly rather than through the base rate. A decision is expected in the case in July 2007.

During fiscal 2006, we received "show cause" resolutions from approximately 80 cities served by our Mid-Tex Division, including the City of Dallas, which require the Mid-Tex Division to demonstrate that the existing distribution rates are just and reasonable. In May 2006, the Mid-Tex Division filed a Statement of Intent with the Railroad Commission of Texas (RRC) which consolidated the "show cause" resolutions and seeks incremental annual revenues of approximately $60 million and several rate design changes including WNA, revenue stabilization and recovery of the gas cost component of bad debt expense. In exchange for an agreement to provide the intervening parties in the case an additional two months to prepare for the hearing, the Mid-Tex Division obtained an agreement and approval to implement WNA in its rates for the 2006-2007 winter season and to implement WNA in the final rates in this proceeding. The hearing was completed on November 17, 2006. The hearing examiners in the case issued their Proposal for Decision (PFD) on February 2, 2007, which contained their recommendations to the RRC. In the PFD, the examiners recommended a total annual decrease in the Mid-Tex Division's rates of approximately $22.8 million, a customer refund of $2.6 million and a permanent weather normalization adjustment mechanism based on 10-year weather data. We are in the process of preparing our responses to the recommendations in the PFD. We continue to believe that the evidence presented in the case supports our request to increase rates in order to earn a fair rate of return. While the RRC is required by statute to issue its final decision by April 2, 2007, it could issue a final order sometime in March 2007. Any rate increase will be effective prospectively from the date of the final order; however, any rate decrease will be effective from May 31, 2006.

In January 2006, the Lubbock, Texas City Council passed a resolution requiring Atmos to submit copies of all documentation necessary for the city to review the rates of Atmos' West Texas Division to ensure they are just and reasonable. Information was provided to the city in February 2006. We believe that we will be able to ultimately demonstrate to the City of Lubbock that our rates are just and reasonable.

In May 2006, Atmos began receiving "show cause" ordinances from several of the cities in the West Texas Division. We made a filing in response to the ordinances in October 2006. We believe that we will be able to ultimately demonstrate to the West Texas cities that our rates are just and reasonable.

Other

In May 2006, we announced plans to form a joint venture and construct a natural gas gathering system in Eastern Kentucky, referred to as the Straight Creek Project. The Company is continuing to evaluate the scale and scope of the original project design, as well as the in-service date.

9. Concentration of Credit Risk

Information regarding our concentration of credit risk is disclosed in Note 15 to our annual report on Form 10-K for the year ended September 30, 2006. During the three months ended December 31, 2006, there were no material changes in our concentration of credit risk.

10. Segment Information

Atmos Energy Corporation and our subsidiaries are engaged primarily in the natural gas utility business as well as certain nonutility businesses. We distribute natural gas through sales and transportation arrangements to approximately 3.2 million residential, commercial, public authority and industrial customers throughout our six regulated utility divisions, which cover service areas located in 12 states. In addition, we transport natural gas for others through our distribution system.

Through our nonutility businesses we provide natural gas management and marketing services to industrial customers, municipalities and other local distribution companies located in 22 states. Additionally, we provide natural gas transportation and storage services to certain of our utility operations and to third parties.

Our operations are divided into four segments:

- the utility segment, which includes our regulated natural gas distribution and related sales operations,
- the natural gas marketing segment, which includes a variety of nonregulated natural gas management services,
- the pipeline and storage segment, which includes our regulated and nonregulated natural gas transmission and storage services and
- the other nonutility segment, which includes all of our other nonregulated nonutility operations.

Our determination of reportable segments considers the strategic operating units under which we manage sales of various products and services to customers in differing regulatory environments. Although our utility segment operations are geographically dispersed, they are reported as a single segment as each utility division has similar economic characteristics. The accounting policies of the segments are the same as those described in the summary of significant accounting policies found in our annual report on Form 10-K for the fiscal year ended September 30, 2006. We evaluate performance based on net income or loss of the respective operating units.

Income statements for the three-month periods ended December 31, 2006 and 2005 by segment are presented in the following tables:

	Three Months Ended December 31, 2006					
	Utility	Natural Gas Marketing	Pipeline and Storage	Other Nonutility	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$964,083	$611,369	$26,775	$ 406	$ —	$1,602,633
Intersegment revenues	161	100,325	23,077	947	(124,510)	—
	964,244	711,694	49,852	1,353	(124,510)	1,602,633
Purchased gas cost	701,676	648,560	225	—	(123,420)	1,227,041
Gross profit	262,568	63,134	49,627	1,353	(1,090)	375,592
Operating expenses						
Operation and maintenance	98,113	5,578	11,616	1,239	(1,176)	115,370
Depreciation and amortization	43,722	329	4,918	26	—	48,995
Taxes, other than income	37,622	249	2,127	69	—	40,067
Total operating expenses	179,457	6,156	18,661	1,334	(1,176)	204,432
Operating income	83,111	56,978	30,966	19	86	171,160
Miscellaneous income	1,780	1,716	776	453	(3,146)	1,579
Interest charges	32,473	1,027	8,421	671	(3,060)	39,532
Income (loss) before income taxes	52,418	57,667	23,321	(199)	—	133,207
Income tax expense (benefit)	20,584	22,720	8,721	(79)	—	51,946
Net income (loss)	$ 31,834	$ 34,947	$14,600	$ (120)	$ —	$ 81,261
Capital expenditures	$ 72,419	$ 338	$14,229	$ —	$ —	$ 86,986

	Three Months Ended December 31, 2005					
	Utility	Natural Gas Marketing	Pipeline and Storage	Other Nonutility	Eliminations	Consolidated
			(In thousands)			
Operating revenues from external parties	$1,404,806	$ 860,613	$17,881	$ 520	$ —	$2,283,820
Intersegment revenues	204	241,232	21,831	972	(264,239)	—
	1,405,010	1,101,845	39,712	1,492	(264,239)	2,283,820
Purchased gas cost	1,124,829	1,075,526	—	—	(263,125)	1,937,230
Gross profit	280,181	26,319	39,712	1,492	(1,114)	346,590
Operating expenses						
Operation and maintenance	92,766	4,352	10,998	1,265	(1,164)	108,217
Depreciation and amortization	38,264	470	4,502	24	—	43,260
Taxes, other than income	42,902	243	2,160	111	—	45,416
Total operating expenses	173,932	5,065	17,660	1,400	(1,164)	196,893
Operating income	106,249	21,254	22,052	92	50	149,697
Miscellaneous income	2,837	590	1,405	661	(5,045)	448
Interest charges	31,588	2,862	5,973	761	(4,995)	36,189
Income (loss) before income taxes	77,498	18,982	17,484	(8)	—	113,956
Income tax expense (benefit)	29,085	7,530	6,317	(3)	—	42,929
Net income (loss)	$ 48,413	$ 11,452	$11,167	$ (5)	$ —	$ 71,027
Capital expenditures	$ 72,415	$ 332	$29,718	$ —	$ —	$ 102,465

Balance sheet information at December 31, 2006 and September 30, 2006 by segment is presented in the following tables:

	December 31, 2006					
	Utility	Natural Gas Marketing	Pipeline and Storage	Other Nonutility	Eliminations	Consolidated
			(In thousands)			
ASSETS						
Property, plant and equipment, net	$3,112,635	$ 7,693	$546,329	$ 1,258	$ —	$3,667,915
Investment in subsidiaries	342,347	(2,155)	—	—	(340,192)	—
Current assets						
Cash and cash equivalents	20,825	66,626	—	6,955	—	94,406
Cash held on deposit in margin account	—	—	—	—	—	—
Assets from risk management activities	241	68,362	33,125	—	(33,317)	68,411
Other current assets	958,929	459,212	29,346	7,934	(42,600)	1,412,821
Intercompany receivables	590,431	—	—	13,431	(603,862)	—
Total current assets	1,570,426	594,200	62,471	28,320	(679,779)	1,575,638
Intangible assets	—	3,000	—	—	—	3,000
Goodwill	567,221	24,282	143,866	—	—	735,369
Noncurrent assets from risk management activities	—	8,345	1	—	(2)	8,344
Deferred charges and other assets	203,499	1,270	5,163	16,197	—	226,129
	$5,796,128	$636,635	$757,830	$45,775	$(1,019,973)	$6,216,395
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	$1,920,457	$179,538	$129,289	$33,520	$ (342,347)	$1,920,457
Long-term debt	1,875,334	—	—	3,399	—	1,878,733
Total capitalization	3,795,791	179,538	129,289	36,919	(342,347)	3,799,190
Current liabilities						
Current maturities of long-term debt	301,250	—	—	1,959	—	303,209
Short-term debt	154,471	—	—	—	—	154,471
Liabilities from risk management activities	33,556	34,399	111	—	(33,236)	34,830
Other current liabilities	747,305	343,128	85,101	—	(40,526)	1,135,008
Intercompany payables	—	101,630	502,232	—	(603,862)	—
Total current liabilities	1,236,582	479,157	587,444	1,959	(677,624)	1,627,518
Deferred income taxes	307,800	(22,878)	37,173	2,201	—	324,296
Noncurrent liabilities from risk management activities	—	278	1	—	(2)	277
Regulatory cost of removal obligation	255,321	—	—	—	—	255,321
Deferred credits and other liabilities	200,634	540	3,923	4,696	—	209,793
	$5,796,128	$636,635	$757,830	$45,775	$(1,019,973)	$6,216,395

	September 30, 2006					
	Utility	Natural Gas Marketing	Pipeline and Storage	Other Nonutility	Eliminations	Consolidated
	(In thousands)					
ASSETS						
Property, plant and equipment, net	$3,083,301	$ 7,531	$537,028	$ 1,296	$ —	$3,629,156
Investment in subsidiaries	281,143	(2,155)	—	—	(278,988)	—
Current assets						
Cash and cash equivalents	8,738	45,481	—	21,596	—	75,815
Cash held on deposit in margin account	—	35,647	—	—	—	35,647
Assets from risk management activities	—	13,164	19,040	—	(19,651)	12,553
Other current assets	714,472	261,435	26,325	8,119	(16,821)	993,530
Intercompany receivables	602,809	—	—	—	(602,809)	—
Total current assets	1,326,019	355,727	45,365	29,715	(639,281)	1,117,545
Intangible assets	—	3,152	—	—	—	3,152
Goodwill	567,221	24,282	143,866	—	—	735,369
Noncurrent assets from risk management activities	—	6,190	5	—	(9)	6,186
Deferred charges and other assets	204,617	1,315	5,301	16,906	—	228,139
	$5,462,301	$396,042	$731,565	$47,917	$(918,278)	$5,719,547
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	$1,648,098	$139,863	$107,640	$33,640	$(281,143)	$1,648,098
Long-term debt	2,176,473	—	—	3,889	—	2,180,362
Total capitalization	3,824,571	139,863	107,640	37,529	(281,143)	3,828,460
Current liabilities						
Current maturities of long-term debt	1,250	—	—	1,936	—	3,186
Short-term debt	382,416	—	—	—	—	382,416
Liabilities from risk management activities	27,209	22,500	531	—	(19,571)	30,669
Other current liabilities	473,101	183,077	61,458	—	(14,746)	702,890
Intercompany payables	—	75,665	525,895	1,249	(602,809)	—
Total current liabilities	883,976	281,242	587,884	3,185	(637,126)	1,119,161
Deferred income taxes	297,821	(25,777)	31,927	2,201	—	306,172
Noncurrent liabilities from risk management activities	—	280	5	—	(9)	276
Regulatory cost of removal obligation	261,376	—	—	—	—	261,376
Deferred credits and other liabilities	194,557	434	4,109	5,002	—	204,102
	$5,462,301	$396,042	$731,565	$47,917	$(918,278)	$5,719,547

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors
Atmos Energy Corporation

We have reviewed the condensed consolidated balance sheet of Atmos Energy Corporation as of December 31, 2006, and the related condensed consolidated statements of income for the three-month periods ended December 31, 2006 and 2005, and the condensed consolidated statements of cash flows for the three-month periods ended December 31, 2006 and 2005. These financial statements are the responsibility of the Company's management.

We conducted our review in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the condensed consolidated financial statements referred to above for them to be in conformity with U.S. generally accepted accounting principles.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Atmos Energy Corporation as of September 30, 2006, and the related consolidated statements of income, shareholders' equity, and cash flows for the year then ended, not presented herein, and in our report dated November 20, 2006, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet as of September 30, 2006, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

ERNST & YOUNG LLP

Dallas, Texas
February 5, 2007

Item 2. ***Management's Discussion and Analysis of Financial Condition and Results of Operations***

INTRODUCTION

The following discussion should be read in conjunction with the condensed consolidated financial statements in this Quarterly Report on Form 10-Q and Management's Discussion and Analysis in our Annual Report on Form 10-K for the year ended September 30, 2006.

Cautionary Statement for the Purposes of the Safe Harbor under the Private Securities Litigation Reform Act of 1995

The statements contained in this Quarterly Report on Form 10-Q may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this Report are forward-looking statements made in good faith by us and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this Report, or any other of our documents or oral presentations, the words "anticipate", "believe", "estimate", "expect", "forecast", "goal", "intend", "objective", "plan", "projection", "seek", "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the statements relating to our strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties include the following: regulatory trends and decisions, including deregulation initiatives and the impact of rate proceedings before various state regulatory commissions; adverse weather conditions, such as warmer than normal weather in our utility service territories or colder than normal weather that could adversely affect our natural gas marketing activities; the concentration of our distribution, pipeline and storage operations in one state; impact of environmental regulations on our business; market risks beyond our control affecting our risk management activities including market liquidity, commodity price volatility, increasing interest rates and counterparty creditworthiness; our ability to continue to access the capital markets; the effects of inflation and changes in the availability and prices of natural gas, including the volatility of natural gas prices; increased competition from energy suppliers and alternative forms of energy; increased costs of providing pension and postretirement health care benefits; the capital-intensive nature of our distribution business; the inherent hazards and risks involved in operating our distribution business; and other uncertainties, which may be discussed herein, all of which are difficult to predict and many of which are beyond our control. A more detailed discussion of these risks and uncertainties may be found in our Form 10-K for the year ended September 30, 2006. Accordingly, while we believe these forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. Further, we undertake no obligation to update or revise any of our forward-looking statements whether as a result of new information, future events or otherwise.

OVERVIEW

Atmos Energy Corporation and our subsidiaries are engaged primarily in the natural gas utility business as well as certain nonutility businesses. We distribute natural gas through sales and transportation arrangements to approximately 3.2 million residential, commercial, public authority and industrial customers throughout our six regulated utility divisions, which cover service areas located in 12 states. In addition, we transport natural gas for others through our distribution system.

Through our nonutility businesses, we primarily provide natural gas management and marketing services to municipalities, other local gas distribution companies and industrial customers in 22 states and natural gas transportation and storage services to certain of our utility operations and to third parties.

Our operations are divided into four segments:

- the utility segment, which includes our regulated natural gas distribution and related sales operations,
- the natural gas marketing segment, which includes a variety of nonregulated natural gas management services,

- the pipeline and storage segment, which includes our regulated and nonregulated natural gas transmission and storage services and
- the other nonutility segment, which includes all of our other nonregulated nonutility operations.

The following summarizes the results of our operations and other significant events for the three months ended December 31, 2006:

- Our utility segment net income decreased by $16.6 million during the three months ended December 31, 2006 compared with the three months ended December 31, 2005. The decrease reflects lower gross profit margin primarily associated with lower revenue-related taxes coupled with higher operating expenses.
- Our natural gas marketing segment net income increased $23.5 million during the three months ended December 31, 2006 compared with the three months ended December 31, 2005. The increase in natural gas marketing net income primarily reflects favorable movements in AEM's unrealized margin, partially offset by lower realized margins.
- Our pipeline and storage segment net income increased $3.4 million during the three months ended December 31, 2006 compared with the three months ended December 31, 2005. Increased net income primarily reflects incremental gross profit margins from our North Side Loop and other pipeline compression projects completed in fiscal 2006 and increased margins from the Gas Reliability Infrastructure Program (GRIP).
- In December 2006, we filed a new $900 million shelf registration statement that replaced our previously existing shelf registration statement. Upon completion of the filing of this new registration statement, we issued approximately 6.3 million shares of common stock, which generated approximately $192 million of net proceeds which we used to repay a portion of our short-term debt.
- Our total-debt-to-capitalization ratio at December 31, 2006 was 54.9 percent compared with 60.9 percent at September 30, 2006 primarily reflecting the favorable impact of our equity offering in December 2006.
- For the three months ended December 31, 2006, we generated $165.0 million in operating cash flow compared with $195.4 million used in operations for the three months ended December 31, 2005, primarily reflecting the favorable impact of lower natural gas prices on our working capital.
- Capital expenditures decreased to $87.0 million during the three months ended December 31, 2006 from $102.5 million in the prior-year period. The decrease primarily reflects the absence of capital spending for the North Side Loop and other compression projects, which were completed in fiscal 2006.

CRITICAL ACCOUNTING ESTIMATES AND POLICIES

Our condensed consolidated financial statements were prepared in accordance with accounting principles generally accepted in the United States. Preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities. We based our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. On an ongoing basis, we evaluate our estimates, including those related to risk management and trading activities, allowance for doubtful accounts, legal and environmental accruals, insurance accruals, pension and postretirement obligations, deferred income taxes and the valuation of goodwill, indefinite-lived intangible assets and other long-lived assets. Actual results may differ from such estimates.

Our critical accounting policies used in the preparation of our consolidated financial statements are described in our Annual Report on Form 10-K for the year ended September 30, 2006 and include the following:

- Regulation
- Revenue Recognition
- Allowance for Doubtful Accounts

- Derivatives and Hedging Activities
- Impairment Assessments
- Pension and Other Postretirement Plans

Our critical accounting policies are reviewed by the Audit Committee on a quarterly basis. There have been no significant changes to these critical accounting policies during the three months ended December 31, 2006.

RESULTS OF OPERATIONS

The following table presents our financial highlights for the three-month periods ended December 31, 2006 and 2005:

	Three Months Ended December 31	
	2006	2005
	(In thousands, unless otherwise noted)	
Operating revenues	$1,602,633	$2,283,820
Gross profit	375,592	346,590
Operating expenses	204,432	196,893
Operating income	171,160	149,697
Miscellaneous income	1,579	448
Interest charges	39,532	36,189
Income before income taxes	133,207	113,956
Income tax expense	51,946	42,929
Net income	$ 81,261	$ 71,027
Utility sales volumes — MMcf	86,400	95,188
Utility transportation volumes — MMcf	32,694	30,602
Total utility throughput — MMcf	119,094	125,790
Natural gas marketing sales volumes — MMcf	77,526	71,496
Pipeline transportation volumes — MMcf	118,955	91,595
Heating degree days[(1)]		
Actual (weighted average)	1,135	1,056
Percent of normal	101%	93%
Consolidated utility average transportation revenue per Mcf	$ 0.48	$ 0.51
Consolidated utility average cost of gas per Mcf sold	$ 8.12	$ 11.82

(1) Adjusted for service areas that have weather-normalized operations. For service areas that have weather normalized operations, normal degree days are used instead of actual degree days in computing the total number of heating degree days.

The following table shows our operating income by segment for the three-month periods ended December 31, 2006 and 2005. The presentation of our utility operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Three Months Ended December 31			
	2006		2005	
	Operating Income	Heating Degree Days Percent of Normal[1]	Operating Income	Heating Degree Days Percent of Normal[1]
	(In thousands, except degree day information)			
Colorado-Kansas	$ 8,672	103%	$ 8,610	99%
Kentucky/Mid-States[2]	14,203	101%	20,490	99%
Louisiana	10,593	107%	7,891	95%
Mid-Tex	35,340	100%	50,787	83%
Mississippi	7,599	103%	9,993	103%
West Texas	6,506	100%	6,131	100%
Other	198	—	2,347	—
Utility segment	83,111	101%	106,249	93%
Natural gas marketing segment	56,978	—	21,254	—
Pipeline and storage segment	30,966	—	22,052	—
Other nonutility segment and other	105	—	142	—
Consolidated operating income	$171,160	101%	$149,697	93%

(1) Adjusted for service areas that have weather-normalized operations.

(2) Effective October 1, 2006, the Kentucky and Mid-States Divisions were combined. Prior year amounts have been restated to conform to this new presentation.

Three Months Ended December 31, 2006 compared with Three Months Ended December 31, 2005

Utility segment

Our utility segment has historically contributed 65 to 85 percent of our consolidated net income. However, in recent years, this contribution has slightly declined as our nonutility businesses have grown and our utility operations have experienced the adverse effects of warmer than normal weather.

Natural gas sales to residential, commercial and public authority customers are affected by winter heating season requirements, whereas natural gas sales to industrial customers are much less weather sensitive. As residential, commercial and public authority customers comprise approximately 90 percent of our gas sales volumes, the results of operations for our utility segment are seasonal. We typically experience higher operating revenues and net income during the period from October through March of each year and lower operating revenues and either lower net income or net losses during the period from April through September of each year. Accordingly, our second fiscal quarter has historically been our most critical earnings quarter with an average of approximately 64 percent of our consolidated net income having been earned in the second quarter during the three most recently completed fiscal years. Additionally, we typically experience higher levels of accounts receivable, accounts payable, gas stored underground and short-term debt balances during the winter heating season due to the seasonal nature of our revenues and the need to purchase and store gas to support these operations.

The primary factors that currently impact the results of our utility operations are regulatory decisions and trends, the increased use of energy-efficient appliances by our customers, competitive factors in the energy industry and economic conditions in our service areas.

Seasonal weather patterns can also affect our utility operations. However, the effect of weather that is above or below normal is substantially offset through weather normalization adjustments, known as WNA, which, beginning with the 2006-2007 winter heating season, are approved by regulators for over 90 percent of our residential and commercial meters in the following states for the following time periods:

Georgia	October – May
Kansas	October – May
Kentucky	November – April
Louisiana[1]	December – March
Mississippi	November – April
Tennessee	November – April
Texas[1]	October – May
Virginia	January – December

(1) Effective beginning for the 2006-2007 winter heating season in our Mid-Tex and Louisiana divisions.

WNA allows us to increase customers' bills to offset lower gas usage when weather is warmer than normal and decrease customers' bills to offset higher gas usage when weather is colder than normal. Although our WNA periods do not cover the entire heating season in all jurisdictions, we believe these mechanisms substantially insulate our utility gross profit margin from the effects of weather.

Our utility operations are also affected by the cost of natural gas. The cost of gas is passed through to our customers without markup. Therefore, increases in the cost of gas are offset by a corresponding increase in revenues. Accordingly, we believe gross profit margin is a better indicator of our financial performance than revenues. However, gross profit margins in our Texas and Mississippi service areas include franchise fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). We record the tax expense as a component of taxes, other than income. Although changes in revenue-related taxes arising from changes in gas cost affect gross profit, over time the impact is usually offset within operating income. Timing differences do exist between the recognition of revenue for franchise fees collected from our customers and the recognition of expense of franchise taxes. The effect of these timing differences can be significant in periods of volatile gas prices, particularly in our Mid-Tex Division. These timing differences may favorably or unfavorably affect net income; however, they offset over time with no permanent impact on net income.

Higher gas costs affect our utility operations in other ways as well. Higher gas costs may cause customers to conserve, or, in the case of industrial customers, to use alternative energy sources. Higher gas costs may also adversely impact our accounts receivable collections, resulting in higher bad debt expense and may require us to increase borrowings under our credit facilities resulting in higher interest expense.

Operating income

Utility gross profit margin decreased $17.6 million to $262.6 million for the three months ended December 31, 2006 from $280.2 million for the three months ended December 31, 2005. Total throughput for our utility business was 119.1 billion cubic feet (Bcf) during the current-year period compared to 125.8 Bcf in the prior-year period.

The decrease in utility gross profit margin primarily reflects a reduction in revenue-related taxes. Due to a significant decline in the cost of gas in the current-year quarter compared with the prior-year quarter, revenue-related taxes included in gross profit margin decreased approximately $15.2 million; however, franchise and state gross receipts tax expense recorded as a component of taxes, other than income only decreased $2.7 million, which resulted in a $12.5 million reduction in operating income when compared with the prior-year quarter.

Gross profit was also adversely affected by a reduction arising from the Tennessee Regulatory Authority's (TRA) decision in October 2006 to reduce our annual rates in Tennessee by $6.1 million, which adversely impacted gross profit margin by $2.0 million during the quarter.

These decreases were partially offset by a $7.5 million increase associated with the implementation of WNA in our Mid-Tex and Louisiana divisions beginning with the 2006-2007 winter heating season coupled with $8.7 million of rate increases received from our fiscal 2004 and 2005 GRIP filings, which became effective in February 2006, and our 2005 Rate Stabilization Clause (RSC) filing in our LGS service area in Louisiana, which became effective in September 2006. As discussed under *Recent Ratemaking Developments*, amounts billed under this RSC were subject to refund until December 2006 when the Louisiana Public Service Commission (LPSC) completed its review of our filing. The final decision from the LPSC did not materially affect the amounts billed subject to refund.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, increased to $179.5 million for the three months ended December 31, 2006 from $173.9 million for the three months ended December 31, 2005.

Operation and maintenance expense, excluding the provision for doubtful accounts, increased $7.3 million primarily due to increased employee costs and other administrative costs and increased costs arising from increased line locate activity in our Mid-Tex Division. Partially offsetting these increases was the absence of $2.0 million of Hurricane Katrina-related costs recorded in the prior-year quarter.

The provision for doubtful accounts decreased $2.0 million to $6.4 million for the three months ended December 31, 2006. The decrease primarily was attributable to lower revenues arising from lower gas costs during the current quarter compared with the prior-year quarter. In the utility segment, the average cost of natural gas for the three months ended December 31, 2006 was $8.12 per thousand cubic feet (Mcf), compared with $11.82 per Mcf for the three months ended December 31, 2005.

Depreciation and amortization expense increased $5.4 million in the first quarter of fiscal 2007 compared with the first quarter of fiscal 2006. This increase was primarily due to the absence in the current-year quarter of a $2.8 million reduction in depreciation expense recorded in the prior-year quarter arising from the Mississippi Public Service Commission's decision to allow certain deferred costs in our rate base. Increases in assets placed in service during fiscal 2006 also contributed to the increase in depreciation and amortization expense in the current-year quarter.

As a result of the aforementioned factors, our utility segment operating income for the three months ended December 31, 2006 decreased to $83.1 million from $106.2 million for the three months ended December 31, 2005.

Interest charges

Interest charges allocated to the utility segment for the three months ended December 31, 2006 increased to $32.5 million from $31.6 million for the three months ended December 31, 2005. The increase was primarily attributable to higher average outstanding short-term debt balances in the current-year period compared with the prior-year period coupled with an approximate 120 basis point increase in the interest rate on our $300 million unsecured floating rate Senior Notes due October 2007 due to an increase in the three-month LIBOR rate. With the completion of our equity offering in December 2006, we anticipate lower outstanding short-term debt balances, which should reduce interest expense for the remainder of the fiscal year.

Natural gas marketing segment

Our natural gas marketing segment aggregates and purchases gas supply, arranges transportation and/or storage logistics and ultimately delivers gas to our customers at competitive prices. To facilitate this process, we utilize proprietary and customer-owned transportation and storage assets to provide the various services our customers request, including furnishing natural gas supplies at fixed and market-based prices, contract negotiation and administration, load forecasting, gas storage acquisition and management services, transportation services, peaking sales and balancing services, capacity utilization strategies and gas price hedging through the use of derivative products. As a result, our revenues arise from the types of commercial transactions we have structured with our customers and include the value we extract by optimizing the storage and transportation capacity we own or control as well as revenues for services we deliver.

To optimize the storage and transportation capacity we own or control, we participate in transactions in which we combine the natural gas commodity and transportation costs to minimize our costs incurred to serve our customers by identifying the lowest cost alternative within the natural gas supplies, transportation and markets to which we have access. Additionally, we engage in natural gas storage transactions in which we seek to find and profit from the pricing differences that occur over time. We purchase physical natural gas and then sell financial contracts at advantageous prices to lock in a gross profit margin. Through the use of transportation and storage services and derivative contracts, we are able to capture gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time.

Operating income

Gross profit margin for our natural gas marketing segment consists primarily of marketing activities, which represent the utilization of proprietary and customer-owned transportation and storage assets to provide various services our customers request and storage activities, which are comprised of the optimization of our managed proprietary and third-party storage and transportation assets.

Our natural gas marketing segment's gross profit margin for the three months ended December 31, 2006 and 2005 is summarized as follows:

	Three Months Ended December 31	
	2006	2005
	(In thousands, except physical position)	
Storage Activities		
Realized margin	$(5,790)	$ 26,272
Unrealized margin	48,891	(23,792)
Total Storage Activities	43,101	2,480
Marketing Activities		
Realized margin	20,069	29,567
Unrealized margin	(36)	(5,728)
Total Marketing Activities	20,033	23,839
Gross profit	$63,134	$ 26,319
Net physical position (Bcf)	21.0	12.8

Our natural gas marketing segment's gross profit margin was $63.1 million for the three months ended December 31, 2006 compared to gross profit of $26.3 million for the three months ended December 31, 2005. Gross profit margin for the three months ended December 31, 2006 included an unrealized gain of $48.9 million compared with an unrealized loss of $29.5 million in the prior-year period. Natural gas marketing sales volumes were 88.0 Bcf during the three months ended December 31, 2006 compared with 87.8 Bcf for the prior-year period. Excluding intersegment sales volumes, natural gas marketing sales volumes were 77.5 Bcf during the current-year period compared with 71.5 Bcf in the prior-year period. The increase in consolidated natural gas marketing sales volumes primarily was attributable to successfully executed marketing strategies.

Our storage activities generated gross profit of $43.1 million for the three months ended December 31, 2006 compared to gross profit of $2.5 million for the three months ended December 31, 2005. The $40.6 million increase in our storage activities was primarily due to favorable movements during the three months ended December 31, 2006 in the forward natural gas prices used to value the financial hedges designated against our physical inventory as well as favorable movements in market (spot) prices used to value our physical storage. This mark-to-market impact was magnified by an 8.2 Bcf increase in our net physical position at December 31, 2006 compared to the prior-year quarter. Differences between the forward and spot prices may continue to cause material volatility in our unrealized margin. However, the economic gross profit we have captured in the original transactions will remain essentially unchanged.

Realized margins from storage activities decreased during the three months ended December 31, 2006 compared with the three months ended December 31, 2005. This decrease was primarily attributable to our ability to successfully capture more favorable arbitrage spreads arising from increased market volatility in the prior-year quarter coupled with the strategic decision to roll storage withdrawal schedules to forward months to obtain improved future arbitrage spreads and buy flowing gas at lower prices to meet current contractual delivery requirements during the three months ended December 31, 2006.

Our marketing activities generated $20.0 million for the three months ended December 31, 2006 compared with $23.8 million for the three months ended December 31, 2005. The $3.8 million decrease in our marketing activities reflects lower realized margins partially offset by increased unrealized margins. The decrease in realized margins is primarily attributable to realizing lower margins in a less volatile market during the quarter compared with the prior-year quarter, partially offset by increased sales volumes attributable to successfully executing marketing strategies. The favorable unrealized margin variance was primarily due to favorable movement during the three months ended December 31, 2006 in the forward natural gas prices associated with financial derivatives used in these activities.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes other than income taxes, increased to $6.2 million for the three months ended December 31, 2006 from $5.1 million for the three months ended December 31, 2005. The increase in operating expense primarily was attributable to an increase in employee and other administrative costs.

The increase in gross profit margin, partially offset by higher operating expenses, resulted in an increase in our natural gas marketing segment operating income to $57.0 million for the three months ended December 31, 2006 compared with operating income of $21.3 million for the three months ended December 31, 2005.

Interest charges

Interest charges allocated to the natural gas marketing segment for the three months ended December 31, 2006 decreased to $1.0 million from $2.9 million for the three months ended December 31, 2005. The decrease was attributable to the use of updated allocation factors for fiscal 2007. These factors are reviewed and updated on an annual basis.

Pipeline and storage segment

Our pipeline and storage segment consists of the regulated pipeline and storage operations of the Atmos Pipeline — Texas Division and the nonregulated pipeline and storage operations of Atmos Pipeline and Storage, LLC (APS). The Atmos Pipeline — Texas Division transports natural gas to our Mid-Tex Division and for third parties and manages five underground storage reservoirs in Texas. We also provide ancillary services customary in the pipeline industry including parking arrangements, lending and sales of inventory on hand. These operations represent one of the largest intrastate pipeline operations in Texas with a heavy concentration in the established natural gas-producing areas of central, northern and eastern Texas, extending into or near the major producing areas of the Texas Gulf Coast and the Delaware and Val Verde Basins of West Texas. This pipeline system provides access to nine basins located in Texas, which are estimated to contain a substantial portion of the nation's remaining onshore natural gas reserves. APS owns or has an interest in underground storage fields in Kentucky and Louisiana. We also use these storage facilities to reduce the need to contract for additional pipeline capacity to meet customer demand during peak periods.

Similar to our utility segment, our pipeline and storage segment is impacted by seasonal weather patterns, competitive factors in the energy industry and economic conditions in our service areas. Natural gas transportation requirements are affected by the winter heating season requirements of our customers. This generally results in higher operating revenues and net income during the period from October through March of each year and lower operating revenues and either lower net income or net losses during the period from April through September of each year. Further, as the Atmos Pipeline — Texas Division operations provide all of the natural gas for our Mid-Tex Division, the results of this segment are highly dependent upon the natural gas requirements of this division. As a regulated pipeline, the operations of the Atmos Pipeline — Texas Division may be impacted by the timing of when costs and expenses are incurred and when these costs and expenses are recovered through its tariffs.

Operating income

Gross profit margin for our pipeline and storage segment primarily consists of transportation margins earned from our Mid-Tex Division and from third parties, other ancillary pipeline services and asset management fees earned by APS. Our pipeline and storage segment's gross profit margin was comprised of the following components for the three months ended December 31, 2006 and 2005:

	Three Months Ended December 31	
	2006	2005
	(In thousands)	
Mid-Tex transportation	$20,464	$19,791
Third-party transportation	16,148	13,699
Asset management fees	1,217	(987)
Storage and park and lend services	3,991	2,514
Unrealized gains	6,220	3,394
Other	1,587	1,301
Gross profit	$49,627	$39,712

Pipeline and storage gross profit increased to $49.6 million for the three months ended December 31, 2006 from $39.7 million for the three months ended December 31, 2005. Total pipeline transportation volumes were 172.8 Bcf during the three months ended December 31, 2006 compared with 147.0 Bcf for the prior year. Excluding intersegment transportation volumes, total pipeline transportation volumes were 119.0 Bcf during the current-year period compared with 91.6 Bcf in the prior-year period.

The increase in gross profit and throughput was primarily attributable to incremental margins and throughput generated from our North Side Loop and other compression projects of $4.3 million coupled with a $1.1 million increase received from our 2005 GRIP filing. Additionally, storage and parking and lending services on Atmos Pipeline — Texas increased compared with the prior-year quarter as a result of the widening of pricing differentials between the pipeline's hubs, which increased the attractiveness of storing gas on the pipeline and our ability to obtain improved margins for these services.

Increases in APS' margins due to its ability to capture more favorable arbitrage spreads on its asset management contracts also contributed to this segment's improved gross profit margin. These margins reflect an unrealized component of this segment's margin as APS hedges its risk associated with these contracts and the associated gain or loss is not recognized until the underlying transaction and derivative contracts are settled. During the first quarter of fiscal 2007, favorable movements in the forward natural gas prices used to value the financial hedges designated against the physical inventory underlying these contracts resulted in an increased unrealized gain compared with the prior-year period.

Operating expenses increased to $18.7 million for the three months ended December 31, 2006 from $17.7 million for the three months ended December 31, 2005 due to higher administrative and other operating costs primarily associated with the North Side Loop and other compression projects that were completed in fiscal 2006.

As a result of the aforementioned factors, our pipeline and storage segment operating income for the three months ended December 31, 2006 increased to $31.0 million from $22.1 million for the three months ended December 31, 2005.

Interest charges

Interest charges allocated to the pipeline and storage segment for the three months ended December 31, 2006 increased to $8.4 million from $6.0 million for the three months ended December 31, 2005. The increase was attributable to the use of updated allocation factors for fiscal 2007. These factors are reviewed and updated on an annual basis.

Other nonutility segment

Our other nonutility businesses consist primarily of the operations of Atmos Energy Services, LLC (AES), and Atmos Power Systems, Inc. Through AES, we provide natural gas management services to our utility operations, other than the Mid-Tex Division. These services include aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering the gas to our utility service areas at competitive prices. The revenues of AES represent charges to our utility divisions equal to the costs incurred to provide those services. Effective January 1, 2007, our shared services division began providing these services to our utility operations, which were formerly provided by AES. Through Atmos Power Systems, Inc., we have constructed electric peaking power-generating plants and associated facilities and have entered into agreements to lease these plants.

Operating income for this segment primarily reflects the leasing income associated with two sales-type lease transactions completed in 2001 and 2002 and was essentially unchanged for the three months ended December 31, 2006 compared with the prior-year quarter.

Liquidity and Capital Resources

Our working capital and liquidity for capital expenditures and other cash needs are provided from internally generated funds, borrowings under our credit facilities and commercial paper program. Additionally, from time to time, we raise funds from the public debt and equity capital markets to fund our liquidity needs.

In October 2007, our $300 million unsecured floating rate Senior Notes will mature. We are currently evaluating alternatives to refinance this debt, and we believe these refinancing efforts will be successful. We believe these funds, combined with the other sources of funds described above will provide the necessary working capital and liquidity for capital expenditures and other cash needs for the remainder of fiscal 2007.

Capitalization

The following table presents our capitalization as of December 31, 2006 and September 30, 2006:

	December 31, 2006		September 30, 2006	
	(In thousands, except percentages)			
Short-term debt	$ 154,471	3.6%	$ 382,416	9.1%
Long-term debt	2,181,942	51.3%	2,183,548	51.8%
Shareholders' equity	1,920,457	45.1%	1,648,098	39.1%
Total capitalization, including short-term debt	$4,256,870	100.0%	$4,214,062	100.0%

Total debt as a percentage of total capitalization, including short-term debt, was 54.9 percent at December 31, 2006, and 60.9 percent at September 30, 2006. The decrease in the debt to capitalization ratio was primarily attributable to the application of the net proceeds provided from our equity offering in December 2006 to repay a portion of our short-term debt. Our ratio of total debt to capitalization is typically greater during the winter heating season as we make additional short-term borrowings to fund natural gas purchases and meet our working capital requirements. We intend to maintain our capitalization ratio in a target range of 50 to 55 percent through cash flow generated from operations, continued issuance of new common stock under our Direct Stock Purchase Plan and Retirement Savings Plan, access to the equity capital markets and reduced annual maintenance and capital expenditures.

Cash Flows

Our internally generated funds may change in the future due to a number of factors, some of which we cannot control. These include regulatory changes, prices for our products and services, demand for such products and services, margin requirements resulting from significant changes in commodity prices, operational risks and other factors.

Cash flows from operating activities

Period-over-period changes in our operating cash flows primarily are attributable to changes in net income, working capital changes, particularly within our utility segment resulting from the price of natural gas and the timing of customer collections, payments for natural gas purchases and deferred gas cost recoveries.

For the three months ended December 31, 2006, we generated operating cash flow of $165.0 million from operating activities compared with a cash outflow of $195.4 million for the three months ended December 31, 2005. Quarter over quarter, our operating cash flow was favorably impacted by lower natural gas prices compared with the prior-year quarter, which reduced the levels of accounts receivable, gas stored underground, undercollected deferred gas costs and accounts payable recorded on our balance sheet as of December 31, 2006. Specifically, changes in accounts receivable and gas stored underground balances increased operating cash flow by $457.2 million. Additionally, improved management of our deferred gas cost balances increased operating cash flow by $86.5 million. Decreases in cash required to collateralize our risk management accounts also increased operating cash flow by $28.8 million. These increases were partially offset by $225.9 million associated with unfavorable timing of payments for accounts payable and other accrued liabilities. Favorable changes in other working capital and other changes totaled $13.8 million and were primarily attributable to increased net income.

Cash flows from investing activities

During the last three years, a substantial portion of our cash resources has been used to fund acquisitions, new pipeline expansion projects and our ongoing utility construction program. Our ongoing utility construction program enables us to provide natural gas distribution services to our existing customer base, to expand our natural gas distribution services into new markets, to enhance the integrity of our pipelines and, more recently, to expand our intrastate pipeline network. In executing our current rate strategy, we are directing discretionary capital spending to jurisdictions that permit us to earn a timely return in excess of our cost of capital. Currently, our Mid-Tex, Louisiana, Mississippi and West Texas utility divisions and our Atmos Pipeline — Texas Division have rate designs that provide the opportunity to include in their rate base approved capital costs on a periodic basis without having to file a rate case.

Capital expenditures for fiscal 2007 are expected to range from $425 million to $440 million. For the three months ended December 31, 2006, we incurred $87.0 million for capital expenditures compared with $102.5 million for the three months ended December 31, 2005. The decrease in capital spending primarily reflects the absence of capital expenditures associated with our North Side Loop and other pipeline compression projects, which were completed in the third quarter of fiscal 2006.

Cash flows from financing activities

For the three months ended December 31, 2006, our financing activities reflected a use of cash of $58.1 million compared with the $308.3 million provided from financing activities in the prior-year period. Our significant financing activities for the three months ended December 31, 2006 and 2005 are summarized as follows.

- In December 2006, we sold 6.3 million shares of common stock, including the underwriters' exercise of their overallotment option of 0.8 million shares, under a new shelf registration statement filed in December 2006, generating net proceeds of approximately $192 million. The net proceeds from this issuance were used to reduce our short-term debt.
- In addition to this equity offering, during the three months ended December 31, 2006, we issued 0.2 million shares of common stock under our various plans which generated net proceeds of $5.6 million. In addition, we granted 0.2 million shares of common stock under our Long-Term Incentive Plan.
- During the three months ended December 31, 2006, we decreased our borrowings under our credit facilities by $227.9 million. The decrease reflects the application of the net proceeds received from the equity offering to reduce short-term indebtedness. Additionally, the reduction in natural gas prices improved our operating cash flow and reduced our need to fund natural gas purchases and other working capital needs from short-term borrowings.
- During the three months ended December 31, 2006, we paid $26.3 million in cash dividends compared with $25.4 million for the three months ended December 31, 2005. The increase in dividends paid over the prior-year period reflects the increase in our dividend rate from $0.315 per share during the three months ended December 31, 2005 to $0.32 per share during the three months ended December 31, 2006 combined with new share issuances under our various plans.

The following table summarizes our share issuances for the three months ended December 31, 2006 and 2005.

	Three Months Ended December 31	
	2006	2005
Shares issued:		
Retirement Savings Plan	85,162	105,875
Direct Stock Purchase Plan	80,701	103,202
Outside Directors Stock-for-Fee Plan	669	667
Long-Term Incentive Plan	273,799	103,753
Public Offering	6,325,000	—
Total shares issued	6,765,331	313,497

Shelf Registration

On December 4, 2006, we filed a registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to $900 million in new common stock and/or debt securities available for issuance, including approximately $401.5 million of capacity carried over from our prior shelf registration statement filed with the SEC in August 2004. In December 2006, we sold 6.3 million shares of common stock and used the net proceeds to reduce short-term debt. After this issuance, we have approximately $701 million of availability remaining under the registration statement.

Credit Facilities

We maintain both committed and uncommitted credit facilities. Borrowings under our uncommitted credit facilities are made on a when-and-as-needed basis at the discretion of the banks. Our credit capacity and the amount of unused borrowing capacity are affected by the seasonal nature of the natural gas business and our short-term borrowing requirements, which are typically highest during colder winter months. Our working capital needs can vary significantly due to changes in the price of natural gas charged by suppliers and the increased gas supplies required to meet customers' needs during periods of cold weather. Our cash needs for working capital have increased substantially in recent years as a result of the significant increase in the price of natural gas.

In December 2006, we replaced our $600 million three-year revolving credit facility with a new $600 million five-year revolving credit facility. In addition, in November 2006, we entered into a new $300 million 364-day revolving credit facility with substantially the same terms as our $600 million credit facility.

As of December 31, 2006, the amount available to us under our credit facilities, net of outstanding letters of credit, was $804.1 million. We believe these credit facilities, combined with our operating cash flows will be sufficient to fund our increased working capital needs. These facilities are described in further detail in Note 4 to the unaudited condensed consolidated financial statements.

Credit Ratings

Our credit ratings directly affect our ability to obtain short-term and long-term financing, in addition to the cost of such financing. In determining our credit ratings, the rating agencies consider a number of quantitative factors, including debt to total capitalization, operating cash flow relative to outstanding debt, operating cash flow coverage of interest and pension liabilities and funding status. In addition, the rating agencies consider qualitative factors such as consistency of our earnings over time, the quality of our management and business strategy, the risks associated with our utility and nonutility businesses and the regulatory structures that govern our rates in the states where we operate.

Our debt is rated by three rating agencies: Standard & Poor's Corporation (S&P), Moody's Investors Service (Moody's) and Fitch Ratings, Ltd. (Fitch). Our current debt ratings are all considered investment grade and are as follows:

	S&P	Moody's	Fitch
Unsecured senior long-term debt	BBB	Baa3	BBB+
Commercial paper	A-2	P-3	F-2

Currently, with respect to our unsecured senior long-term debt, S&P, Moody's and Fitch maintain their stable outlook. None of our ratings are currently under review.

A credit rating is not a recommendation to buy, sell or hold securities. The highest investment grade credit rating for S&P is AAA, Moody's is Aaa and Fitch is AAA. The lowest investment grade credit rating for S&P is BBB-, Moody's is Baa3 and Fitch is BBB-. Our credit ratings may be revised or withdrawn at any time by the rating agencies, and each rating should be evaluated independent of any other rating. There can be no assurance that a rating will remain in effect for any given period of time or that a rating will not be lowered, or withdrawn entirely, by a rating agency if, in its judgment, circumstances so warrant.

Debt Covenants

We were in compliance with all of our debt covenants as of December 31, 2006. Our debt covenants are described in Note 4 to the unaudited condensed consolidated financial statements.

Contractual Obligations and Commercial Commitments

Significant commercial commitments are described in Note 8 to the unaudited condensed consolidated financial statements. There were no significant changes in our contractual obligations and commercial commitments during the three months ended December 31, 2006.

Risk Management Activities

We conduct risk management activities through both our utility and natural gas marketing segments. In our utility segment, we use a combination of storage, fixed physical contracts and fixed financial contracts to reduce our exposure to unusually large winter-period gas price increases. In our natural gas marketing segment, we manage our exposure to the risk of natural gas price changes and lock in our gross profit margin through a combination of storage and financial derivatives, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. To the extent our inventory cost and actual sales and actual purchases do not correlate with the changes in the market indices we use in our hedges, we could experience ineffectiveness or the hedges may no longer meet the accounting requirements for hedge accounting, resulting in the derivatives being treated as mark-to-market instruments through earnings.

We record our derivatives as a component of risk management assets and liabilities, which are classified as current or noncurrent based upon the anticipated settlement date of the underlying derivative. Substantially all of our derivative financial instruments are valued using external market quotes and indices. The following tables show the components of the change in the fair value of our utility and natural gas marketing commodity derivative contracts for the three months ended December 31, 2006 and 2005:

	Three Months Ended December 31, 2006		Three Months Ended December 31, 2005	
	Utility	Natural Gas Marketing	Utility	Natural Gas Marketing
	(In thousands)			
Fair value of contracts at beginning of period	$(27,209)	$15,003	$ 93,310	$(61,898)
Contracts realized/settled	(15,757)	45,899	29,955	(27,669)
Fair value of new contracts	(1,910)	—	(2,101)	—
Other changes in value	11,561	14,061	(82,891)	30,199
Fair value of contracts at end of period	$(33,315)	$74,963	$ 38,273	$(59,368)

The fair value of our utility and natural gas marketing derivative contracts at December 31, 2006, is segregated below by time period and fair value source:

	Fair Value of Contracts at December 31, 2006				
	Maturity in Years				
Source of Fair Value	Less than 1	1-3	4-5	Greater Than 5	Total Fair Value
	(In thousands)				
Prices actively quoted	$34,974	$ 9,257	$—	$—	$44,231
Prices based on models and other valuation methods	(1,393)	(1,190)	—	—	(2,583)
Total Fair Value	$33,581	$ 8,067	$—	$—	$41,648

Storage and Hedging Outlook

AEM participates in transactions in which it seeks to find and profit from pricing differences that occur over time. AEM purchases physical natural gas and then sells financial contracts at advantageous prices to lock in a gross profit margin. AEM is able to capture gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time.

Natural gas inventory is marked to market at the end of each month with changes in fair value recognized as unrealized gains and losses in the period of change. Derivatives associated with our natural gas inventory, which are designated as fair value hedges, are marked to market each month based upon the NYMEX price with changes in fair value recognized as unrealized gains and losses in the period of change. The changes in the difference between the indices used to mark to market our physical inventory (Gas Daily) and the related fair-value hedge (NYMEX) is reported as a component of revenue and can result in volatility in our reported net income. Over time, gains and losses on the sale of storage gas inventory will be offset by gains and losses on the fair-value hedges; therefore, the economic gross profit AEM captured in the original transaction remains essentially unchanged.

AEM continually manages its positions to enhance the future economic profit it captured in the original transaction. Therefore, AEM may change its scheduled injection and withdrawal plans from one time period to another based on market conditions or adjust the amount of storage capacity it holds on a discretionary basis in an effort to achieve this objective. AEM monitors the impacts of these profit optimization efforts by estimating the economic gross profit that it captured through the purchase and sale of physical natural gas and the associated financial derivatives. The reconciliation below of the economic gross profit, combined with the effect of unrealized gains or losses recognized in accordance with generally accepted accounting principles in the financial statements in prior periods, is presented in order to provide a measure of the potential gross profit that could occur in future periods if AEM's optimization efforts are fully successful. We consider this measure of potential gross profit a non-GAAP financial measure as it is calculated using both forward-looking and historical financial information. The following table presents, by quarter, AEM's economic gross profit and its potential gross profit.

Period Ending	Net Physical Position (Bcf)	Economic Gross Profit (In millions)	Associated Net Unrealized Gains (Losses) (In millions)	Potential Gross Profit (In millions)
September 30, 2006	14.5	$60.0	$(16.0)	$76.0
December 31, 2006	21.0	$60.6	$ 32.8	$27.8

As of December 31, 2006, based upon AEM's derivatives position and inventory withdrawal schedule, the economic gross profit was $60.6 million. In addition, $32.8 million of net unrealized gains were recorded in the financial statements as of December 31, 2006. Therefore, the potential gross profit was $27.8 million. The potential gross profit amount will not result in an equal increase in future net income as AEM will incur additional storage and other operational expenses to realize this amount.

The economic gross profit is based upon planned injection and withdrawal schedules, and the realization of the economic gross profit is contingent upon the execution of this plan, weather and other execution factors. Since AEM actively manages and optimizes its portfolio to enhance the future profitability of its storage position, it may change its scheduled injection and withdrawal plans from one time period to another based on market conditions. Therefore, we cannot ensure that the economic gross profit or the potential gross profit calculated as of December 31, 2006 will be fully realized in the future or in what time period. Further, if we experience operational or other issues which limit our ability to optimally manage our stored gas positions, our earnings could be adversely impacted.

Pension and Postretirement Benefits Obligations

For the three months ended December 31, 2006 and 2005 our total net periodic pension and other benefits cost was $12.1 million and $12.5 million. All of these costs are recoverable through our gas utility rates; however, a portion of these costs is capitalized into our utility rate base. The remaining costs are recorded as a component of operation and maintenance expense.

The decrease in total net periodic pension and other benefits cost during the current-year period compared with the prior-year period primarily reflects changes in assumptions we made during our annual pension plan valuation completed June 30, 2006. The discount rate used to compute the present value of a plan's liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid. In the period leading up to our June 30, 2006 measurement date, these interest rates were increasing, which resulted in a 130 basis point increase in our discount rate used to determine our fiscal 2007 net periodic and post-retirement cost to 6.30 percent. This increase has the effect of decreasing the present value of our plan liabilities and associated expenses. This favorable impact was partially offset by the unfavorable impact of reducing the expected return on our pension plan assets by 25 basis points to 8.25 percent, which has the effect of increasing our pension and postretirement benefit cost.

During the three months ended December 31, 2006, we contributed $2.8 million to our other postretirement plans, and we expect to contribute a total of approximately $11 million to these plans during fiscal 2007.

OPERATING STATISTICS AND OTHER INFORMATION

The following tables present certain operating statistics for our utility, natural gas marketing, pipeline and storage and other nonutility segments for the three-month periods ended December 31, 2006 and 2005.

Utility Sales and Statistical Data

	Three Months Ended December 31	
	2006	2005
METERS IN SERVICE, end of period		
Residential	2,915,864	2,910,467
Commercial	277,684	279,263
Industrial	3,023	3,074
Agricultural	8,626	9,470
Public authority and other	8,216	8,202
Total meters	3,213,413	3,210,476
INVENTORY STORAGE BALANCE — Bcf	60.3	59.6
HEATING DEGREE DAYS[(1)]		
Actual (weighted average)	1,135	1,056
Percent of normal	101%	93%
UTILITY SALES VOLUMES — MMcf[(2)]		
Gas sales volumes		
Residential	50,699	53,709
Commercial	27,085	29,139
Industrial	5,735	9,009
Agricultural	110	40
Public authority and other	2,771	3,291
Total gas sales volumes	86,400	95,188
Utility transportation volumes	33,883	31,756
Total utility throughput	120,283	126,944
UTILITY OPERATING REVENUES (000's)[(2)]		
Gas sales revenues		
Residential	$ 574,736	$ 783,346
Commercial	283,033	424,338
Industrial	53,983	128,471
Agricultural	575	786
Public authority and other	27,169	43,971
Total utility gas sales revenues	939,496	1,380,912
Transportation revenues	15,850	15,867
Other gas revenues	8,898	8,231
Total utility operating revenues	$ 964,244	$1,405,010
Utility average transportation revenue per Mcf	$ 0.47	$ 0.50
Utility average cost of gas per Mcf sold	$ 8.12	$ 11.82

See footnotes following these tables.

Natural Gas Marketing, Pipeline and Storage and Other Nonutility Operations Sales and Statistical Data

	Three Months Ended December 31	
	2006	2005
CUSTOMERS, end of period		
Industrial	700	657
Municipal	60	71
Other	420	395
Total	1,180	1,123
INVENTORY STORAGE BALANCE — Bcf		
Natural gas marketing	21.2	15.7
Pipeline and storage	2.7	2.4
Total	23.9	18.1
NATURAL GAS MARKETING SALES VOLUMES — MMcf(2)	88,038	87,822
PIPELINE TRANSPORTATION VOLUMES — MMcf(2)	172,759	146,954
OPERATING REVENUES (000's)(2)		
Natural gas marketing	$711,694	$1,101,845
Pipeline and storage	49,852	39,712
Other nonutility	1,353	1,492
Total operating revenues	$762,899	$1,143,049

Notes to preceding tables:

(1) A heating degree day is equivalent to each degree that the average of the high and the low temperatures for a day is below 65 degrees. The colder the climate, the greater the number of heating degree days. Heating degree days are used in the natural gas industry to measure the relative coldness of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on 30-year average National Weather Service data for selected locations. For service areas that have weather normalized operations, normal degree days are used instead of actual degree days in computing the total number of heating degree days.

(2) Sales volumes and revenues reflect segment operations, including intercompany sales and transportation amounts.

Recent Ratemaking Developments

The following describes the significant ratemaking developments that occurred during the three months ended December 31, 2006. The amounts described below represent the gross revenues that were requested or received in the rate filing, which may not necessarily reflect the increase in operating income obtained, as certain operating costs may have increased as a result of a commission's final ruling.

Atmos Energy Colorado-Kansas Division. In December 2006, the Colorado-Kansas Division filed its third annual ad valorem tax surcharge for $1.5 million. The surcharge is designed to collect Kansas property taxes in excess of the amount included in Atmos' most recent general rate case. We began to bill this surcharge in January 2007.

Atmos Energy Kentucky/Mid-States Division. In April 2006, Atmos filed a rate case in its Missouri service area seeking a rate increase of $3.4 million. The Company is proposing to consolidate the rates for its Missouri properties into three sets of regional rates and consolidate the current purchased gas adjustment (PGA) into one statewide PGA. The Company is also proposing a WNA mechanism. An evidentiary hearing was held in

November 2006. An order is expected to be issued in late February 2007 with any resulting change in rates effective in March 2007.

In November 2005, we received a notice from the TRA that it was opening an investigation into allegations by the Consumer Advocate and Protection Division of the Tennessee Attorney General's Office that we were overcharging customers in parts of Tennessee by approximately $10 million per year. A hearing was held in August 2006. Of the $10 million rate reduction requested by the Consumer Advocate and Protection Division, the TRA approved a $6.1 million rate reduction in October 2006, that became effective in December 2006.

In February 2005, the Attorney General of the State of Kentucky filed a complaint with the Kentucky Public Service Commission (KPSC) alleging that our rates were producing revenues in excess of reasonable levels. We answered the complaint and filed a Motion to Dismiss with the KPSC. In February 2006, the KPSC issued an Order denying our Motion to Dismiss but stated that the Attorney General had not met his burden of proof concerning his complaint. In November 2006, we requested dismissal of the case through our filing a notice of intent to file a general rate case in December 2006. Upon receipt of the notice of intent, the KPSC suspended the procedural schedule until it issues a decision regarding the motion for dismissal. A hearing should be scheduled for early 2007. We believe that the Attorney General will not be able to demonstrate that our present rates are in excess of reasonable levels.

In December 2006, the Company filed a rate application for an increase in base rates of $10.4 million in Kentucky. Additionally, we proposed to implement a process to review our rates annually and to collect the bad debt portion of gas costs directly rather than through the base rate. A decision is expected in the case in July 2007.

Atmos Energy Louisiana Division. In May 2006, the LPSC voted to approve a settlement which included renewal of the RSC for both the LGS and TransLa service areas with provisions that will reduce regulatory lag. The first RSC filing was in August 2006 for approximately $10.8 million, based on a test year ended December 31, 2005, for the LGS service area. The Company reached a settlement agreement on the case in December 2006 which resulted in an increase of $9.5 million. The first filing for the TransLa service area for approximately $1.8 million was made on December 28, 2006, for the test period ending September 30, 2006, with an effective rate adjustment of April 1, 2007.

Atmos Energy Mid-Tex Division. During fiscal 2006, we received "show cause" resolutions from approximately 80 cities served by our Mid-Tex Division, including the City of Dallas, which require the Mid-Tex Division to demonstrate that the existing distribution rates are just and reasonable. In May 2006, the Mid-Tex Division filed a Statement of Intent with the Railroad Commission of Texas (RRC) which consolidated the "show cause" resolutions and seeks incremental annual revenues of approximately $60 million and several rate design changes including WNA, revenue stabilization and recovery of the gas cost component of bad debt expense. In exchange for an agreement to provide the intervening parties in the case an additional two months to prepare for the hearing, the Mid-Tex Division obtained an agreement and approval to implement WNA in its rates for the 2006-2007 winter season and to implement WNA in the final rates in this proceeding. The hearing was completed on November 17, 2006. The hearing examiners in the case issued their Proposal for Decision (PFD) on February 2, 2007, which contained their recommendations to the RRC. In the PFD, the examiners recommended a total annual decrease in the Mid-Tex Division's rates of approximately $22.8 million, a customer refund of $2.6 million and a permanent weather normalization adjustment mechanism based on 10-year weather data. We are in the process of preparing our responses to the recommendations in the PFD. We continue to believe that the evidence presented in the case supports our request to increase rates in order to earn a fair rate of return. While the RRC is required by statute to issue its final decision by April 2, 2007, it could issue a final order sometime in March 2007. Any rate increase will be effective prospectively from the date of the final order; however, any rate decrease will be effective from May 31, 2006.

In September 2006, the Mid-Tex Division filed its annual gas cost reconciliation with the RRC. The filing reflects approximately $24 million in refunds of amounts that were overcollected from customers between July 2005 and June 2006. The Mid-Tex Division received approval to refund these amounts over a six-month period which began in November 2006.

The Mid-Tex Division is also pursuing an appeal to the Travis County District Court of the Final Order in its last system-wide rate case completed in May 2004 to obtain a return of and on its investment associated with the Poly I replacement pipe that was originally disallowed in its rate case completed in May 2004. The Travis County District Court upheld the Commission's final order. An appeal to the Court of Appeals in Travis County has been prepared but no briefings or hearing schedule has been established.

RECENT ACCOUNTING DEVELOPMENTS

Recent accounting developments and their impact on our financial position, results of operations and cash flows are described in Note 2 to the unaudited condensed consolidated financial statements.

Item 3. *Quantitative and Qualitative Disclosures About Market Risk*

Information regarding our quantitative and qualitative disclosures about market risk are disclosed in Item 7A in our annual report on Form 10-K for the year ended September 30, 2006. During the three months ended December 31, 2006, there were no material changes in our quantitative and qualitative disclosures about market risk.

Item 4. *Controls and Procedures*

As indicated in the certifications in Exhibit 31 of this report, the Company's Chief Executive Officer and Chief Financial Officer have evaluated the Company's disclosure controls and procedures as of December 31, 2006. Based on that evaluation, these officers have concluded that the Company's disclosure controls and procedures are effective in ensuring that material information required to be disclosed in this quarterly report is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. In addition, there were no changes during the Company's last fiscal quarter that materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. *Legal Proceedings*

During the three months ended December 31, 2006, there were no material changes in the status of the litigation and environmental-related matters that were disclosed in Note 13 to our annual report on Form 10-K for the year ended September 30, 2006. We continue to believe that the final outcome of such litigation and environmental-related matters or claims will not have a material adverse effect on our financial condition, results of operations or net cash flows.

Item 6. *Exhibits*

A list of exhibits required by Item 601 of Regulation S-K and filed as part of this report is set forth in the Exhibits Index, which immediately precedes such exhibits.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ATMOS ENERGY CORPORATION
(Registrant)

By: /s/ JOHN P. REDDY

John P. Reddy
Senior Vice President and Chief Financial Officer
(Duly authorized signatory)

Date: February 7, 2007

EXHIBITS INDEX
Item 6(a)

Exhibit Number	Description	Page Number
12	Computation of ratio of earnings to fixed charges	
15	Letter regarding unaudited interim financial information	
31	Rule 13a-14(a)/15d-14(a) Certifications	
32	Section 1350 Certifications*	

* These certifications, which were made pursuant to 18 U.S.C. Section 1350 by the Company's Chief Executive Officer and Chief Financial Officer, furnished as Exhibit 32 to this Quarterly Report on Form 10-Q, will not be deemed to be filed with the Commission or incorporated by reference into any filing by the Company under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent that the Company specifically incorporates such certifications by reference.

EXHIBIT CF-R-2

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

(Mark One)

☑ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended March 31, 2007

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number 1-10042

Atmos Energy Corporation
(Exact name of registrant as specified in its charter)

Texas and Virginia *(State or other jurisdiction of incorporation or organization)*	**75-1743247** *(IRS employer identification no.)*
Three Lincoln Centre, Suite 1800 **5430 LBJ Freeway, Dallas, Texas** *(Address of principal executive offices)*	**75240** *(Zip code)*

(972) 934-9227
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer ☑ Accelerated Filer ☐ Non-Accelerated Filer ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act) Yes ☐ No ☑

Number of shares outstanding of each of the issuer's classes of common stock, as of April 25, 2007.

Class	Shares Outstanding
No Par Value	88,806,235

GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
AES	Atmos Energy Services, LLC
APS	Atmos Pipeline and Storage, LLC
Bcf	Billion cubic feet
EITF	Emerging Issues Task Force
FASB	Financial Accounting Standards Board
FIN	FASB Interpretation
Fitch	Fitch Ratings, Ltd.
GRIP	Gas Reliability Infrastructure Program
KPSC	Kentucky Public Service Commission
LGS	Louisiana Gas Service Company and LGS Natural Gas Company, which were acquired July 1, 2001
LPSC	Louisiana Public Service Commission
Mcf	Thousand cubic feet
MMcf	Million cubic feet
Moody's	Moody's Investors Services, Inc.
NYMEX	New York Mercantile Exchange, Inc.
RRC	Railroad Commission of Texas
RSC	Rate Stabilization Clause
S&P	Standard & Poor's Corporation
SEC	United States Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
TRA	Tennessee Regulatory Authority
WNA	Weather Normalization Adjustment

PART I. FINANCIAL INFORMATION

Item 1. ***Financial Statements***

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

	March 31, 2007	September 30, 2006
	(Unaudited)	
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$5,228,334	$5,101,308
Less accumulated depreciation and amortization	1,516,504	1,472,152
Net property, plant and equipment	3,711,830	3,629,156
Current assets		
Cash and cash equivalents	176,280	75,815
Cash held on deposit in margin account	40,763	35,647
Accounts receivable, net	721,058	374,629
Gas stored underground	364,478	461,502
Other current assets	126,838	169,952
Total current assets	1,429,417	1,117,545
Goodwill and intangible assets	738,217	738,521
Deferred charges and other assets	229,634	234,325
	$6,109,098	$5,719,547
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: March 31, 2007 — 88,764,353 shares; September 30, 2006 — 81,739,516 shares	$ 444	$ 409
Additional paid-in capital	1,679,228	1,467,240
Retained earnings	357,425	224,299
Accumulated other comprehensive loss	(15,144)	(43,850)
Shareholders' equity	2,021,953	1,648,098
Long-term debt	1,878,331	2,180,362
Total capitalization	3,900,284	3,828,460
Current liabilities		
Accounts payable and accrued liabilities	665,212	345,108
Other current liabilities	421,386	388,451
Short-term debt	—	382,416
Current maturities of long-term debt	303,232	3,186
Total current liabilities	1,389,830	1,119,161
Deferred income taxes	342,328	306,172
Regulatory cost of removal obligation	261,984	261,376
Deferred credits and other liabilities	214,672	204,378
	$6,109,098	$5,719,547

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended March 31	
	2007	2006
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Utility segment	$1,461,033	$1,447,620
Natural gas marketing segment	795,041	818,629
Pipeline and storage segment	59,362	45,483
Other nonutility segment	783	1,595
Intersegment eliminations	(240,637)	(279,481)
	2,075,582	2,033,846
Purchased gas cost		
Utility segment	1,114,787	1,131,885
Natural gas marketing segment	771,988	774,652
Pipeline and storage segment	229	211
Other nonutility segment	—	—
Intersegment eliminations	(240,108)	(278,305)
	1,646,896	1,628,443
Gross profit	428,686	405,403
Operating expenses		
Operation and maintenance	111,862	112,698
Depreciation and amortization	51,066	47,076
Taxes, other than income	56,746	64,796
Total operating expenses	219,674	224,570
Operating income	209,012	180,833
Miscellaneous income (expense)	1,838	(2,439)
Interest charges	35,262	35,492
Income before income taxes	175,588	142,902
Income tax expense	69,083	54,106
Net income	$ 106,505	$ 88,796
Basic net income per share	$ 1.21	$ 1.10
Diluted net income per share	$ 1.20	$ 1.10
Cash dividends per share	$ 0.320	$ 0.315
Weighted average shares outstanding:		
Basic	88,078	80,573
Diluted	88,735	81,040

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Six Months Ended March 31	
	2007	2006
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Utility segment	$2,425,277	$2,852,630
Natural gas marketing segment	1,506,735	1,920,474
Pipeline and storage segment	109,214	85,195
Other nonutility segment	2,136	3,087
Intersegment eliminations	(365,147)	(543,720)
	3,678,215	4,317,666
Purchased gas cost		
Utility segment	1,816,463	2,256,714
Natural gas marketing segment	1,420,548	1,850,178
Pipeline and storage segment	454	211
Other nonutility segment	—	—
Intersegment eliminations	(363,528)	(541,430)
	2,873,937	3,565,673
Gross profit	804,278	751,993
Operating expenses		
Operation and maintenance	227,232	220,915
Depreciation and amortization	100,061	90,336
Taxes, other than income	96,813	110,212
Total operating expenses	424,106	421,463
Operating income	380,172	330,530
Miscellaneous income (expense)	3,417	(1,991)
Interest charges	74,794	71,681
Income before income taxes	308,795	256,858
Income tax expense	121,029	97,035
Net income	$ 187,766	$ 159,823
Basic net income per share	$ 2.20	$ 1.99
Diluted net income per share	$ 2.18	$ 1.98
Cash dividends per share	$ 0.64	$ 0.63
Weighted average shares outstanding:		
Basic	85,404	80,444
Diluted	86,061	80,911

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended March 31	
	2007	2006
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	$ 187,766	$ 159,823
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization:		
Charged to depreciation and amortization	100,061	90,336
Charged to other accounts	118	334
Deferred income taxes	72,755	58,199
Other	9,472	7,587
Net assets / liabilities from risk management activities	50,540	(24,041)
Net change in operating assets and liabilities	91,215	(143,847)
Net cash provided by operating activities	511,927	148,391
Cash Flows From Investing Activities		
Capital expenditures	(172,792)	(213,230)
Other, net	(3,749)	(2,842)
Net cash used in investing activities	(176,541)	(216,072)
Cash Flows From Financing Activities		
Net increase (decrease) in short-term debt	(382,416)	117,506
Repayment of long-term debt	(2,206)	(2,162)
Cash dividends paid	(54,640)	(50,933)
Issuance of common stock	12,428	12,053
Net proceeds from equity offering	191,913	—
Net cash provided by (used in) financing activities	(234,921)	76,464
Net increase in cash and cash equivalents	100,465	8,783
Cash and cash equivalents at beginning of period	75,815	40,116
Cash and cash equivalents at end of period	$ 176,280	$ 48,899

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
March 31, 2007

1. Nature of Business

Atmos Energy Corporation ("Atmos" or "the Company") and our subsidiaries are engaged primarily in the natural gas utility business as well as other natural gas nonutility businesses. Our natural gas utility business distributes natural gas through sales and transportation arrangements to approximately 3.2 million residential, commercial, public authority and industrial customers throughout our six regulated natural gas utility divisions, in the service areas described below:

Division	Service Area
Atmos Energy Colorado-Kansas Division	Colorado, Kansas, Missouri[2]
Atmos Energy Kentucky/Mid-States Division[1]	Georgia[2], Illinois[2], Iowa[2], Kentucky, Missouri[2], Tennessee, Virginia[2]
Atmos Energy Louisiana Division	Louisiana
Atmos Energy Mid-Tex Division	Texas, including the Dallas/Fort Worth Metroplex
Atmos Energy Mississippi Division	Mississippi
Atmos Energy West Texas Division	West Texas

(1) Effective October 1, 2006, the Kentucky and Mid-States Divisions were combined.

(2) Denotes locations where we have more limited service areas.

In addition, we transport natural gas for others through our distribution system. Our utility business is subject to federal and state regulation and/or regulation by local authorities in each of the states in which the utility divisions operate. Our shared services function is located in Dallas, Texas, and our customer support centers are located in Amarillo and Waco, Texas.

Our nonutility businesses operate in 22 states and include our natural gas marketing operations, pipeline and storage operations and other nonutility operations. These operations are either organized under or managed by Atmos Energy Holdings, Inc. (AEH), which is a wholly-owned subsidiary of the Company.

Our natural gas marketing operations are managed by Atmos Energy Marketing, LLC (AEM), which is wholly-owned by AEH. AEM provides a variety of natural gas management services to municipalities, natural gas utility systems and industrial natural gas customers, primarily in the southeastern and midwestern states and to our Louisiana and Kentucky/Mid-States utility divisions. These services consist primarily of furnishing natural gas supplies at fixed and market-based prices, contract negotiation and administration, load forecasting, gas storage acquisition and management services, transportation services, peaking sales and balancing services, capacity utilization strategies and gas price hedging through the use of derivative instruments.

Our pipeline and storage business includes the regulated operations of our Atmos Pipeline — Texas Division, a division of the Company, and the nonregulated operations of Atmos Pipeline and Storage, LLC (APS), which is wholly-owned by AEH. The Atmos Pipeline — Texas Division transports natural gas to our Atmos Energy Mid-Tex Division and to third parties, as well as manages five underground storage reservoirs in Texas. Through APS, we own or have an interest in underground storage fields in Kentucky and Louisiana. We also use these storage facilities to reduce the need to contract for additional pipeline capacity to meet customer demand during peak periods.

Our other nonutility businesses consist primarily of the operations of Atmos Energy Services, LLC (AES) and Atmos Power Systems, Inc., which are each wholly-owned by AEH. Through December 31, 2006, AES provided natural gas management services to our utility operations, other than the Mid-Tex Division. These services included aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering the gas to our utility service areas at competitive prices. Effective January 1, 2007, our shared services function began providing these services to our utility operations. AES continues to provide limited services to our utility division, and the revenues AES receives are equal to the costs incurred to provide those services. Through Atmos Power Systems, Inc., we have constructed electric peaking power-generating plants and associated facilities and lease these plants through sales-type lease agreements.

2. Unaudited Interim Financial Information

In the opinion of management, all material adjustments (consisting of normal recurring accruals) necessary for a fair presentation have been made to the unaudited consolidated interim-period financial statements. These consolidated interim-period financial statements are condensed as permitted by the instructions to Form 10-Q and should be read in conjunction with the audited consolidated financial statements of Atmos Energy Corporation included in its Annual Report on Form 10-K for the fiscal year ended September 30, 2006. Because of seasonal and other factors, the results of operations for the three and six-month periods ended March 31, 2007 are not indicative of expected results of operations for the full 2007 fiscal year, which ends September 30, 2007.

Significant accounting policies

Our accounting policies are described in Note 2 to our Annual Report on Form 10-K for the year ended September 30, 2006. There were no significant changes to those accounting policies during the six months ended March 31, 2007.

Additionally, during the second quarter of fiscal 2007, we completed our annual goodwill impairment assessment. Based on the assessment performed, our goodwill was not impaired.

Regulatory assets and liabilities

We record certain costs as regulatory assets in accordance with Statement of Financial Accounting Standards (SFAS) 71, *Accounting for the Effects of Certain Types of Regulation*, when future recovery through customer rates is considered probable. Regulatory liabilities are recorded when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. Substantially all of our regulatory assets are recorded as a component of deferred charges and other assets and substantially all of our regulatory liabilities are recorded as a component of deferred credits and other liabilities. Deferred gas costs are recorded either in other current assets or liabilities and the regulatory cost of removal obligation is separately reported.

Significant regulatory assets and liabilities as of March 31, 2007 and September 30, 2006 included the following:

	March 31, 2007	September 30, 2006
	(In thousands)	
Regulatory assets:		
Merger and integration costs, net	$ 8,438	$ 8,644
Deferred gas costs	85,244	44,992
Environmental costs	1,291	1,234
Rate case costs	9,344	10,579
Deferred franchise fees	917	1,311
Other	12,069	9,055
	$117,303	$ 75,815
Regulatory liabilities:		
Deferred gas costs	$ 27,428	$ 68,959
Regulatory cost of removal obligation	282,942	276,490
Deferred income taxes, net	235	235
Other	9,816	10,825
	$320,421	$356,509

Currently, our authorized rates do not include a return on certain of our merger and integration costs; however, we recover the amortization of these costs. Merger and integration costs, net, are generally amortized on a straight-line basis over estimated useful lives ranging up to 20 years. Environmental costs have been deferred to be included in future rate filings in accordance with rulings received from various state regulatory commissions.

Comprehensive income

The following table presents the components of comprehensive income, net of related tax, for the three-month and six-month periods ended March 31, 2007 and 2006:

	Three Months Ended March 31		Six Months Ended March 31	
	2007	2006	2007	2006
	(In thousands)			
Net income	$106,505	$88,796	$187,766	$159,823
Unrealized holding gains (losses) on investments, net of tax expense (benefit) of $(134) and $294 for the three months ended March 31, 2007 and 2006 and of $749 and $542 for the six months ended March 31, 2007 and 2006	(219)	479	1,222	884
Amortization and unrealized gain on interest rate hedging transactions, net of tax expense of $982 and $527 for the three months ended March 31, 2007 and 2006 and $1,510 and $1,055 for the six months ended March 31, 2007 and 2006	1,602	861	2,462	1,721
Net unrealized gains (losses) on commodity hedging transactions, net of tax expense (benefit) of $8,117 and $(2,927) for the three months ended March 31, 2007 and 2006 and $15,336 and $(17,676) for the six months ended March 31, 2007 and 2006	13,244	(4,776)	25,022	(28,839)
Comprehensive income	$121,132	$85,360	$216,472	$133,589

Accumulated other comprehensive loss, net of tax, as of March 31, 2007 and September 30, 2006 consisted of the following unrealized gains (losses):

	March 31, 2007	September 30, 2006
	(In thousands)	
Accumulated other comprehensive loss:		
Unrealized holding gains on investments	$ 2,788	$ 1,566
Treasury lock agreements	(18,078)	(20,540)
Cash flow hedges	146	(24,876)
	$(15,144)	$(43,850)

Recent accounting pronouncements

In February 2007, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities — Including an amendment of FASB Statement No. 115.* The new standard permits an entity to measure certain financial assets and financial liabilities at fair value. The objective of the standard is to improve financial reporting by allowing entities to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. Entities that elect the fair value option will report unrealized gains and losses in earnings at each subsequent reporting date. The fair value option may be elected on an instrument-by-instrument basis. The fair value option is irrevocable, unless a new election date occurs. The provisions of this standard will be effective October 1, 2008. We are currently evaluating the impact this standard may have on our financial position, results of operations and cash flows.

In September 2006, the FASB issued SFAS 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R).* The new standard represents a significant change to the existing rules by requiring recognition in the balance sheet of the overfunded or underfunded positions of defined benefit pension and other postretirement plans based upon the projected benefit obligation, along with a corresponding noncash, after-tax adjustment to stockholders' equity. Additionally, this standard requires that the measurement date must correspond to the fiscal year end balance sheet date but it does not change how net periodic pension and postretirement cost or the projected benefit obligation is determined. The balance sheet recognition guidance of this standard will be effective as of September 30, 2007, while the measurement date provisions of this guidance can be adopted as late as fiscal 2008 for the Company.

In June 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109* (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes by establishing standards for measurement and recognition in financial statements of positions taken by an entity in its income tax returns. This interpretation also provides guidance on derecognition of income tax assets and liabilities, classification of current and deferred income tax assets and liabilities, accounting for interest and penalties, accounting for income taxes in interim periods and income tax disclosures. We will be required to apply the provisions of FIN 48 beginning October 1, 2007. We are currently evaluating the impact this standard may have on our financial position, results of operations and cash flows.

3. Derivative Instruments and Hedging Activities

We conduct risk management activities through both our utility and natural gas marketing segments. We record our derivatives as a component of risk management assets and liabilities, which are classified as current or noncurrent other assets or liabilities based upon the anticipated settlement date of the underlying derivative. Our determination of the fair value of these derivative financial instruments reflects the estimated amounts that we would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains and losses on open contracts. In our determination of fair value, we consider various factors, including closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts. These risk management assets and liabilities are subject to continuing market risk until the underlying derivative contracts are settled.

The following table shows the fair values of our risk management assets and liabilities by segment at March 31, 2007 and September 30, 2006:

	Utility	Natural Gas Marketing	Total
		(In thousands)	
March 31, 2007:			
Assets from risk management activities, current	$ 3,804	$ 708	$ 4,512
Assets from risk management activities, noncurrent	—	7,105	7,105
Liabilities from risk management activities, current	(2)	(32,369)	(32,371)
Liabilities from risk management activities, noncurrent	—	(438)	(438)
Net assets (liabilities)	$ 3,802	$(24,994)	$(21,192)
September 30, 2006:			
Assets from risk management activities, current	$ —	$ 12,553	$ 12,553
Assets from risk management activities, noncurrent	—	6,186	6,186
Liabilities from risk management activities, current	(27,209)	(3,460)	(30,669)
Liabilities from risk management activities, noncurrent	—	(276)	(276)
Net assets (liabilities)	$(27,209)	$ 15,003	$(12,206)

Utility Hedging Activities

We use a combination of storage, fixed physical contracts and fixed financial contracts to partially insulate us and our customers against gas price volatility during the winter heating season. Because the gains or losses of financial derivatives used in our utility segment ultimately will be recovered through our rates, current period changes in the assets and liabilities from these risk management activities are recorded as a component of deferred gas costs in accordance with SFAS 71, *Accounting for the Effects of Certain Types of Regulation.* Accordingly, there is no earnings impact to our utility segment as a result of the use of these financial derivatives.

Nonutility Hedging Activities

Our nonutility hedging activities are subject to various market risks, including risks known as flat price risk, time spread risk and basis risk.

Flat price risk arises from maintaining unhedged open positions. Time spread risk arises when we enter into transactions to buy and sell natural gas that over a period of months offset one another but do not offset in any particular month within the overall time period. This risk arises even when we have no unhedged open positions for the overall time period. Finally, basis risk arises when the pricing of a physical contract is based on a pricing location that differs from the Henry Hub, the NYMEX clearing location.

We seek to mitigate these risks by continually monitoring our positions to maximize our gains. Additionally, under our risk management policies, we seek to match our financial derivative positions to our physical storage positions as well as our expected current and future sales and purchase obligations to maintain no open positions at the end of each trading day. The determination of our net open position as of any day, however, requires us to make assumptions as to future circumstances, including the use of gas by our customers in relation to our anticipated storage and market positions. Because the flat price risk associated with any net open position at the end of each day may increase if the assumptions are not realized, we review these assumptions as part of our daily monitoring activities. We may also be affected by intraday fluctuations of gas prices, since the price of natural gas purchased or sold for future delivery earlier in the day may not be hedged until later in the day. At times, limited net open positions related to our existing and anticipated commitments may occur. At the close of business on March 31, 2007, AEH had a net open position (including existing storage) of 0.2 Bcf.

Finally, AEM manages its exposure to the risk of natural gas price changes through a combination of storage and financial derivatives, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. Our financial derivative activities include fair value hedges to offset changes in the fair value of our natural gas inventory and cash flow hedges to offset anticipated purchases and sales of gas in the future. AEM also utilizes basis swaps and other non-hedge derivative instruments to manage its exposure to market volatility.

For the three and six-month periods ended March 31, 2007, the change in the deferred hedging position in accumulated other comprehensive loss was attributable to decreases in future natural gas prices relative to the natural gas prices stipulated in the derivative contracts. The recognition in net income for the six months ended March 31, 2007 of $27.2 million in net deferred hedging losses ($6.2 million being attributable to the three months ended March 31, 2007) was the result of the maturing of derivative contracts. The net deferred hedging loss associated with open cash flow hedges remains subject to market price fluctuations until the positions are either settled under the terms of the hedge contracts or terminated prior to settlement. The majority of the deferred hedging balance as of March 31, 2007 is expected to be recognized in net income during fiscal 2008 along with the corresponding hedged purchases and sales of natural gas.

Gains and losses recognized in the income statement from hedge ineffectiveness primarily result from basis risk and from differences between the timing of the settlement of physical contracts and the settlement of the related hedge, that is referred to below as timing ineffectiveness. The following summarizes the gains and losses recognized in the income statement for the three and six months ended March 31, 2007.

	Three Months Ended March 31		Six Months Ended March 31	
	2007	2006	2007	2006
	(In thousands)			
Basis ineffectiveness:				
Fair value basis ineffectiveness	$ 515	$5,635	$ (131)	$13,754
Cash flow basis ineffectiveness	(893)	2,629	(769)	3,611
Total basis ineffectiveness	(378)	8,264	(900)	17,365
Timing ineffectiveness:				
Fair value timing ineffectiveness	(306)	764	(1,590)	325
Total hedge ineffectiveness	$(684)	$9,028	$(2,490)	$17,690

Treasury Activities

Effective March 2, 2007, we entered into a Treasury lock agreement to fix the Treasury yield component of the interest cost associated with $100 million of an anticipated financing to repay long-term debt maturing in October 2007. The Treasury lock is scheduled to terminate on June 29, 2007.

We have designated this Treasury lock as a cash flow hedge of an anticipated transaction. Accordingly, to the extent effective, unrealized gains and losses associated with the Treasury lock will be recorded as a component of accumulated other comprehensive income. Generally, unrealized gains will be recorded when interest rates increase and unrealized losses will be recorded when interest rates decline relative to the interest rate stipulated in the Treasury lock agreement. Upon termination of the Treasury lock agreement, the unrealized gain or loss will be recognized over the life of the related financing arrangement. Any gains or losses arising from ineffectiveness will be recognized in earnings as incurred. At March 31, 2007, we recorded a deferred hedging gain of $0.7 million, net of tax, as a component of accumulated other comprehensive income related to this treasury lock due to an increase in the 10 year Treasury rates between inception of the Treasury lock and March 31, 2007.

4. Debt

Long-term debt

Long-term debt at March 31, 2007 and September 30, 2006 consisted of the following:

	March 31, 2007	September 30, 2006
	(In thousands)	
Unsecured floating rate Senior Notes, due October 2007	$ 300,000	$ 300,000
Unsecured 4.00% Senior Notes, due 2009	400,000	400,000
Unsecured 7.375% Senior Notes, due 2011	350,000	350,000
Unsecured 10% Notes, due 2011	2,303	2,303
Unsecured 5.125% Senior Notes, due 2013	250,000	250,000
Unsecured 4.95% Senior Notes, due 2014	500,000	500,000
Unsecured 5.95% Senior Notes, due 2034	200,000	200,000
Medium term notes		
Series A, 1995-2, 6.27%, due 2010	10,000	10,000
Series A, 1995-1, 6.67%, due 2025	10,000	10,000
Unsecured 6.75% Debentures, due 2028	150,000	150,000
First Mortgage Bonds		
Series P, 10.43% due 2013	7,500	8,750
Other term notes due in installments through 2013	4,869	5,825
Total long-term debt	2,184,672	2,186,878
Less:		
Original issue discount on unsecured senior notes and debentures	(3,109)	(3,330)
Current maturities	(303,232)	(3,186)
	$1,878,331	$2,180,362

Our unsecured floating rate debt bears interest at a rate equal to the three-month LIBOR rate plus 0.375 percent per year. At March 31, 2007, the interest rate on our floating rate debt was 5.735 percent.

Short-term debt

At March 31, 2007, there were no borrowings outstanding under our commercial paper program or bank credit facilities. At September 30, 2006, there was $379.3 million outstanding under our commercial paper program and $3.1 million outstanding under our bank credit facilities.

Shelf Registration

On December 4, 2006, we filed a registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to $900 million in new common stock and/or debt securities available for issuance, including approximately $401.5 million of capacity carried over from our prior shelf registration statement filed with the SEC in August 2004. As discussed in Note 5, in December 2006, we sold approximately 6.3 million shares of common stock under the new registration statement, the net proceeds of which were used to reduce short-term debt. As of March 31, 2007, we had approximately $701 million of availability remaining under the registration statement. However, due to certain restrictions placed by one state regulatory commission on our ability to issue securities under the registration statement, we now have remaining and available for issuance a total of approximately $100 million of equity securities, $300 million of senior debt securities and $300 million of subordinated debt securities. In addition, due to restrictions imposed by another state regulatory commission, if the credit ratings on our senior unsecured debt were to fall below investment grade from either Standard & Poor's Corporation (BBB-), Moody's Investors Services, Inc. (Baa3) or Fitch Ratings, Ltd. (BBB-), our ability to issue any type of debt securities under the registration statement would be suspended until an investment grade rating from any of the three credit rating agencies was achieved.

Credit facilities

We maintain both committed and uncommitted credit facilities. Borrowings under our uncommitted credit facilities are made on a when-and-as-needed basis at the discretion of the banks. Our credit capacity and the amount of unused borrowing capacity are affected by the seasonal nature of the natural gas business and our short-term borrowing requirements, which are typically highest during colder winter months. Our working capital needs can vary significantly due to changes in the price of natural gas and the increased gas supplies required to meet customers' needs during periods of cold weather.

Committed credit facilities

As of March 31, 2007, we had three short-term committed revolving credit facilities totaling $918 million. The first facility is a five-year unsecured facility for $600 million that we entered into in December 2006, which replaced our previously existing $600 million three-year revolving credit facility. The new facility, expiring December 2011, bears interest at a base rate or at the LIBOR rate plus from 0.30 percent to 0.75 percent, based on the Company's credit ratings, and serves as a backup liquidity facility for our $600 million commercial paper program. At March 31, 2007, there were no borrowings outstanding under our commercial paper program.

The second facility is a $300 million unsecured 364-day facility expiring November 2007, that bears interest at a base rate or at the LIBOR rate plus from 0.30 percent to 0.75 percent, based on the Company's credit ratings. At March 31, 2007, there were no borrowings under this facility.

The third facility is an $18 million unsecured facility that bears interest at the Federal Funds rate plus 0.5 percent. This facility expired on March 31, 2007 and was renewed effective April 1, 2007 for one year with no material changes to the terms and pricing. At March 31, 2007, there were no borrowings under this facility.

The availability of funds under our credit facilities is subject to conditions specified in the respective credit agreements, all of which we currently satisfy. These conditions include our compliance with financial covenants and the continued accuracy of representations and warranties contained in these agreements. We are required by the financial covenants in both our $600 million and $300 million credit facilities to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At March 31, 2007, our total-debt-to-total-capitalization ratio, as defined, was 55 percent. In addition, the fees that we pay on unused amounts under both the $600 million and $300 million credit facilities are subject to adjustment depending upon our credit ratings.

Uncommitted credit facilities

AEM has a $580 million uncommitted demand working capital credit facility. On March 30, 2007, AEM and the banks in the facility amended the facility, primarily to extend it to March 31, 2008. Borrowings under the credit facility can be made either as revolving loans or offshore rate loans. Revolving loan borrowings will bear interest at a floating rate equal to a base rate defined as the higher of (i) 0.50 percent per annum above the Federal Funds rate or (ii) the lender's prime rate plus 0.25 percent. Offshore rate loan borrowings will bear interest at a floating rate equal to a base rate based upon LIBOR plus an applicable margin, ranging from 1.25 percent to 1.625 percent per annum, depending on the excess tangible net worth of AEM, as defined in the credit facility. Borrowings drawn down under letters of credit issued by the banks will bear interest at a floating rate equal to the base rate, as defined above, plus an applicable margin, which will range from 1.00 percent to 1.875 percent per annum, depending on the excess tangible net worth of AEM and whether the letters of credit are swap-related standby letters of credit.

AEM is required by the financial covenants in the credit facility to maintain a maximum ratio of total liabilities to tangible net worth of 5 to 1, along with minimum levels of net working capital ranging from $20 million to $120 million. Additionally, AEM must maintain a minimum tangible net worth ranging from $21 million to $121 million, and must not have a maximum cumulative loss for the most recent 12 month reporting period exceeding $4 million to $23 million, depending on the total amount of borrowing elected from time to time by AEM. At March 31, 2007, AEM's ratio of total liabilities to tangible net worth, as defined, was 1.61 to 1.

At March 31, 2007, there were no borrowings outstanding under this credit facility. However, at March 31, 2007, AEM letters of credit totaling $130.9 million had been issued under the facility, which reduced the amount available by a corresponding amount. The amount available under this credit facility is also limited by various covenants, including covenants based on working capital. Under the most restrictive covenant, the amount available to AEM under this credit facility was $19.1 million at March 31, 2007. This line of credit is collateralized by substantially all of the assets of AEM and is guaranteed by AEH.

The Company also has an unsecured short-term uncommitted credit line of $25 million that is used for working-capital and letter-of-credit purposes. There were no borrowings under this uncommitted credit facility at March 31, 2007, but letters of credit reduced the amount available by $5.4 million. This uncommitted line is renewed or renegotiated at least annually with varying terms, and we pay no fee for the availability of the line. Borrowings under this line are made on a when-and-as-available basis at the discretion of the bank.

AEH, the parent company of AEM, has a $100 million intercompany uncommitted demand credit facility with the Company which bears interest at LIBOR plus 2.75 percent. State regulators have approved this facility through December 31, 2007 and have authorized an increase in the intercompany facility to $200 million. At March 31, 2007, there were no borrowings under this facility.

In addition, to supplement its $580 million credit facility, AEM has a $120 million intercompany uncommitted demand credit facility with AEH, which bears interest at LIBOR plus 2.75 percent. Any outstanding amounts under this facility are subordinated to AEM's $580 million uncommitted demand credit facility. At March 31, 2007, there were no borrowings under this facility.

Debt Covenants

We have other covenants in addition to those described above. Our Series P First Mortgage Bonds contain provisions that allow us to prepay the outstanding balance in whole at any time, after November 2007, subject to a prepayment premium. The First Mortgage Bonds provide for certain cash flow requirements and restrictions on additional indebtedness, sale of assets and payment of dividends. Under the most restrictive of such covenants, cumulative cash dividends paid after December 31, 1985 may not exceed the sum of accumulated net income for periods after that date plus $9 million. At March 31, 2007, approximately $336.5 million of retained earnings was unrestricted with respect to the payment of dividends.

We were in compliance with all of our debt covenants as of March 31, 2007. If we were unable to comply with our debt covenants, we could be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions. Our two public debt indentures relating to our senior notes and debentures, as well as our $600 million and $300 million revolving credit agreements, each contain a default provision that is triggered if outstanding indebtedness arising out of any other credit agreements in amounts ranging from in excess of $15 million to in excess of $100 million becomes due by acceleration or is not paid at maturity. In addition, AEM's credit agreement contains a cross-default provision whereby AEM would be in default if it defaults on other indebtedness, as defined, by at least $250 thousand in the aggregate. Additionally, this agreement contains a provision that would limit the amount of credit available if Atmos were downgraded below an S&P rating of BBB and a Moody's rating of Baa2.

Except as described above, we have no triggering events in our debt instruments that are tied to changes in specified credit ratings or stock price, nor have we entered into any transactions that would require us to issue equity, based on our credit rating or other triggering events.

5. Public Offering

On December 13, 2006, we completed the public offering of 6,325,000 shares of our common stock including the underwriters' exercise of their overallotment option of 825,000 shares. The offering was priced at $31.50 per share and generated net proceeds of approximately $192 million. We used the net proceeds from this offering to reduce short-term debt.

6. Earnings Per Share

Basic and diluted earnings per share for the three and six months ended March 31, 2007 and 2006 are calculated as follows:

	For the Three Months Ended March 31		For the Six Months Ended March 31	
	2007	2006	2007	2006
	(In thousands, except per share amounts)			
Net income	$106,505	$88,796	$187,766	$159,823
Denominator for basic income per share — weighted average common shares	88,078	80,573	85,404	80,444
Effect of dilutive securities:				
Restricted and other shares	486	369	486	369
Stock options	171	98	171	98
Denominator for diluted income per share — weighted average common shares	88,735	81,040	86,061	80,911
Income per share — basic	$ 1.21	$ 1.10	$ 2.20	$ 1.99
Income per share — diluted	$ 1.20	$ 1.10	$ 2.18	$ 1.98

There were no out-of-the-money options excluded from the computation of diluted earnings per share for the three and six months ended March 31, 2007 and 2006 as their exercise price was less than the average market price of the common stock during that period.

7. Interim Pension and Other Postretirement Benefit Plan Information

The components of our net periodic pension cost for our pension and other postretirement benefit plans for the three and six months ended March 31, 2007 and 2006 are presented in the following tables. All of these costs are recoverable through our gas utility rates; however, a portion of these costs is capitalized into our utility rate base. The remaining costs are recorded as a component of operation and maintenance expense.

	Three Months Ended March 31			
	Pension Benefits		Other Benefits	
	2007	2006	2007	2006
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 4,018	$ 4,117	$2,807	$3,271
Interest cost	6,495	5,722	2,641	2,210
Expected return on assets	(6,089)	(6,400)	(597)	(547)
Amortization of transition asset	—	—	378	378
Amortization of prior service cost	45	16	8	90
Amortization of actuarial loss	2,434	3,299	—	320
Net periodic pension cost	$ 6,903	$ 6,754	$5,237	$5,722

	Six Months Ended March 31			
	Pension Benefits		Other Benefits	
	2007	2006	2007	2006
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 8,036	$ 8,234	$ 5,614	$ 6,542
Interest cost	12,990	11,444	5,281	4,420
Expected return on assets	(12,178)	(12,800)	(1,194)	(1,094)
Amortization of transition asset	—	—	756	756
Amortization of prior service cost	90	32	16	180
Amortization of actuarial loss	4,868	6,598	—	640
Net periodic pension cost	$ 13,806	$ 13,508	$10,473	$11,444

The assumptions used to develop our net periodic pension cost for the three and six months ended March 31, 2007 and 2006 are as follows:

	Pension Benefits		Other Benefits	
	2007	2006	2007	2006
Discount rate	6.30%	5.00%	6.30%	5.00%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Expected return on plan assets	8.25%	8.50%	5.20%	5.30%

The discount rate used to compute the present value of a plan's liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid. Generally, our funding policy is to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974. However, additional voluntary contributions are made to satisfy regulatory requirements in certain of our jurisdictions. During the six months ended March 31, 2007, we contributed $6.0 million to our other postretirement plans, and we expect to contribute a total of approximately $12 million to these plans during fiscal 2007.

8. Commitments and Contingencies

Litigation and Environmental Matters

With respect to the specific litigation and environmental-related matters or claims that were disclosed in Note 13 to our annual report on Form 10-K for the year ended September 30, 2006, there were no material changes in the status of such litigation and environmental-related matters or claims during the six months ended March 31, 2007. We continue to believe that the final outcome of such litigation and environmental-related matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

In addition, we are involved in other litigation and environmental-related matters or claims that arise in the ordinary course of our business. While the ultimate results of such litigation and response actions to such environmental-related matters or claims cannot be predicted with certainty, we believe the final outcome of such litigation and response actions will not have a material adverse effect on our financial condition, results of operations or cash flows.

Purchase Commitments

AEM has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At March 31, 2007, AEM was committed to purchase 99.7 Bcf within one year and 49.4 Bcf within one to three years under indexed contracts. AEM is committed to purchase 2.2 Bcf within one year and less than 0.1 Bcf within one to three years under fixed price contracts with prices ranging from $6.27 to $9.96. Purchases under these contracts totaled $563.0 million and $531.8 million for the three months ended March 31, 2007 and 2006 and $983.4 million and $1,319.5 million for the six months ended March 31, 2007 and 2006.

Our utility operations, other than the Mid-Tex Division, maintain supply contracts with several vendors that generally cover a period of up to one year. Commitments for estimated base gas volumes are established under these contracts on a monthly basis at contractually negotiated prices. Commitments for incremental daily purchases are made as necessary during the month in accordance with the terms of the individual contract.

Our Mid-Tex Division maintains long-term supply contracts to ensure a reliable source of gas for our customers in its service area which obligate it to purchase specified volumes at market prices. The estimated fiscal year commitments under these contracts as of March 31, 2007 are as follows (in thousands):

2007	$117,811
2008	122,199
2009	10,789
2010	9,940
2011	9,559
Thereafter	21,927
	$292,225

Regulatory Matters

At March 31, 2007, we were involved in a number of "show cause" proceedings filed by cities in several of our jurisdictions. We are currently providing information to and addressing questions raised by the respective regulatory commissions. We believe we will be able to demonstrate to these regulators that our rates are just and reasonable. Additionally, we have a rate case in progress in our Kentucky service area. These regulatory proceedings are discussed in further detail in *Management's Discussion and Analysis — Recent Ratemaking Developments.*

Other

In May 2006, we announced plans to form a joint venture and construct a natural gas gathering system in Eastern Kentucky, referred to as the Straight Creek Project. In an attempt to better serve the needs of the local producers in the area and to meet the Company's economic requirements, we are currently redesigning the original project, which will likely be marginally smaller in both size and scope. Accordingly, the in-service date is expected to be delayed into the second half of fiscal 2008.

9. Concentration of Credit Risk

Information regarding our concentration of credit risk is disclosed in Note 15 to our annual report on Form 10-K for the year ended September 30, 2006. During the six months ended March 31, 2007, there were no material changes in our concentration of credit risk.

10. Segment Information

Atmos Energy Corporation and our subsidiaries are engaged primarily in the natural gas utility business as well as certain nonutility businesses. We distribute natural gas through sales and transportation arrangements to approximately 3.2 million residential, commercial, public authority and industrial customers throughout our six regulated utility divisions, which cover service areas located in 12 states. In addition, we transport natural gas for others through our distribution system.

Through our nonutility businesses we provide natural gas management and marketing services to industrial customers, municipalities and other local distribution companies located in 22 states. Additionally, we provide natural gas transportation and storage services to certain of our utility operations and to third parties.

Our operations are divided into four segments:

- the utility segment, which includes our regulated natural gas distribution and related sales operations,
- the natural gas marketing segment, which includes a variety of nonregulated natural gas management services,
- the pipeline and storage segment, which includes our regulated and nonregulated natural gas transmission and storage services and
- the other nonutility segment, which includes all of our other nonregulated nonutility operations.

Our determination of reportable segments considers the strategic operating units under which we manage sales of various products and services to customers in differing regulatory environments. Although our utility segment operations are geographically dispersed, they are reported as a single segment as each utility division has similar economic characteristics. The accounting policies of the segments are the same as those described in the summary of significant accounting policies found in our annual report on Form 10-K for the fiscal year ended September 30, 2006. We evaluate performance based on net income or loss of the respective operating units.

Income statements for the three and six-month periods ended March 31, 2007 and 2006 by segment are presented in the following tables:

	Three Months Ended March 31, 2007					
	Utility	Natural Gas Marketing	Pipeline and Storage	Other Nonutility	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$1,460,861	$583,269	$31,055	$ 397	$ —	$2,075,582
Intersegment revenues	172	211,772	28,307	386	(240,637)	—
	1,461,033	795,041	59,362	783	(240,637)	2,075,582
Purchased gas cost	1,114,787	771,988	229	—	(240,108)	1,646,896
Gross profit	346,246	23,053	59,133	783	(529)	428,686
Operating expenses						
Operation and maintenance	92,328	6,590	12,801	758	(615)	111,862
Depreciation and amortization	45,904	448	4,682	32	—	51,066
Taxes, other than income	53,665	407	2,619	55	—	56,746
Total operating expenses	191,897	7,445	20,102	845	(615)	219,674
Operating income (loss)	154,349	15,608	39,031	(62)	86	209,012
Miscellaneous income	2,621	2,522	829	448	(4,582)	1,838
Interest charges	29,704	379	9,036	639	(4,496)	35,262
Income (loss) before income taxes	127,266	17,751	30,824	(253)	—	175,588
Income tax expense (benefit)	50,946	6,720	11,515	(98)	—	69,083
Net income (loss)	$ 76,320	$ 11,031	$19,309	$(155)	$ —	$ 106,505
Capital expenditures	$ 71,278	$ 312	$14,216	$ —	$ —	$ 85,806

	Three Months Ended March 31, 2006					
	Utility	Natural Gas Marketing	Pipeline and Storage	Other Nonutility	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$1,447,376	$564,737	$21,238	$ 495	$ —	$2,033,846
Intersegment revenues	244	253,892	24,245	1,100	(279,481)	—
	1,447,620	818,629	45,483	1,595	(279,481)	2,033,846
Purchased gas cost	1,131,885	774,652	211	—	(278,305)	1,628,443
Gross profit	315,735	43,977	45,272	1,595	(1,176)	405,403
Operating expenses						
Operation and maintenance	94,363	5,821	12,363	1,361	(1,210)	112,698
Depreciation and amortization	41,907	475	4,669	25	—	47,076
Taxes, other than income	61,701	348	2,654	93	—	64,796
Total operating expenses	197,971	6,644	19,686	1,479	(1,210)	224,570
Operating income	117,764	37,333	25,586	116	34	180,833
Miscellaneous income (expense)	155	608	132	1,183	(4,517)	(2,439)
Interest charges	30,303	1,997	6,621	1,054	(4,483)	35,492
Income before income taxes	87,616	35,944	19,097	245	—	142,902
Income tax expense	32,988	14,012	7,010	96	—	54,106
Net income	$ 54,628	$ 21,932	$12,087	$ 149	$ —	$ 88,796
Capital expenditures	$ 83,749	$ 235	$26,781	$ —	$ —	$ 110,765

	Six Months Ended March 31, 2007					
	Utility	Natural Gas Marketing	Pipeline and Storage	Other Nonutility	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$2,424,944	$1,194,638	$ 57,830	$ 803	$ —	$3,678,215
Intersegment revenues	333	312,097	51,384	1,333	(365,147)	—
	2,425,277	1,506,735	109,214	2,136	(365,147)	3,678,215
Purchased gas cost	1,816,463	1,420,548	454	—	(363,528)	2,873,937
Gross profit	608,814	86,187	108,760	2,136	(1,619)	804,278
Operating expenses						
Operation and maintenance	190,441	12,168	24,417	1,997	(1,791)	227,232
Depreciation and amortization	89,626	777	9,600	58	—	100,061
Taxes, other than income	91,287	656	4,746	124	—	96,813
Total operating expenses	371,354	13,601	38,763	2,179	(1,791)	424,106
Operating income (loss)	237,460	72,586	69,997	(43)	172	380,172
Miscellaneous income	4,401	4,238	1,605	901	(7,728)	3,417
Interest charges	62,177	1,406	17,457	1,310	(7,556)	74,794
Income (loss) before income taxes	179,684	75,418	54,145	(452)	—	308,795
Income tax expense (benefit)	71,530	29,440	20,236	(177)	—	121,029
Net income (loss)	$ 108,154	$ 45,978	$ 33,909	$ (275)	$ —	$ 187,766
Capital expenditures	$ 143,697	$ 650	$ 28,445	$ —	$ —	$ 172,792

	Six Months Ended March 31, 2006 (In thousands)					
	Utility	Natural Gas Marketing	Pipeline and Storage	Other Nonutility	Eliminations	Consolidated
Operating revenues from external parties	$2,852,182	$1,425,350	$39,119	$1,015	$ —	$4,317,666
Intersegment revenues	448	495,124	46,076	2,072	(543,720)	—
	2,852,630	1,920,474	85,195	3,087	(543,720)	4,317,666
Purchased gas cost	2,256,714	1,850,178	211	—	(541,430)	3,565,673
Gross profit	595,916	70,296	84,984	3,087	(2,290)	751,993
Operating expenses						
Operation and maintenance	187,129	10,173	23,361	2,626	(2,374)	220,915
Depreciation and amortization	80,171	945	9,171	49	—	90,336
Taxes, other than income	104,603	591	4,814	204	—	110,212
Total operating expenses	371,903	11,709	37,346	2,879	(2,374)	421,463
Operating income	224,013	58,587	47,638	208	84	330,530
Miscellaneous income (expense)	2,992	1,198	1,537	1,844	(9,562)	(1,991)
Interest charges	61,891	4,859	12,594	1,815	(9,478)	71,681
Income before income taxes	165,114	54,926	36,581	237	—	256,858
Income tax expense	62,073	21,542	13,327	93	—	97,035
Net income	$ 103,041	$ 33,384	$23,254	$ 144	$ —	$ 159,823
Capital expenditures	$ 156,164	$ 567	$56,499	$ —	$ —	$ 213,230

Balance sheet information at March 31, 2007 and September 30, 2006 by segment is presented in the following tables:

	March 31, 2007					
	Utility	Natural Gas Marketing	Pipeline and Storage	Other Nonutility	Eliminations	Consolidated
	(In thousands)					
ASSETS						
Property, plant and equipment, net	$3,146,950	$ 7,788	$555,860	$ 1,232	$ —	$3,711,830
Investment in subsidiaries	385,776	(2,106)	—	—	(383,670)	—
Current assets						
Cash and cash equivalents	48,611	51,061	80	76,528	—	176,280
Cash held on deposit in margin account	—	40,763	—	—	—	40,763
Assets from risk management activities	3,804	2,013	—	—	(1,305)	4,512
Other current assets	714,663	489,577	26,510	8,996	(31,884)	1,207,862
Intercompany receivables	572,757	—	—	—	(572,757)	—
Total current assets	1,339,835	583,414	26,590	85,524	(605,946)	1,429,417
Intangible assets	—	2,848	—	—	—	2,848
Goodwill	567,221	24,282	143,866	—	—	735,369
Noncurrent assets from risk management activities	—	7,105	—	—	—	7,105
Deferred charges and other assets	200,728	1,327	5,044	15,430	—	222,529
	$5,640,510	$624,658	$731,360	$102,186	$(989,616)	$6,109,098
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	$2,021,953	$170,055	$132,357	$ 83,364	$(385,776)	$2,021,953
Long-term debt	1,875,445	—	—	2,886	—	1,878,331
Total capitalization	3,897,398	170,055	132,357	86,250	(385,776)	3,900,284
Current liabilities						
Current maturities of long-term debt	301,250	—	—	1,982	—	303,232
Short-term debt	—	—	—	—	—	—
Liabilities from risk management activities	2	32,278	1,396	—	(1,305)	32,371
Other current liabilities	657,611	328,298	98,096	—	(29,778)	1,054,227
Intercompany payables	—	97,748	467,660	7,349	(572,757)	—
Total current liabilities	958,863	458,324	567,152	9,331	(603,840)	1,389,830
Deferred income taxes	316,818	(4,806)	28,115	2,201	—	342,328
Noncurrent liabilities from risk management activities	—	438	—	—	—	438
Regulatory cost of removal obligation	261,984	—	—	—	—	261,984
Deferred credits and other liabilities	205,447	647	3,736	4,404	—	214,234
	$5,640,510	$624,658	$731,360	$102,186	$(989,616)	$6,109,098

	September 30, 2006					
	Utility	Natural Gas Marketing	Pipeline and Storage	Other Nonutility	Eliminations	Consolidated
	(In thousands)					
ASSETS						
Property, plant and equipment, net	$3,083,301	$ 7,531	$537,028	$ 1,296	$ —	$3,629,156
Investment in subsidiaries	281,143	(2,155)	—	—	(278,988)	—
Current assets						
Cash and cash equivalents	8,738	45,481	—	21,596	—	75,815
Cash held on deposit in margin account	—	35,647	—	—	—	35,647
Assets from risk management activities	—	13,164	19,040	—	(19,651)	12,553
Other current assets	714,472	261,435	26,325	8,119	(16,821)	993,530
Intercompany receivables	602,809	—	—	—	(602,809)	—
Total current assets	1,326,019	355,727	45,365	29,715	(639,281)	1,117,545
Intangible assets	—	3,152	—	—	—	3,152
Goodwill	567,221	24,282	143,866	—	—	735,369
Noncurrent assets from risk management activities	—	6,190	5	—	(9)	6,186
Deferred charges and other assets	204,617	1,315	5,301	16,906	—	228,139
	$5,462,301	$396,042	$731,565	$47,917	$(918,278)	$5,719,547
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	$1,648,098	$139,863	$107,640	$33,640	$(281,143)	$1,648,098
Long-term debt	2,176,473	—	—	3,889	—	2,180,362
Total capitalization	3,824,571	139,863	107,640	37,529	(281,143)	3,828,460
Current liabilities						
Current maturities of long-term debt	1,250	—	—	1,936	—	3,186
Short-term debt	382,416	—	—	—	—	382,416
Liabilities from risk management activities	27,209	22,500	531	—	(19,571)	30,669
Other current liabilities	473,101	183,077	61,458	—	(14,746)	702,890
Intercompany payables	—	75,665	525,895	1,249	(602,809)	—
Total current liabilities	883,976	281,242	587,884	3,185	(637,126)	1,119,161
Deferred income taxes	297,821	(25,777)	31,927	2,201	—	306,172
Noncurrent liabilities from risk management activities	—	280	5	—	(9)	276
Regulatory cost of removal obligation	261,376	—	—	—	—	261,376
Deferred credits and other liabilities	194,557	434	4,109	5,002	—	204,102
	$5,462,301	$396,042	$731,565	$47,917	$(918,278)	$5,719,547

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors
Atmos Energy Corporation

We have reviewed the condensed consolidated balance sheet of Atmos Energy Corporation as of March 31, 2007, and the related condensed consolidated statements of income for the three-month and six-month periods ended March 31, 2007 and 2006, and the condensed consolidated statements of cash flows for the six-month periods ended March 31, 2007 and 2006. These financial statements are the responsibility of the Company's management.

We conducted our review in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the condensed consolidated financial statements referred to above for them to be in conformity with U.S. generally accepted accounting principles.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Atmos Energy Corporation as of September 30, 2006, and the related consolidated statements of income, shareholders' equity, and cash flows for the year then ended, not presented herein, and in our report dated November 20, 2006, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet as of September 30, 2006, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

ERNST & YOUNG LLP

Dallas, Texas
May 2, 2007

Item 2. ***Management's Discussion and Analysis of Financial Condition and Results of Operations***

INTRODUCTION

The following discussion should be read in conjunction with the condensed consolidated financial statements in this Quarterly Report on Form 10-Q and Management's Discussion and Analysis in our Annual Report on Form 10-K for the year ended September 30, 2006.

Cautionary Statement for the Purposes of the Safe Harbor under the Private Securities Litigation Reform Act of 1995

The statements contained in this Quarterly Report on Form 10-Q may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this Report are forward-looking statements made in good faith by us and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this Report, or any other of our documents or oral presentations, the words "anticipate", "believe", "estimate", "expect", "forecast", "goal", "intend", "objective", "plan", "projection", "seek", "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the statements relating to our strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties include the following: regulatory trends and decisions, including deregulation initiatives and the impact of rate proceedings before various state regulatory commissions; adverse weather conditions, such as warmer than normal weather in our utility service territories or colder than normal weather that could adversely affect our natural gas marketing activities; the concentration of our distribution, pipeline and storage operations in one state; impact of environmental regulations on our business; market risks beyond our control affecting our risk management activities including market liquidity, commodity price volatility, increasing interest rates and counterparty creditworthiness; our ability to continue to access the capital markets; the effects of inflation and changes in the availability and prices of natural gas, including the volatility of natural gas prices; increased competition from energy suppliers and alternative forms of energy; increased costs of providing pension and postretirement health care benefits; the capital-intensive nature of our distribution business; the inherent hazards and risks involved in operating our distribution business; effects of natural disasters or terrorist activities and other risks and uncertainties, which may be discussed herein, all of which are difficult to predict and many of which are beyond our control. A more detailed discussion of these risks and uncertainties may be found in our Annual Report on Form 10-K for the year ended September 30, 2006. Accordingly, while we believe these forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. Further, we undertake no obligation to update or revise any of our forward-looking statements whether as a result of new information, future events or otherwise.

OVERVIEW

Atmos Energy Corporation and our subsidiaries are engaged primarily in the natural gas utility business as well as certain nonutility businesses. We distribute natural gas through sales and transportation arrangements to approximately 3.2 million residential, commercial, public authority and industrial customers throughout our six regulated utility divisions, which cover service areas located in 12 states. In addition, we transport natural gas for others through our distribution system.

Through our nonutility businesses, we primarily provide natural gas management and marketing services to municipalities, other local gas distribution companies and industrial customers in 22 states and natural gas transportation and storage services to certain of our utility operations and to third parties.

Our operations are divided into four segments:

- the utility segment, which includes our regulated natural gas distribution and related sales operations,
- the natural gas marketing segment, which includes a variety of nonregulated natural gas management services,
- the pipeline and storage segment, which includes our regulated and nonregulated natural gas transmission and storage services and
- the other nonutility segment, which includes all of our other nonregulated nonutility operations.

CRITICAL ACCOUNTING ESTIMATES AND POLICIES

Our condensed consolidated financial statements were prepared in accordance with accounting principles generally accepted in the United States. Preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities. We based our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. On an ongoing basis, we evaluate our estimates, including those related to risk management and trading activities, allowance for doubtful accounts, legal and environmental accruals, insurance accruals, pension and postretirement obligations, deferred income taxes and the valuation of goodwill, indefinite-lived intangible assets and other long-lived assets. Actual results may differ from such estimates.

Our critical accounting policies used in the preparation of our consolidated financial statements are described in our Annual Report on Form 10-K for the year ended September 30, 2006 and include the following:

- Regulation
- Revenue Recognition
- Allowance for Doubtful Accounts
- Derivatives and Hedging Activities
- Impairment Assessments
- Pension and Other Postretirement Plans

Our critical accounting policies are reviewed by the Audit Committee on a quarterly basis. There have been no significant changes to these critical accounting policies during the six months ended March 31, 2007.

RESULTS OF OPERATIONS

Consolidated financial highlights for the three-month and six-month periods ended March 31, 2007 and 2006 are presented below:

	Three Months Ended March 31		Six Months Ended March 31	
	2007	2006	2007	2006
	(In thousands)			
Operating revenues	$2,075,582	$2,033,846	$3,678,215	$4,317,666
Gross profit	428,686	405,403	804,278	751,993
Operating expenses	219,674	224,570	424,106	421,463
Operating income	209,012	180,833	380,172	330,530
Miscellaneous income (expense)	1,838	(2,439)	3,417	(1,991)
Interest charges	35,262	35,492	74,794	71,681
Income before income taxes	175,588	142,902	308,795	256,858
Income tax expense	69,083	54,106	121,029	97,035
Net income	$ 106,505	$ 88,796	$ 187,766	$ 159,823

For the six months ended March 31, 2007, we earned $187.8 million, or $2.18 per diluted share, compared with net income of $159.8 million, or $1.98 per diluted share during the six months ended March 31, 2006. The 18 percent period-over-period increase in net income was primarily attributable to strong financial results in our natural gas marketing and pipeline and storage segments coupled with improved results in our utility segment. Our utility operations contributed $108.2 million ($1.26 per diluted share) or 58 percent to our results for the six months ended March 31, 2007. Our nonutility operations, comprised of our natural gas marketing, pipeline and storage and other nonutility segments, contributed $79.6 million ($0.92 per diluted share), or 42 percent to our results for the six months ended March 31, 2007.

Key financial and other events for the six months ended March 31, 2007 include the following:

- Our utility segment net income increased by $5.1 million during the six months ended March 31, 2007 compared with the six months ended March 31, 2006. The increase primarily reflects the net favorable impact of various ratemaking rulings, including the implementation of WNA in our Mid-Tex and Louisiana Divisions.

- Our natural gas marketing segment net income increased $12.6 million during the six months ended March 31, 2007 compared with the six months ended March 31, 2006. The increase in natural gas marketing net income primarily reflects significantly improved realized storage margins partially offset by lower period-over-period realized marketing and unrealized margins.

- Our pipeline and storage segment net income increased $10.7 million during the six months ended March 31, 2007 compared with the six months ended March 31, 2006. Increased net income primarily reflects increased margins from increased throughput, including incremental gross profit margins from our North Side Loop and other pipeline compression projects completed in fiscal 2006, higher margins on Atmos Pipeline & Storage, LLC's asset management agreements and increased margins from the Gas Reliability Infrastructure Program (GRIP).

- In December 2006, we filed a new $900 million shelf registration statement with the Securities and Exchange Commission (SEC) that replaced our previously existing shelf registration statement. Upon completion of the filing of this new registration statement, we received net proceeds of approximately $192 million through the issuance of approximately 6.3 million shares of common stock. The net proceeds received were used to repay a portion of our then-existing short-term debt balance.

- Our total-debt-to-capitalization ratio at March 31, 2007 was 51.9 percent compared with 60.9 percent at September 30, 2006 primarily reflecting the favorable impact of our equity offering in December 2006, the absence of outstanding short-term debt as of March 31, 2007 and increased retained earnings due to strong current-year earnings, partially offset by increased dividend payments.

- For the six months ended March 31, 2007, we generated $511.9 million in operating cash flow compared with $148.4 million for the six months ended March 31, 2006, primarily reflecting the favorable impact of increased earnings, increased sales volumes attributable to colder weather during the period and lower natural gas prices.

- Capital expenditures decreased to $172.8 million during the six months ended March 31, 2007 from $213.2 million in the prior-year period. The decrease primarily reflects the absence of capital spending for the North Side Loop and other compression projects completed in fiscal 2006.

- In March 2007, the Texas Railroad Commission issued an order in our Mid-Tex Division's rate case, which prospectively increased annual revenues by approximately $4.8 million and established a permanent WNA based upon a 10-year average effective for the months of November through April. However, the ruling also reduced the Mid-Tex Division's total return to 7.903 percent from 8.258 percent and required a $2.3 million refund, inclusive of interest, of amounts collected from our calendar 2003 — 2005 GRIP filings.

Three Months Ended March 31, 2007 compared with Three Months Ended March 31, 2006

Utility segment

Our utility segment has historically contributed 65 to 85 percent of our consolidated net income. However, in recent years, this contribution has declined slightly as our nonutility businesses have grown and our utility operations have experienced the adverse effects of warmer-than-normal weather and declining usage.

Natural gas sales to residential, commercial and public authority customers are affected by winter heating season requirements, whereas natural gas sales to industrial customers are much less weather sensitive. As residential, commercial and public authority customers comprise approximately 90 percent of our gas sales volumes, the results of operations for our utility segment are seasonal. We typically experience higher operating revenues and net income during the period from October through March of each year and lower operating revenues and either lower net income or net losses during the period from April through September of each year. Accordingly, our second fiscal quarter has historically been our most critical earnings quarter with an average of approximately 64 percent of our consolidated net income having been earned in the second quarter during the three most recently completed fiscal years. Additionally, we typically experience higher levels of accounts receivable, accounts payable, gas stored underground and short-term debt balances during the winter heating season due to the seasonal nature of our revenues and the need to purchase and store gas to support these operations.

The primary factors that currently impact the results of our utility operations are regulatory decisions and trends, the increased use of energy-efficient appliances by our customers, competitive factors in the energy industry and economic conditions in our service areas.

Seasonal weather patterns can also affect our utility operations. However, the effect of weather that is above or below normal is substantially offset through weather normalization adjustments, known as WNA, which, beginning with the 2006-2007 winter heating season, has been approved by regulators for approximately 90 percent of our residential and commercial meters in the following states for the following time periods:

Georgia	October – May
Kansas	October – May
Kentucky	November – April
Louisiana[1]	December – March
Mississippi	November – April
Tennessee	November – April
Texas[1]	October – May
Virginia	January – December

(1) Effective beginning for the 2006-2007 winter heating season in our Mid-Tex and Louisiana Divisions.

WNA allows us to increase customers' bills to offset lower gas usage when weather is warmer than normal and decrease customers' bills to offset higher gas usage when weather is colder than normal. Although our WNA periods do not cover the entire heating season in all jurisdictions, we believe these mechanisms substantially insulate our utility gross profit margin from the effects of weather.

Our utility operations are also affected by the cost of natural gas. The cost of gas is passed through to our customers without markup. Therefore, increases in the cost of gas are offset by a corresponding increase in revenues. Accordingly, we believe gross profit is a better indicator of our financial performance than revenues. However, gross profit in our Texas and Mississippi service areas include franchise fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenues is influenced by the cost of gas and the level of gas sales volumes. We record the tax expense as a component of taxes, other than income. Although changes in revenue-related taxes arising from changes in gas cost affect gross profit, over time the impact is offset within operating income. Timing differences do exist between the recognition of revenue for franchise fees collected from our customers and the recognition of expense of franchise taxes. The effect of these timing differences can be significant in periods of volatile gas prices, particularly in our Mid-Tex Division. These timing differences may favorably or unfavorably affect net income; however, these amounts should offset over time with no permanent impact on net income.

Higher gas costs affect our utility operations in other ways as well. Higher gas costs may cause customers to conserve, or, in the case of industrial customers, to use alternative energy sources. Higher gas costs may also adversely impact our accounts receivable collections, resulting in higher bad debt expense and may require us to increase borrowings under our credit facilities, resulting in higher interest expense.

Review of Financial and Operating Results

Financial and operational highlights for our utility segment for the three months ended March 31, 2007 and 2006 are presented below:

	Three Months Ended March 31	
	2007	**2006**
	(Dollars in thousands, except per Mcf amounts)	
Gross profit	$346,246	$315,735
Operating expenses	191,897	197,971
Operating income	154,349	117,764
Miscellaneous income	2,621	155
Interest charges	29,704	30,303
Income before income taxes	127,266	87,616
Income tax expense	50,946	32,988
Net income	$ 76,320	$ 54,628
Utility sales volumes — MMcf	133,856	111,721
Utility transportation volumes — MMcf	39,567	31,152
Total utility throughput — MMcf	173,423	142,873
Heating degree days		
Actual (weighted average)	1,575	1,330
Percent of normal	100%	84%
Consolidated utility average transportation revenue per Mcf	$ 0.48	$ 0.61
Consolidated utility average cost of gas per Mcf sold	$ 8.33	$ 10.13

The following table shows our operating income by utility division for the three months ended March 31, 2007 and 2006. The presentation of our utility operating income by division is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Three Months Ended March 31			
	2007		2006	
	Operating Income	Heating Degree Days Percent of Normal[1]	Operating Income	Heating Degree Days Percent of Normal[1]
	(In thousands, except degree day information)			
Colorado-Kansas	$ 14,968	106%	$ 14,650	100%
Kentucky/Mid-States[2]	28,948	97	33,950	97
Louisiana	23,026	100	8,596	70
Mid-Tex	59,007	100	29,455	68
Mississippi	16,204	100	16,752	100
West Texas	12,115	100	13,539	100
Other	81	—	822	—
Total	$154,349	100%	$117,764	84%

(1) Adjusted for service areas that have weather-normalized operations.

(2) Effective October 1, 2006, the Kentucky and Mid-States Divisions were combined. Prior year amounts have been restated to conform to this new presentation.

The $30.5 million improvement in utility gross profit primarily reflects a 21 percent increase in throughput, which increased gross profit by $25.7 million, a $4.3 million increase attributable to the implementation of WNA in our Mid-Tex and Louisiana divisions beginning with the 2006-2007 winter heating season and $9.6 million of rate increases received from our 2005 Rate Stabilization Clause (RSC) filing in our LGS service area in Louisiana, which became effective in September 2006, and from our fiscal 2004 and 2005 GRIP filings, which became effective in February 2006.

Gross profit also increased approximately $5.9 million in revenue-related taxes primarily due to increased throughput, partially offset by lower revenues, on which the tax is calculated, due to a significant decline in the cost of gas in the current-year quarter compared with the prior-year quarter. This increase, coupled with a $2.6 million quarter-over-quarter decrease in the associated franchise and state gross receipts tax expense recorded as a component of taxes resulted in an $8.5 million increase in operating income when compared with the prior-year quarter.

Gross profit was adversely affected by rate rulings received during fiscal 2007. In March 2007, the Texas Railroad Commission issued an order in our Mid-Tex Division's rate case filed in May 2006. Although the order resulted in a $4.8 million prospective annual increase in rates, it also required the immediate refund of $2.3 million collected under GRIP (inclusive of interest) for filings pertaining to calendar years 2003-2005, which reduced gross profit in the current-year quarter. Additionally, the Tennessee Regulatory Authority's (TRA) decision in October 2006 to reduce our annual rates in Tennessee by $6.1 million adversely impacted gross profit by $4.2 million during the quarter.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, decreased to $191.9 million for the three months ended March 31, 2007 from $198.0 million for the three months ended March 31, 2006.

Operation and maintenance expense, excluding the provision for doubtful accounts, increased $0.6 million primarily due to higher employee and administrative costs partially offset by a deferral of $4.3 million of operation and maintenance expense in our Louisiana Division resulting from the Louisiana Public Service Commission's ruling to allow recovery of all incremental operation and maintenance expense incurred in fiscal 2005 and 2006 in connection with our Hurricane Katrina recovery efforts.

The provision for doubtful accounts decreased $2.7 million to $4.4 million for the three months ended March 31, 2007. The decrease primarily was attributable to reduced collection risk as a result of lower natural gas prices. In the utility segment, the average cost of natural gas for the three months ended March 31, 2007 was $8.33 per thousand cubic feet (Mcf), compared with $10.13 per Mcf for the three months ended March 31, 2006.

Interest charges allocated to the utility segment for the three months ended March 31, 2007 decreased to $29.7 million from $30.3 million for the three months ended March 31, 2006. The decrease was primarily attributable to reduced interest expense attributable to lower average outstanding short-term debt balances in the current-year quarter compared with the prior-year quarter, partially offset by a 76 basis point increase in the interest rate on our $300 million unsecured floating rate senior notes due October 2007 due to an increase in the three-month LIBOR rate.

Natural gas marketing segment

Our natural gas marketing segment aggregates and purchases gas supply, arranges transportation and/or storage logistics and ultimately delivers gas to our customers at competitive prices. To facilitate this process, we utilize proprietary and customer-owned transportation and storage assets to provide the various services our customers request, including furnishing natural gas supplies at fixed and market-based prices, contract negotiation and administration, load forecasting, gas storage acquisition and management services, transportation services, peaking sales and balancing services, capacity utilization strategies and gas price hedging through the use of derivative products. As a result, our revenues arise from the types of commercial transactions we have structured with our customers and include the value we extract by optimizing the storage and transportation capacity we own or control as well as revenues for services we perform.

To optimize the storage and transportation capacity we own or control, we participate in transactions in which we combine the natural gas commodity and transportation costs to minimize our costs incurred to serve our customers by identifying the lowest cost alternative within the natural gas supplies, transportation and markets to which we have access. Additionally, we engage in natural gas storage transactions in which we seek to find and profit from the pricing differences that occur over time. We purchase physical natural gas and then sell financial contracts at advantageous prices to lock in a gross profit margin. Through the use of transportation and storage services and derivative contracts, we are able to capture gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time.

Review of Financial and Operating Results

Financial and operational highlights for our natural gas marketing segment for the three months ended March 31, 2007 and 2006 are presented below. Gross profit for our natural gas marketing segment consists primarily of storage activities and marketing activities. Storage activities represent the optimization of our managed proprietary and third-party storage and transportation assets. Marketing activities represent the utilization of proprietary and customer-owned transportation and storage assets to provide various services our customers request.

	Three Months Ended March 31	
	2007	2006
	(Dollars in thousands)	
Storage Activities		
Realized margin	$ 77,724	$10,611
Unrealized margin	(57,025)	2,741
Total Storage Activities	20,699	13,352
Marketing Activities		
Realized margin	14,252	21,005
Unrealized margin	(11,898)	9,620
Total Marketing Activities	2,354	30,625
Gross profit	23,053	43,977
Operating expenses	7,445	6,644
Operating income	15,608	37,333
Miscellaneous income	2,522	608
Interest charges	379	1,997
Income before income taxes	17,751	35,944
Income tax expense	6,720	14,012
Net income	$ 11,031	$21,932
Natural gas marketing sales volumes — MMcf	101,386	69,450
Net physical position (Bcf)	19.6	23.6

The $20.9 million decrease in our natural gas marketing segment's gross profit reflects an $81.3 million decrease in unrealized margins during the current-year quarter compared with the prior-year quarter offset by a $60.4 million increase in realized storage and marketing margins.

The $7.3 million increase in gross profit associated with our storage activities primarily reflects a $67.1 million increase in realized margins attributable to our ability to successfully capture more favorable arbitrage spreads arising from increased market volatility during the current-year quarter compared to the prior-year quarter, coupled with our ability to cycle more physical storage in the current-year quarter compared with the prior-year quarter and realize previously captured spread opportunities due to colder weather.

These increases were partially offset by a $59.8 million increase in unrealized losses attributable to a widening of the spreads between the forward natural gas prices used to value the financial hedges designated against our physical inventory and the market (spot) prices used to value our physical storage, coupled with the realization of previously unrealized gains on storage spreads associated with physical gas cycled during the current quarter. This mark-to-market impact was partially offset by a 4.0 Bcf decrease in our net physical position at March 31, 2007 compared to the prior-year quarter. Differences between the forward and spot prices may continue to cause material volatility in our unrealized margin. However, the economic gross profit we have captured in the original transactions will remain essentially unchanged.

The $28.2 million decrease in gross profit associated with our marketing activities reflects a $6.7 million decrease in realized margins primarily attributable to realizing lower margins in a less volatile market during the quarter compared with the prior-year quarter, partially offset by increased sales volumes attributable to colder weather in the current period and successfully executing marketing strategies.

The $21.5 million increase in unrealized losses associated with our marketing activities is attributable to unfavorable movement in the forward natural gas prices associated with financial derivatives used in these activities during the three months ended March 31, 2007.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes other than income taxes, increased to $7.4 million for the three months ended March 31, 2007 from $6.6 million for the three months ended March 31, 2006. The increase in operating expense primarily was attributable to an increase in employee and other administrative costs.

Interest charges allocated to the natural gas marketing segment for the three months ended March 31, 2007 decreased to $0.4 million from $2.0 million for the three months ended March 31, 2006. The decrease was attributable to lower intercompany borrowings during the current year period.

Pipeline and storage segment

Our pipeline and storage segment consists of the regulated pipeline and storage operations of the Atmos Pipeline — Texas Division and the nonregulated pipeline and storage operations of Atmos Pipeline and Storage, LLC (APS). The Atmos Pipeline — Texas Division transports natural gas to our Mid-Tex Division and for third parties and manages five underground storage reservoirs in Texas. We also provide ancillary services customary in the pipeline industry including parking arrangements, lending and sales of inventory on hand. These operations represent one of the largest intrastate pipeline operations in Texas with a heavy concentration in the established natural gas-producing areas of central, northern and eastern Texas, extending into or near the major producing areas of the Texas Gulf Coast and the Delaware and Val Verde Basins of West Texas. This pipeline system provides access to nine basins located in Texas, which are estimated to contain a substantial portion of the nation's remaining onshore natural gas reserves. APS owns or has an interest in underground storage fields in Kentucky and Louisiana. We also use these storage facilities to reduce the need to contract for additional pipeline capacity to meet customer demand during peak periods.

Similar to our utility segment, our pipeline and storage segment is impacted by seasonal weather patterns, competitive factors in the energy industry and economic conditions in our service areas. Natural gas transportation requirements are affected by the winter heating season requirements of our customers. This generally results in higher operating revenues and net income during the period from October through March of each year and lower operating revenues and either lower net income or net losses during the period from April through September of each year. Further, as the Atmos Pipeline — Texas Division operations provide all of the natural gas for our Mid-Tex Division, the results of this segment are highly dependent upon the natural gas requirements of this division. As a regulated pipeline, the operations of the Atmos Pipeline — Texas Division may be impacted by the timing of when costs and expenses are incurred and when these costs and expenses are recovered through its tariffs.

Review of Financial and Operating Results

Financial and operational highlights for our pipeline and storage segment for the three months ended March 31, 2007 and 2006 are presented below. Gross profit for our pipeline and storage segment primarily consists of transportation margins earned from our Mid-Tex Division and from third parties, other ancillary pipeline services and asset management fees earned by APS. Additionally, this segment's margins include an unrealized component as APS hedges its risk associated with its asset management contracts. Our pipeline and storage segment's gross profit was comprised of the following components for the three months ended March 31, 2007 and 2006:

	Three Months Ended March 31	
	2007	2006
	(Dollars in thousands)	
Mid-Tex transportation	$ 25,967	$22,085
Third-party transportation	14,841	11,833
Asset management fees	15,489	8,691
Storage and park and lend services	2,703	2,568
Unrealized losses	(4,395)	(1,450)
Other	4,528	1,545
Gross profit	59,133	45,272
Operating expenses	20,102	19,686
Operating income	39,031	25,586
Miscellaneous income	829	132
Interest charges	9,036	6,621
Income before income taxes	30,824	19,097
Income tax expense	11,515	7,010
Net income	$ 19,309	$12,087
Pipeline transportation volumes — MMcf	119,057	85,957

The $13.9 million increase in gross profit is primarily attributable to a $6.8 million increase in asset management fees earned by APS due to its ability to capture more favorable arbitrage spreads on its asset management contracts coupled with incremental margins received from APS' asset management contract with our Mississippi utility division executed in July 2006. Additionally, margins increased $4.2 million from increased throughput driven by colder weather in the current-year quarter compared with the prior-year quarter. Incremental throughput from our North Side Loop and other compression projects generated incremental gross profit of $2.9 million. Finally, other pipeline and storage margins increased $3.0 million, primarily due to the addition of new and favorably renegotiated blending and measuring capacity contracts and the sale of $1.6 million of excess gas inventory in our Atmos Pipeline — Texas Division. These increases were partially offset by increased unrealized losses of $2.9 million due to a widening of the spreads between the forward natural gas prices used to value the financial hedges and the spot prices used to value the physical inventory underlying these contracts.

Operating expenses increased to $20.1 million for the three months ended March 31, 2007 from $19.7 million for the three months ended March 31, 2006 due to higher administrative and other operating costs primarily associated with the North Side Loop and other compression projects that were completed in fiscal 2006.

Interest charges allocated to the pipeline and storage segment for the three months ended March 31, 2007 increased to $9.0 million from $6.6 million for the three months ended March 31, 2006. The increase was attributable to the use of updated allocation factors for fiscal 2007. These factors are reviewed and updated on an annual basis.

Other nonutility segment

Our other nonutility businesses consist primarily of the operations of Atmos Energy Services, LLC (AES), and Atmos Power Systems, Inc. Through December 31, 2006, AES provided natural gas management services to our utility operations, other than the Mid-Tex Division. These services included aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering the gas to our utility service areas at competitive prices. Effective January 1, 2007, our shared services function began providing these services to our utility operations. AES continues to provide limited services to our utility divisions, and the revenues AES receives are equal to the costs incurred to provide those services. Through Atmos Power Systems, Inc., we have constructed electric peaking power-generating plants and associated facilities and have entered into agreements to lease these plants.

Operating income for this segment primarily reflects the leasing income associated with two sales-type lease transactions completed in 2001 and 2002 and did not materially change for the three months ended March 31, 2007 compared with the prior-year quarter.

Six Months Ended March 31, 2007 compared with Six Months Ended March 31, 2006

Utility segment

Financial and operational highlights for our utility segment for the six months ended March 31, 2007 and 2006 are presented below:

	Six Months Ended March 31	
	2007	2006
	(Dollars in thousands, except per Mcf amounts)	
Gross profit	$608,814	$595,916
Operating expenses	371,354	371,903
Operating income	237,460	224,013
Miscellaneous income	4,401	2,992
Interest charges	62,177	61,891
Income before income taxes	179,684	165,114
Income tax expense	71,530	62,073
Net income	$108,154	$103,041
Utility sales volumes — MMcf	220,256	206,909
Utility transportation volumes — MMcf	72,261	61,754
Total utility throughput — MMcf	292,517	268,663
Heating degree days		
Actual (weighted average)	2,710	2,387
Percent of normal	101%	88%
Consolidated utility average transportation revenue per Mcf	$ 0.48	$ 0.56
Consolidated utility average cost of gas per Mcf sold	$ 8.25	$ 10.91

The following table shows our operating income by utility division for the six months ended March 31, 2007 and 2006. The presentation of our utility operating income by division is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Six Months Ended March 31			
	2007		2006	
	Operating Income	Heating Degree Days Percent of Normal(1)	Operating Income	Heating Degree Days Percent of Normal(1)
	(In thousands, except degree day information)			
Colorado-Kansas	$ 23,640	105%	$ 23,260	100%
Kentucky/Mid-States(2)	43,151	99	54,440	98
Louisiana	33,619	103	16,487	80
Mid-Tex	94,347	100	80,242	74
Mississippi	23,803	101	26,745	101
West Texas	18,621	100	19,670	100
Other	279	—	3,169	—
Utility segment	$237,460	101%	$224,013	88%

(1) Adjusted for service areas that have weather-normalized operations.

(2) Effective October 1, 2006, the Kentucky and Mid-States Divisions were combined. Prior year amounts have been restated to conform to this new presentation.

The $12.9 million increase in utility gross profit primarily reflects a nine percent increase in throughput, which increased gross profit by $15.1 million, an $11.8 million increase associated with the implementation of WNA in our Mid-Tex and Louisiana Divisions beginning with the 2006-2007 winter heating season coupled with $18.3 million of rate increases received from our 2005 Rate Stabilization Clause (RSC) filing in our LGS service area in Louisiana, which became effective in September 2006 and from our fiscal 2004 and 2005 GRIP filings, which became effective in February 2006.

Offsetting these increases was a reduction in revenue-related taxes. Due to a significant decline in the cost of gas in the current-year period compared with the prior-year period, franchise and state gross receipts taxes included in gross profit decreased approximately $9.3 million; however, franchise and state gross receipts tax expense recorded as a component of taxes, other than income only decreased $5.3 million, which resulted in a $4.0 million reduction in operating income when compared with the prior-year period. Gross profit was also adversely affected by $8.5 million from unfavorable rate rulings received in Tennessee and our Mid-Tex Division during fiscal 2007 and a reduction in other pass-through items.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, decreased to $371.4 million for the six months ended March 31, 2007 from $371.9 million for the six months ended March 31, 2006.

Operation and maintenance expense, excluding the provision for doubtful accounts, increased $8.0 million, primarily due to increased employee and other administrative costs. These increases were partially offset by the deferral of $4.3 million of incremental Hurricane Katrina-related operation and maintenance expense in our Louisiana Division and the absence of a $2.0 million charge for losses related to Hurricane-Katrina recorded in the prior-year period.

The provision for doubtful accounts decreased $4.6 million to $10.8 million for the six months ended March 31, 2007. The decrease primarily was attributable to reduced collection risk as a result of lower natural gas prices. In the utility segment, the average cost of natural gas for the six months ended March 31, 2007 was $8.25 Mcf, compared with $10.91 per Mcf for the six months ended March 31, 2006.

Depreciation and amortization expense increased $9.5 million in the six months ended March 31, 2007 compared with the prior-year period. The increase was primarily attributable to increases in assets placed in service during fiscal 2006. Additionally, the increase was partially attributable to the absence in the current-year period of a $2.8 million reduction in depreciation expense recorded in the prior-year period arising from the Mississippi Public Service Commission's decision to allow certain deferred costs in our rate base.

Interest charges allocated to the utility segment for the six months ended March 31, 2007 increased to $62.2 million from $61.9 million for the six months ended March 31, 2006. The increase was primarily attributable to increased interest rates on our $300 million unsecured floating rate senior notes due October 2007 partially offset by reduced interest expense attributable to lower average outstanding short-term debt balances in the current-year period compared with the prior-year period.

Natural gas marketing segment

Financial and operational highlights for our natural gas marketing segment for the six months ended March 31, 2007 and 2006 are presented below.

	Six Months Ended March 31	
	2007	2006
	(Dollars in thousands)	
Storage Activities		
Realized margin	$ 71,934	$ 36,883
Unrealized margin	(8,134)	(21,051)
Total Storage Activities	63,800	15,832
Marketing Activities		
Realized margin	34,321	50,572
Unrealized margin	(11,934)	3,892
Total Marketing Activities	22,387	54,464
Gross profit	86,187	70,296
Operating expenses	13,601	11,709
Operating income	72,586	58,587
Miscellaneous income	4,238	1,198
Interest charges	1,406	4,859
Income before income taxes	75,418	54,926
Income tax expense	29,440	21,542
Net income	$ 45,978	$ 33,384
Natural gas marketing sales volumes — MMcf	178,912	140,946
Net physical position (Bcf)	19.6	23.6

The $15.9 million increase in our natural gas marketing segment's gross profit reflects an $18.8 million increase in realized storage and marketing margins partially offset by a $2.9 million reduction in unrealized margin.

The $48.0 million increase in gross profit associated with our storage activities primarily reflects a $35.1 million increase in realized margins attributable to our ability to successfully capture more favorable arbitrage spreads arising from increased market volatility during the current-year period compared to the prior-year period, coupled with our ability to cycle more physical storage in the current-year period compared with the prior-year period and realize previously captured spread opportunities due to colder weather.

Additionally, the $12.9 million decrease in unrealized losses associated with our storage activities contributed to the increased gross profit. This favorable change was attributable to a narrowing of the spreads between the forward natural gas prices used to value the financial hedges against our physical inventory and the market (spot) prices used to value our physical storage.

The $32.1 million decrease in gross profit associated with our marketing activities primarily reflects a $16.3 million decrease in realized margins primarily attributable to realizing lower margins in a less volatile market during the current-year period compared with the prior-year period, partially offset by increased sales volumes attributable to colder weather in the current-year period and successfully executing marketing strategies.

The $15.8 million increase in unrealized losses associated with our marketing activities is attributable to unfavorable movement in the forward natural gas prices associated with financial derivatives used in these activities during the six months ended March 31, 2007.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes other than income taxes, increased to $13.6 million for the six months ended March 31, 2007 from $11.7 million for the six months ended March 31, 2006. The increase in operating expense primarily was attributable to an increase in employee and other administrative costs.

Interest charges allocated to the natural gas marketing segment for the six months ended March 31, 2007 decreased to $1.4 million from $4.9 million for the six months ended March 31, 2006. The decrease was attributable to lower intercompany borrowings during the current year period.

Pipeline and storage segment

Financial and operational highlights for our pipeline and storage segment for the six months ended March 31, 2007 and 2006 are presented below.

	Six Months Ended March 31	
	2007	2006
	(Dollars in thousands)	
Mid-Tex transportation	$ 46,431	$ 41,876
Third-party transportation	30,989	25,532
Asset management fees	16,706	7,704
Storage and park and lend services	6,694	5,082
Unrealized gains	1,825	1,944
Other	6,115	2,846
Gross profit	108,760	84,984
Operating expenses	38,763	37,346
Operating income	69,997	47,638
Miscellaneous income	1,605	1,537
Interest charges	17,457	12,594
Income before income taxes	54,145	36,581
Income tax expense	20,236	13,327
Net income	$ 33,909	$ 23,254
Pipeline transportation volumes — MMcf	238,012	177,552

The $23.8 million increase in gross profit is primarily attributable to a $9.0 million increase in asset management fees earned by APS due to its ability to capture more favorable arbitrage spreads on its asset management contracts, coupled with incremental margins received from APS' asset management contract with our Mississippi utility division executed in July 2006. Additionally, gross profit increased $5.9 million from incremental throughput associated with our North Side Loop and other compression projects. Gross profit was also favorably affected by incremental throughput attributable to colder weather and increased demand for storage services, which increased gross profit by $5.6 million. Finally, gross profit increased $1.6 million from the sale of excess gas inventory by our Atmos Pipeline-Texas Division and $1.4 million due to rate adjustments resulting from Atmos Pipeline-Texas Division's 2005 GRIP filing.

Operating expenses increased to $38.8 million for the six months ended March 31, 2007 from $37.3 million for the six months ended March 31, 2006 due to higher administrative and other operating costs primarily associated with the North Side Loop and other compression projects that were completed in fiscal 2006.

Interest charges allocated to the pipeline and storage segment for the six months ended March 31, 2007 increased to $17.5 million from $12.6 million for the six months ended March 31, 2006. The increase was attributable to the use of updated allocation factors for fiscal 2007. These factors are reviewed and updated on an annual basis.

Other nonutility segment

Operating income for this segment primarily reflects the leasing income associated with two sales-type lease transactions completed in 2001 and 2002 and did not materially change for the six months ended March 31, 2007 compared with the prior-year period.

Liquidity and Capital Resources

Our internally generated funds and borrowings under our credit facilities and commercial paper program generally provide the liquidity needed to fund our working capital, capital expenditures and other cash needs. Additionally, from time to time, we raise funds from the public debt and equity capital markets through our existing shelf registration statement to fund our liquidity needs.

In October 2007, our $300 million unsecured floating rate senior notes will mature. We are currently evaluating alternatives to refinance this debt, and we believe this refinancing effort will be successful. We believe these funds, combined with the other sources of funds described above will provide the necessary working capital and liquidity for capital expenditures and other cash needs for the remainder of fiscal 2007.

Cash Flows

Our internally generated funds may change in the future due to a number of factors, some of which we cannot control. These include regulatory changes, prices for our products and services, demand for such products and services, margin requirements resulting from significant changes in commodity prices, operational risks and other factors.

Cash flows from operating activities

Period-over-period changes in our operating cash flows primarily are attributable to changes in net income and working capital changes, particularly within our utility segment. Our utility segment's working capital is primarily affected by the price of natural gas, the timing of customer collections, payments for natural gas purchases and deferred gas cost recoveries.

For the six months ended March 31, 2007, we generated operating cash flow of $511.9 million from operating activities compared with $148.4 million for the six months ended March 31, 2006. Period over period, our operating cash flow was favorably impacted by improved net income, increased sales volumes attributable to colder weather in the current-year period and lower natural gas prices compared with the prior-year period. Specifically, changes in accounts receivable and gas stored underground balances increased operating cash flow by $79.5 million. Additionally, improved management of our deferred gas cost balances increased operating cash flow by $93.0 million. Finally, the timing of the collection of and payment for other current assets, accounts payable and other accrued liabilities increased operating cash flow by $141.8 million. Other changes in working capital and other items increased operating cash flow by $49.2 million, primarily resulting from increased net income and favorable net changes associated with our risk management activities.

Cash flows from investing activities

During the last three years, a substantial portion of our cash resources has been used to fund acquisitions, new pipeline expansion projects and our ongoing utility construction program. Our ongoing utility construction program enables us to provide natural gas distribution services to our existing customer base, expand our natural gas distribution services into new markets, enhance the integrity of our pipelines and, more recently, expand our intrastate pipeline network. In executing our current rate strategy, we are directing discretionary capital spending to jurisdictions that permit us to earn a timely return in excess of our cost of capital. Currently, our Mid-Tex, Louisiana, Mississippi and West Texas utility divisions and our Atmos Pipeline — Texas Division have rate designs that provide the opportunity to include in their rate base approved capital costs on a periodic basis without having to file a rate case.

Capital expenditures for fiscal 2007 are expected to range from $365 million to $385 million. For the six months ended March 31, 2007, we incurred $172.8 million for capital expenditures compared with $213.2 million for the six months ended March 31, 2006. The decrease in capital spending primarily reflects the absence of capital expenditures associated with our North Side Loop and other pipeline compression projects, which were completed in the third quarter of fiscal 2006.

Cash flows from financing activities

For the six months ended March 31, 2007, our financing activities reflected a use of cash of $234.9 million compared with the $76.5 million provided from financing activities in the prior-year period. Our significant financing activities for the six months ended March 31, 2007 and 2006 are summarized as follows.

- In December 2006, we raised net proceeds of approximately $192 million from the sale of approximately 6.3 million shares of common stock, including the underwriters' exercise of their overallotment option of 0.8 million shares, under a new shelf registration statement filed with the SEC in December 2006. The net proceeds from this issuance were used to reduce our then-existing short-term debt balance.

- In addition to this equity offering, during the six months ended March 31, 2007, we issued 0.4 million shares of common stock under our various plans which generated net proceeds of $12.4 million. We also granted 0.3 million shares of common stock under our Long-Term Incentive Plan. The following table summarizes our share issuances for the six months ended March 31, 2007 and 2006.

	Six Months Ended March 31	
	2007	2006
Shares issued:		
Retirement Savings Plan	191,617	224,881
Direct Stock Purchase Plan	158,416	206,762
Outside Directors Stock-for-Fee Plan	1,162	1,268
Long-Term Incentive Plan	348,642	104,585
Long-Term Stock Plan for Mid-States Division	—	300
Public Offering	6,325,000	—
Total shares issued	7,024,837	537,796

- During the six months ended March 31, 2007, we repaid all amounts outstanding under our credit facilities, which represented a $382.4 million use of cash. The repayment reflects the positive impact of our strong operating cash flow during fiscal 2007 and the net proceeds received from our December 2006 offering.

- During the six months ended March 31, 2007, we paid $54.6 million in cash dividends compared with $50.9 million for the six months ended March 31, 2006. The increase in dividends paid over the prior-year period reflects the increase in our dividend rate from $0.63 per share during the six months ended March 31, 2006 to $0.64 per share during the six months ended March 31, 2007 combined with share issuances in connection with our December 2006 equity offering and new share issuances under our various plans.

Credit Facilities

As of March 31, 2007, we maintained three short-term committed credit facilities totaling $918 million. We also maintain one uncommitted credit facility totaling $25 million and, through AEM, a second uncommitted credit facility that can provide up to $580 million. Borrowings under our uncommitted credit facilities are made on a when-and-as-needed basis at the discretion of the banks. Our credit capacity and the amount of unused borrowing capacity are affected by the seasonal nature of the natural gas business and our short-term borrowing requirements, which are typically highest during colder winter months. Our working capital needs can vary significantly due to changes in the price of natural gas charged by suppliers and the increased gas supplies required to meet customers' needs during periods of cold weather.

As of March 31, 2007, the amount available to us under our credit facilities, net of outstanding letters of credit, was $956.7 million. We believe these credit facilities, combined with our operating cash flows will be sufficient to fund our working capital needs. These facilities are described in further detail in Note 4 to the unaudited condensed consolidated financial statements.

Shelf Registration

On December 4, 2006, we filed a registration statement with the SEC to issue, from time to time, up to $900 million in new common stock and/or debt securities available for issuance, including approximately $401.5 million of capacity carried over from our prior shelf registration statement filed with the SEC in August 2004. In December 2006, we sold approximately 6.3 million shares of common stock and used the net proceeds to reduce short-term debt. After this issuance, we have approximately $701 million of availability remaining under the registration statement. However, due to certain restrictions placed by one state regulatory commission on our ability to issue securities under the registration statement, we now have remaining and available for issuance a total of approximately $100 million of equity securities, $300 million of senior debt securities and $300 million of subordinated debt securities. In addition, due to restrictions imposed by another state regulatory commission, if the credit ratings on our senior unsecured debt were to fall below investment grade from either Standard & Poor's Corporation (BBB-), Moody's Investors Services, Inc. (Baa3) or Fitch Ratings, Ltd. (BBB-), our ability to issue any type of debt securities under the registration statement would be suspended until an investment grade rating from any of the three credit rating agencies was achieved.

Debt Covenants

We were in compliance with all of our debt covenants as of March 31, 2007. Our debt covenants are described in Note 4 to the unaudited condensed consolidated financial statements.

Credit Ratings

Our credit ratings directly affect our ability to obtain short-term and long-term financing, in addition to the cost of such financing. In determining our credit ratings, the rating agencies consider a number of quantitative factors, including debt to total capitalization, operating cash flow relative to outstanding debt, operating cash flow coverage of interest and pension liabilities and funding status. In addition, the rating agencies consider qualitative factors such as consistency of our earnings over time, the quality of our management and business strategy, the risks associated with our utility and nonutility businesses and the regulatory structures that govern our rates in the states in which we operate.

Our debt is rated by three rating agencies: Standard & Poor's Corporation (S&P), Moody's Investors Service (Moody's) and Fitch Ratings, Ltd. (Fitch). Our current debt ratings are all considered investment grade and are as follows:

	S&P	Moody's	Fitch
Unsecured senior long-term debt	BBB	Baa3	BBB+
Commercial paper	A-2	P-3	F-2

Currently, with respect to our unsecured senior long-term debt, S&P, Moody's and Fitch maintain their stable outlook. None of our ratings are currently under review.

A credit rating is not a recommendation to buy, sell or hold securities. The highest investment grade credit rating for S&P is AAA, Moody's is Aaa and Fitch is AAA. The lowest investment grade credit rating for S&P is BBB-, Moody's is Baa3 and Fitch is BBB-. Our credit ratings may be revised or withdrawn at any time by the rating agencies, and each rating should be evaluated independent of any other rating. There can be no assurance that a rating will remain in effect for any given period of time or that a rating will not be lowered, or withdrawn entirely, by a rating agency if, in its judgment, circumstances so warrant.

Capitalization

As noted above, our capitalization is a leading quantitative factor used to determine our credit ratings. The following table presents our capitalization as of March 31, 2007 September 30, 2006 and March 31, 2006.

	March 31, 2007		September 30, 2006		March 31, 2006	
	(In thousands, except percentages)					
Short-term debt	$ —	—%	$ 382,416	9.1%	$ 262,315	6.3%
Long-term debt	2,181,563	51.9%	2,183,548	51.8%	2,184,428	52.6%
Shareholders' equity	2,021,953	48.1%	1,648,098	39.1%	1,706,291	41.1%
Total capitalization	$4,203,516	100.0%	$4,214,062	100.0%	$4,153,034	100.0%

Total debt as a percentage of total capitalization, including short-term debt, was 51.9 percent at March 31, 2007, 60.9 percent at September 30, 2006 and 58.9 percent at March 31, 2006. The decrease in the debt to capitalization ratio was primarily attributable to the application of the net proceeds provided from our equity offering in December 2006 to repay a portion of our short-term debt. Our ratio of total debt to capitalization is typically greater during the winter heating season as we make additional short-term borrowings to fund natural gas purchases and meet our working capital requirements. We intend to maintain our capitalization ratio in a target range of 50 to 55 percent through cash flow generated from operations, continued issuance of new common stock under our Direct Stock Purchase Plan and Retirement Savings Plan, access to the equity capital markets and reduced annual maintenance and capital expenditures.

Contractual Obligations and Commercial Commitments

Significant commercial commitments are described in Note 8 to the unaudited condensed consolidated financial statements. There were no significant changes in our contractual obligations and commercial commitments during the six months ended March 31, 2007.

Risk Management Activities

We conduct risk management activities through both our utility and natural gas marketing segments. In our utility segment, we use a combination of storage, fixed physical contracts and fixed financial contracts to reduce our exposure to unusually large winter-period gas price increases. In our natural gas marketing segment, we manage our exposure to the risk of natural gas price changes and lock in our gross profit margin through a combination of storage and financial derivatives, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. To the extent our inventory cost and actual sales and actual purchases do not correlate with the changes in the market indices we use in our hedges, we could experience ineffectiveness or the hedges may no longer meet the accounting requirements for hedge accounting, resulting in the derivatives being treated as mark-to-market instruments through earnings.

We record our derivatives as a component of risk management assets and liabilities, which are classified as current or noncurrent based upon the anticipated settlement date of the underlying derivative. Substantially all of our derivative financial instruments are valued using external market quotes and indices. The following tables show the components of the change in the fair value of our utility and natural gas marketing commodity derivative contracts for the three and six months ended March 31, 2007 and 2006:

	Three Months Ended March 31, 2007		Three Months Ended March 31, 2006	
	Utility	Natural Gas Marketing	Utility	Natural Gas Marketing
	(In thousands)			
Fair value of contracts at beginning of period	$(33,315)	$ 74,963	$ 38,273	$(59,368)
Contracts realized/settled	(11,761)	(72,486)	(3,057)	50,691
Fair value of new contracts	649	—	(2,659)	—
Other changes in value	48,229	(27,471)	(20,205)	5,263
Fair value of contracts at end of period	$ 3,802	$(24,994)	$ 12,352	$ (3,414)

	Six Months Ended March 31, 2007		Six Months Ended March 31, 2006	
	Utility	Natural Gas Marketing	Utility	Natural Gas Marketing
	(In thousands)			
Fair value of contracts at beginning of period	$(27,209)	$ 15,003	$ 93,310	$(61,898)
Contracts realized/settled	(27,518)	(26,587)	26,898	23,022
Fair value of new contracts	(1,261)	—	(4,760)	—
Other changes in value	59,790	(13,410)	(103,096)	35,462
Fair value of contracts at end of period	$ 3,802	$(24,994)	$ 12,352	$ (3,414)

The fair value of our utility and natural gas marketing derivative contracts at March 31, 2007, is segregated below by time period and fair value source:

	Fair Value of Contracts at March 31, 2007				
	Maturity in Years				
Source of Fair Value	Less than 1	1-3	4-5	Greater Than 5	Total Fair Value
	(In thousands)				
Prices actively quoted	$(27,996)	$7,481	$—	$—	$(20,515)
Prices based on models and other valuation methods	137	(814)	—	—	(677)
Total Fair Value	$(27,859)	$6,667	$—	$—	$(21,192)

Storage and Hedging Outlook

AEM participates in transactions in which it seeks to find and profit from pricing differences that occur over time. AEM purchases physical natural gas and then sells financial contracts at advantageous prices to lock in a gross profit margin, which we refer to as the economic gross profit. AEM is able to capture the economic gross profit through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time.

Natural gas inventory is marked to market at the end of each month with changes in fair value recognized as unrealized gains and losses in the period of change. Derivatives associated with our natural gas inventory, which are designated as fair value hedges, are marked to market each month based upon the NYMEX price with changes in fair value recognized as unrealized gains and losses in the period of change. The changes in the difference between the indices used to mark to market our physical inventory (Gas Daily) and the related fair-value hedge (NYMEX) is reported as a component of revenue and can result in volatility in our reported net income. Over time, gains and losses on the sale of storage gas inventory will be offset by gains and losses on the fair-value hedges; therefore, the economic gross profit AEM captured in the original transaction remains essentially unchanged.

AEM continually manages its positions to enhance the economic gross profit it captured in the original transaction. Therefore, AEM may change its scheduled injection and withdrawal plans from one time period to another based on market conditions or adjust the amount of storage capacity it holds on a discretionary basis in an effort to achieve this objective. AEM monitors the impacts of these profit optimization efforts by estimating the economic gross profit that it captured through the purchase and sale of physical natural gas and the associated financial derivatives. The reconciliation below of the economic gross profit, combined with the effect of unrealized gains or losses recognized in accordance with generally accepted accounting principles in the financial statements in prior periods, is presented in order to provide a measure of the potential gross profit that could occur in future periods if AEM's optimization efforts are fully successful. We consider this measure of potential gross profit a non-GAAP financial measure as it is calculated using both forward-looking and historical financial information. The following table presents, by quarter, AEM's economic gross profit and its potential future gross profit.

Period Ending	Net Physical Position	Economic Gross Profit	Associated Net Unrealized Gains (Losses) At Period End	Potential Future Gross Profit
	(Bcf)	(In millions)	(In millions)	(In millions)
September 30, 2006	14.5	$60.0	$(16.0)	$76.0
December 31, 2006	21.0	$60.6	$ 32.8	$27.8
March 31, 2007	19.6	$10.8	$(24.2)	$35.0

As of March 31, 2007, based upon AEM's derivatives position and inventory withdrawal schedule, the economic gross profit was $10.8 million. In addition, $24.2 million of net unrealized losses that will reverse when the inventory is withdrawn were recorded in the financial statements as of March 31, 2007. Therefore, the potential future gross profit was $35.0 million. The potential future gross profit amount will not result in an equal increase in future net income as AEM will incur additional storage and other operational expenses to realize this amount.

The economic gross profit is based upon planned injection and withdrawal schedules, and the realization of the economic gross profit is contingent upon the execution of this plan, weather and other execution factors. Since AEM actively manages and optimizes its portfolio to enhance the future profitability of its storage position, it may change its scheduled injection and withdrawal plans from one time period to another based on market conditions. Therefore, we cannot ensure that the economic gross profit or the potential future gross profit calculated as of March 31, 2007 will be fully realized in the future or in what time period. Further, if we experience operational or other issues which limit our ability to optimally manage our stored gas positions, our earnings could be adversely impacted.

Pension and Postretirement Benefits Obligations

For the six months ended March 31, 2007 and 2006 our total net periodic pension and other benefits cost was $24.3 million and $25.0 million. All of these costs are recoverable through our gas utility rates; however, a portion of these costs is capitalized into our utility rate base. The remaining costs are recorded as a component of operation and maintenance expense.

The decrease in total net periodic pension and other benefits cost during the current-year period compared with the prior-year period primarily reflects changes in assumptions we made during our annual pension plan valuation completed June 30, 2006. The discount rate used to compute the present value of a plan's liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid. In the period leading up to our June 30, 2006 measurement date, these interest rates were increasing, which resulted in a 130 basis point increase in our discount rate used to determine our fiscal 2007 net periodic and post-retirement cost to 6.30 percent. This increase has the effect of decreasing the present value of our plan liabilities and associated expenses. This favorable impact was partially offset by the unfavorable impact of reducing the expected return on our pension plan assets by 25 basis points to 8.25 percent, which has the effect of increasing our pension and postretirement benefit cost.

During the six months ended March 31, 2007, we contributed $6.0 million to our other postretirement plans, and we expect to contribute a total of approximately $12 million to these plans during fiscal 2007.

OPERATING STATISTICS AND OTHER INFORMATION

The following tables present certain operating statistics for our utility, natural gas marketing, pipeline and storage and other nonutility segments for the three and six-month periods ended March 31, 2007 and 2006.

Utility Sales and Statistical Data

	Three Months Ended March 31		Six Months Ended March 31	
	2007	2006	2007	2006
METERS IN SERVICE, end of period				
Residential	2,922,314	2,929,613	2,922,314	2,929,613
Commercial	276,901	278,657	276,901	278,657
Industrial	2,745	3,070	2,745	3,070
Agricultural	8,499	9,152	8,499	9,152
Public-authority and other	8,219	8,216	8,219	8,216
Total meters	3,218,678	3,228,708	3,218,678	3,228,708
INVENTORY STORAGE BALANCE — Bcf	31.4	38.8	31.4	38.8
HEATING DEGREE DAYS(1)				
Actual (weighted average)	1,575	1,330	2,710	2,387
Percent of normal	100%	84%	101%	88%
UTILITY SALES VOLUMES — MMcf(2)				
Gas sales volumes				
Residential	82,901	65,869	133,600	119,578
Commercial	39,474	33,833	66,559	62,972
Industrial	7,568	8,054	13,303	17,063
Agricultural	87	316	197	356
Public authority and other	3,826	3,649	6,597	6,940
Total gas sales volumes	133,856	111,721	220,256	206,909
Utility transportation volumes	40,811	32,838	74,694	64,594
Total utility throughput	174,667	144,559	294,950	271,503
UTILITY OPERATING REVENUES (000's)(2)				
Gas sales revenues				
Residential	$ 925,632	$ 884,126	$1,500,368	$1,667,472
Commercial	402,010	408,153	685,043	832,491
Industrial	64,293	77,386	118,276	205,857
Agricultural	729	2,850	1,304	3,636
Public-authority and other	37,884	43,240	65,053	87,211
Total utility gas sales revenues	1,430,548	1,415,755	2,370,044	2,796,667
Transportation revenues	19,107	19,192	34,957	35,059
Other gas revenues	11,378	12,673	20,276	20,904
Total utility operating revenues	$1,461,033	$1,447,620	$2,425,277	$2,852,630
Utility average transportation revenue per Mcf	$ 0.47	$ 0.58	$ 0.47	$ 0.54
Utility average cost of gas per Mcf sold	$ 8.33	$ 10.13	$ 8.25	$ 10.91

See footnotes following these tables.

Natural Gas Marketing, Pipeline and Storage and Other Nonutility Operations Sales and Statistical Data

	Three Months Ended March 31		Six Months Ended March 31	
	2007	2006	2007	2006
CUSTOMERS, end of period				
Industrial	717	665	717	665
Municipal	62	70	62	70
Other	453	412	453	412
Total	1,232	1,147	1,232	1,147
INVENTORY STORAGE BALANCE — Bcf				
Natural gas marketing	21.2	23.2	21.2	23.2
Pipeline and storage	1.0	2.1	1.0	2.1
Total	22.2	25.3	22.2	25.3
NATURAL GAS MARKETING SALES VOLUMES — MMcf(2)	114,110	82,384	202,148	170,206
PIPELINE TRANSPORTATION VOLUMES — MMcf(2)	201,763	150,925	374,522	297,879
OPERATING REVENUES (000's)(2)				
Natural gas marketing	$795,041	$818,629	$1,506,735	$1,920,474
Pipeline and storage	59,362	45,483	109,214	85,195
Other nonutility	783	1,595	2,136	3,087
Total operating revenues	$855,186	$865,707	$1,618,085	$2,008,756

Notes to preceding tables:

(1) A heating degree day is equivalent to each degree that the average of the high and the low temperatures for a day is below 65 degrees. The colder the climate, the greater the number of heating degree days. Heating degree days are used in the natural gas industry to measure the relative coldness of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on 30-year average National Weather Service data for selected locations. For service areas that have weather normalized operations, normal degree days are used instead of actual degree days in computing the total number of heating degree days.

(2) Sales volumes and revenues reflect segment operations, including intercompany sales and transportation amounts.

Recent Ratemaking Developments

The following describes the significant ratemaking developments that occurred during the six months ended March 31, 2007. The amounts described below represent the gross revenues that were requested or received in the rate filing, which may not necessarily reflect the increase in operating income obtained, as certain operating costs may have increased as a result of a commission's final ruling.

Atmos Energy Colorado-Kansas Division. In December 2006, the Colorado-Kansas Division filed its third annual ad valorem tax surcharge for $1.5 million. The surcharge is designed to collect Kansas property taxes in excess of the amount included in Atmos' most recent general rate case. We began to bill this surcharge in January 2007.

Atmos Energy Kentucky/Mid-States Division. In April 2006, Atmos filed a rate case in its Missouri service area seeking a rate increase of $3.4 million, the consolidation of rates for its Missouri properties into three sets of regional rates and the current purchased gas adjustment (PGA) into one statewide PGA and a

WNA mechanism. The Missouri Commission issued an order in March 2007 approving a settlement with rate design changes including revenue decoupling through the recovery of all non-gas cost revenues through fixed monthly charges and no rate increase.

In November 2005, we received a notice from the TRA that it was opening an investigation into allegations by the Consumer Advocate and Protection Division of the Tennessee Attorney General's Office that we were overcharging customers in parts of Tennessee by approximately $10 million per year. A hearing was held in August 2006. Of the $10 million rate reduction requested by the Consumer Advocate and Protection Division, the TRA approved a $6.1 million rate reduction in October 2006, which became effective in December 2006.

In February 2005, the Attorney General of the State of Kentucky filed a complaint with the Kentucky Public Service Commission (KPSC) alleging that our rates were producing revenues in excess of reasonable levels. We answered the complaint and filed a Motion to Dismiss with the KPSC. In February 2006, the KPSC issued an order denying our Motion to Dismiss but stated that the Attorney General had not met his burden of proof concerning his complaint. In November 2006, we requested dismissal of the case through our filing a notice of intent to file a general rate case in December 2006. Upon receipt of the notice of intent, the KPSC suspended the procedural schedule until it issues a decision regarding the motion for dismissal. A hearing is scheduled for July 2007. We believe that the Attorney General will not be able to demonstrate that our present rates are in excess of reasonable levels.

As discussed above, in December 2006, the Company filed a rate application for an increase in base rates of $10.4 million in Kentucky. Additionally, we proposed to implement a process to review our rates annually and to collect the bad debt portion of gas costs directly rather than through the base rate. A decision is expected in the case in July 2007.

Atmos Energy Louisiana Division. In May 2006, the LPSC voted to approve a settlement which included renewal of the RSC for both the LGS and TransLa service areas with provisions that should reduce regulatory lag. The first RSC filing was in August 2006 for approximately $10.8 million, based on a test year ended December 31, 2005, for the LGS service area. The Company reached a settlement agreement on the case in December 2006, which resulted in an increase in annual revenue of $9.5 million. The first filing for the TransLa service area for approximately $1.8 million was made in December 2006. The Company reached a settlement agreement on the case in March 2007 which resulted in an increase of $1.4 million in annual revenue effective April 1, 2007. The 2006 RSC filing for the LGS service area was filed in March 2007 seeking an approximate $0.8 million annual increase in rates. The effective date for any rate adjustment will be July 1, 2007.

Atmos Energy Mid-Tex Division. In May 2006, the Mid-Tex Division filed a Statement of Intent with the Railroad Commission of Texas (RRC), which consolidated approximately 80 "show cause" resolutions and sought incremental annual revenues of approximately $60 million and several rate design changes. In March 2007, the RRC issued an order, which increases the Mid-Tex Division's annual revenues by approximately $4.8 million and establishes a permanent WNA based on 10-year average weather effective for the months of November through April of each year. The RRC also approved a cost allocation method that eliminates a subsidy received from industrial and transportation customers and increases the revenue responsibility for residential and commercial customers. However, the order also requires a refund of amounts collected from our 2003 — 2005 GRIP filings of approximately $2.3 million, consisting of $2.2 million plus interest and reduces our total return to 7.903 percent from 8.258 percent based on a capital structure of 48.1 percent equity and 51.9 percent debt with a return on equity of 10 percent.

On April 18, 2007, the parties in the rate case, including Atmos Energy, filed motions for rehearing with the RRC concerning various aspects of the RRC's order. We cannot predict at this time whether the RRC will grant these motions for rehearing or the impact on us if these motions are granted.

In September 2006, the Mid-Tex Division filed its annual gas cost reconciliation with the RRC. The filing reflects approximately $24 million in refunds of amounts that were overcollected from customers between July

2005 and June 2006. The Mid-Tex Division received approval to refund these amounts over a six-month period which began in November 2006.

The Mid-Tex Division is also pursuing an appeal to the Travis County District Court of the Final Order in its previous system-wide rate case completed in May 2004 to obtain a return of and on its investment associated with the Poly I replacement pipe that was originally disallowed in its rate case completed in May 2004. The Travis County District Court upheld the Commission's final order. An appeal to the Court of Appeals in Travis County has been prepared and initial briefs have been filed, but no reply briefing or hearing schedule has been established.

RECENT ACCOUNTING DEVELOPMENTS

Recent accounting developments and their impact on our financial position, results of operations and cash flows are described in Note 2 to the unaudited condensed consolidated financial statements.

Item 3. *Quantitative and Qualitative Disclosures About Market Risk*

Information regarding our quantitative and qualitative disclosures about market risk are disclosed in Item 7A in our annual report on Form 10-K for the year ended September 30, 2006. During the six months ended March 31, 2007, there were no material changes in our quantitative and qualitative disclosures about market risk.

Item 4. *Controls and Procedures*

As indicated in the certifications in Exhibit 31 of this report, the Company's Chief Executive Officer and Chief Financial Officer have evaluated the Company's disclosure controls and procedures as of March 31, 2007. Based on that evaluation, these officers have concluded that the Company's disclosure controls and procedures are effective in ensuring that material information required to be disclosed in this quarterly report is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. In addition, there were no changes during the Company's last fiscal quarter that materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. *Legal Proceedings*

During the six months ended March 31, 2007, there were no material changes in the status of the litigation and environmental-related matters that were disclosed in Note 13 to our annual report on Form 10-K for the year ended September 30, 2006. We continue to believe that the final outcome of such litigation and environmental-related matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

Item 4. *Submission of Matters to a Vote of Security Holders*

At the Annual Meeting of Shareholders of Atmos Energy Corporation on February 7, 2007, 73,922,748 votes were cast as follows:

	Votes For	Votes Withheld	Votes Abstaining	Broker Non-Votes
Class III Directors:				
Robert W. Best	56,225,642	17,697,106	—	—
Thomas J. Garland	72,427,058	1,495,690	—	—
Phillip E. Nichol	72,217,982	1,704,766	—	—
Charles K. Vaughan	61,575,002	12,347,746	—	—
Approval of amendment to the 1998 Long-Term Incentive Plan to increase the number of shares reserved for issuance under the Plan by 2,500,000 and extend the term of the Plan for an additional three years	46,480,494	11,851,342	683,690	14,907,222
Approval of amendment to the Annual Incentive Plan for Management to extend the term of the Plan for an additional five years	68,934,473	4,204,122	784,133	20

Mr. Gene C. Koonce, a Class I director, retired on February 7, 2007, at the conclusion of the Annual Meeting of Shareholders, in accordance with the Board's mandatory retirement policy. The other directors will continue to serve until the expiration of their terms. The term of the Class I directors, Travis W. Bain II, Dan Busbee and Richard K. Gordon, will expire in 2008. The term of the Class II directors, Richard W. Cardin, Thomas C. Meredith, Nancy K. Quinn, Stephen R. Springer and Richard Ware II, will expire in 2009. The term of the Class III directors, Robert W. Best, Thomas J. Garland, Phillip E. Nichol and Charles K. Vaughan, will expire in 2010.

Item 6. *Exhibits*

A list of exhibits required by Item 601 of Regulation S-K and filed as part of this report is set forth in the Exhibits Index, which immediately precedes such exhibits.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ATMOS ENERGY CORPORATION
(Registrant)

By: /s/ JOHN P. REDDY

John P. Reddy
Senior Vice President and Chief Financial Officer
(Duly authorized signatory)

Date: May 3, 2007

EXHIBITS INDEX
Item 6(a)

Exhibit Number	Description	Page Number or Incorporation by Reference to
3.1	Amended and Restated Articles of Incorporation of Atmos Energy Corporation (as of February 9, 2005)	Exhibit 3(I) to Form 10-Q dated March 31, 2005 (File No. 1-10042)
3.2	Amended and Restated Bylaws of Atmos Energy Corporation (as of May 2, 2007)	Exhibit 3.1 to Form 8-K dated May 2, 2007 (File No. 1-10042)
10.1*	Amendment No. Two to the Atmos Energy Corporation Performance-Based Supplemental Executive Benefits Plan (Effective Date: August 12, 1998)	
10.2*	Atmos Energy Corporation 1998 Long-Term Incentive Plan (as amended and restated February 9, 2007)	
10.3*	Atmos Energy Corporation Annual Incentive Plan for Management (as amended and restated February 9, 2007)	
10.4	Third Amendment, dated as of March 30, 2007, to the Uncommitted Second Amended and Restated Credit Agreement, dated as of March 30, 2005, as amended by the First Amendment, dated November 28, 2005, the Second Amendment, dated March 31, 2006, and as otherwise amended, restated, supplemented or modified prior to the date thereof, among Atmos Energy Marketing, LLC, a Delaware limited liability company, the financial institutions from time to time parties thereto (the "Banks"), Fortis Capital Corp., a Connecticut corporation, as Joint Lead Arranger and Joint Bookrunner, as Administrative Agent for the Banks, as Collateral Agent, as an Issuing Bank, and as a Bank; BNP Paribas, a bank organized under the laws of France, as Joint Lead Arranger and Joint Bookrunner, and as Documentation Agent, as an Issuing Bank, and as a Bank; and Société Générale, as Syndication Agent and as a Bank	Exhibit 10.1 to Form 8-K dated March 30, 2007 (File No. 1-10042)
12	Computation of ratio of earnings to fixed charges	
15	Letter regarding unaudited interim financial information	
31	Rule 13a-14(a)/15d-14(a) Certifications	
32	Section 1350 Certifications**	

* This exhibit constitutes a "management contract or compensatory plan, contract, or arrangement."

** These certifications, which were made pursuant to 18 U.S.C. Section 1350 by the Company's Chief Executive Officer and Chief Financial Officer, furnished as Exhibit 32 to this Quarterly Report on Form 10-Q, will not be deemed to be filed with the Commission or incorporated by reference into any filing by the Company under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent that the Company specifically incorporates such certifications by reference.

EXHIBIT CF-R-3

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

(Mark One)

☑ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2007

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number 1-10042

Atmos Energy Corporation
(Exact name of registrant as specified in its charter)

Texas and Virginia *(State or other jurisdiction of incorporation or organization)*	**75-1743247** *(IRS employer identification no.)*
Three Lincoln Centre, Suite 1800 **5430 LBJ Freeway, Dallas, Texas** *(Address of principal executive offices)*	**75240** *(Zip code)*

(972) 934-9227
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer ☑ Accelerated Filer ☐ Non-Accelerated Filer ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act) Yes ☐ No ☑

Number of shares outstanding of each of the issuer's classes of common stock, as of July 31, 2007.

Class	Shares Outstanding
No Par Value	89,160,099

GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
AES	Atmos Energy Services, LLC
APS	Atmos Pipeline and Storage, LLC
Bcf	Billion cubic feet
EITF	Emerging Issues Task Force
FASB	Financial Accounting Standards Board
FIN	FASB Interpretation
Fitch	Fitch Ratings, Ltd.
GRIP	Gas Reliability Infrastructure Program
KPSC	Kentucky Public Service Commission
LGS	Louisiana Gas Service Company and LGS Natural Gas Company, which were acquired July 1, 2001
LPSC	Louisiana Public Service Commission
Mcf	Thousand cubic feet
MMcf	Million cubic feet
Moody's	Moody's Investors Services, Inc.
NYMEX	New York Mercantile Exchange, Inc.
RRC	Railroad Commission of Texas
RSC	Rate Stabilization Clause
S&P	Standard & Poor's Corporation
SEC	United States Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
TRA	Tennessee Regulatory Authority
WNA	Weather Normalization Adjustment

PART I. FINANCIAL INFORMATION

Item 1. ***Financial Statements***

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

	June 30, 2007	September 30, 2006
	(Unaudited)	
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$5,289,268	$5,101,308
Less accumulated depreciation and amortization	1,531,792	1,472,152
Net property, plant and equipment	3,757,476	3,629,156
Current assets		
Cash and cash equivalents	350,383	75,815
Cash held on deposit in margin account	13,576	35,647
Accounts receivable, net	429,119	374,629
Gas stored underground	463,896	461,502
Other current assets	77,519	169,952
Total current assets	1,334,493	1,117,545
Goodwill and intangible assets	738,065	738,521
Deferred charges and other assets	225,775	234,325
	$6,055,809	$5,719,547
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: June 30, 2007 — 89,112,585 shares; September 30, 2006 — 81,739,516 shares	$ 446	$ 409
Additional paid-in capital	1,688,482	1,467,240
Retained earnings	315,587	224,299
Accumulated other comprehensive loss	(16,373)	(43,850)
Shareholders' equity	1,988,142	1,648,098
Long-term debt	2,126,526	2,180,362
Total capitalization	4,114,668	3,828,460
Current liabilities		
Accounts payable and accrued liabilities	428,806	345,108
Other current liabilities	360,920	388,451
Short-term debt	—	382,416
Current maturities of long-term debt	303,992	3,186
Total current liabilities	1,093,718	1,119,161
Deferred income taxes	367,025	306,172
Regulatory cost of removal obligation	261,436	261,376
Deferred credits and other liabilities	218,962	204,378
	$6,055,809	$5,719,547

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended June 30 2007	Three Months Ended June 30 2006
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Utility segment	$ 548,251	$ 402,044
Natural gas marketing segment	854,167	562,447
Pipeline and storage segment	37,937	35,862
Other nonutility segment	843	1,413
Intersegment eliminations	(223,046)	(138,523)
	1,218,152	863,243
Purchased gas cost		
Utility segment	357,608	232,192
Natural gas marketing segment	854,743	563,333
Pipeline and storage segment	228	379
Other nonutility segment	—	—
Intersegment eliminations	(222,443)	(137,161)
	990,136	658,743
Gross profit	228,016	204,500
Operating expenses		
Operation and maintenance	118,430	104,380
Depreciation and amortization	48,974	46,838
Taxes, other than income	52,881	48,479
Total operating expenses	220,285	199,697
Operating income	7,731	4,803
Miscellaneous income	4,266	963
Interest charges	34,479	35,944
Loss before income taxes	(22,482)	(30,178)
Income tax benefit	(9,122)	(12,033)
Net loss	$ (13,360)	$ (18,145)
Basic net loss per share	$ (0.15)	$ (0.22)
Diluted net loss per share	$ (0.15)	$ (0.22)
Cash dividends per share	$ 0.320	$ 0.315
Weighted average shares outstanding:		
Basic	88,366	80,840
Diluted	88,366	80,840

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Nine Months Ended June 30	
	2007	2006
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Utility segment	$2,973,528	$3,254,674
Natural gas marketing segment	2,360,902	2,482,921
Pipeline and storage segment	147,151	121,057
Other nonutility segment	2,979	4,500
Intersegment eliminations	(588,193)	(682,243)
	4,896,367	5,180,909
Purchased gas cost		
Utility segment	2,174,071	2,488,906
Natural gas marketing segment	2,275,291	2,413,511
Pipeline and storage segment	682	590
Other nonutility segment	—	—
Intersegment eliminations	(585,971)	(678,591)
	3,864,073	4,224,416
Gross profit	1,032,294	956,493
Operating expenses		
Operation and maintenance	345,662	325,295
Depreciation and amortization	149,035	137,174
Taxes, other than income	149,694	158,691
Total operating expenses	644,391	621,160
Operating income	387,903	335,333
Miscellaneous income (expense)	7,683	(1,028)
Interest charges	109,273	107,625
Income before income taxes	286,313	226,680
Income tax expense	111,907	85,002
Net income	$ 174,406	$ 141,678
Basic net income per share	$ 2.02	$ 1.76
Diluted net income per share	$ 2.00	$ 1.75
Cash dividends per share	$ 0.960	$ 0.945
Weighted average shares outstanding:		
Basic	86,378	80,520
Diluted	87,011	81,013

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended June 30	
	2007	2006
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	$ 174,406	$ 141,678
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization:		
Charged to depreciation and amortization	149,035	137,174
Charged to other accounts	148	359
Deferred income taxes	37,266	36,160
Other	17,959	12,063
Net assets / liabilities from risk management activities	12,325	(3,940)
Net change in operating assets and liabilities	161,531	(100,051)
Net cash provided by operating activities	552,670	223,443
Cash Flows From Investing Activities		
Capital expenditures	(263,023)	(322,691)
Other, net	(9,867)	(4,811)
Net cash used in investing activities	(272,890)	(327,502)
Cash Flows From Financing Activities		
Net increase (decrease) in short-term debt	(382,416)	152,278
Net proceeds from debt offering	247,461	—
Settlement of Treasury lock agreement	4,750	—
Repayment of long-term debt	(2,685)	(2,618)
Cash dividends paid	(83,118)	(76,559)
Issuance of common stock	18,883	17,691
Net proceeds from equity offering	191,913	—
Net cash provided by (used in) financing activities	(5,212)	90,792
Net increase (decrease) in cash and cash equivalents	274,568	(13,267)
Cash and cash equivalents at beginning of period	75,815	40,116
Cash and cash equivalents at end of period	$ 350,383	$ 26,849

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
June 30, 2007

1. Nature of Business

Atmos Energy Corporation ("Atmos" or "the Company") and our subsidiaries are engaged primarily in the natural gas utility business as well as other natural gas nonutility businesses. Our natural gas utility business distributes natural gas through sales and transportation arrangements to approximately 3.2 million residential, commercial, public authority and industrial customers throughout our six regulated natural gas utility divisions, in the service areas described below:

Division	Service Area
Atmos Energy Colorado-Kansas Division	Colorado, Kansas, Missouri[2]
Atmos Energy Kentucky/Mid-States Division[1]	Georgia[2], Illinois[2], Iowa[2], Kentucky, Missouri[2], Tennessee, Virginia[2]
Atmos Energy Louisiana Division	Louisiana
Atmos Energy Mid-Tex Division	Texas, including the Dallas/Fort Worth Metroplex
Atmos Energy Mississippi Division	Mississippi
Atmos Energy West Texas Division	West Texas

(1) Effective October 1, 2006, the Kentucky and Mid-States Divisions were combined.

(2) Denotes locations where we have more limited service areas.

In addition, we transport natural gas for others through our distribution system. Our utility business is subject to federal and state regulation and/or regulation by local authorities in each of the states in which the utility divisions operate. Our corporate headquarters and shared services function are located in Dallas, Texas, and our customer support centers are located in Amarillo and Waco, Texas.

Our nonutility businesses operate in 22 states and include our natural gas marketing operations, pipeline and storage operations and other nonutility operations. These operations are either organized under or managed by Atmos Energy Holdings, Inc. (AEH), a wholly-owned subsidiary of the Company based in Houston, Texas.

Our natural gas marketing operations are managed by Atmos Energy Marketing, LLC (AEM), which is wholly-owned by AEH. AEM provides a variety of natural gas management services to municipalities, natural gas utility systems and industrial natural gas customers, primarily in the southeastern and midwestern states and to our Colorado-Kansas, Kentucky/Mid-States and Louisiana utility divisions. These services consist primarily of furnishing natural gas supplies at fixed and market-based prices, contract negotiation and administration, load forecasting, gas storage acquisition and management services, transportation services, peaking sales and balancing services, capacity utilization strategies and gas price hedging through the use of derivative instruments.

Our pipeline and storage business includes the regulated operations of our Atmos Pipeline — Texas Division, a division of the Company, and the nonregulated operations of Atmos Pipeline and Storage, LLC (APS), which is wholly-owned by AEH. The Atmos Pipeline — Texas Division transports natural gas to our Atmos Energy Mid-Tex Division and to third parties, and manages five underground storage reservoirs in Texas. Through APS, we own or have an interest in underground storage fields in Kentucky and Louisiana. We also use these storage facilities to reduce the need to contract for additional pipeline capacity to meet customer demand during peak periods.

Our other nonutility businesses consist primarily of the operations of Atmos Energy Services, LLC (AES) and Atmos Power Systems, Inc., which are each wholly-owned by AEH. Through December 31, 2006, AES provided natural gas management services to our utility operations, other than the Mid-Tex Division. These services included aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering the gas to our utility service areas at competitive prices. Effective January 1, 2007, our shared services function began providing these services to our utility operations. AES continues to provide limited services to our utility division, and the revenues AES receives are equal to the costs incurred to provide those services. Through Atmos Power Systems, Inc., we have constructed electric peaking power-generating plants and associated facilities and lease these plants through lease agreements that are accounted for as sales under generally accepted accounting principles.

2. Unaudited Interim Financial Information

In the opinion of management, all material adjustments (consisting of normal recurring accruals) necessary for a fair presentation have been made to the unaudited consolidated interim-period financial statements. These consolidated interim-period financial statements are condensed as permitted by the instructions to Form 10-Q and should be read in conjunction with the audited consolidated financial statements of Atmos Energy Corporation included in its Annual Report on Form 10-K for the fiscal year ended September 30, 2006. Because of seasonal and other factors, the results of operations for the three and nine-month periods ended June 30, 2007 are not indicative of expected results of operations for the full 2007 fiscal year, which ends September 30, 2007.

Significant accounting policies

Our accounting policies are described in Note 2 to our Annual Report on Form 10-K for the year ended September 30, 2006. There were no significant changes to those accounting policies during the nine months ended June 30, 2007.

Additionally, during the second quarter of fiscal 2007, we completed our annual goodwill impairment assessment. Based on the assessment performed, our goodwill was not impaired.

Regulatory assets and liabilities

We record certain costs as regulatory assets in accordance with Statement of Financial Accounting Standards (SFAS) 71, *Accounting for the Effects of Certain Types of Regulation,* when future recovery through customer rates is considered probable. Regulatory liabilities are recorded when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. Substantially all of our regulatory assets are recorded as a component of deferred charges and other assets and substantially all of our regulatory liabilities are recorded as a component of deferred credits and other liabilities. Deferred gas costs are recorded either in other current assets or liabilities and the regulatory cost of removal obligation is separately reported.

Significant regulatory assets and liabilities as of June 30, 2007 and September 30, 2006 included the following:

	June 30, 2007	September 30, 2006
	(In thousands)	
Regulatory assets:		
Merger and integration costs, net	$ 8,095	$ 8,644
Deferred gas costs	9,068	44,992
Environmental costs	1,299	1,234
Rate case costs	9,428	10,579
Deferred franchise fees	830	1,311
Other	10,898	9,055
	$ 39,618	$ 75,815
Regulatory liabilities:		
Deferred gas costs	$ 59,494	$ 68,959
Regulatory cost of removal obligation	284,700	276,490
Deferred income taxes, net	235	235
Other	9,456	10,825
	$353,885	$356,509

Currently, our authorized rates do not include a return on certain of our merger and integration costs; however, we recover the amortization of these costs. Merger and integration costs, net, are generally amortized on a straight-line basis over estimated useful lives ranging up to 20 years. Environmental costs have been deferred to be included in future rate filings in accordance with rulings received from various state regulatory commissions.

Comprehensive income

The following table presents the components of comprehensive income, net of related tax, for the three-month and nine-month periods ended June 30, 2007 and 2006:

	Three Months Ended June 30		Nine Months Ended June 30	
	2007	2006	2007	2006
	(In thousands)			
Net income (loss)	$(13,360)	$(18,145)	$174,406	$141,678
Unrealized holding gains (losses) on investments, net of tax expense (benefit) of $215 and $(187) for the three months ended June 30, 2007 and 2006 and of $964 and $355 for the nine months ended June 30, 2007 and 2006	353	(304)	1,575	580
Amortization and unrealized gain on interest rate hedging transactions, net of tax expense of $1,863 and $528 for the three months ended June 30, 2007 and 2006 and $3,373 and $1,583 for the nine months ended June 30, 2007 and 2006	3,039	860	5,501	2,581
Net unrealized gains (losses) on commodity hedging transactions, net of tax expense (benefit) of $(2,832) and $(4,182) for the three months ended June 30, 2007 and 2006 and $12,504 and $(21,858) for the nine months ended June 30, 2007 and 2006	(4,621)	(6,821)	20,401	(35,660)
Comprehensive income (loss)	$(14,589)	$(24,410)	$201,883	$109,179

Accumulated other comprehensive loss, net of tax, as of June 30, 2007 and September 30, 2006 consisted of the following unrealized gains (losses):

	June 30, 2007	September 30, 2006
	(In thousands)	
Accumulated other comprehensive loss:		
Unrealized holding gains on investments	$ 3,141	$ 1,566
Treasury lock agreements	(15,039)	(20,540)
Cash flow hedges	(4,475)	(24,876)
	$(16,373)	$(43,850)

Recent accounting pronouncements

In February 2007, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities — Including an amendment of FASB Statement No. 115.* This new standard permits an entity to measure certain financial assets and financial liabilities at fair value. The objective of the standard is to improve financial reporting by allowing entities to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. Entities that elect the fair value option will report unrealized gains and losses in earnings at each subsequent reporting date. The fair value option may be elected on an instrument-by-instrument basis. The fair value option is irrevocable, unless a new election date occurs. The provisions of this standard will be effective October 1, 2008. We are currently evaluating the impact this standard may have on our financial position, results of operations and cash flows.

In September 2006, the FASB issued SFAS 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R).* The new standard represents a significant change to the existing rules by requiring recognition in the balance sheet of the overfunded or underfunded positions of defined benefit pension and other postretirement plans based upon the projected benefit obligation, along with a corresponding noncash, after-tax adjustment to stockholders' equity. Additionally, this standard requires that the measurement date must correspond to the fiscal year end balance sheet date but it does not change how net periodic pension and postretirement cost or the projected benefit obligation is determined. The balance sheet recognition-related provisions of this standard will be effective as of September 30, 2007, while the measurement date provisions of this standard may be adopted as late as fiscal 2009 for the Company.

In June 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109* (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes by establishing standards for measurement and recognition in financial statements of positions taken by an entity in its income tax returns. This interpretation also provides guidance on removing income tax assets and liabilities from the balance sheet, classification of current and deferred income tax assets and liabilities, accounting for interest and penalties, accounting for income taxes in interim periods and income tax disclosures. We will be required to apply the provisions of FIN 48 beginning October 1, 2007. We are currently evaluating the impact this standard may have on our financial position, results of operations and cash flows.

3. Derivative Instruments and Hedging Activities

We conduct risk management activities with independent third parties through both our utility and natural gas marketing segments. We record our derivatives as a component of risk management assets and liabilities, which are classified as current or noncurrent other assets or liabilities based upon the anticipated settlement date of the underlying derivative. Our determination of the fair value of these derivative financial instruments reflects the estimated amounts that we would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains and losses on open contracts. In our determination of fair value, we consider various factors, including closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts. These risk management assets and liabilities are subject to continuing market risk until the underlying derivative contracts are settled.

The following table shows the fair values of our risk management assets and liabilities by segment at June 30, 2007 and September 30, 2006:

	Utility	Natural Gas Marketing	Total
		(In thousands)	
June 30, 2007:			
Assets from risk management activities, current	$ —	$10,362	$ 10,362
Assets from risk management activities, noncurrent	—	7,077	7,077
Liabilities from risk management activities, current	(7,524)	(980)	(8,504)
Liabilities from risk management activities, noncurrent	—	(561)	(561)
Net assets (liabilities)	$ (7,524)	$15,898	$ 8,374
September 30, 2006:			
Assets from risk management activities, current	$ —	$12,553	$ 12,553
Assets from risk management activities, noncurrent	—	6,186	6,186
Liabilities from risk management activities, current	(27,209)	(3,460)	(30,669)
Liabilities from risk management activities, noncurrent	—	(276)	(276)
Net assets (liabilities)	$(27,209)	$15,003	$(12,206)

Utility Hedging Activities

We use a combination of storage, fixed physical contracts and fixed financial contracts to partially insulate us and our customers against gas price volatility during the winter heating season. Because the gains or losses of financial derivatives used in our utility segment ultimately will be recovered through our rates, current period changes in the assets and liabilities from these risk management activities are recorded as a component of deferred gas costs in accordance with SFAS 71, *Accounting for the Effects of Certain Types of Regulation*. Accordingly, there is no earnings impact to our utility segment as a result of the use of these financial derivatives.

Nonutility Hedging Activities

Our nonutility hedging activities are subject to various market risks, including risks known as flat price risk, time spread risk and basis risk.

Flat price risk arises from maintaining unhedged open positions. Time spread risk arises when we enter into transactions to buy and sell natural gas that over a period of months offset one another but do not offset in any particular month within the overall time period. This risk arises even when we have no unhedged open positions for the overall time period. Finally, basis risk arises when the pricing of a physical contract is based on a pricing location that differs from the Henry Hub, the NYMEX clearing location.

We seek to mitigate these risks by continually monitoring our positions to maximize our gains. Additionally, under our risk management policies, we seek to match our financial derivative positions to our physical storage positions as well as our expected current and future sales and purchase obligations to maintain no open positions at the end of each trading day. The determination of our net open position as of any day, however, requires us to make assumptions as to future circumstances, including the use of gas by our customers in relation to our anticipated storage and market positions. Because the flat price risk associated with any net open position at the end of each day may increase if the assumptions are not realized, we review these assumptions as part of our daily monitoring activities. We may also be affected by intraday fluctuations of gas prices, since the price of natural gas purchased or sold for future delivery earlier in the day may not be hedged until later in the day. At times, limited net open positions related to our existing and anticipated commitments may occur. At the close of business on June 30, 2007, AEH had a net open position (including existing storage) of 0.1 Bcf.

Finally, AEM manages its exposure to the risk of natural gas price changes through a combination of storage and financial derivatives, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. Our financial derivative activities include fair value hedges to offset changes in the fair value of our natural gas inventory and cash flow hedges to offset anticipated purchases and sales of gas in the future. AEM also utilizes basis swaps and other non-hedge derivative instruments to manage its exposure to market volatility.

For the three and nine-month periods ended June 30, 2007, the change in the deferred hedging position in accumulated other comprehensive loss was attributable to decreases in future natural gas prices relative to the natural gas prices stipulated in the derivative contracts. The recognition in net income for the nine months ended June 30, 2007 of $27.4 million in net deferred hedging losses (of which $0.2 million was recognized during the three months ended June 30, 2007) was the result of the maturing of derivative contracts. The net deferred hedging loss associated with open cash flow hedges remains subject to market price fluctuations until the positions are either settled under the terms of the hedge contracts or terminated prior to settlement. The majority of the deferred hedging balance as of June 30, 2007 is expected to be recognized in net income by the end of fiscal 2007 along with the corresponding hedged purchases and sales of natural gas.

Gains and losses recognized in the income statement from hedge ineffectiveness primarily result from basis risk and from differences between the timing of the settlement of physical contracts and the settlement of the related hedge, that is referred to below as timing ineffectiveness. The following summarizes the gains and losses recognized in the income statement for the three and nine months ended June 30, 2007.

	Three Months Ended June 30		Nine Months Ended June 30	
	2007	2006	2007	2006
	(In thousands)			
Basis ineffectiveness:				
Fair value basis ineffectiveness	$ 1,073	$ 578	$ 942	$ 14,332
Cash flow basis ineffectiveness	1,479	521	710	4,132
Total basis ineffectiveness	2,552	1,099	1,652	18,464
Timing ineffectiveness:				
Fair value timing ineffectiveness	(1,887)	(11,448)	(3,477)	(11,123)
Total hedge ineffectiveness	$ 665	$(10,349)	$(1,825)	$ 7,341

Treasury Activities

In March 2007, we entered into a Treasury lock agreement to fix the Treasury yield component of the interest cost associated with $100 million of our $250 million 6.35% Senior Notes issued in June 2007 (the Senior Notes Offering).

We designated this Treasury lock as a cash flow hedge of an anticipated transaction. This Treasury lock was settled in June 2007 upon completion of the Senior Notes Offering with the receipt of $4.8 million from the counterparties due to an increase in the 10 year Treasury rates between inception of the Treasury lock and settlement. Because the Treasury lock was effective, the net $2.9 million unrealized gain was recorded as a component of accumulated other comprehensive income and will be recognized over the ten year life of the senior notes.

4. Debt

Long-term debt

Long-term debt at June 30, 2007 and September 30, 2006 consisted of the following:

	June 30, 2007	September 30, 2006
	(In thousands)	
Unsecured floating rate Senior Notes, due July 2007	$ 300,000	$ 300,000
Unsecured 4.00% Senior Notes, due 2009	400,000	400,000
Unsecured 7.375% Senior Notes, due 2011	350,000	350,000
Unsecured 10% Notes, due 2011	2,303	2,303
Unsecured 5.125% Senior Notes, due 2013	250,000	250,000
Unsecured 4.95% Senior Notes, due 2014	500,000	500,000
Unsecured 6.35% Senior Notes, due 2017	250,000	—
Unsecured 5.95% Senior Notes, due 2034	200,000	200,000
Medium term notes		
Series A, 1995-2, 6.27%, due 2010	10,000	10,000
Series A, 1995-1, 6.67%, due 2025	10,000	10,000
Unsecured 6.75% Debentures, due 2028	150,000	150,000
First Mortgage Bonds		
Series P, 10.43% due 2013	7,500	8,750
Other term notes due in installments through 2013	4,390	5,825
Total long-term debt	2,434,193	2,186,878
Less:		
Original issue discount on unsecured senior notes and debentures	(3,675)	(3,330)
Current maturities	(303,992)	(3,186)
	$2,126,526	$2,180,362

Our unsecured floating rate senior notes bear interest at a rate equal to the three-month LIBOR rate plus 0.375 percent per year. At June 30, 2007, the interest rate on our floating rate debt was 5.731 percent.

Short-term debt

At June 30, 2007, there were no borrowings outstanding under our commercial paper program or bank credit facilities. At September 30, 2006, there was $379.3 million outstanding under our commercial paper program and $3.1 million outstanding under our bank credit facilities.

Shelf Registration

On December 4, 2006, we filed a registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to $900 million in common stock and/or debt securities available for issuance, including approximately $401.5 million of capacity carried over from our prior shelf registration statement filed with the SEC in August 2004. As discussed in Note 5, in December 2006, we sold approximately 6.3 million shares of common stock under the new registration statement.

On June 14, 2007, we closed our Senior Notes Offering. The effective interest rate on these notes is 6.26 percent after giving effect to the $100 million Treasury lock discussed in Note 3. The net proceeds of approximately $247 million, together with $53 million of available cash, were used to repay our $300 million unsecured floating rate senior notes, which were called in May for redemption on July 15, 2007. Under the terms of the indenture under which the unsecured floating rate senior notes were issued, if we elected to redeem the notes prior to their maturity, we were required to do so only on any January 15, April 15, July 15 or October 15.

As of June 30, 2007, we had approximately $450 million of availability remaining under the registration statement. However, due to certain restrictions placed by one state regulatory commission on our ability to issue securities under the registration statement, we now have remaining and available for issuance a total of approximately $100 million of equity securities, $50 million of senior debt securities and $300 million of subordinated debt securities. In addition, due to restrictions imposed by another state regulatory commission, if the credit ratings on our senior unsecured debt were to fall below investment grade from either Standard & Poor's Corporation (BBB-), Moody's Investors Services, Inc. (Baa3) or Fitch Ratings, Ltd. (BBB-), our ability to issue any type of debt securities under the registration statement would be suspended until an investment grade rating from any of the three credit rating agencies was achieved.

Credit facilities

We maintain both committed and uncommitted credit facilities. Borrowings under our uncommitted credit facilities are made on a when-and-as-needed basis at the discretion of the banks. Our credit capacity and the amount of unused borrowing capacity are affected by the seasonal nature of the natural gas business and our short-term borrowing requirements, which are typically highest during colder winter months. Our working capital needs can vary significantly due to changes in the price of natural gas and the increased gas supplies required to meet customers' needs during periods of cold weather.

Committed credit facilities

As of June 30, 2007, we had three short-term committed revolving credit facilities totaling $918 million. The first facility is a five-year unsecured facility for $600 million that we entered into in December 2006, which replaced our previously existing $600 million three-year revolving credit facility. The new facility, expiring December 2011, bears interest at a base rate or at the LIBOR rate plus from 0.30 percent to 0.75 percent, based on the Company's credit ratings, and serves as a backup liquidity facility for our $600 million commercial paper program. At June 30, 2007, there were no borrowings outstanding under our commercial paper program.

The second facility is a $300 million unsecured 364-day facility expiring November 2007, that bears interest at a base rate or at the LIBOR rate plus from 0.30 percent to 0.75 percent, based on the Company's credit ratings. At June 30, 2007, there were no borrowings under this facility.

The third facility is an $18 million unsecured facility that bears interest at the Federal Funds rate plus 0.5 percent. This facility expired on March 31, 2007 and was renewed effective April 1, 2007 for one year with no material changes to the terms and pricing. At June 30, 2007, there were no borrowings under this facility.

The availability of funds under our credit facilities is subject to conditions specified in the respective credit agreements, all of which we currently satisfy. These conditions include our compliance with financial covenants and the continued accuracy of representations and warranties contained in these agreements. We are required by the financial covenants in both our $600 million and $300 million credit facilities to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At June 30, 2007, our total-debt-to-total-capitalization ratio, as defined, was 58 percent. In addition, the fees that we pay on unused amounts under both the $600 million and $300 million credit facilities are subject to adjustment depending upon our credit ratings.

Uncommitted credit facilities

AEM has a $580 million uncommitted demand working capital credit facility. On March 30, 2007, AEM and the banks in the facility amended the facility, primarily to extend it to March 31, 2008. Borrowings under the credit facility can be made either as revolving loans or offshore rate loans. Revolving loan borrowings will bear interest at a floating rate equal to a base rate defined as the higher of (i) 0.50 percent per annum above the Federal Funds rate or (ii) the lender's prime rate plus 0.25 percent. Offshore rate loan borrowings will bear interest at a floating rate equal to a base rate based upon LIBOR plus an applicable margin, ranging from 1.25 percent to 1.625 percent per annum, depending on the excess tangible net worth of AEM, as defined in the credit facility. Borrowings drawn down under letters of credit issued by the banks will bear interest at a floating rate equal to the base rate, as defined above, plus an applicable margin, which will range from 1.00 percent to 1.875 percent per annum, depending on the excess tangible net worth of AEM and whether the letters of credit are swap-related standby letters of credit.

AEM is required by the financial covenants in the credit facility not to exceed a maximum ratio of total liabilities to tangible net worth of 5 to 1, along with minimum levels of net working capital ranging from $20 million to $120 million. Additionally, AEM must maintain a minimum tangible net worth ranging from $21 million to $121 million, and must not have a maximum cumulative loss for the most recent 12 month reporting period exceeding $4 million to $23 million, depending on the total amount of borrowing elected from time to time by AEM. At June 30, 2007, AEM's ratio of total liabilities to tangible net worth, as defined, was 1.70 to 1.

At June 30, 2007, there were no borrowings outstanding under this credit facility. However, at June 30, 2007, AEM letters of credit totaling $131.7 million had been issued under the facility, which reduced the amount available by a corresponding amount. The amount available under this credit facility is also limited by various covenants, including covenants based on working capital. Under the most restrictive covenant, the amount available to AEM under this credit facility was $18.3 million at June 30, 2007. This line of credit is collateralized by substantially all of the assets of AEM and is guaranteed by AEH.

The Company also has an unsecured short-term uncommitted credit line of $25 million that is used for working-capital and letter-of-credit purposes. There were no borrowings under this uncommitted credit facility at June 30, 2007, but letters of credit reduced the amount available by $5.4 million. This uncommitted line is renewed or renegotiated at least annually with varying terms, and we pay no fee for the availability of the line. Borrowings under this line are made on a when-and-as-available basis at the discretion of the bank.

AEH, the parent company of AEM, has an intercompany uncommitted demand credit facility with the Company which bears interest at the rate of AEM's $580 million uncommitted demand working capital credit facility plus 0.25 percent. Effective May 1, 2007, the intercompany credit facility was increased from $100 million to $200 million. State regulators have approved this facility through December 31, 2007. At June 30, 2007, there were no borrowings under this facility.

In June 2007, the Company entered into a $200 million intercompany uncommitted revolving credit facility and promissory note with AEH. The new facility, expiring December 2007, bears interest at the lesser of (i) LIBOR plus 0.20 percent or (ii) the marginal borrowing rate available to the Company on any such date under its commercial paper program. At June 30, 2007, there were no borrowings under this facility.

In addition, to supplement its $580 million credit facility, AEM has an intercompany uncommitted demand credit facility with AEH, which bears interest at LIBOR plus 2.75 percent. Effective May 1, 2007, this intercompany credit facility was increased from $120 million to $175 million. Any outstanding amounts under this facility are subordinated to AEM's $580 million uncommitted demand credit facility. At June 30, 2007, there were no borrowings under this facility.

Debt Covenants

We have other debt covenants in addition to those described above. Our Series P First Mortgage Bonds contain provisions that allow us to prepay the outstanding balance in whole at any time, after November 2007, subject to a prepayment premium. The First Mortgage Bonds provide for certain cash flow requirements and restrictions on additional indebtedness, sale of assets and payment of dividends. Under the most restrictive of such covenants, cumulative cash dividends paid after December 31, 1985 may not exceed the sum of accumulated net income for periods after that date plus $9 million. At June 30, 2007, approximately $294.6 million of retained earnings was unrestricted with respect to the payment of dividends.

We were in compliance with all of our debt covenants as of June 30, 2007. If we were unable to comply with our debt covenants, we could be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions. Our public debt indentures relating to our senior notes and debentures, as well as our $600 million and $300 million revolving credit agreements, each contain a default provision that is triggered if outstanding indebtedness arising out of any other credit agreements in amounts ranging from in excess of $15 million to in excess of $100 million becomes due by acceleration or is not paid at maturity. In addition, AEM's credit agreement contains a cross-default provision whereby AEM would be in default if it defaults on other indebtedness, as defined, by at least $250 thousand in the aggregate. Additionally, this agreement contains a provision that would limit the amount of credit available if Atmos were downgraded below an S&P rating of BBB and a Moody's rating of Baa2.

Except as described above, we have no triggering events in our debt instruments that are tied to changes in specified credit ratings or stock price, nor have we entered into any transactions that would require us to issue equity, based on our credit rating or other triggering events.

5. Public Offering

On December 13, 2006, we completed the public offering of 6,325,000 shares of our common stock including the underwriters' exercise of their overallotment option of 825,000 shares. The offering was priced at $31.50 per share and generated net proceeds of approximately $192 million. We used the net proceeds from this offering to reduce short-term debt.

6. Earnings Per Share

Basic and diluted earnings per share for the three and nine months ended June 30, 2007 and 2006 are calculated as follows:

	For the Three Months Ended June 30		For the Nine Months Ended June 30	
	2007	2006	2007	2006
	(In thousands, except per share amounts)			
Net income (loss)	$(13,360)	$(18,145)	$174,406	$141,678
Denominator for basic income per share — weighted average common shares	88,366	80,840	86,378	80,520
Effect of dilutive securities:				
Restricted and other shares	—	—	464	394
Stock options	—	—	169	99
Denominator for diluted income per share — weighted average common shares	88,366	80,840	87,011	81,013
Income (loss) per share — basic	$ (0.15)	$ (0.22)	$ 2.02	$ 1.76
Income (loss) per share — diluted	$ (0.15)	$ (0.22)	$ 2.00	$ 1.75

There were approximately 466,000 and 396,000 restricted and other shares and approximately 165,000 and 102,000 stock options that were excluded from the calculation of diluted earnings per share for the three months ended June 30, 2007 and 2006 as their inclusion in the computation would be anti-dilutive.

There were no out-of-the-money options excluded from the computation of diluted earnings per share for the three and nine months ended June 30, 2007 and 2006 as their exercise price was less than the average market price of the common stock during that period.

7. Interim Pension and Other Postretirement Benefit Plan Information

The components of our net periodic pension cost for our pension and other postretirement benefit plans for the three and nine months ended June 30, 2007 and 2006 are presented in the following tables. The costs relating to our utility operations are recoverable through our gas utility rates; however, a portion of these costs is capitalized into our utility rate base. The remaining costs are recorded as a component of operation and maintenance expense.

	Three Months Ended June 30			
	Pension Benefits		Other Benefits	
	2007	2006	2007	2006
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 4,017	$ 4,117	$2,807	$3,271
Interest cost	6,496	5,722	2,640	2,210
Expected return on assets	(6,089)	(6,400)	(597)	(547)
Amortization of transition asset	—	—	377	378
Amortization of prior service cost	44	16	9	90
Amortization of actuarial loss	2,435	3,299	—	320
Net periodic pension cost	$ 6,903	$ 6,754	$5,236	$5,722

	Nine Months Ended June 30			
	Pension Benefits		Other Benefits	
	2007	2006	2007	2006
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 12,053	$ 12,351	$ 8,421	$ 9,813
Interest cost	19,486	17,166	7,921	6,630
Expected return on assets	(18,267)	(19,200)	(1,791)	(1,641)
Amortization of transition asset	—	—	1,133	1,134
Amortization of prior service cost	134	48	25	270
Amortization of actuarial loss	7,303	9,897	—	960
Net periodic pension cost	$ 20,709	$ 20,262	$15,709	$17,166

The assumptions used to develop our net periodic pension cost for the three and nine months ended June 30, 2007 and 2006 are as follows:

	Pension Benefits		Other Benefits	
	2007	2006	2007	2006
Discount rate	6.30%	5.00%	6.30%	5.00%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Expected return on plan assets	8.25%	8.50%	5.20%	5.30%

The discount rate used to compute the present value of a plan's liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid. Generally, our funding policy is to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974. However, additional voluntary contributions are made to satisfy regulatory requirements in certain of our jurisdictions. During the nine months ended June 30, 2007, we contributed $8.5 million to our other postretirement plans, and we expect to contribute a total of approximately $12 million to these plans during fiscal 2007.

8. Commitments and Contingencies

Litigation and Environmental Matters

With respect to the specific litigation and environmental-related matters or claims that were disclosed in Note 13 to our annual report on Form 10-K for the year ended September 30, 2006, there were no material changes in the status of such litigation and environmental-related matters or claims during the nine months ended June 30, 2007. We continue to believe that the final outcome of such litigation and environmental-related matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

In addition, we are involved in other litigation and environmental-related matters or claims that arise in the ordinary course of our business. While the ultimate results of such litigation and response actions to such environmental-related matters or claims cannot be predicted with certainty, we believe the final outcome of such litigation and response actions will not have a material adverse effect on our financial condition, results of operations or cash flows.

Purchase Commitments

AEM has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At June 30, 2007, AEM was committed to purchase 87.0 Bcf within one year and 48.2 Bcf within one to three years under indexed contracts. AEM is committed to purchase 1.9 Bcf within one year and less than 0.1 Bcf within one to three years under fixed price contracts with prices ranging from $6.00 to $9.85. Purchases under these contracts totaled $567.9 million and $398.9 million for the three months ended June 30, 2007 and 2006 and $1,551.3 million and $1,718.4 million for the nine months ended June 30, 2007 and 2006.

Our utility operations, other than the Mid-Tex Division, maintain supply contracts with several vendors that generally cover a period of up to one year. Commitments for estimated base gas volumes are established under these contracts on a monthly basis at contractually negotiated prices. Commitments for incremental daily purchases are made as necessary during the month in accordance with the terms of the individual contract.

Our Mid-Tex Division maintains long-term supply contracts to ensure a reliable source of gas for our customers in its service area which obligate it to purchase specified volumes at market prices. The estimated fiscal year commitments under these contracts as of June 30, 2007 are as follows (in thousands):

2007	$ 67,149
2008	435,955
2009	169,085
2010	107,603
2011	9,683
Thereafter	22,033
	$811,508

Regulatory Matters

At June 30, 2007, we were involved in a number of "show cause" proceedings filed by cities in several of our jurisdictions. We are currently providing information to and addressing questions raised by the respective regulatory commissions. We believe we will be able to demonstrate to these regulators that our rates are just and reasonable. Additionally, we have a rate case in progress in our Tennessee service area. These regulatory proceedings are discussed in further detail in *Management's Discussion and Analysis — Recent Ratemaking Developments.*

9. Concentration of Credit Risk

Information regarding our concentration of credit risk is disclosed in Note 15 to our annual report on Form 10-K for the year ended September 30, 2006. During the nine months ended June 30, 2007, there were no material changes in our concentration of credit risk.

10. Segment Information

Atmos Energy Corporation and our subsidiaries are engaged primarily in the natural gas utility business as well as certain nonutility businesses. We distribute natural gas through sales and transportation arrangements to approximately 3.2 million residential, commercial, public authority and industrial customers throughout our six regulated utility divisions, which cover service areas located in 12 states. In addition, we transport natural gas for others through our distribution system.

Through our nonutility businesses we provide natural gas management and marketing services to industrial customers, municipalities and other local distribution companies located in 22 states. Additionally, we provide natural gas transportation and storage services to certain of our utility operations and to third parties.

Our operations are divided into four segments:

- the utility segment, which includes our regulated natural gas distribution and related sales operations,
- the natural gas marketing segment, which includes a variety of nonregulated natural gas management services,
- the pipeline and storage segment, which includes our regulated and nonregulated natural gas transmission and storage services and
- the other nonutility segment, which includes all of our other nonregulated nonutility operations.

Our determination of reportable segments considers the strategic operating units under which we manage sales of various products and services to customers in differing regulatory environments. Although our utility segment operations are geographically dispersed, they are reported as a single segment as each utility division has similar economic characteristics. The accounting policies of the segments are the same as those described in the summary of significant accounting policies found in our annual report on Form 10-K for the fiscal year ended September 30, 2006. We evaluate performance based on net income or loss of the respective operating units.

Income statements for the three and nine-month periods ended June 30, 2007 and 2006 by segment are presented in the following tables:

	Three Months Ended June 30, 2007					
	Utility	Natural Gas Marketing	Pipeline and Storage	Other Nonutility	Eliminations	Consolidated
			(In thousands)			
Operating revenues from external parties	$548,104	$649,633	$20,033	$382	$ —	$1,218,152
Intersegment revenues	147	204,534	17,904	461	(223,046)	—
	548,251	854,167	37,937	843	(223,046)	1,218,152
Purchased gas cost	357,608	854,743	228	—	(222,443)	990,136
Gross profit	190,643	(576)	37,709	843	(603)	228,016
Operating expenses						
Operation and maintenance	96,912	6,854	14,732	621	(689)	118,430
Depreciation and amortization	43,661	376	4,908	29	—	48,974
Taxes, other than income	50,005	295	2,540	41	—	52,881
Total operating expenses	190,578	7,525	22,180	691	(689)	220,285
Operating income (loss)	65	(8,101)	15,529	152	86	7,731
Miscellaneous income	2,232	1,578	3,899	713	(4,156)	4,266
Interest charges	28,987	2,012	7,125	425	(4,070)	34,479
Income (loss) before income taxes	(26,690)	(8,535)	12,303	440	—	(22,482)
Income tax expense (benefit)	(11,000)	(2,925)	4,631	172	—	(9,122)
Net income (loss)	$(15,690)	$ (5,610)	$ 7,672	$268	$ —	$ (13,360)
Capital expenditures	$ 78,829	$ 187	$11,215	$ —	$ —	$ 90,231

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Three Months Ended June 30, 2006					
	Utility	Natural Gas Marketing	Pipeline and Storage	Other Nonutility	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$401,896	$441,418	$19,597	$ 332	$ —	$863,243
Intersegment revenues	148	121,029	16,265	1,081	(138,523)	—
	402,044	562,447	35,862	1,413	(138,523)	863,243
Purchased gas cost	232,192	563,333	379	—	(137,161)	658,743
Gross profit	169,852	(886)	35,483	1,413	(1,362)	204,500
Operating expenses						
Operation and maintenance	85,372	5,725	13,485	1,227	(1,429)	104,380
Depreciation and amortization	41,537	466	4,807	28	—	46,838
Taxes, other than income	45,853	273	2,272	81	—	48,479
Total operating expenses	172,762	6,464	20,564	1,336	(1,429)	199,697
Operating income (loss)	(2,910)	(7,350)	14,919	77	67	4,803
Miscellaneous income	3,022	556	309	1,372	(4,296)	963
Interest charges	30,892	1,716	6,384	1,181	(4,229)	35,944
Income (loss) before income taxes	(30,780)	(8,510)	8,844	268	—	(30,178)
Income tax expense (benefit)	(11,809)	(3,341)	3,012	105	—	(12,033)
Net income (loss)	$(18,971)	$ (5,169)	$ 5,832	$ 163	$ —	$(18,145)
Capital expenditures	$ 75,973	$ 500	$32,988	$ —	$ —	$109,461

	Nine Months Ended June 30, 2007					
	Utility	Natural Gas Marketing	Pipeline and Storage	Other Nonutility	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$2,973,048	$1,844,271	$ 77,863	$1,185	$ —	$4,896,367
Intersegment revenues	480	516,631	69,288	1,794	(588,193)	—
	2,973,528	2,360,902	147,151	2,979	(588,193)	4,896,367
Purchased gas cost	2,174,071	2,275,291	682	—	(585,971)	3,864,073
Gross profit	799,457	85,611	146,469	2,979	(2,222)	1,032,294
Operating expenses						
Operation and maintenance	287,353	19,022	39,149	2,618	(2,480)	345,662
Depreciation and amortization	133,287	1,153	14,508	87	—	149,035
Taxes, other than income	141,292	951	7,286	165	—	149,694
Total operating expenses	561,932	21,126	60,943	2,870	(2,480)	644,391
Operating income	237,525	64,485	85,526	109	258	387,903
Miscellaneous income	6,633	5,816	5,504	1,614	(11,884)	7,683
Interest charges	91,164	3,418	24,582	1,735	(11,626)	109,273
Income (loss) before income taxes	152,994	66,883	66,448	(12)	—	286,313
Income tax expense (benefit)	60,530	26,515	24,867	(5)	—	111,907
Net income (loss)	$ 92,464	$ 40,368	$ 41,581	$ (7)	$ —	$ 174,406
Capital expenditures	$ 222,526	$ 837	$ 39,660	$ —	$ —	$ 263,023

	Nine Months Ended June 30, 2006					
	Utility	Natural Gas Marketing	Pipeline and Storage	Other Nonutility	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$3,254,078	$1,866,768	$ 58,716	$1,347	$ —	$5,180,909
Intersegment revenues	596	616,153	62,341	3,153	(682,243)	—
	3,254,674	2,482,921	121,057	4,500	(682,243)	5,180,909
Purchased gas cost	2,488,906	2,413,511	590	—	(678,591)	4,224,416
Gross profit	765,768	69,410	120,467	4,500	(3,652)	956,493
Operating expenses						
Operation and maintenance	272,501	15,898	36,846	3,853	(3,803)	325,295
Depreciation and amortization	121,708	1,411	13,978	77	—	137,174
Taxes, other than income	150,456	864	7,086	285	—	158,691
Total operating expenses	544,665	18,173	57,910	4,215	(3,803)	621,160
Operating income	221,103	51,237	62,557	285	151	335,333
Miscellaneous income (expense)	6,014	1,754	1,846	3,216	(13,858)	(1,028)
Interest charges	92,783	6,575	18,978	2,996	(13,707)	107,625
Income before income taxes	134,334	46,416	45,425	505	—	226,680
Income tax expense	50,264	18,201	16,339	198	—	85,002
Net income	$ 84,070	$ 28,215	$ 29,086	$ 307	$ —	$ 141,678
Capital expenditures	$ 232,137	$ 1,067	$ 89,487	$ —	$ —	$ 322,691

Balance sheet information at June 30, 2007 and September 30, 2006 by segment is presented in the following tables:

	June 30, 2007					
	Utility	Natural Gas Marketing	Pipeline and Storage	Other Nonutility	Eliminations	Consolidated
	(In thousands)					
ASSETS						
Property, plant and equipment, net	$3,186,885	$ 7,794	$561,592	$ 1,205	$ —	$3,757,476
Investment in subsidiaries	383,486	(2,106)	—	—	(381,380)	—
Current assets						
Cash and cash equivalents	279,824	48,864	190	21,505	—	350,383
Cash held on deposit in margin account	—	13,576	—	—	—	13,576
Assets from risk management activities	—	12,018	9,096	—	(10,752)	10,362
Other current assets	541,364	459,119	31,059	11,499	(82,869)	960,172
Intercompany receivables	536,238	—	—	45,400	(581,638)	—
Total current assets	1,357,426	533,577	40,345	78,404	(675,259)	1,334,493
Intangible assets	—	2,696	—	—	—	2,696
Goodwill	567,221	24,282	143,866	—	—	735,369
Noncurrent assets from risk management activities	—	7,077	—	—	—	7,077
Deferred charges and other assets	197,731	1,296	4,936	14,735	—	218,698
	$5,692,749	$574,616	$750,739	$94,344	$(1,056,639)	$6,055,809
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	$1,988,142	$154,529	$145,324	$83,633	$ (383,486)	$1,988,142
Long-term debt	2,124,878	—	—	1,648	—	2,126,526
Total capitalization	4,113,020	154,529	145,324	85,281	(383,486)	4,114,668
Current liabilities						
Current maturities of long-term debt	301,250	—	—	2,742	—	303,992
Short-term debt	—	—	—	—	—	—
Liabilities from risk management activities	7,524	10,520	1,212	—	(10,752)	8,504
Other current liabilities	459,152	307,266	95,567	—	(80,763)	781,222
Intercompany payables	—	111,932	469,706	—	(581,638)	—
Total current liabilities	767,926	429,718	566,485	2,742	(673,153)	1,093,718
Deferred income taxes	340,432	(10,884)	35,276	2,201	—	367,025
Noncurrent liabilities from risk management activities	—	561	—	—	—	561
Regulatory cost of removal obligation	261,436	—	—	—	—	261,436
Deferred credits and other liabilities	209,935	692	3,654	4,120	—	218,401
	$5,692,749	$574,616	$750,739	$94,344	$(1,056,639)	$6,055,809

	September 30, 2006					
	Utility	Natural Gas Marketing	Pipeline and Storage	Other Nonutility	Eliminations	Consolidated
	(In thousands)					
ASSETS						
Property, plant and equipment, net	$3,083,301	$ 7,531	$537,028	$ 1,296	$ —	$3,629,156
Investment in subsidiaries	281,143	(2,155)	—	—	(278,988)	—
Current assets						
Cash and cash equivalents	8,738	45,481	—	21,596	—	75,815
Cash held on deposit in margin account	—	35,647	—	—	—	35,647
Assets from risk management activities	—	13,164	19,040	—	(19,651)	12,553
Other current assets	714,472	261,435	26,325	8,119	(16,821)	993,530
Intercompany receivables	602,809	—	—	—	(602,809)	—
Total current assets	1,326,019	355,727	45,365	29,715	(639,281)	1,117,545
Intangible assets	—	3,152	—	—	—	3,152
Goodwill	567,221	24,282	143,866	—	—	735,369
Noncurrent assets from risk management activities	—	6,190	5	—	(9)	6,186
Deferred charges and other assets	204,617	1,315	5,301	16,906	—	228,139
	$5,462,301	$396,042	$731,565	$47,917	$(918,278)	$5,719,547
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	$1,648,098	$139,863	$107,640	$33,640	$(281,143)	$1,648,098
Long-term debt	2,176,473	—	—	3,889	—	2,180,362
Total capitalization	3,824,571	139,863	107,640	37,529	(281,143)	3,828,460
Current liabilities						
Current maturities of long-term debt	1,250	—	—	1,936	—	3,186
Short-term debt	382,416	—	—	—	—	382,416
Liabilities from risk management activities	27,209	22,500	531	—	(19,571)	30,669
Other current liabilities	473,101	183,077	61,458	—	(14,746)	702,890
Intercompany payables	—	75,665	525,895	1,249	(602,809)	—
Total current liabilities	883,976	281,242	587,884	3,185	(637,126)	1,119,161
Deferred income taxes	297,821	(25,777)	31,927	2,201	—	306,172
Noncurrent liabilities from risk management activities	—	280	5	—	(9)	276
Regulatory cost of removal obligation	261,376	—	—	—	—	261,376
Deferred credits and other liabilities	194,557	434	4,109	5,002	—	204,102
	$5,462,301	$396,042	$731,565	$47,917	$(918,278)	$5,719,547

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors
Atmos Energy Corporation

We have reviewed the condensed consolidated balance sheet of Atmos Energy Corporation as of June 30, 2007, and the related condensed consolidated statements of income for the three-month and nine-month periods ended June 30, 2007 and 2006, and the condensed consolidated statements of cash flows for the nine-month periods ended June 30, 2007 and 2006. These financial statements are the responsibility of the Company's management.

We conducted our review in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the condensed consolidated financial statements referred to above for them to be in conformity with U.S. generally accepted accounting principles.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Atmos Energy Corporation as of September 30, 2006, and the related consolidated statements of income, shareholders' equity, and cash flows for the year then ended, not presented herein, and in our report dated November 20, 2006, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet as of September 30, 2006, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

ERNST & YOUNG LLP

Dallas, Texas
August 8, 2007

Item 2. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

INTRODUCTION

The following discussion should be read in conjunction with the condensed consolidated financial statements in this Quarterly Report on Form 10-Q and Management's Discussion and Analysis in our Annual Report on Form 10-K for the year ended September 30, 2006.

Cautionary Statement for the Purposes of the Safe Harbor under the Private Securities Litigation Reform Act of 1995

The statements contained in this Quarterly Report on Form 10-Q may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this Report are forward-looking statements made in good faith by us and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this Report, or any other of our documents or oral presentations, the words "anticipate", "believe", "estimate", "expect", "forecast", "goal", "intend", "objective", "plan", "projection", "seek", "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the statements relating to our strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties include the following: regulatory trends and decisions, including deregulation initiatives and the impact of rate proceedings before various state regulatory commissions; adverse weather conditions, such as warmer than normal weather in our utility service territories or colder than normal weather that could adversely affect our natural gas marketing activities; the concentration of our distribution, pipeline and storage operations in one state; impact of environmental regulations on our business; market risks beyond our control affecting our risk management activities including market liquidity, commodity price volatility, increasing interest rates and counterparty creditworthiness; our ability to continue to access the capital markets; the effects of inflation and changes in the availability and prices of natural gas, including the volatility of natural gas prices; increased competition from energy suppliers and alternative forms of energy; increased costs of providing pension and postretirement health care benefits; the capital-intensive nature of our distribution business; the inherent hazards and risks involved in operating our distribution business; effects of natural disasters or terrorist activities and other risks and uncertainties, which may be discussed herein, all of which are difficult to predict and many of which are beyond our control. A more detailed discussion of these risks and uncertainties may be found in our Annual Report on Form 10-K for the year ended September 30, 2006. Accordingly, while we believe these forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. Further, we undertake no obligation to update or revise any of our forward-looking statements whether as a result of new information, future events or otherwise.

OVERVIEW

Atmos Energy Corporation and our subsidiaries are engaged primarily in the natural gas utility business as well as certain nonutility businesses. We distribute natural gas through sales and transportation arrangements to approximately 3.2 million residential, commercial, public authority and industrial customers throughout our six regulated utility divisions, which cover service areas located in 12 states. In addition, we transport natural gas for others through our distribution system.

Through our nonutility businesses, we primarily provide natural gas management and marketing services to municipalities, other local gas distribution companies and industrial customers in 22 states and natural gas transportation and storage services to certain of our utility operations and to third parties.

Our operations are divided into four segments:

- the utility segment, which includes our regulated natural gas distribution and related sales operations,

- the natural gas marketing segment, which includes a variety of nonregulated natural gas management services,
- the pipeline and storage segment, which includes our regulated and nonregulated natural gas transmission and storage services and
- the other nonutility segment, which includes all of our other nonregulated nonutility operations.

CRITICAL ACCOUNTING ESTIMATES AND POLICIES

Our condensed consolidated financial statements were prepared in accordance with accounting principles generally accepted in the United States. Preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities. We based our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. On an ongoing basis, we evaluate our estimates, including those related to risk management and trading activities, allowance for doubtful accounts, legal and environmental accruals, insurance accruals, pension and postretirement obligations, deferred income taxes and the valuation of goodwill, indefinite-lived intangible assets and other long-lived assets. Actual results may differ from such estimates.

Our critical accounting policies used in the preparation of our consolidated financial statements are described in our Annual Report on Form 10-K for the year ended September 30, 2006 and include the following:

- Regulation
- Revenue Recognition
- Allowance for Doubtful Accounts
- Derivatives and Hedging Activities
- Impairment Assessments
- Pension and Other Postretirement Plans

Our critical accounting policies are reviewed by the Audit Committee on a quarterly basis. There have been no significant changes to these critical accounting policies during the nine months ended June 30, 2007.

RESULTS OF OPERATIONS

Consolidated financial highlights for the three-month and nine-month periods ended June 30, 2007 and 2006 are presented below:

	Three Months Ended June 30		Nine Months Ended June 30	
	2007	2006	2007	2006
	(In thousands)			
Operating revenues	$1,218,152	$863,243	$4,896,367	$5,180,909
Gross profit	228,016	204,500	1,032,294	956,493
Operating expenses	220,285	199,697	644,391	621,160
Operating income	7,731	4,803	387,903	335,333
Miscellaneous income (expense)	4,266	963	7,683	(1,028)
Interest charges	34,479	35,944	109,273	107,625
Income (loss) before income taxes	(22,482)	(30,178)	286,313	226,680
Income tax expense (benefit)	(9,122)	(12,033)	111,907	85,002
Net income (loss)	$ (13,360)	$(18,145)	$ 174,406	$ 141,678

For the nine months ended June 30, 2007, we earned $174.4 million, or $2.00 per diluted share, compared with net income of $141.7 million, or $1.75 per diluted share during the nine months ended June 30, 2006. The 23 percent period-over-period increase in net income was primarily attributable to strong financial results in our natural gas marketing and pipeline and storage segments coupled with improved results in our utility segment. Our utility operations contributed $92.5 million ($1.06 per diluted share) or 53 percent to our results for the nine months ended June 30, 2007. Our nonutility operations, comprised of our natural gas marketing, pipeline and storage and other nonutility segments, contributed $81.9 million ($0.94 per diluted share), or 47 percent to our results for the nine months ended June 30, 2007.

Key financial and other events for the nine months ended June 30, 2007 include the following:

- Our utility segment net income increased by $8.4 million during the nine months ended June 30, 2007 compared with the nine months ended June 30, 2006. The increase primarily reflects the net favorable impact of various ratemaking rulings, including the implementation of WNA in our Mid-Tex and Louisiana Divisions.

- Our natural gas marketing segment net income increased $12.2 million during the nine months ended June 30, 2007 compared with the nine months ended June 30, 2006. The increase in natural gas marketing net income primarily reflects higher margins associated with storage activities partially offset by lower margins from marketing activities.

- Our pipeline and storage segment net income increased $12.5 million during the nine months ended June 30, 2007 compared with the nine months ended June 30, 2006. Increased net income primarily reflects increased margins from increased throughput, including incremental gross profit margins from our North Side Loop and other pipeline compression projects completed in fiscal 2006, higher asset management fees earned by Atmos Pipeline & Storage, LLC and increased margins from the Gas Reliability Infrastructure Program (GRIP).

- In December 2006, we filed a $900 million shelf registration statement with the Securities and Exchange Commission (SEC) that replaced our previously existing shelf registration statement. Upon completion of the filing of this registration statement, we received net proceeds of approximately $192 million through the issuance of approximately 6.3 million shares of common stock. The net proceeds received were used to repay a portion of our then-existing short-term debt balance. In June 2007, we received net proceeds of approximately $247 million from the issuance of senior notes. The net proceeds received, together with $53 million of available cash, were used to repay our $300 million unsecured floating rate senior notes, which were called in May for redemption on July 15, 2007.

- Our total-debt-to-capitalization ratio at June 30, 2007 was 55.0 percent compared with 60.9 percent at September 30, 2006 primarily reflecting the favorable impact of our equity offering in December 2006 and the absence of outstanding short-term debt as of June 30, 2007, partially offset by the timing of the repayment of our $300 million unsecured floating rate senior notes. Had we been able to repay the notes as of June 30, 2007, our total-debt-to-capitalization ratio would have been 51.7 percent.

- For the nine months ended June 30, 2007, we generated $552.7 million in operating cash flow compared with $223.4 million for the nine months ended June 30, 2006, primarily reflecting the favorable impact of increased earnings, increased sales volumes attributable to colder weather during the period and lower natural gas prices.

- Capital expenditures decreased to $263.0 million during the nine months ended June 30, 2007 from $322.7 million in the prior-year period. The decrease primarily reflects the absence of capital spending for the North Side Loop and other compression projects completed in fiscal 2006.

- In March 2007, the Texas Railroad Commission issued an order in our Mid-Tex Division's rate case, which prospectively increased annual revenues by approximately $4.8 million and established a permanent WNA based upon a 10-year average effective for the months of November through April. However, the ruling also reduced the Mid-Tex Division's total return to 7.903 percent from 8.258 percent and required a $2.9 million refund, inclusive of interest, of amounts collected from our calendar 2003 — 2005 GRIP filings.

Three Months Ended June 30, 2007 compared with Three Months Ended June 30, 2006

Utility segment

Our utility segment has historically contributed 65 to 85 percent of our consolidated net income. However, in recent years, this contribution has declined as our nonutility businesses have grown and our utility operations have experienced the adverse effects of warmer-than-normal weather and declining average gas usage per customer.

Natural gas sales to residential, commercial and public authority customers are affected by winter heating season requirements, whereas natural gas sales to industrial customers are much less weather sensitive. As residential, commercial and public authority customers comprise approximately 90 percent of our gas sales volumes, the results of operations for our utility segment are seasonal. We typically experience higher operating revenues and net income during the period from October through March of each year and lower operating revenues and either lower net income or net losses during the period from April through September of each year. Accordingly, our second fiscal quarter has historically been our most critical earnings quarter with an average of approximately 64 percent of our consolidated net income having been earned in the second quarter during the three most recently completed fiscal years. Additionally, we typically experience higher levels of accounts receivable, accounts payable, gas stored underground and short-term debt balances during the winter heating season due to the seasonal nature of our revenues and the need to purchase and store gas to support these operations.

The primary factors that currently impact the results of our utility operations are regulatory decisions and trends, the increased use of energy-efficient appliances by our customers, competitive factors in the energy industry and economic conditions in our service areas.

Seasonal weather patterns can also affect our utility operations. However, the effect of weather that is above or below normal is substantially offset through weather normalization adjustments, known as WNA, which, beginning with the 2006-2007 winter heating season, has been approved by regulators for approximately 90 percent of our residential and commercial meters in the following states for the following time periods:

Georgia	October – May
Kansas	October – May
Kentucky	November – April
Louisiana[1]	December – March
Mississippi	November – April
Tennessee	November – April
Texas: Mid-Tex[1]	November – April
Texas: West Texas	October – May
Virginia	January – December

[1] Effective beginning for the 2006-2007 winter heating season in our Mid-Tex and Louisiana Divisions.

WNA allows us to increase customers' bills to offset lower gas usage when weather is warmer than normal and decrease customers' bills to offset higher gas usage when weather is colder than normal. Although our WNA periods do not cover the entire heating season in all jurisdictions, we believe these mechanisms substantially insulate our utility gross profit margin from the effects of weather.

Our utility operations are also affected by the cost of natural gas. The cost of gas is passed through to our customers without markup. Therefore, increases in the cost of gas are offset by a corresponding increase in revenues. Accordingly, we believe gross profit is a better indicator of our financial performance than revenues. However, gross profit in our Texas and Mississippi service areas include franchise fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenues is influenced by the cost of gas and the level of gas sales volumes. We record the tax expense as a component of taxes, other than income. Although changes in revenue-related taxes arising from changes in gas cost affect gross profit, over time the impact is offset within operating income. Timing differences exist between the recognition of revenue for franchise fees collected from our customers and the recognition of expense of franchise taxes. The effect of these timing differences can be significant in periods of volatile gas prices, particularly in our Mid-Tex Division. These timing differences may favorably or unfavorably affect net income; however, these amounts should offset over time with no permanent impact on net income.

Higher gas costs affect our utility operations in other ways as well. Higher gas costs may cause customers to conserve, or, in the case of industrial customers, to use alternative energy sources. Higher gas costs may also adversely impact our accounts receivable collections, resulting in higher bad debt expense and may require us to increase borrowings under our credit facilities, resulting in higher interest expense.

Review of Financial and Operating Results

Financial and operational highlights for our utility segment for the three months ended June 30, 2007 and 2006 are presented below:

	Three Months Ended June 30	
	2007	2006
	(Dollars in thousands, except per Mcf amounts)	
Gross profit	$190,643	$169,852
Operating expenses	190,578	172,762
Operating income (loss)	65	(2,910)
Miscellaneous income	2,232	3,022
Interest charges	28,987	30,892
Loss before income taxes	(26,690)	(30,780)
Income tax benefit	(11,000)	(11,809)
Net loss	$(15,690)	$(18,971)
Utility sales volumes — MMcf	45,252	32,653
Utility transportation volumes — MMcf	29,311	29,630
Total utility throughput — MMcf	74,563	62,283
Heating degree days		
Actual (weighted average)	163	119
Percent of normal	98%	69%
Consolidated utility average transportation revenue per Mcf	$ 0.41	$ 0.46
Consolidated utility average cost of gas per Mcf sold	$ 7.90	$ 7.11

The following table shows our operating income by utility division for the three months ended June 30, 2007 and 2006. The presentation of our utility operating income by division is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Three Months Ended June 30			
	2007		2006	
	Operating Income (Loss)	Heating Degree Days Percent of Normal[1]	Operating Income (Loss)	Heating Degree Days Percent of Normal[1]
	(In thousands, except degree day information)			
Colorado-Kansas	$ 884	99%	$ 163	87%
Kentucky/Mid-States[2]	1,762	87	(3,105)	94
Louisiana	5,921	195	8,715	14
Mid-Tex	(11,415)	93	(12,819)	7
Mississippi	2,115	105	(1,265)	115
West Texas	(391)	100	4,383	98
Other	1,189	—	1,018	—
Total	$ 65	98%	$ (2,910)	69%

(1) Adjusted for service areas that have weather-normalized operations.

(2) Effective October 1, 2006, the Kentucky and Mid-States Divisions were combined. Prior year amounts have been reclassified to conform to this new presentation.

The $20.8 million improvement in utility gross profit primarily reflects a 20 percent increase in throughput, which increased gross profit by $18.9 million and $7.3 million of rate increases received from our Rate Stabilization Clause (RSC) filings in our Louisiana service areas, GRIP-related recoveries in our Texas service areas and rate design changes in our Missouri service areas. These increases in the current-year period were partially offset by the recognition in the prior-year's gross profit margin of $6.2 million in previously deferred gross profit from the 2003 RSC filing in our Louisiana Division.

Gross profit also increased approximately $6.9 million in revenue-related taxes primarily due to increased throughput and higher revenues, on which the tax is calculated, due to an increase in the cost of gas in the current-year quarter compared with the prior-year quarter. This increase, partially offset by a $3.5 million quarter-over-quarter increase in the associated franchise and state gross receipts tax expense recorded as a component of taxes, other than income resulted in a $3.4 million increase in operating income when compared with the prior-year quarter.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, increased to $190.6 million for the three months ended June 30, 2007 from $172.8 million for the three months ended June 30, 2006.

Operation and maintenance expense, excluding the provision for doubtful accounts, increased $10.7 million primarily due to higher employee and administrative costs and a one-time $3.3 million noncash charge to write off software that will no longer be used. These increases were partially offset by a $2.0 million reversal of an accrual in the prior-year quarter for Hurricane Katrina losses after the outlook to recover the losses sustained from the storm had improved.

The provision for doubtful accounts increased $0.9 million to $3.0 million for the three months ended June 30, 2007. The increase primarily was attributable to increased revenues. In the utility segment, the average cost of natural gas for the three months ended June 30, 2007 was $7.90 per thousand cubic feet (Mcf), compared with $7.11 per Mcf for the three months ended June 30, 2006.

Interest charges associated with the utility segment for the three months ended June 30, 2007 decreased to $29.0 million from $30.9 million for the three months ended June 30, 2006. The decrease was primarily attributable to reduced interest expense attributable to lower average outstanding short-term debt balances in the current-year quarter compared with the prior-year quarter, partially offset by a 28 basis point increase in the interest rate on our $300 million unsecured floating rate senior notes due July 2007 due to an increase in the three-month LIBOR rate.

Natural gas marketing segment

Our natural gas marketing segment aggregates and purchases gas supply, arranges transportation and/or storage logistics and ultimately delivers gas to our customers at competitive prices. To facilitate this process, we utilize proprietary and customer-owned transportation and storage assets to provide the various services our customers request, including furnishing natural gas supplies at fixed and market-based prices, contract negotiation and administration, load forecasting, gas storage acquisition and management services, transportation services, peaking sales and balancing services, capacity utilization strategies and gas price hedging through the use of derivative products. As a result, our revenues arise from the types of commercial transactions we have structured with our customers and include the value we extract by optimizing the storage and transportation capacity we own or control as well as revenues for services we perform.

To optimize the storage and transportation capacity we own or control, we participate in transactions in which we combine the natural gas commodity and transportation costs to minimize our costs incurred to serve our customers by identifying the lowest cost alternative within the natural gas supplies, transportation and markets to which we have access. Additionally, we engage in natural gas storage transactions in which we seek to find and profit from the pricing differences that occur over time. We purchase physical natural gas and then sell financial contracts at advantageous prices to lock in a gross profit margin. Through the use of transportation and storage services and derivative contracts, we are able to capture gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time.

The natural gas inventory used in our natural gas marketing storage activities is marked to market at the end of each month based upon the Gas Daily index with changes in fair value recognized as unrealized gains and losses in the period of change. We use derivatives, designated as fair value hedges, to hedge this natural gas inventory. These derivatives are marked to market each month based upon the NYMEX price with changes in fair value recognized as unrealized gains and losses in the period of change. The changes between the spreads between the forward natural gas prices used to value the financial hedges designated against our physical inventory and the market (spot) prices used to value our physical storage result in the unrealized margins reported as a part of our storage activities until the underlying physical gas is cycled and the related financial derivatives are settled.

AEM also uses derivative instruments to capture additional storage arbitrage opportunities that arise subsequent to the execution of the original physical inventory hedge and to insulate and protect the economic value within its storage and marketing activities. Changes in fair value associated with these financial instruments are recognized as unrealized gains and losses within AEM's storage and marketing activities until they are settled.

Review of Financial and Operating Results

Financial and operational highlights for our natural gas marketing segment for the three months ended June 30, 2007 and 2006 are presented below. Gross profit for our natural gas marketing segment consists primarily of storage activities and marketing activities. Storage activities represent the optimization of our managed proprietary and third-party storage and transportation assets. Marketing activities represent the utilization of proprietary and customer-owned transportation and storage assets to provide various services our customers request.

	Three Months Ended June 30	
	2007	2006
	(Dollars in thousands)	
Storage Activities		
Realized margin	$(33,376)	$ 7,717
Unrealized margin	16,998	(21,873)
Total Storage Activities	(16,378)	(14,156)
Marketing Activities		
Realized margin	9,999	12,691
Unrealized margin	5,803	579
Total Marketing Activities	15,802	13,270
Gross profit	(576)	(886)
Operating expenses	7,525	6,464
Operating loss	(8,101)	(7,350)
Miscellaneous income	1,578	556
Interest charges	2,012	1,716
Loss before income taxes	(8,535)	(8,510)
Income tax benefit	(2,925)	(3,341)
Net loss	$ (5,610)	$ (5,169)
Natural gas marketing sales volumes — MMcf	85,413	66,472
Net physical position (Bcf)	21.5	19.0

The $0.3 million increase in our natural gas marketing segment's gross profit reflects a $44.1 million increase in unrealized margins during the current-year quarter compared with the prior-year quarter offset by a $43.8 million decrease in realized storage and marketing margins.

Realized gross profit from our storage activities decreased $41.1 million compared with the prior-year quarter. The decrease reflects an increase in storage fees, park and loan fees and the impact of a less volatile market, which reduced the arbitrage spreads earned from these activities. Additionally, AEM recognized financial hedge settlement losses associated with the deferral of storage withdrawals.

These decreases were partially offset by a $38.9 million increase in unrealized gains primarily attributable to a narrowing of the spreads between the physical and forward natural gas prices. This mark-to-market impact was magnified by a 2.5 Bcf increase in our net physical position at June 30, 2007 compared to the prior-year quarter. Differences between the forward and spot prices may continue to cause material volatility in our unrealized margin. However, the economic gross profit we have captured in the original transactions should remain essentially unchanged.

Realized gross profit from our marketing activities decreased $2.7 million compared with the prior-year quarter. This decrease reflects the impact of a less volatile market, which reduced opportunities to take advantage of pricing differences between hubs, partially offset by increased sales volumes attributable to successful execution of our marketing strategies. This decrease was more than offset by a $5.2 million increase in unrealized margins primarily attributable to a favorable movement in the forward natural gas prices associated with the financial derivatives used in these activities during the three months ended June 30, 2007.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes other than income taxes, increased to $7.5 million for the three months ended June 30, 2007 from $6.5 million for the three months ended June 30, 2006. The increase in operating expense primarily was attributable to an increase in employee and other administrative costs.

Interest charges for the three months ended June 30, 2007 increased to $2.0 million from $1.7 million for the three months ended June 30, 2006. The increase was attributable to higher intercompany borrowings during the current-year quarter.

Pipeline and storage segment

Our pipeline and storage segment consists of the regulated pipeline and storage operations of the Atmos Pipeline — Texas Division and the nonregulated pipeline and storage operations of Atmos Pipeline and Storage, LLC (APS). The Atmos Pipeline — Texas Division transports natural gas to our Mid-Tex Division and for third parties and manages five underground storage reservoirs in Texas. We also provide ancillary services customary in the pipeline industry including parking arrangements, lending and sales of inventory on hand. These operations represent one of the largest intrastate pipeline operations in Texas with a heavy concentration in the established natural gas-producing areas of central, northern and eastern Texas, extending into or near the major producing areas of the Texas Gulf Coast and the Delaware and Val Verde Basins of West Texas. This pipeline system provides access to nine basins located in Texas, which are estimated to contain a substantial portion of the nation's remaining onshore natural gas reserves. APS owns or has an interest in underground storage fields in Kentucky and Louisiana. We also use these storage facilities to reduce the need to contract for additional pipeline capacity to meet customer demand during peak periods.

Similar to our utility segment, our pipeline and storage segment is impacted by seasonal weather patterns, competitive factors in the energy industry and economic conditions in our service areas. Natural gas transportation requirements are affected by the winter heating season requirements of our customers. This generally results in higher operating revenues and net income during the period from October through March of each year and lower operating revenues and either lower net income or net losses during the period from April through September of each year. Further, as the Atmos Pipeline — Texas Division operations provide all of the natural gas for our Mid-Tex Division, the results of this segment are highly dependent upon the natural gas requirements of this division. As a regulated pipeline, the operations of the Atmos Pipeline — Texas Division may be impacted by the timing of when costs and expenses are incurred and when these costs and expenses are recovered through its tariffs.

Review of Financial and Operating Results

Financial and operational highlights for our pipeline and storage segment for the three months ended June 30, 2007 and 2006 are presented below. Gross profit for our pipeline and storage segment primarily consists of transportation margins earned from our Mid-Tex Division and from third parties, other ancillary pipeline services and asset management fees earned by APS. Additionally, this segment's margins include an unrealized component as APS hedges its risk associated with its asset management contracts. Our pipeline and storage segment's gross profit was comprised of the following components for the three months ended June 30, 2007 and 2006:

	Three Months Ended June 30	
	2007	2006
	(Dollars in thousands)	
Mid-Tex transportation	$ 15,718	$ 13,974
Third-party transportation	18,284	16,201
Asset management fees	(1,907)	(31)
Storage and park and lend services	4,135	4,655
Unrealized losses	(813)	(997)
Other	2,292	1,681
Gross profit	37,709	35,483
Operating expenses	22,180	20,564
Operating income	15,529	14,919
Miscellaneous income	3,899	309
Interest charges	7,125	6,384
Income before income taxes	12,303	8,844
Income tax expense	4,631	3,012
Net income	$ 7,672	$ 5,832
Pipeline transportation volumes — MMcf	127,491	106,999

The $2.2 million increase in gross profit is primarily attributable to a 19 percent increase in throughput, including $2.8 million of margin from our North Side Loop and other compression projects, coupled with a $0.7 million increase due to rate adjustments resulting from Atmos Pipeline — Texas Division's 2005 GRIP filing. These increases were partially offset by a $1.1 million decrease in reservation, demand and deficiency fees which are market driven and reduced asset management margins in APS.

Operating expenses increased to $22.2 million for the three months ended June 30, 2007 from $20.6 million for the three months ended June 30, 2006 due to higher administrative and other operating costs primarily associated with the North Side Loop and other compression projects that were completed in fiscal 2006.

Interest charges associated with the pipeline and storage segment for the three months ended June 30, 2007 increased to $7.1 million from $6.4 million for the three months ended June 30, 2006. The increase was attributable to the use of updated allocation factors for fiscal 2007. These factors are reviewed and updated on an annual basis.

Miscellaneous income increased to $3.9 million for the three months ended June 30, 2007 from $0.3 million for the three months ended June 30, 2006. The increase was primarily attributable to $2.1 million received from leasing certain mineral interests coupled with an increase in interest income recorded in the pipeline and storage segment.

Other nonutility segment

Our other nonutility businesses consist primarily of the operations of Atmos Energy Services, LLC (AES), and Atmos Power Systems, Inc. Through December 31, 2006, AES provided natural gas management services to our utility operations, other than the Mid-Tex Division. These services included aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering the gas to our utility service areas at competitive prices. Effective January 1, 2007, our shared services function began providing these services to our utility operations. AES continues to provide limited services to our utility divisions, and the revenues AES receives are equal to the costs incurred to provide those services. Through Atmos Power Systems, Inc., we have constructed electric peaking power-generating plants and associated facilities and lease these plants through agreements that are accounted for as sales under generally accepted accounting principles.

Operating income for this segment primarily reflects the leasing income associated with two sales-type lease transactions completed in 2001 and 2002 and did not materially change for the three months ended June 30, 2007 compared with the prior-year quarter.

Nine Months Ended June 30, 2007 compared with Nine Months Ended June 31, 2006

Utility segment

Financial and operational highlights for our utility segment for the nine months ended June 30, 2007 and 2006 are presented below:

	Nine Months Ended June 30	
	2007	2006
	(Dollars in thousands, except per Mcf amounts)	
Gross profit	$799,457	$765,768
Operating expenses	561,932	544,665
Operating income	237,525	221,103
Miscellaneous income	6,633	6,014
Interest charges	91,164	92,783
Income before income taxes	152,994	134,334
Income tax expense	60,530	50,264
Net income	$ 92,464	$ 84,070
Utility sales volumes — MMcf	265,508	239,562
Utility transportation volumes — MMcf	101,572	91,384
Total utility throughput — MMcf	367,080	330,946
Heating degree days		
Actual (weighted average)	2,873	2,507
Percent of normal	101%	87%
Consolidated utility average transportation revenue per Mcf	$ 0.46	$ 0.53
Consolidated utility average cost of gas per Mcf sold	$ 8.19	$ 10.39

The following table shows our operating income by utility division for the nine months ended June 30, 2007 and 2006. The presentation of our utility operating income by division is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Nine Months Ended June 30			
	2007		2006	
	Operating Income	Heating Degree Days Percent of Normal(1)	Operating Income	Heating Degree Days Percent of Normal(1)
	(In thousands, except degree day information)			
Colorado-Kansas	$ 24,524	104%	$ 23,423	98%
Kentucky/Mid-States(2)	44,913	98	51,335	98
Louisiana	39,540	105	25,202	78
Mid-Tex	82,932	100	67,423	72
Mississippi	25,918	101	25,480	102
West Texas	18,230	100	24,053	100
Other	1,468	—	4,187	—
Utility segment	$237,525	101%	$221,103	87%

(1) Adjusted for service areas that have weather-normalized operations.

(2) Effective October 1, 2006, the Kentucky and Mid-States Divisions were combined. Prior year amounts have been reclassified to conform to this new presentation.

The $33.7 million increase in utility gross profit primarily reflects an eleven percent increase in throughput, which increased gross profit by $33.4 million, a $10.8 million increase associated with the implementation of WNA in our Mid-Tex and Louisiana Divisions beginning with the 2006-2007 winter heating season coupled with $25.6 million of rate increases received from our Rate Stabilization Clause (RSC) filings in our Louisiana service areas, GRIP-related recoveries in our Texas service areas and rate design changes in our Missouri service areas.

Offsetting these increases in gross profit was a reduction in revenue-related taxes. Due to a significant decline in the cost of gas in the current-year period compared with the prior-year period, franchise and state gross receipts taxes included in gross profit decreased approximately $2.4 million; however, franchise and state gross receipts tax expense recorded as a component of taxes, other than income increased $6.5 million, which resulted in a $4.1 million increase in operating income when compared with the prior-year period. Gross profit was also adversely affected by $9.1 million from unfavorable rate rulings received in Tennessee and our Mid-Tex Division during fiscal 2007 and a reduction in other pass-through items. The prior-year's gross profit margin also reflects the recognition of $6.2 million in previously deferred gross profit from the 2003 RSC filing in our Louisiana Division.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, increased to $561.9 million for the nine months ended June 30, 2007 from $544.7 million for the nine months ended June 30, 2006.

Operation and maintenance expense, excluding the provision for doubtful accounts, increased $18.7 million, primarily due to increased employee and other administrative costs and a one-time $3.3 million noncash charge to write off software that will no longer be used. These increases were partially offset by the deferral of $4.3 million of incremental Hurricane Katrina-related operation and maintenance expense in our Louisiana Division.

The provision for doubtful accounts decreased $3.8 million to $13.7 million for the nine months ended June 30, 2007. The decrease primarily was attributable to reduced collection risk as a result of lower natural gas prices. In the utility segment, the average cost of natural gas for the nine months ended June 30, 2007 was $8.19 Mcf, compared with $10.39 per Mcf for the nine months ended June 30, 2006.

Depreciation and amortization expense increased $11.6 million in the nine months ended June 30, 2007 compared with the prior-year period. The increase was primarily attributable to increases in assets placed in service during fiscal 2006. Additionally, the increase was partially attributable to the absence in the current-year period of a $2.8 million reduction in depreciation expense recorded in the prior-year period arising from the Mississippi Public Service Commission's decision to allow certain deferred costs in our rate base.

Interest charges allocated to the utility segment for the nine months ended June 30, 2007 decreased to $91.2 million from $92.8 million for the nine months ended June 30, 2006. The decrease was primarily attributable to lower average outstanding short-term debt balances in the current-year period compared with the prior-year period partially offset by increased interest rates on our $300 million unsecured floating rate senior notes due July 2007.

Natural gas marketing segment

Financial and operational highlights for our natural gas marketing segment for the nine months ended June 30, 2007 and 2006 are presented below.

	Nine Months Ended June 30	
	2007	2006
	(Dollars in thousands)	
Storage Activities		
Realized margin	$ 38,558	$ 44,600
Unrealized margin	8,864	(42,924)
Total Storage Activities	47,422	1,676
Marketing Activities		
Realized margin	44,320	63,263
Unrealized margin	(6,131)	4,471
Total Marketing Activities	38,189	67,734
Gross profit	85,611	69,410
Operating expenses	21,126	18,173
Operating income	64,485	51,237
Miscellaneous income	5,816	1,754
Interest charges	3,418	6,575
Income before income taxes	66,883	46,416
Income tax expense	26,515	18,201
Net income	$ 40,368	$ 28,215
Natural gas marketing sales volumes — MMcf	264,325	207,418
Net physical position (Bcf)	21.5	19.0

The $16.2 million increase in our natural gas marketing segment's gross profit reflects a $41.2 million increase in unrealized storage and marketing margins partially offset by a $25.0 million reduction in realized margins.

Realized gross profit from our storage activities decreased $6.1 million compared with the prior-year period. The decrease reflects an increase in storage fees, park and loan fees and the impact of a less volatile market, which reduced the arbitrage spreads earned from these activities. These decreases were more than offset by a $51.8 million increase in unrealized margins attributable to a narrowing of the spreads between the physical and forward natural gas prices, coupled with the increase in our net physical position.

Realized gross profit from our marketing activities decreased $18.9 million compared with the prior-year period. This decrease reflects the impact of a less volatile market, which reduced opportunities to take advantage of pricing differences between hubs, partially offset by increased sales volumes attributable to successful execution of our marketing strategies. Also contributing to the decrease in our marketing activities was a $10.6 million decrease in unrealized margins primarily attributable to an unfavorable movement in the forward natural gas prices associated with the financial derivatives used in these activities during the nine months ended June 30, 2007.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes other than income taxes, increased to $21.1 million for the nine months ended June 30, 2007 from $18.2 million for the nine months ended June 30, 2006. The increase in operating expense primarily was attributable to an increase in employee and other administrative costs.

Interest charges for the nine months ended June 30, 2007 decreased to $3.4 million from $6.6 million for the nine months ended June 30, 2006. The decrease was attributable to lower borrowing requirements during the current year period.

Pipeline and storage segment

Financial and operational highlights for our pipeline and storage segment for the nine months ended June 30, 2007 and 2006 are presented below.

	Nine Months Ended June 30	
	2007	2006
	(Dollars in thousands)	
Mid-Tex transportation	$ 62,149	$ 55,850
Third-party transportation	49,273	41,733
Asset management fees	11,971	4,883
Storage and park and lend services	13,657	12,527
Unrealized gains	1,012	947
Other	8,407	4,527
Gross profit	146,469	120,467
Operating expenses	60,943	57,910
Operating income	85,526	62,557
Miscellaneous income	5,504	1,846
Interest charges	24,582	18,978
Income before income taxes	66,448	45,425
Income tax expense	24,867	16,339
Net income	$ 41,581	$ 29,086
Pipeline transportation volumes — MMcf	365,503	284,551

The $26.0 million increase in gross profit is primarily attributable to a 28 percent increase in throughput and increased demand for storage services. These activities increased gross profit by $14.3 million, of which, $8.7 million was associated with our North Side Loop and other compression projects. Gross profit also includes an increase of $1.6 million from the sale of excess gas inventory by our Atmos Pipeline-Texas Division and $2.1 million from rate adjustments resulting from Atmos Pipeline-Texas Division's 2005 GRIP filing. Finally, gross profit increased $7.1 million from asset management fees earned by APS due to its ability to capture more favorable arbitrage spreads on its asset management contracts, coupled with incremental margins received from APS' asset management contract with our Mississippi utility division executed in July 2006.

Operating expenses increased to $60.9 million for the nine months ended June 30, 2007 from $57.9 million for the nine months ended June 30, 2006 due to higher administrative and other operating costs primarily associated with the North Side Loop and other compression projects that were completed in fiscal 2006.

Interest charges allocated to the pipeline and storage segment for the nine months ended June 30, 2007 increased to $24.6 million from $19.0 million for the nine months ended June 30, 2006. The increase was attributable to the use of updated allocation factors for fiscal 2007. These factors are reviewed and updated on an annual basis.

Miscellaneous income increased to $5.5 million for the nine months ended June 30, 2007 from $1.8 million for the nine months ended June 30, 2006. The increase was primarily attributable to $2.1 million received from leasing certain mineral interests coupled with an increase in interest income recorded in the pipeline and storage segment.

Other nonutility segment

Operating income for this segment primarily reflects the leasing income associated with two sales-type lease transactions completed in 2001 and 2002 and did not materially change for the nine months ended June 30, 2007 compared with the prior-year period.

Liquidity and Capital Resources

Our internally generated funds and borrowings under our credit facilities and commercial paper program generally provide the liquidity needed to fund our working capital, capital expenditures and other cash needs. Additionally, from time to time, we raise funds from the public debt and equity capital markets through our existing shelf registration statement to fund our liquidity needs.

In May 2007, we called our $300 million unsecured floating rate senior notes for redemption on July 15, 2007. In June 2007, we issued $250 million of 6.35% Senior Notes due 2017. The net proceeds from this issuance, together with available cash, were used to repay our $300 million senior notes in July 2007. We believe the new senior notes, combined with the other sources of funds described above will provide the necessary working capital and liquidity for capital expenditures and other cash needs for the remainder of fiscal 2007.

Cash Flows

Our internally generated funds may change in the future due to a number of factors, some of which we cannot control. These include regulatory changes, prices for our products and services, demand for such products and services, margin requirements resulting from significant changes in commodity prices, operational risks and other factors.

Cash flows from operating activities

Period-over-period changes in our operating cash flows primarily are attributable to changes in net income and working capital changes, particularly within our utility segment. Our utility segment's working capital is primarily affected by the price of natural gas, the timing of customer collections, payments for natural gas purchases and deferred gas cost recoveries.

For the nine months ended June 30, 2007, we generated operating cash flow of $552.7 million from operating activities compared with $223.4 million for the nine months ended June 30, 2006. Period over period, our operating cash flow was favorably impacted by improved net income, increased sales volumes attributable to colder weather in the current-year period and lower natural gas prices compared with the prior-year period. Specifically, the timing of the collection of and payment for other current assets, accounts payable and other accrued liabilities increased operating cash flow by $309.6 million. Additionally, improved management of our deferred gas cost balances increased operating cash flow by $77.4 million. These increases were partially offset by $99.8 million associated with the unfavorable timing of accounts receivable. Finally, other changes in working capital and other items increased operating cash flow by $42.1 million, primarily resulting from increased net income and favorable net changes associated with our risk management activities.

Cash flows from investing activities

In recent years, a substantial portion of our cash resources has been used to fund acquisitions, new pipeline expansion projects and our ongoing utility construction program. Our ongoing utility construction program enables us to provide natural gas distribution services to our existing customer base, expand our natural gas distribution services into new markets, enhance the integrity of our pipelines and, more recently, expand our intrastate pipeline network. In executing our current rate strategy, we are directing discretionary capital spending to jurisdictions that permit us to earn a timely return in excess of our cost of capital. Currently, our Mid-Tex, Louisiana, Mississippi and West Texas utility divisions and our Atmos Pipeline — Texas Division have rate designs that provide the opportunity to include in their rate base approved capital costs on a periodic basis without having to file a rate case.

Capital expenditures for fiscal 2007 are expected to range from $365 million to $385 million. For the nine months ended June 30, 2007, we incurred $263.0 million for capital expenditures compared with $322.7 million for the nine months ended June 30, 2006. The decrease in capital spending primarily reflects the absence of capital expenditures associated with our North Side Loop and other pipeline compression projects, which were completed in the third quarter of fiscal 2006.

Cash flows from financing activities

For the nine months ended June 30, 2007, our financing activities reflected a use of cash of $5.2 million compared with the $90.8 million provided from financing activities in the prior-year period. Our significant financing activities for the nine months ended June 30, 2007 and 2006 are summarized as follows.

- In December 2006, we raised net proceeds of approximately $192 million from the sale of approximately 6.3 million shares of common stock, including the underwriters' exercise of their overallotment option of 0.8 million shares, under a shelf registration statement filed with the SEC in December 2006. The net proceeds from this issuance were used to reduce our then-existing short-term debt balance.
- In addition to this equity offering, during the nine months ended June 30, 2007, we issued 0.6 million shares of common stock under our various plans which generated net proceeds of $18.9 million. We also granted 0.5 million shares of common stock under our 1998 Long-Term Incentive Plan. The following table summarizes our share issuances for the nine months ended June 30, 2007 and 2006.

	Nine Months Ended June 30	
	2007	2006
Shares issued:		
Retirement Savings Plan	306,920	344,573
Direct Stock Purchase Plan	238,689	302,501
Outside Directors Stock-for-Fee Plan	1,776	1,865
1998 Long-Term Incentive Plan	500,684	349,509
Long-Term Stock Plan for Mid-States Division	—	300
Public Offering	6,325,000	—
Total shares issued	7,373,069	998,748

- In June 2007, we issued $250 million of 6.35% Senior Notes due 2017. The effective interest rate of this offering, inclusive of all debt issue costs, was 6.45 percent. After giving effect to the settlement of our $100 million Treasury lock agreement in June 2007, the effective rate on these senior notes was reduced to 6.26 percent. The net proceeds of $247 million, together with $53 million of available cash, were used to repay our $300 million unsecured floating rate senior notes, which were called in May for redemption on July 15, 2007.

- During the nine months ended June 30, 2007, we repaid all amounts outstanding under our credit facilities. The $382.4 million repayment reflects the positive impact of our strong operating cash flow during fiscal 2007 and the net proceeds received from our December 2006 offering.
- During the nine months ended June 30, 2007, we paid $83.1 million in cash dividends compared with $76.6 million for the nine months ended June 30, 2006. The increase in dividends paid over the prior-year period reflects the increase in our dividend rate from $0.945 per share during the nine months ended June 30, 2006 to $0.96 per share during the nine months ended June 30, 2007 combined with a 7.4 million increase in shares outstanding due to share issuances in connection with our December 2006 equity offering and new share issuances under our various plans.

Credit Facilities

As of June 30, 2007, we had a total of approximately $1.5 billion of credit facilities, comprised of three short-term committed credit facilities totaling $918 million, one uncommitted credit facility totaling $25 million and, through AEM, a second uncommitted credit facility that can provide up to $580 million. Borrowings under our uncommitted credit facilities are made on a when-and-as-needed basis at the discretion of the banks. Our credit capacity and the amount of unused borrowing capacity are affected by the seasonal nature of the natural gas business and our short-term borrowing requirements, which are typically highest during colder winter months. Our working capital needs can vary significantly due to changes in the price of natural gas charged by suppliers and the increased gas supplies required to meet customers' needs during periods of cold weather.

As of June 30, 2007, the amount available to us under our credit facilities, net of outstanding letters of credit, was $955.9 million. We believe these credit facilities, combined with our operating cash flows will be sufficient to fund our working capital needs. These facilities are described in further detail in Note 4 to the unaudited condensed consolidated financial statements.

Shelf Registration

On December 4, 2006, we filed a registration statement with the SEC to issue, from time to time, up to $900 million in common stock and/or debt securities available for issuance, including approximately $401.5 million of capacity carried over from our prior shelf registration statement filed with the SEC in August 2004. In December 2006, we sold approximately 6.3 million shares of common stock and used the net proceeds to reduce short-term debt.

In June 2007, we issued $250 million of 6.35% Senior Notes due 2017 under the registration statement. The net proceeds of approximately $247 million, together with $53 million of available cash, were used to repay our $300 million unsecured floating rate senior notes, which were called in May for redemption on July 15, 2007.

After these issuances, we have approximately $450 million of availability remaining under the registration statement. However, due to certain restrictions imposed by one state regulatory commission on our ability to issue securities under the registration statement, we now have remaining and available for issuance a total of approximately $100 million of equity securities, $50 million of senior debt securities and $300 million of subordinated debt securities. In addition, due to restrictions imposed by another state regulatory commission, if the credit ratings on our senior unsecured debt were to fall below investment grade from either Standard & Poor's Corporation (BBB-), Moody's Investors Services, Inc. (Baa3) or Fitch Ratings, Ltd. (BBB-), our ability to issue any type of debt securities under the registration statement would be suspended until an investment grade rating from all three credit rating agencies was achieved.

Debt Covenants

We were in compliance with all of our debt covenants as of June 30, 2007. Our debt covenants are described in Note 4 to the unaudited condensed consolidated financial statements.

Credit Ratings

Our credit ratings directly affect our ability to obtain short-term and long-term financing, in addition to the cost of such financing. In determining our credit ratings, the rating agencies consider a number of quantitative factors, including debt to total capitalization, operating cash flow relative to outstanding debt, operating cash flow coverage of interest and pension liabilities and funding status. In addition, the rating agencies consider qualitative factors such as consistency of our earnings over time, the quality of our management and business strategy, the risks associated with our utility and nonutility businesses and the regulatory structures that govern our rates in the states in which we operate.

Our debt is rated by three rating agencies: Standard & Poor's Corporation (S&P), Moody's Investors Service (Moody's) and Fitch Ratings, Ltd. (Fitch). Our current debt ratings are all considered investment grade and are as follows:

	S&P	Moody's	Fitch
Unsecured senior long-term debt	BBB	Baa3	BBB+
Commercial paper	A-2	P-3	F-2

Currently, with respect to our unsecured senior long-term debt, Moody's and Fitch maintain their stable outlook. In June 2007, S&P upgraded their outlook from stable to positive. None of our ratings are currently under review.

A credit rating is not a recommendation to buy, sell or hold securities. The highest investment grade credit rating for S&P is AAA, Moody's is Aaa and Fitch is AAA. The lowest investment grade credit rating for S&P is BBB-, Moody's is Baa3 and Fitch is BBB-. Our credit ratings may be revised or withdrawn at any time by the rating agencies, and each rating should be evaluated independent of any other rating. There can be no assurance that a rating will remain in effect for any given period of time or that a rating will not be lowered, or withdrawn entirely, by a rating agency if, in its judgment, circumstances so warrant.

Capitalization

As noted above, our capitalization is a leading quantitative factor used to determine our credit ratings. The following table presents our capitalization as of June 30, 2007 September 30, 2006 and June 30, 2006.

	June 30, 2007		September 30, 2006		June 30, 2006	
	(In thousands, except percentages)					
Short-term debt	$ —	—%	$ 382,416	9.1%	$ 297,087	7.2%
Long-term debt	2,430,518	55.0%	2,183,548	51.8%	2,184,083	52.7%
Shareholders' equity	1,988,142	45.0%	1,648,098	39.1%	1,664,556	40.1%
Total capitalization	$4,418,660	100.0%	$4,214,062	100.0%	$4,145,726	100.0%

Total debt as a percentage of total capitalization, including short-term debt, was 55.0 percent at June 30, 2007, 60.9 percent at September 30, 2006 and 59.9 percent at June 30, 2006. The decrease in the debt to capitalization ratio primarily reflects the favorable impact of our December 2006 equity offering and the absence of short-term debt as of June 30, 2007, partially offset by the timing of the repayment of our $300 million unsecured floating rate senior notes. Had we been able to repay the notes as of June 30, 2007, our total-debt-to-capitalization ratio would have been 51.7 percent. Our ratio of total debt to capitalization is typically greater during the winter heating season as we make additional short-term borrowings to fund natural gas purchases and meet our working capital requirements. We intend to maintain our capitalization ratio in a target range of 50 to 55 percent through cash flow generated from operations, continued issuance of new common stock under our Direct Stock Purchase Plan and Retirement Savings Plan and access to the capital markets.

Contractual Obligations and Commercial Commitments

Significant commercial commitments are described in Note 8 to the unaudited condensed consolidated financial statements. There were no significant changes in our contractual obligations and commercial commitments during the nine months ended June 30, 2007, except for the issuance of our $250 million ten year senior notes in June 2007 and the repayment of our $300 million unsecured floating rate senior notes in July 2007, as discussed in Note 4 to the unaudited consolidated financial statements.

Additionally, in May 2006, we announced plans to construct a natural gas gathering system in Eastern Kentucky, referred to as the Straight Creek Project. This project has recently been reconfigured and renamed the Phoenix Gas Gathering Project (the "Phoenix Project"). The Phoenix Project, as currently designed, would consist of approximately 40 miles of 12-inch and 20-inch pipe with an initial throughput capacity of 50 MMcf/day but can be expanded, if market conditions demand. We anticipate the initial capital requirement to be approximately $50 million. The inception of the project and the in-service date are contingent on finalizing gathering agreements covering sufficient minimum volumes to support the project. We expect the project not to have a financial impact on fiscal 2008 earnings.

Risk Management Activities

We conduct risk management activities through both our utility and natural gas marketing segments. In our utility segment, we use a combination of storage, fixed physical contracts and fixed financial contracts to reduce our exposure to unusually large winter-period gas price increases. In our natural gas marketing segment, we manage our exposure to the risk of natural gas price changes and lock in our gross profit margin through a combination of storage and financial derivatives, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. To the extent our inventory cost and actual sales and actual purchases do not correlate with the changes in the market indices we use in our hedges, we could experience ineffectiveness or the hedges may no longer meet the accounting requirements for hedge accounting, resulting in the derivatives being treated as mark-to-market instruments through earnings.

We record our derivatives as a component of risk management assets and liabilities, which are classified as current or noncurrent based upon the anticipated settlement date of the underlying derivative. Substantially all of our derivative financial instruments are valued using external market quotes and indices. The following tables show the components of the change in the fair value of our utility and natural gas marketing commodity derivative contracts for the three and nine months ended June 30, 2007 and 2006:

	Three Months Ended June 30, 2007		Three Months Ended June 30, 2006	
	Utility	Natural Gas Marketing	Utility	Natural Gas Marketing
	(In thousands)			
Fair value of contracts at beginning of period	$ 3,802	$(24,994)	$12,352	$ (3,414)
Contracts realized/settled	(144)	15,994	(1,099)	(20,923)
Fair value of new contracts	(5,797)	—	(2,577)	—
Other changes in value	(5,385)	24,898	(1,045)	(5,460)
Fair value of contracts at end of period	$(7,524)	$ 15,898	$ 7,631	$(29,797)

	Nine Months Ended June 30, 2007		Nine Months Ended June 30, 2006	
	Utility	Natural Gas Marketing	Utility	Natural Gas Marketing
	(In thousands)			
Fair value of contracts at beginning of period	$(27,209)	$ 15,003	$ 93,310	$(61,898)
Contracts realized/settled	(27,662)	(10,593)	25,799	2,099
Fair value of new contracts	(7,058)	—	(7,337)	—
Other changes in value	54,405	11,488	(104,141)	30,002
Fair value of contracts at end of period	$ (7,524)	$ 15,898	$ 7,631	$(29,797)

The fair value of our utility and natural gas marketing derivative contracts at June 30, 2007, is segregated below by time period and fair value source:

	Fair Value of Contracts at June 30, 2007				
	Maturity in Years				
Source of Fair Value	Less than 1	1-3	4-5	Greater Than 5	Total Fair Value
	(In thousands)				
Prices actively quoted	$2,552	$7,252	$—	$—	$ 9,804
Prices based on models and other valuation methods	(694)	(736)	—	—	(1,430)
Total Fair Value	$1,858	$6,516	$—	$—	$ 8,374

Storage and Hedging Outlook

AEM participates in transactions in which it seeks to find and profit from pricing differences that occur over time. AEM purchases physical natural gas and then sells financial contracts at advantageous prices to lock in a gross profit margin, which we refer to as the economic gross profit. AEM is able to capture the economic gross profit through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time.

Natural gas inventory is marked to market at the end of each month with changes in fair value recognized as unrealized gains and losses in the period of change. Derivatives associated with our natural gas inventory, which are designated as fair value hedges, are marked to market each month based upon the NYMEX price with changes in fair value recognized as unrealized gains and losses in the period of change. The changes in the difference between the indices used to mark to market our physical inventory (Gas Daily) and the related fair-value hedge (NYMEX) is reported as a component of revenue and can result in volatility in our reported net income. Over time, gains and losses on the sale of storage gas inventory will be offset by gains and losses on the fair-value hedges; therefore, the economic gross profit AEM captured in the original transaction remains essentially unchanged.

AEM continually manages its positions to enhance the economic gross profit it captured in the original transaction. Therefore, AEM may change its scheduled injection and withdrawal plans from one time period to another based on market conditions or adjust the amount of storage capacity it holds on a discretionary basis in an effort to achieve this objective. AEM monitors the impacts of these profit optimization efforts by estimating the economic gross profit that it captured through the purchase and sale of physical natural gas and the associated financial derivatives. The reconciliation below of the economic gross profit, combined with the effect of unrealized gains or losses recognized in accordance with generally accepted accounting principles in the financial statements in prior periods, is presented in order to provide a measure of the potential gross profit that could occur in future periods if AEM's optimization efforts are fully successful. We consider this measure of potential gross profit a non-GAAP financial measure as it is calculated using both forward-looking and historical financial information. The following table presents, by quarter, AEM's economic gross profit and its potential future gross profit.

Period Ending	Net Physical Position	Economic Gross Profit	Associated Net Unrealized Gains (Losses) At Period End	Potential Future Gross Profit
	(Bcf)	(In millions)	(In millions)	(In millions)
September 30, 2006	14.5	$60.0	$(16.0)	$76.0
December 31, 2006	21.0	$60.6	$ 32.8	$27.8
March 31, 2007	19.6	$10.8	$(24.2)	$35.0
June 30, 2007	21.5	$41.2	$ (7.2)	$48.4

As of June 30, 2007, based upon AEM's derivatives position and inventory withdrawal schedule, the economic gross profit was $41.2 million. In addition, $7.2 million of net unrealized losses that will reverse when the inventory is withdrawn were recorded in the financial statements as of June 30, 2007. Therefore, the potential future gross profit was $48.4 million. The potential future gross profit amount will not result in an equal increase in future net income as AEM will incur additional storage and other operational expenses and increased income taxes to realize this amount.

The economic gross profit is based upon planned injection and withdrawal schedules, and the realization of the economic gross profit is contingent upon the execution of this plan, weather and other execution factors. Since AEM actively manages and optimizes its portfolio to enhance the future profitability of its storage position, it may change its scheduled injection and withdrawal plans from one time period to another based on market conditions. Therefore, we cannot ensure that the economic gross profit or the potential future gross profit calculated as of June 30, 2007 will be fully realized in the future or in what time period. Further, if we experience operational or other issues which limit our ability to optimally manage our stored gas positions, our earnings could be adversely impacted.

Pension and Postretirement Benefits Obligations

For the nine months ended June 30, 2007 and 2006 our total net periodic pension and other benefits cost was $36.4 million and $37.4 million. The costs relating to our utility operations are recoverable through our gas utility rates; however, a portion of these costs is capitalized into our utility rate base. The remaining costs are recorded as a component of operation and maintenance expense.

The decrease in total net periodic pension and other benefits cost during the current-year period compared with the prior-year period primarily reflects changes in assumptions we made during our annual pension plan valuation completed June 30, 2006. The discount rate used to compute the present value of a plan's liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid. In the period leading up to our June 30, 2006 measurement date, these interest rates were increasing, which resulted in a 130 basis point increase in our discount rate used to determine our fiscal 2007 net periodic and post-retirement cost to 6.30 percent. This increase has the effect of decreasing the present value of our plan liabilities and associated expenses. This favorable impact was partially offset by the unfavorable impact of reducing the expected return on our pension plan assets by 25 basis points to 8.25 percent, which has the effect of increasing our pension and postretirement benefit cost.

We are currently in the process of evaluating our fiscal 2007 pension plan valuation. Based upon market conditions as of the June 30, 2007 valuation date, we expect no significant increase in our fiscal 2008 net periodic pension cost.

During the nine months ended June 30, 2007, we contributed $8.5 million to our other postretirement plans, and we expect to contribute a total of approximately $12 million to these plans during fiscal 2007.

OPERATING STATISTICS AND OTHER INFORMATION

The following tables present certain operating statistics for our utility, natural gas marketing, pipeline and storage and other nonutility segments for the three and nine-month periods ended June 30, 2007 and 2006.

Utility Sales and Statistical Data

	Three Months Ended June 30		Nine Months Ended June 30	
	2007	2006	2007	2006
METERS IN SERVICE, end of period				
Residential	2,900,716	2,889,470	2,900,716	2,889,470
Commercial	274,273	276,492	274,273	276,492
Industrial	2,739	3,056	2,739	3,056
Agricultural	8,376	8,924	8,376	8,924
Public authority and other	8,200	8,210	8,200	8,210
Total meters	3,194,304	3,186,152	3,194,304	3,186,152
INVENTORY STORAGE BALANCE — Bcf	43.9	46.7	43.9	46.7
HEATING DEGREE DAYS(1)				
Actual (weighted average)	163	119	2,873	2,507
Percent of normal	98%	69%	101%	87%
UTILITY SALES VOLUMES — MMcf(2)				
Gas sales volumes				
Residential	21,421	13,176	155,021	132,754
Commercial	16,672	11,719	83,231	74,691
Industrial	5,248	4,161	18,551	21,224
Agricultural	490	2,759	687	3,115
Public authority and other	1,421	838	8,018	7,778
Total gas sales volumes	45,252	32,653	265,508	239,562
Utility transportation volumes	30,431	30,735	105,125	95,329
Total utility throughput	75,683	63,388	370,633	334,891
UTILITY OPERATING REVENUES (000's)(2)				
Gas sales revenues				
Residential	$ 294,756	$ 208,164	$1,795,124	$1,875,636
Commercial	170,425	112,100	855,468	944,591
Industrial	44,345	31,417	162,621	237,274
Agricultural	4,534	18,940	5,838	22,576
Public authority and other	13,659	8,094	78,712	95,305
Total utility gas sales revenues	527,719	378,715	2,897,763	3,175,382
Transportation revenues	12,040	13,662	46,997	48,721
Other gas revenues	8,492	9,667	28,768	30,571
Total utility operating revenues	$ 548,251	$ 402,044	$2,973,528	$3,254,674
Utility average transportation revenue per Mcf	$ 0.40	$ 0.44	$ 0.45	$ 0.51
Utility average cost of gas per Mcf sold	$ 7.90	$ 7.11	$ 8.19	$ 10.39

See footnotes following these tables.

Natural Gas Marketing, Pipeline and Storage and Other Nonutility Operations Sales and Statistical Data

	Three Months Ended June 30		Nine Months Ended June 30	
	2007	2006	2007	2006
CUSTOMERS, end of period				
Industrial	700	679	700	679
Municipal	64	73	64	73
Other	424	444	424	444
Total	1,188	1,196	1,188	1,196
INVENTORY STORAGE BALANCE — Bcf				
Natural gas marketing	25.1	20.1	25.1	20.1
Pipeline and storage	1.9	2.5	1.9	2.5
Total	27.0	22.6	27.0	22.6
NATURAL GAS MARKETING SALES VOLUMES — MMcf(2)	104,783	79,850	306,931	250,056
PIPELINE TRANSPORTATION VOLUMES — MMcf(2)	159,678	133,306	534,200	431,185
OPERATING REVENUES (000's)(2)				
Natural gas marketing	$854,167	$562,447	$2,360,902	$2,482,921
Pipeline and storage	37,937	35,862	147,151	121,057
Other nonutility	843	1,413	2,979	4,500
Total operating revenues	$892,947	$599,722	$2,511,032	$2,608,478

Notes to preceding tables:

(1) A heating degree day is equivalent to each degree that the average of the high and the low temperatures for a day is below 65 degrees. The colder the climate, the greater the number of heating degree days. Heating degree days are used in the natural gas industry to measure the relative coldness of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on 30-year average National Weather Service data for selected locations. For service areas that have weather normalized operations, normal degree days are used instead of actual degree days in computing the total number of heating degree days.

(2) Sales volumes and revenues reflect segment operations, including intercompany sales and transportation amounts.

Recent Ratemaking Developments

The following describes the significant ratemaking developments that occurred during the nine months ended June 30, 2007. The amounts described below represent the gross revenues that were requested or received in the rate filing, which may not necessarily reflect the increase in operating income obtained, as certain operating costs may have increased as a result of a commission's final ruling.

Atmos Pipeline — Texas. In May 2007, Atmos Pipeline — Texas filed its 2006 GRIP filing with the Railroad Commission of Texas (RRC). The filing seeks authorization to increase rates by approximately $13.2 million annually based on an increased net investment of $88.9 million. The RRC has suspended the implementation date of the increase until September 2007. It is currently anticipated that the RRC will issue a final order in this proceeding by September 2007.

Atmos Energy Colorado-Kansas Division. In December 2006, the Colorado-Kansas Division filed its third annual ad valorem tax surcharge for $1.5 million. The surcharge is designed to collect Kansas property taxes in excess of the amount included in Atmos' most recent general rate case. We began to bill this surcharge in January 2007. In June 2007, we gave notice to the Kansas Corporation Commission of our intent to file a rate case within 90 days.

Atmos Energy Kentucky/Mid-States Division. In April 2006, Atmos filed a rate case in its Missouri service area seeking a rate increase of $3.4 million, the consolidation of rates for its Missouri properties into three sets of regional rates and the current purchased gas adjustment (PGA) into one statewide PGA and a WNA mechanism. The Missouri Commission issued an order in March 2007 approving a settlement with rate design changes including revenue decoupling through the recovery of all non-gas cost revenues through fixed monthly charges and no rate increase.

In October 2006, the Tennessee Regulatory Authority approved a $6.1 million rate reduction as a result of an investigation of our rates by the Consumer Advocate and Protection Division of the Tennessee Attorney General's Office. The rate decrease became effective in December 2006. In May 2007, we filed an application for a rate increase of $11.1 million and approval of a Customer Utilization Adjustment that would complement our WNA rider by compensating for variances in customer usage related to factors other than weather. A decision is expected by November 2007.

In February 2005, the Attorney General of the State of Kentucky filed a complaint with the Kentucky Public Service Commission (KPSC) alleging that our rates were producing revenues in excess of reasonable levels. We answered the complaint and filed a Motion to Dismiss with the KPSC. In June 2007, the KPSC issued an order dismissing the case.

In December 2006, the Company filed a rate application for an increase in base rates of $10.4 million in Kentucky. Additionally, we proposed to implement a process to review our rates annually and to collect the bad debt portion of gas costs directly rather than through the base rate. In July 2007, the KPSC approved a settlement we reached with the Attorney General for an increase of $5.5 million effective August 1, 2007.

Atmos Energy Louisiana Division. In December 2006, our LGS service area received a $9.5 million annual revenue increase from its 2005 RSC filing filed in August 2006. The 2006 RSC filing for the LGS service area was filed in March 2007 seeking an approximate $0.8 million annual increase in rates. The Company reached a settlement on the LGS filing in May 2007 which resulted in an increase of $0.7 million in annual revenue effective July 1, 2007. Our TransLa service area filed for a $1.8 million annual revenue increase in December 2006. The Company reached a settlement in the case in March 2007, which resulted in an increase of $1.4 million in annual revenue effective April 1, 2007.

Atmos Energy Mid-Tex Division. In May 2006, the Mid-Tex Division filed a Statement of Intent with the RRC, which consolidated approximately 80 "show cause" resolutions and sought incremental annual revenues of approximately $60 million and several rate design changes. In March 2007, the RRC issued an order, which increased the Mid-Tex Division's annual revenues by approximately $4.8 million beginning April 2007 and established a permanent WNA based on 10-year average weather effective for the months of November through April of each year. The RRC also approved a cost allocation method that eliminates a subsidy received from industrial and transportation customers and increases the revenue responsibility for residential and commercial customers. However, the order also required an immediate refund of amounts collected from our 2003 — 2005 GRIP filings of approximately $2.3 million and reduces our total return to 7.903 percent from 8.258 percent based on a capital structure of 48.1 percent equity and 51.9 percent debt with a return on equity of 10 percent.

Pursuant to motions for rehearing, in June 2007, the RRC revised its March 2007 order to correct the calculation of the GRIP refund, thereby increasing the GRIP refund to approximately $2.9 million. Additional motions for rehearing have been filed, but we cannot predict at this time whether the RRC will grant these motions for rehearing or the impact on us if these motions are granted.

In September 2006, the Mid-Tex Division filed its annual gas cost reconciliation with the RRC. The filing reflects approximately $24 million in refunds of amounts that were overcollected from customers between July 2005 and June 2006. The Mid-Tex Division received approval to refund these amounts over a six-month period which began in November 2006.

In May 2007, the Mid-Tex Division filed a 36-month gas contract review filing. This filing is mandated by prior RRC orders and covers the prudence of gas purchases made from November 2003 through October 2006, which total approximately $2.7 billion. An agreed procedural schedule has been filed with the RRC which establishes a hearing beginning in December 2007.

In May 2007, we filed our 2006 GRIP filing for the Mid-Tex Division with the RRC and all incorporated cities served by the Mid-Tex Division. If approved as filed, annual revenues would increase by approximately $12.5 million based on an increase in net investment of approximately $62.4 million. A decision from the RRC should be issued by September 2007, and the city actions, including appeals to the RRC, should be completed by November 2007.

RECENT ACCOUNTING DEVELOPMENTS

Recent accounting developments and their impact on our financial position, results of operations and cash flows are described in Note 2 to the unaudited condensed consolidated financial statements.

Item 3. *Quantitative and Qualitative Disclosures About Market Risk*

Information regarding our quantitative and qualitative disclosures about market risk are disclosed in Item 7A in our annual report on Form 10-K for the year ended September 30, 2006. During the nine months ended June 30, 2007, there were no material changes in our quantitative and qualitative disclosures about market risk.

Item 4. *Controls and Procedures*

As indicated in the certifications in Exhibit 31 of this report, the Company's Chief Executive Officer and Chief Financial Officer have evaluated the Company's disclosure controls and procedures as of June 30, 2007. Based on that evaluation, these officers have concluded that the Company's disclosure controls and procedures are effective in ensuring that material information required to be disclosed in this quarterly report is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. In addition, there were no changes during the Company's last fiscal quarter that materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. *Legal Proceedings*

During the nine months ended June 30, 2007, there were no material changes in the status of the litigation and environmental-related matters that were disclosed in Note 13 to our annual report on Form 10-K for the year ended September 30, 2006. We continue to believe that the final outcome of such litigation and environmental-related matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

Item 6. *Exhibits*

A list of exhibits required by Item 601 of Regulation S-K and filed as part of this report is set forth in the Exhibits Index, which immediately precedes such exhibits.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ATMOS ENERGY CORPORATION
(Registrant)

By: /s/ JOHN P. REDDY

John P. Reddy
Senior Vice President and Chief Financial Officer
(Duly authorized signatory)

Date: August 8, 2007

EXHIBITS INDEX
Item 6(a)

Exhibit Number	Description	Page Number or Incorporation by Reference to
3.1	Amended and Restated Articles of Incorporation of Atmos Energy Corporation (as of February 9, 2005)	Exhibit 3(I) to Form 10-Q dated March 31, 2005 (File No. 1-10042)
3.2	Amended and Restated Bylaws of Atmos Energy Corporation (as of May 2, 2007)	Exhibit 3.1 to Form 8-K dated May 2, 2007 (File No. 1-10042)
12	Computation of ratio of earnings to fixed charges	
15	Letter regarding unaudited interim financial information	
31	Rule 13a-14(a)/15d-14(a) Certifications	
32	Section 1350 Certifications*	

* These certifications, which were made pursuant to 18 U.S.C. Section 1350 by the Company's Chief Executive Officer and Chief Financial Officer, furnished as Exhibit 32 to this Quarterly Report on Form 10-Q, will not be deemed to be filed with the Commission or incorporated by reference into any filing by the Company under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent that the Company specifically incorporates such certifications by reference.

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:	)	
	)	
PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	
ADJUSTMENT OF ITS RATES AND	)	
REVISED TARIFF	)	**DOCKET NO. 07-00105**

VERIFICATION

STATE OF TEXAS)
)
COUNTY OF DALLAS)

I, Christopher Forsythe, being first duly sworn, state that I am the Director of Financial Reporting of Atmos Energy Corporation, that I am authorized to testify on behalf of Atmos Energy Corporation in the above referenced docket, that the Rebuttal Testimony of Christopher Forsythe and exhibits thereto pre-filed in this docket on the date of filing herein are true and correct to the best of my knowledge, information and belief.

Christopher J Forsythe
Christopher Forsythe

Sworn and subscribed before me this 19 day of September, 2007.

Easter Bunny Dixon
Notary Public

My Commission Expires: March 5, 2011

Easter Bunny Dixon
Notary Public
STATE OF TEXAS
My Commission Expires
March 05, 2011

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:	)	
	)	
PETITION OF ATMOS ENERGY CORPORATION FOR APPROVAL OF ADJUSTMENT OF ITS RATES AND REVISED TARIFF	)	**Docket No. 07-00105**

REBUTTAL TESTIMONY OF DR. DONALD A. MURRY
ON BEHALF OF ATMOS ENERGY CORPORATION

I. PURPOSE OF REBUTTAL TESTIMONY

Q. PLEASE STATE YOUR NAME.

A. My name is Donald A. Murry.

Q. ARE YOU THE SAME DR. MURRY WHO FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed direct testimony on behalf of Atmos Energy Corporation ("Atmos" or the "Company").

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

A. I am providing rebuttal testimony to the direct testimony of Dr. Steve Brown filed on the behalf of the Consumer Advocate and Protection Division, Office of the Tennessee Attorney General.

Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR REBUTTAL TESTIMONY?

A. Yes. I am sponsoring an exhibit that I have attached to my testimony which includes Rebuttal Schedules DAM-R1 through DAM-R5.

Q. WAS THIS EXHIBIT PREPARED EITHER BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, it was.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. My testimony addresses just three issues which are the major points of departure between my direct testimony and the direct testimony of Dr. Brown. First, Dr. Brown included short-term debt in Atmos' capital structure for this proceeding. This is both conceptually and factually incorrect in this instance. Second, Dr. Brown based his Capital Asset Pricing Model (CAPM) analysis on two fatally flawed assumptions that rendered his results useless for the purpose of setting an allowed return for Atmos in this proceeding. Third, Dr. Brown's selective application of data in his Discounted Cash Flow (DCF) analysis similarly produced unrealistic results relative to current market information, so they are not reliable. Taken together, these problems with his analysis indicate that Dr. Brown's recommended allowed return on total capital of 6.86 percent, as he reported on page 2 of 106 of his direct testimony, is completely inadequate and lacks the underlying foundation to be useful for setting rates for Atmos in this proceeding.

III. SHORT-TERM DEBT

Q. WHAT IS THE NATURE OF YOUR REBUTTAL OF DR. BROWN'S SHORT-TERM DEBT IN HIS RECOMMENDED CAPITAL STRUCTURE?

A. Dr. Brown included 13 percent short-term debt in his capital structure as stated in his table on line 26, page 2 of 106 of his direct testimony. He characterizes current maturities of long-term debt as being short-term debt, but the Company in its filing included current maturities as part of total long-term debt. Therefore, the portion of short-term debt that he actually proposes for inclusion in Atmos' capital structure is 11.3%. In support of his inclusion of this high percentage of short-term debt in Atmos' capital structure, he mischaracterized my testimony and ignored critical facts. As to the mischaracterization of my testimony, he stated on lines 17-19, page 3 of 106, that I relied "…on data from the publication Value Line to determine capital structure." Dr. Brown repeated this erroneous conclusion on lines 5-8, page 17 of 106 where he stated that I relied "…not at all on primary sources…" and that my "…testimony relies wholly on data filtered through third parties…."

Q. WHAT WERE THE ACTUAL DATA SOURCES THAT YOU USED IN YOUR DIRECT TESTIMONY TO DETERMINE THE CAPITAL STRUCTURE FOR ATMOS IN THIS PROCEEDING?

A. Contrary to Dr. Brown's assertion that I relied on *Value Line* data, as shown on Schedule DAM-6 of my direct testimony, entitled "Projected Capital Structure," I actually relied on, and clearly cited the source as, "Atmos Energy Corporation

Work Papers." Although he was factually in error as to the source of data for the capital structure in my direct testimony, his criticism of *Value Line* and assertion about the use of audited data is also misdirected.

Q. WHAT IS WRONG WITH DR. BROWN'S CONCERN ABOUT THE USE OF VALUE LINE IN DETERMINING THE CAPITAL STRUCTURE IN A RATE PROCEEDING?

A. Instead of using *Value Line* data, Dr. Brown asserted that an analyst should use the 10-K reports filed with the Securities and Exchange Commission because "...they are audited and certified by public accountants." Two things are wrong with Dr. Brown's position regarding these data. One is his dismissal of *Value Line*. The other is his argument that analysts should rely exclusively on data audited and certified by public accountants for setting rates for the future. In regards to *Value Line,* it is a widely respected, independent financial service used by many analysts and investors and commonly accepted by regulatory agencies as authoritative. Dr. Brown's statement on lines 19-24, page 19 of 106 of his direct testimony, "that *Value Line's* owner was pulling money out of the business and the company's future is expected to be brief," is without any substantiation.

Q. IS DR. BROWN CORRECT WHEN HE ARGUED THAT ANALYSTS SHOULD RELY EXCLUSIVELY ON DATA AUDITED BY CERTIFIED PUBLIC ACCOUNTANTS FOR DETERMINING CAPITAL STRUCTURE SPECIFICALLY AND THE COST OF CAPITAL GENERALLY?

A. Dr. Brown's argument that analysts should rely entirely upon audited data to determine a capital structure for ratemaking is inappropriately restrictive, inconsistent with common regulatory practice and also likely to be misleading. The purpose of a utility rate proceeding is to set rates for the future, but audited capital accounts of a utility are by definition historical. The historical capital structure may not be representative of the capital structure appropriate for setting rates for the future. The rebuttal testimonies of Company witnesses Ms. Laurie Sherwood and Mr. Christopher Forsythe more fully address the reasons why Dr. Brown's assumption on this point do not apply to Atmos in this proceeding.

Q. WHAT DID THE COMPANY WORKPAPERS THAT YOU REVIEWED SHOW ABOUT THE APPROPRIATE CAPITAL STRUCTURE FOR ATMOS IN THIS PROCEEDING?

A. As I illustrated clearly in Schedule DAM-9, during the calendar years 2004-05, Atmos' short-term debt balances were equal to zero for 12 out of 24 months. As also demonstrated in Ms. Sherwood's rebuttal testimony, Atmos' short-term debt balance was at or near zero for half of the twelve most recent fiscal quarters. If Atmos' short-term debt can fall to zero and remain at that level half the time, it is not possible for the Company to use short-term debt as permanent capital to support the rate base supplying utility service to customers. This reason alone confirms that Dr. Brown's assertion that Atmos' permanent capital should include a short-term debt component is wrong.

Q. OTHER THAN HIS MISINTERPRETATION OF THE FACTUAL SHORT-TERM DEBT DATA, WAS DR. BROWN'S CONCEPTUAL UNDERSTANDING OF THE ROLE OF SHORT-TERM DEBT CORRECT?

A. No. He mischaracterized how my consideration of short-term debt affected my recommended capital structure for Atmos in this proceeding. In his direct testimony, on lines 12-13, page 3 of 106 he says, "their [Atmos'] treatment of short-term debt as if it were equity." Again on lines 7-9, page 4 of 106 he stated that I treated "…short-term debt as if it were equity, adding the short-term debt ratio to the equity ratio…." He continued on lines 8-10, on page 44 of 106 when he declared, "Dr. Murry has treated the short-term debt of 9.15% as equity, as I mentioned in my summary." He repeated this assertion on lines 16-29, page 57 of 106 and in a chart on page 59 of 106. He is both conceptually and mathematically wrong. Instead, I simply excluded short-term debt from the calculation of the total capital of Atmos because it is not part of the Company's permanent capital.

Q. ARE YOU AWARE OF OTHER AREAS OF HIS TESTIMONY REGARDING THE USE OF SHORT-TERM DEBT WHERE DR. BROWN MISCHARACTERIZED YOUR TESTIMONY?

A. In one instance, he cited, on page 50 of 106 of his direct testimony, previous testimony of mine in a completely different gas utility's rate case in which I had included short-term debt as a portion of permanent capital. On lines 1-6, page 51 of 106 of his direct testimony concerning my recommendation of inclusion of short-term debt in a utility's capital structure, he stated,

> …an expert can change an opinion, but there has to be a reason for the change. Dr. Murry has not acknowledged that he has changed his opinion and he has not offered any reason for the change.

This is a mischaracterization of my testimony in this case and many others. I have maintained for years that short-term debt should be included in a utility's capital structure, if, and only if it is a component of permanent capital. In the case of Atmos in this proceeding, this is not the case.

As I noted in my rebuttal testimony, on page 10, lines 3 – 6, in the Piedmont Natural Gas case that he referenced above, i.e., Docket No. 03-00313:

> How one determines equity ratios and capital structures depends on how one defines them. As Dr. Brown himself noted, *Value Line* does not include short-term debt in its reported capital structures. This is not unusual as short-term debt is usually not a component of the permanent capital structure.

Q. COULD YOU UNDERSTAND THE REASON WHY DR. BROWN INCLUDED SHORT-TERM DEBT IN ATMOS' CAPITAL STRUCTURE?

A. I believe that Dr. Brown is confused about the role of short-term debt in the capital structure for ratemaking. For example, Dr. Brown, on lines 6-21, page 6 of 106, revealed a basic misunderstanding of the role of permanent capital for ratemaking purposes, where he stated,

> …short-term debt can be used for any purpose as a company sees fit, including construction and operating expenses in general. Thus short-term debt is a permanent capital source which reduces the need for long-term debt financing and common equity….

Short-term debt used as temporary financing during the time of construction is normally not treated as permanent capital for ratemaking unless the plant under construction is determined, through the regulatory process, to be appropriately included in rate base. Furthermore, "operating expenses" are definitely not part of a rate base used to determine rates.

Q. HOW DID DR. BROWN'S INCLUSION OF SHORT-TERM DEBT IN ATMOS' CAPITAL STRUCTURE AFFECT HIS RECOMMENDED CAPITAL STRUCTURE IN THIS PROCEEDING?

A. On line 26, page 2 of 106 and lines 8-11, page 60 of 106 Dr. Brown indicates that the appropriate capital structure in this proceeding is 11.3 percent short-term debt, 1.7 percent short-term debt as the current portion of long-term debt, 46.3 percent long-term debt and 40.7 percent common equity. If one removes from Dr. Brown's proposed capital structure the total short-term debt of 13 percent that is not part of Atmos' permanent capital structure, this results in a total long-term debt of 53.2 percent and common equity of 46.8 percent. This is very close to the Company's proposed capital structure of 51.5 percent long-term debt and 48.5 percent common equity, and it indicates that differences between Dr. Brown's recommended capital structure and mine are due to his inappropriate inclusion of short-term debt.

Q. ALTHOUGH DR. BROWN INAPPROPRIATELY INCLUDED SHORT-TERM DEBT, DID HE OTHERWISE ACCURATELY REPRESENT ATMOS ENERGY'S HISTORICAL FINANCIAL DATA IN HIS DIRECT TESTIMONY?

A. No. On a schedule on page 58 of 106 of his direct testimony, Dr. Brown reported that Atmos had a balance of preferred stock outstanding in 2004. This is factually in error. TXU Gas Company had preferred stock, but the Company did not assume that stock as part of its acquisition of TXU Gas. Likewise, Dr. Brown represented balances of long-term debt in excess of the amount reported on the 10-K reports that he cited as sources for the years 1997 to 2000. I have made these corrections in Rebuttal Schedule DAM-R1.

Q. CAN YOU TELL HOW THE ERRORS IN THE TABLE ON PAGE 58 OF

HIS DIRECT TESTIMONY MAY HAVE AFFECTED DR. BROWN'S CONCLUSIONS REGARDING THE APPROPRIATE RETURN FOR ATMOS IN THIS PROCEEDING?

A. I cannot tell how these data errors may have affected his recommended allowed return on common stock. Since the data from his table on page 58 forms the basis for many charts and tables in his direct testimony, Dr. Brown may have reached some erroneous conclusions at various stages of his analysis. For example, at least the table on page 2, the chart on page 8, the chart on page 53, the chart on page 54, the table on page 59, and the table on page 60 of Dr. Brown's direct testimony all may have faulty underlying data.

IV. CAPITAL ASSET PRICING MODEL

Q. YOU STATED THAT DR. BROWN'S CAPM ANALYSIS INCLUDED TWO FATAL FLAWS. CAN YOU EXPLAIN WHAT YOU MEANT BY THAT STATEMENT?

A. Dr. Brown's CAPM was flawed because he either incorrectly interpreted or misunderstood both the risk premium and the beta that he used in his analysis. In both cases, a source that Dr. Brown relied on does not support the data that he used. I attempted to replicate his CAPM calculations which I illustrated in Rebuttal Schedule DAM-R2. This produced a CAPM estimate of 6.67 percent for Atmos Energy and a return of 6.28 percent for the comparable gas companies. Given that current yield on Baa-rated utility bonds is 6.44 percent, Dr. Brown should have concluded that his CAPM yielded poor common equity cost estimates.

Q. HOW DID DR. BROWN MISINTERPRET OR MISUNDERSTAND THE RISK PREMIUM THAT HE USED IN HIS CAPM ANALYSIS?

A. Dr. Brown, on lines 7-10, page 90 of 106 of his direct testimony, stated the following, "the risk premium, (Rm-Rf) is about 3.5%, the difference between the current market wide equity return of 8.7 & [sic] and the risk free rate of 5%." However, Morningstar, the data source that he cited extensively as authoritative (see, for example, lines 26-28, page 19 and pages 77-82 of 106 of Brown's direct testimony), indicates that the equity risk premiums for "Building Blocks for Expected Return Construction," for large companies is 7.1 percent to 8.6 percent depending upon the length of the investment horizon. I have attached this page showing these figures as Rebuttal Schedule DAM-R3 from the *2007 SBBI Yearbook*[1], published by Morningstar. The range of Morningstar risk premiums far exceeds Dr. Brown's risk premium which he claimed came from Morningstar.

Q. WHY DID YOU STATE THAT MORNINGSTAR DOES NOT SUPPORT THE BETA THAT DR. BROWN USED FOR HIS CAPM ANALYSIS?

A. Analyst Brian Lund says in an article that is available on the Morningstar website, morningstar.com:

> Because we advise investors to think like long-term owners of a company rather than short-term traders of stock, we fall squarely on the Buffet end of the spectrum. We don't use beta to determine our costs of equity….

Q. WHAT IS WRONG WITH THE MORNINGSTAR BETAS THAT DR. BROWN USED?

[1] "Chapter 9: Using Historical Data in Forecasting and Optimization," Stocks, Bonds, Bills and Inflation 2007 Yearbook: Classic Edition, edited by James P. Harrington, (Morningstar: 2007, Chicago, IL), p. 166.

A. As unadjusted betas, these betas are too low to produce a reasonable estimate of a cost of capital for a company with a beta less than one, which, of course, will include most utilities. Dr. Brown's selection of them overlooks a vast body of literature that cautions against using raw, unadjusted betas in CAPM calculations. Consequently, Dr. Brown's CAPM result is very biased to the low side and unreliable for the purpose of estimating the cost of common equity for Atmos in this proceeding.

V. DISCOUNTED CASH FLOW

Q. WHAT DID YOU DETERMINE WHEN YOU ANALYZED THE DCF REPORTED BY DR. BROWN?

A. Dr. Brown's DCF was difficult to interpret because he did not provide exhibits or schedules in his testimony showing his DCF calculations for Atmos or his comparable gas companies. On page 88 of 106 of his direct testimony he stated that the cost of equity using the DCF method for the comparable companies is 7.8 percent. To reach this conclusion, he used the comparable companies' current dividend yield and their five-year historical dividend growth. As I pointed out in my direct testimony, the use of historical information may be misleading as it may not represent the expectations of investors about the future returns to the company. As I also pointed out in my direct testimony, in recent years the declared dividends of natural gas utilities generally have grown slowly relative to earnings, which represent a conservative dividend policy. As a consequence, using historical dividend growth figures to calculate a DCF also misrepresents investors' expectations of future returns. Consequently, Dr. Brown's DCF result will be biased to the low side.

Q. DESPITE YOUR CONCERNS ABOUT HIS SELECTION OF DATA FOR HIS DCF, WERE YOU ABLE TO REPLICATE DR. BROWN'S DCF RESULT?

A. No. I took the raw data he provided for each of the comparable gas utilities in his workpapers and calculated a DCF cost of equity using the companies' current yield and historical dividend growth rate. As Rebuttal Schedule DAM-R4 shows, Dr. Brown's DCF method produced a return on common equity estimate of 5.93 percent for Atmos and 6.38 percent for the comparable gas utilities. Both of these cost of equity estimates are below the current yield on Baa-rated utility bonds of 6.44 percent. These results are nonsensical. At this return level, a rational, risk-adverse investor would choose to purchase a low-rated utility bond rather than Atmos' or any utility's common stock. At minimum, Dr. Brown should have recognized the inadequacy of his DCF results. These DCF results that underlie his return recommendation are not sufficient to attract and maintain capital in current markets.

Q. NOTING THE DIFFERENCES BETWEEN YOUR DCF METHOD AND HIS CALCULATION AND METHOD, DID DR. BROWN TAKE ISSUE WITH THE RESULTS OF YOUR DCF ANALYSIS?

A. No.

Q. DID YOU UPDATE YOUR PREVIOUS DCF ANALYSIS THAT YOU USED IN REACHING A RECOMMENDED ALLOWED RETURN ON COMMON EQUITY FOR ATMOS IN THIS PROCEEDING?

A. Yes. I updated my DCF calculation that used the 52-week share price range, and the projected earnings growth rates from Standard & Poor's and *Value Line*. I illustrated those updated results in Rebuttal Schedule DAM-R5. The DCF estimate for Atmos Energy is 11.36 percent. The estimated cost of equity for the comparable gas utilities with Standard & Poor's credit ratings closer to Atmos is 11.69 percent.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

County of Oklahoma)
)
State of Oklahoma)

AFFIDAVIT OF DONALD A. MURRY

Donald A. Murry, being first duly sworn, deposes and says that he is the witness who sponsors the accompanying testimony, that said testimony was prepared by him and under his direction and supervision; that if inquiries were made as to the facts in said testimony and schedules, he would respond as therein set forth; and that the aforesaid testimony and schedules are true and correct to the best of his knowledge, information, and belief.

Donald A. Murry

Donald A. Murry

Subscribed and sworn to before me this 19 day of September, 2007.

05005618

Notary Public #

Crystal Nance

CRYSTAL NANCE NOTARY # 05005618 EXP. 6/17/09 PUBLIC STATE OF OKLAHOMA

My Commission expires:

6/17/09

Atmos Energy Corporation

Capital Structure

According to CAPD Witness Steve Brown

Components As Of	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
Short Term Debt Notes Due	$382,416	$144,809	$0	$118,595	$145,791	$201,247	$250,047	$168,304	$17,491	$119,178
Current Portion of Long Term Debt	$3,186	$3,264	$5,908	$9,345	$21,695	$20,695	$17,566	$17,848	$57,783	$15,201
Correct Long-Term Debt	$2,180,362	$2,183,104	$861,311	$862,500	$670,463	$692,399	$363,198	$377,483	$398,548	$302,981
Common Equity	$1,648,098	$1,602,422	$1,133,459	$857,517	$573,235	$583,864	$392,466	$377,663	$371,158	$327,260
Total	$4,214,062	$3,933,599	$2,000,678	$1,847,957	$1,411,184	$1,498,205	$1,023,277	$941,298	$844,980	$764,620

Sources:
Direct Testimony of CAPD Witness Steve Brown, page 58 of 106
Atmos Energy Corporations' Form 10K for the Years 1997-2000 and 2004

Rebuttal Schedule DAM-R1

Atmos Energy Corporation

CAPD Witness Steve Brown

Capital Asset Pricing Model

Company	Risk Free Return	NASDAQ Web Site Beta	Market Risk Premium	Adjusted Risk Premium	CAPM Returns
Atmos Energy	5.00%	0.45	3.71%	1.67%	6.67%
AGL Resources	5.00%	0.34	3.71%	1.26%	6.26%
New Jersey Resources	5.00%	0.06	3.71%	0.22%	5.22%
Nicor	5.00%	0.89	3.71%	3.30%	8.30%
Northwest NaturalGas	5.00%	0.17	3.71%	0.63%	5.63%
Piedmont Natural Gas	5.00%	0.34	3.71%	1.26%	6.26%
South Jersey Industries	5.00%	0.35	3.71%	1.30%	6.30%
Southwest Gas	5.00%	0.28	3.71%	1.04%	6.04%
WGL Holdings	5.00%	0.33	3.71%	1.22%	6.22%
Median	5.00%	0.34	3.71%	1.24%	6.24%
Average	5.00%	0.35	3.71%	1.28%	6.28%

Source:
Direct Testimony CAPD Witness Steve Brown, page 91 and 95 of 106

For Treasury bills, the expected return over a given time horizon is equal to the expected return on a Treasury bond of a similar horizon, less the expected horizon premium of bonds over bills. This premium is estimated by the historical average of the difference of the income return on bonds and the return on bills. From Table 9-1, this is 1.6 percent. Subtracting this from the riskless rate gives us an expected return on bills of 3.3 percent. Of course, this forecast typically differs from the current yield on a Treasury bill, since a portfolio of Treasury bills is rolled over (the proceeds of maturing bills are invested in new bills, at yields not yet known) during the time horizon described.

Standard Deviations

Standard deviations are estimated from historical data as described in Chapter 6. Since there is no evidence of a major change in the variability of returns on large company stocks, we use the entire period 1926–2006 to estimate the standard deviation of these asset classes. For bonds and bills, we use the period 1970–2006. The use of this more recent period reflects the fact that the volatility of bonds has increased over time.

Table 9-1
Building Blocks for Expected Return Construction

	Value (in percent)
Yields (Riskless Rates)[1]	
Long-Term (20-year) U.S. Treasury Coupon Bond Yield	4.9
Intermediate-Term (5-year) U.S. Treasury Coupon Note Yield	4.6
Short-Term (30-day) U.S. Treasury Bill Yield	4.8
Fixed Income Risk Premia[2]	
Expected default premium: *long-term corporate bond total returns minus long-term government bond total returns*	0.2
Expected long-term horizon premium: *long-term government bond income returns minus U.S. Treasury bill total returns**	1.6
Expected intermediate-term horizon premium: *intermediate-term government bond income returns minus U.S. Treasury bill total returns**	1.1
Equity Risk Premia[3]	
Long-horizon expected equity risk premium: *large company stock total returns minus long-term government bond income returns*	7.1
Intermediate-horizon expected equity risk premium: *large company stock total returns minus intermediate-term government bond income returns*	7.6
Short-horizon expected equity risk premium: *large company stock total returns minus U.S. Treasury bill total returns**	8.6
Small Stock Premium: *small company stock total return minus large company stock total return*	5.0

1 As of December 31, 2006. Maturities are approximate.

2 Expected risk premia for fixed income are based on the differences of historical arithmetic mean returns from 1970–2006.

3 Expected risk premia for equities are based on the differences of historical arithmetic mean returns from 1926–2006.

*For U.S. Treasury bills, the income return and total return are the same.

Atmos Energy Corporation

CAPD Witness Steve Brown

Discounted Cash Flow Analysis

Company	Yield	5-Year Historical Dividend Growth Rate	DCF ROE
Atmos Energy	4.28%	1.65%	5.93%
AGL Resources	3.73%	7.07%	10.80%
New Jersey Resources	2.74%	4.52%	7.26%
Nicor	3.93%	0.88%	4.81%
Northwest NaturalGas	2.83%	2.29%	5.12%
Piedmont Natural Gas	3.74%	4.51%	8.25%
South Jersey Industries	2.44%	4.83%	7.27%
Southwest Gas	2.20%	0.00%	2.20%
WGL Holdings	3.94%	1.39%	5.33%
Median	3.28%	3.40%	6.30%
Average	3.19%	3.19%	6.38%

Source:
Work papers of CAPD Witness Steve Brown

Atmos Energy Corporation
Comparable Gas Companies
Discounted Cash Flow using Earnings per Share Growth Rate
52 Week Stock Price Range

	Share Price		2007	2007 Yield		Growth Rate		Cost of Capital	
	low	high	Dividend	low	high	S&P	Value Line	low	high
Atmos Energy Corp.	$23.87	$33.47	$1.28	3.82%	5.36%	5.00%	6.00%	8.82%	11.36%
AGL Resources	$34.76	$44.67	$1.64	3.67%	4.72%	5.00%	3.50%	7.17%	9.72%
New Jersey Resources	$45.50	$56.45	$1.52	2.69%	3.34%	5.00%	3.00%	5.69%	8.34%
Nicor	$37.80	$53.66	$1.90	3.54%	5.03%	5.00%	4.50%	8.04%	10.03%
Northwest Natural Gas	$37.67	$52.85	$1.46	2.76%	3.88%	5.00%	6.50%	7.76%	10.38%
Piedmont Natural Gas	$22.00	$28.44	$0.99	3.48%	4.50%	5.00%	4.00%	7.48%	9.50%
South Jersey Industries	$28.55	$41.27	$0.98	2.37%	3.43%	7.00%	11.85%	9.37%	15.28%
Southwest Gas	$26.45	$39.95	$0.86	2.15%	3.25%	5.00%	9.00%	7.15%	12.25%
WGL Holdings	$29.79	$35.91	$1.36	3.79%	4.57%	3.00%	2.00%	5.79%	7.57%
Comparable Companies' Average	$32.82	$44.15	$1.34	3.06%	4.09%	5.00%	5.54%	7.31%	10.38%
Comparable Companies with S&P rating of A+ or higher								6.82%	9.08%
Comparable Companies with S&P rating below A+								7.79%	11.69%

Sources
YAHOO! Finance
Value Line Investment Survey
Standard & Poor's Earning Guide August 2007

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:

PETITION OF ATMOS ENERGY CORPORATION FOR APPROVAL OF ADJUSTMENT OF ITS RATES AND REVISED TARIFF	))))	**DOCKET NO. 07-00105**

REBUTTAL TESTIMONY OF THOMAS H. PETERSEN
ON BEHALF OF ATMOS ENERGY CORPORATION

I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. My name is Thomas H. Petersen. I am Director of Rates for Atmos Energy Corporation ("Atmos" or the "Company"). My business address is 5430 LBJ Freeway, Dallas, Texas 75240. I am responsible for rate studies of the Company's gas utility operations in 12 states including Tennessee.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS CASE?

A. Yes, I filed direct testimony on four areas: projected revenue deficiency for the attrition year, average rate base for the attrition year, cash working capital requirement based on my lead-lag analysis, and the resulting rate of return and return on equity.

Q. WHAT IS THE SCOPE OF YOUR REBUTTAL TESTIMONY?

A. I will address Consumer Advocate Protection Division's ("CAPD") witness Mr. Terry Buckner's testimony regarding the deferred rate case expense, cash working capital and accumulated depreciation portions of rate base. I will present updated schedules that incorporate settled issues into the calculation of the revenue requirement. I will also discuss some financial and customer implications of CAPD witness Mr. Charles King's depreciation rate proposal.

Q. HAVE YOU PREPARED ANY SCHEDULES OR WORKPAPERS IN CONNECTION WITH YOUR REBUTTAL TESTIMONY?

A. Yes. I have prepared Schedules THP-R-1 through THP-R-11 to show the effect of the stipulated amounts on my testimony in this case and Schedules THP-R-CWC1 and THP-R-CWC2 to show recalculations of cash working capital.

II. DEFERRED RATE CASE EXPENSE

Q. DO YOU AGREE WITH MR. BUCKNER'S RECOMMENDATION ON DEFERRED RATE CASE EXPENSE?

A. Yes. Mr. Buckner's recommended $540,336 of deferred rate case expense is based on a three year amortization of rate case expenses. The Company's original proposal was based on a two year amortization. The Company and the CAPD have settled on a three year amortization as part of stipulating operation and maintenance expense. Given the three year amortization I agree with Mr. Buckner's calculation of his recommended rate base amount.

III. CASH WORKING CAPITAL

Q. HOW DOES MR. BUCKNER'S RECOMMENDATION ON CASH WORKING CAPITAL DIFFER FROM THE COMPANY'S PROPOSAL?

A. His recommendation differs in the payment lag for the current portions of franchise tax, state excise tax and federal income tax. It also differs in the forecasted expense amounts included in the lead-lag study. Attached Rebuttal Schedule THP-R-CWC1 shows the calculation of cash working capital in the Company's format using Mr. Buckner's payment lags and expense amounts. The result verifies Mr. Buckner's calculation. I agree with Mr. Buckner's calculations based upon his recommended payment lags. I disagree, however, with his calculations regarding the level of return, state excise tax and income tax included in Mr. Buckner's lead-lag calculation. He only includes the return and tax amounts from his calculation of adjusted net operating income ***before*** adjustment for deficiency or surplus. That is, he does not consider his recommended $1.36 million decrease in rates in the lead-lag calculation. Additionally Mr. Buckner does not fully include the effects of adjustments to net operating income.

Q. HAVE YOU CALCULATED CASH WORKING CAPITAL CONSIDERING MR. BUCKNER'S RECOMMENDED RATE DECREASE?

A. Yes. Attached Rebuttal Schedule THP-R-CWC2 shows the calculation of cash working capital adjusting Mr. Buckner's expense amounts for the effects of his recommended $1.36 million decrease, the effects of adjustments to net operating income and correcting for a couple of minor data entry errors. The resulting cash working capital requirement is $3,879,415.

Q. HAVE YOU RECALCULATED CASH WORKING CAPITAL IN LIGHT OF THE STIPULATIONS REACHED BY THE PARTIES?

A. Yes. Attached Rebuttal Schedule THP-R-11 shows the calculation of cash working capital adjusting the company's proposal to reflect Mr. Buckner's leads and lags and to incorporate the stipulated expense, revenue and rate base items. The recalculated cash working capital requirement for inclusion in rate base is $5,180,448.

IV. REVENUE REQUIREMENTS

Q. HAVE YOU UPDATED THE REVENUE REQUIREMENTS SCHEDULES?

A. Yes, Schedules THP-R-1 through THP-R-11 to show the effect of the stipulated amounts on my recommendations in this case. Schedule THP-R-1 shows a recalculated revenue deficiency of $8,728,796. Schedules THP-R-2 through THP-R-9 show the calculations of each of the line items in Schedule THP-R-1. Schedule THP-R-10 calculates a rate of return on equity using the stipulated and revised amounts of 5.87%.

V. DEPRECIATION

Q. HOW DO MR. KING'S AND THE COMPANY'S PROPOSALS WITH RESPECT TO DEPRECIATION EXPENSE DIFFER?

A. Atmos proposed to reduce annual depreciation expense from approx $12.5 million per year to approximately $10.5 million per year. Mr. King's proposal would reduce depreciation expense to approximately $7.5 million. Of the approximately $3 million dollar additional reduction in attrition year depreciation recommended by Mr. King, approximately $1.4 million is due to Mr. King using the average life group ("ALG") method rather and Mr. Roff using the equal life group method ("ELG"). The remaining difference is related to different recommendations regarding accruals for cost of removal.

Q. DOES MR. KING'S PROPOSAL HAVE ANY NEGATIVE IMPLICATIONS FOR CUSTOMERS?

A. Yes. Such a drastic cut in depreciation expense would reduce the Company's cash flow. Such a reduction leads to more borrowing and higher debt costs and speeds up rate base growth. The acceleration in the expansion of the rate base causes rate cases to become more frequent. Mr. King's proposal will ultimately lead to higher utility rates for future generations of ratepayers, because it delays payment for assets while requiring a rate of return on the deferred payments. Atmos aims to match recovery of investment in assets to the useful life of assets in order to avoid overly dampening financial growth and to provide for equity among generations of customers meaning that customers pay for the assets they are using at the time they are using them.

Q. HOW DOES MR. KING'S PROPOSAL CREATE INEQUITY AMONG GENERATIONS OF CUSTOMERS?

A. Today's customers should not be asked to subsidize future rate payers by paying more than their fair share. Likewise, today's customers should not be subsidized by future customers by paying less than their fair share. To the extent that Mr. King's proposal does not provide for the accrual of enough dollars for cost of removal during the useful life of assets to pay for the cost of removal that is likely to be incurred at the price level likely at the time of payments, he is pushing costs that should be borne by current consumers on to future consumers. Mr. Roff's study indicates that our current depreciation rates are too high and that his proposed rates would provide a more appropriate rate of cost recovery. Mr. Roff will further address Mr. King's testimony regarding depreciation. It simply does not make ratemaking or economic sense from the Ratepayer, Company or Commission point of view, to cut depreciation rates in the manner Mr. King suggests.

Q. ARE THERE ANY FURTHER REASONS THAT THE DEPRECIATION RATE FOR THE COMPANY'S SHARED SERVICES BE APPROVED?

A. The Company's proposed depreciation rates for shared services ("SSU") account for about $40,000 of the difference between King and Roff. The SSU depreciation rates proposed by Mr. Roff have already been approved in Kentucky and Louisiana. They are based upon the equal life group ("ELG") method typically approved for Texas where Atmos has close to one-half of its customers, and where its Shared Services assets are located. Atmos proposes that, even if the decision in this case is to use average life group method ("ALG") for assets in Tennessee, this Authority approve the Company's proposed depreciation rates for SSU assets located elsewhere.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:	)	
	)	
PETITION OF ATMOS ENERGY CORPORATION FOR APPROVAL OF ADJUSTMENT OF ITS RATES AND REVISED TARIFF	))))	**DOCKET NO. 07-00105**

VERIFICATION

STATE OF TEXAS	)
	)
COUNTY OF DALLAS	)

I, Thomas H. Petersen, being first duly sworn, state that I am Director of Rates for Atmos Energy Corporation, that I am authorized to testify on behalf of Atmos Energy Corporation in the above referenced docket, that the Rebuttal Testimony of Thomas H. Petersen pre-filed in this docket on the date of filing herein is true and correct to the best of my knowledge, information and belief.

Thomas H. Petersen
Thomas H. Petersen

Sworn and subscribed before me this 20th day of September, 2007.

Ethel Z. Taylor
Notary Public

My Commission Expires: August 13, 2010

ETHEL Z TAYLOR
My Commission Expires
August 13, 2010

Tennessee Distribution System
Cost of Service
Twelve Months Ended October 31, 2008

Line No.	Description	Reference	Amount
	(a)	(b)	(c)
1	Cost of Gas	Schedule 3	$125,663,944
2			
3	Operation & Maintenance Expense	Schedule 4	14,875,386
4			
5	Taxes Other Than Income Taxes	Schedule 5	7,010,799
6			
7	Depreciation & Amortization Expense	Schedule 6	10,890,872
8			
9	Return	Schedule 7	16,432,693
10			
11	Federal Income and State Excise Tax	Schedule 8	6,708,343
12			
13	AFUDC	Wp 1-2	(199,216)
14			
15	Interest on Customer Deposits	Wp 1-1	401,369
16			
17	Total Cost of Service		181,784,190
18			
19			
20	Revenue at Present Rates	Schedule 2	173,055,394
21			
22	Net Revenue Deficiency		8,728,796

Tennessee Distribution System
Summary of Revenue at Present Rates
Twelve Months Ended October 31, 2008

Line No.	Description		Amount
	(a)		(b)
1	Test year per books revenue [1]		184,574,748
2			
3	Change from Test Year to Attrition Year		(11,519,354)
4			
5	Projected Attrition Year Revenue		
	Margin at current WNA		
	Change in Margin due to updating WNA		
	Margin at proposed WNA	47,391,450	
	Gas cost	125,663,944	
	Total		173,055,394

[1] Twelve months ended December 31, 2006

Schedule THP-R3

Tennessee Distribution System
Cost of Gas
Twelve Months Ended October 31, 2008

Line No.	Description	Amount
	(a)	(b)
1	Test year per books cost of gas [1]	$136,629,859
2		
3	Adjustments	
4	Change from Test Year to Attrition Year	(9,323,437)
5		
6	Total Adjusted Gas Cost	127,306,422
7		
8	Net Elimination of Intercompany Leased Storage Property	(1,642,478)
9		
10	Projected Attrition Year Gas Cost	125,663,944

[1] Twelve months ended December 31, 2006

Tennessee Distribution System
Operation and Maintenance Expenses
Twelve Months Ended October 31, 2008

Line No.	Description	Amount ($)
	(b)	(c)
1	Test year per books O&M Expense [1]	14,789,621
2		
3	Change from Test Year to Attrition Year	1,051,821
4		
5	Attrition Year O&M Expenses - Unadjusted	15,841,442
6		
7	Adjustments to O&M	
8	Net Elimination of Intercompany Leased Property - Rent	(531,996)
9	Gain on sale of Maryland Way Property	(16,899)
10	Settled O&M Adjustments	(417,161)
11		
12		
13	Total Adjustments	(966,056)
14		
15	Total Adjusted Operation and Maintenance Expenses	14,875,386

[1] Twelve months ended December 31, 2006

Schedule THP-R5

Tennessee\ Distribution System
Taxes Other Than Income Taxes
Twelve Months Ended October 31, 2008

Line No.	Description		Total
	(a)		(b)
1	Test year per books Other Taxes Expense [1]	$	5,851,994
2			
3	Change from Test Year to Attrition Year		1,158,805
4			
5	Attrition Year Taxes Other Than Income Taxes	$	7,010,799

[1] Twelve months ended December 31, 2006

Tennessee Distribution System
Depreciation and Amortization Expense
Twelve Months Ended October 31, 2008

Line No.	Description		Amount	Source
	(a)		(b)	
1	Test year per books Depreciation Expense [1]	$	11,498,043	
2				
3	Change from Test Year to Attrition Year		1,251,899	
4				
5	Attrition Year Depreciation Expense at current Depreciation Rates	$	12,749,942	
6				
7	Adjustment to reflect Proposed Depreciation Rates		(2,097,654)	
8				
9	Attrition Year Depreciation Expense at proposed Depreciation Rates		10,652,288	
10				
11	Net Elimination of Intercompany Leased Property		238,584	
12				
13	Total Depreciation and Amortization Expense, As Adjusted	$	10,890,872	

[1] Twelve months ended December 31, 2006

Tennessee Distribution System
Rate Base & Return
Twelve Months Ended October 31, 2008
Thirteen Month Average

Line No.	Description	Test Year [1]	Change	Attrition Year	
	(a)	(b)	(c)	(d)	(e)
1	Original Cost of Plant	307,235,302	38,154,813	345,390,115	
2					
3	Accumulated Depreciation and Amortization	(132,372,710)	(16,534,603)	(148,907,313)	
4					
5	Construction Work in Progress per Books	5,670,631	(905,124)	4,765,507	
6					
7	Storage Gas Investment & Materials & Supplies	15,435,630	(724,418)	14,711,212	
8					
9	Cash Working Capital	4,321,563	858,885	5,180,448	
10					
11	Material & Supplies	58,752	(58,752)	-	
12					
13	Deferred Rate Case Expenses	110,000	430,336	540,336	
14					
15	Accumulated Deferred Income Tax	(34,830,861)	(320,680)	(35,151,541)	
16					
17	Customer Advances for Construction	(33,862)	(5,653)	(39,515)	
18					
19	Customer Deposits	(6,283,250)	(406,240)	(6,689,490)	
20					
21	Accumulated Interest on Customer Deposits	(563,662)	(283,343)	(847,005)	
22					
23	Unadjusted Rate Base	158,747,533	20,205,221	178,952,754	
24					
25	Adjustments:				
26	Net Elimination of Intercompany Leased Property	7,377,614	(433,009)	6,944,605	
27	Unamortized Maryland Way Gain	(43,891)	36,729	(7,162)	
28					
29	Total Rate Base	166,081,256	19,808,941	185,890,197	
30					
31	Return @ Overall Cost of Capital on Rate Base	14,681,583	1,751,110	16,432,693	

[1] Twelve months ended December 31, 2006

Schedule THP-R8

Tennessee Distribution System
Computation of State Excise & Federal Income Taxes
Twelve Months Ended October 31, 2008

Line No.	Description		Test Year [1]	Change	Attrition Year
	(a)		(b)	(c)	(d)
1	Required Return		$14,681,583	$1,751,110	$16,432,693
2					
3	Interest Deduction		5,214,951	$622,001	5,836,952
4					
5	Equity Portion of Return		9,466,632	$1,129,109	10,595,741
6					
7	Application of Tax Rate to Equity Return - Tennessee	6.5%	615,331	$73,392	688,723
8					
9	Application of Tax Rate to Equity Return - Federal	35%	$3,097,955	$369,501	$3,467,456
10					
11	Sub total				$4,156,179
12					
13	ITC Amortization (Tax Effect)				(79,175)
14					
15			$3,713,286	$363,718	4,077,004
16					
17	Tax Expansion Factor		1.64541	1.64541	1.64541
18					
19	Total Income Tax Liability		$6,109,878	$598,465	$6,708,343
20					

[1] Twelve months ended December 31, 2006

Tennessee Distribution System
Overall Cost of Capital
Twelve Months Ended October 31, 2008

Line No.	Description	Percent	Cost Rate	Overall Cost of Capital
	(a)	(b)	(c)	(d)
1	Long Term Debt Capital	51.50%	6.10%	3.14%
2	Equity Capital	48.50%	11.75%	5.70%
3				
4	Total Capital	100.0%		8.84%

Schedule THP-R10

Tennessee Distribution System
Rate of Return
Twelve Months Ended October 31, 2008

Line No.	Description	Reference	Test Year [1]	Change	Attrition Year	Ratemaking Adjustments	Adjusted Amount
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Total Reveunes	Sch. 2	$ 184,574,748	$ (3,182,332)	$181,392,416	(8,337,022)	$173,055,394
2							
3	Gas Cost	Sch. 3	135,046,808	-	135,046,808	(9,382,864)	125,663,944
4							
5	Operation & Maintenance Expense	Sch. 4	14,237,381	1,604,061	15,841,442	(966,056)	14,875,386
6							
7	Taxes Other Than Income Taxes	Sch. 5	5,851,994	1,158,939	7,010,933	(134)	7,010,799
8							
9	Depreciation & Amortization Expense	Sch. 6	11,736,627	1,013,315	12,749,942	(1,859,070)	10,890,872
10							
11	Federal Income and State Excise Tax	Wp 10-1	4,801,887	(2,943,628)	1,858,259	1,426,223	3,284,482
12							
13	Interest on Customer Deposits	Wp 1-1	376,995	46,517	423,512	(22,143)	401,369
14							
15	Return on Rate Base		$ 12,523,056	$ (4,061,536)	$ 8,461,520	$2,467,022	$ 10,928,541
16							
17	Total Rate Base	Sch. 7	166,081,256	15,901,356	181,982,612	3,907,585	185,890,197
18							
19	Rate of Return on Rate Base		7.54%	-2.89%	4.65%	63.13%	5.88%
20							
21	Interest Expense	Sch. 8	5,214,951	499,303	5,714,254	122,698	5,836,952
22							
23	AFUDC Interest credit	Wp 1-2	(131,911)	-	(131,911)	(67,305)	(199,216)
24							
25	Return on Equity		$ 7,440,016		$ 2,879,177		$ 5,290,805
26							
27	Rate of Return on Equity		9.24%		3.26%		5.87%

Adjsuted Return - ROE plus Interest Expense	11,127,757
Required Return	16,432,693
Required Return less Adjusted Return	5,304,936
Grossed up Change in Return	8,728,794

[1] Twelve months ended December 31, 2006

Tennessee Distribution System
Computation of State Excise and Federal Income Taxes for Sch 10
Twelve Months Ended October 31, 2008

Line No.	Description		Test Year [1]	Projected Amount	Adjusted Amount
	(a)			(b)	(c)
1	Net Operating Income Before Income Tax		$17,324,943	$10,319,779	$14,213,023
2					
3	Interest Deduction		5,083,040	5,582,343	5,637,736
4					
5	Equity Portion of Return		12,241,903	4,737,436	8,575,287
6					
7	Application of Tax Rate to Equity Return - Tennessee	6.5%	795,724	307,933	557,394
8					
9	Application of Tax Rate to Equity Return - Federal	35%	$4,006,163	$1,550,326	$2,806,263
10					
11	ITC amortization				(79,175)
12					
13	Income Tax Expense		$4,801,887	$1,858,259	$ 3,284,482

[1] Twelve months ended December 31, 2006

Atmos Energy Corporation-Tennessee
Cash Working Capital Lead/Lag Analysis
For Attrition Period Ended October 31, 2008

Line No.	Description	Test Year Expenses	Average Daily Expense (b) / 365 days		Revenue Lag		Expense Lag	Net Lag (d) - (e)	CWC Requirement (c) x (f)
	(a)	(b)	(c)		(d)		(e)	(f)	(g)
1	Gas Supply Expense								
2	Purchased Gas	125,663,944	344,285	*Sch 2*	45.39	*Sch 3*	40.51	4.88	1,680,111
3									
4	Operation and Maintenance Expense								
5	O&M, Labor	6,236,891	17,087	*Sch 2*	45.39	*Sch 4*	14.23	31.16	532,431
6	O&M, Non-Labor	8,638,495	23,667	*Sch 2*	45.39	*Sch 5*	21.81	23.58	558,068
7	Total O&M Expense	14,875,386	40,754						1,090,499
8									
9									
10	Taxes Other Than Income								
11	Ad Valorem	2,829,817	7,753	*Sch 2*	45.39	*Sch 6*	241.50	(196.11)	(1,520,441)
12	State Gross Receipts Tax	2,764,034	7,573	*Sch 2*	45.39	*Sch 6*	(151.50)	196.89	1,491,048
13	Payroll Taxes	532,274	1,458	*Sch 2*	45.39	*Sch 6*	18.55	26.84	39,127
14	State Franchise Tax	540,998	1,482	*Sch 2*	45.39	*Sch 6*	37.00	8.39	12,434
15	TRA Inspection Fee	330,676	906	*Sch 2*	45.39	*Sch 6*	272.50	(227.11)	(205,762)
16	DOT	13,000	36	*Sch 2*	45.39	*Sch 6*	241.50	(196.11)	(7,060)
17	Total Taxes Other Than Income	7,010,799	19,208						(190,654)
18									
19	Federal Income Tax	*5,583,575*							
20	Current Taxes	3,347,915	9,172	*Sch 2*	45.39	*Sch 7*	37.00	8.39	76,953
21	Deferred Taxes	2,235,660	6,125	*Sch 2*	45.39	*Sch 7*	0.00	45.39	278,014
22									
23	State Excise Tax	*1,124,766*							
24	Current Taxes	0	0	*Sch 2*	45.39	*Sch 8*	37.00	8.39	0
25	Deferred Taxes	1,124,766	3,082	*Sch 2*	45.39	*Sch 8*	0.00	45.39	139,892
26									
27	Depreciation	10,890,872	29,838	*Sch 2*	45.39		0	45.39	1,354,347
28									
29	Interest on Customer Deposits	401,369	1,100	*Sch 2*	45.39		15.5	29.89	32,879
30									
31	Interest Expense - LTD	5,637,736	15,446	*Sch 2*	45.39	*Sch 9*	84.18	(38.79)	(599,219)
32									
33	Return on Equity	10,595,741	29,029	*Sch 2*	45.39		0	45.39	1,317,626
34									
35									
36	TOTAL	181,784,188	498,039						5,180,448

Tennessee Distribution System
Computation of State Excise and Federal Income Taxes for CWC
Twelve Months Ended October 31, 2008

Line No.	Description		Adjusted Amount
	(a)		(b)
1	Equity Portion of Return		8,575,287
2			
3	Application of Tax Rate to Equity Return - Tennessee	6.5%	557,394
4			
5	Application of Tax Rate to Equity Return - Federal	35%	$2,806,263
6	ITC		($79,175)
7	FIT after ITC		$2,727,088
8			
9	Income Tax Expense		$3,284,482
10			
11	Deficiency		$5,304,936
12	Gross Up		$3,423,859
13	Grossed up		$8,728,794
14	Gross up - State	6.5%	$567,372
15	Gross up - Federal		$2,856,487
16	Total - State		$1,124,766
17	Total - Federal		$5,583,575

[1] Twelve months ended December 31, 2006

Tennessee Distribution System
Computation of State Excise and Federal Income Taxes for Sch 10
Twelve Months Ended October 31, 2008

Line No.	Description		CAPD Filed	CAPD Corrected
	(a)			
1	Equity Portion of Return		11,235,210	11,235,188
2				
3	Application of Tax Rate to Equity Return - Tennessee	6.5%	730,289	730,287
4				
5	Application of Tax Rate to Equity Return - Federal	35%	$3,676,722	$3,676,715
6	ITC		($79,175)	($79,175)
7	FIT after ITC		$3,597,547	$3,597,540
8				
9	Income Tax Expense		$4,327,836	$4,327,827
10				
11	Deficiency		($831,394)	($831,394)
12	Gross Up		($529,369)	($529,369)
13	Grossed up		($1,360,763)	($1,360,763)
14	Gross up - State	6.17%	($83,991)	($83,991)
15	Gross up - Federal	33.24%	($424,346)	($424,346)
16	Total - State		$646,298	$646,296
17	Total - Federal		$3,173,201	$3,173,194
18				
19	CWC Taxes - State		730,289	730,289
20	CWC Taxes - Federal		3,597,547	3,597,547
21				
22	NIAT - pre-rate change		6,907,374	6,907,361
23	NIAT - post-rate change		6,075,980	6,075,967
24				

[1] Twelve months ended December 31, 2006

Atmos Energy Corporation-Tennessee
Cash Working Capital Lead/Lag Analysis
For Attrition Period Ended October 31, 2008

Tie back to CAPD filed position

Line No.	Description	Test Year Expenses	Average Daily Expense (b) / 365 days		Revenue Lag		Expense Lag	Net Lag (d) - (e)	CWC Requirement (c) x (f)
	(a)	(b)	(c)		(d)		(e)	(f)	(g)
1	Gas Supply Expense								
2	Purchased Gas	125,663,944	344,285	*Sch 2*	45.39	*Sch 3*	40.51	4.88	1,680,111
3									
4	Operation and Maintenance Expense								
5	O&M, Labor	6,236,891	17,087	*Sch 2*	45.39	*Sch 4*	14.23	31.16	532,431
6	O&M, Non-Labor	8,910,740	24,413	*Sch 2*	45.39	*Sch 5*	21.81	23.58	575,659
7	Total O&M Expense	15,147,631	41,500						1,108,089
8									
9									
10	Taxes Other Than Income								
11	Ad Valorem	2,829,817	7,753	*Sch 2*	45.39	*Sch 6*	241.50	(196.11)	(1,520,441)
12	State Gross Receipts Tax	2,661,991	7,293	*Sch 2*	45.39	*Sch 6*	(151.50)	196.89	1,435,919
13	Payroll Taxes	532,274	1,458	*Sch 2*	45.39	*Sch 6*	18.55	26.84	39,127
14	State Franchise Tax	540,998	1,482	*Sch 2*	45.39	*Sch 6*	37.00	8.39	12,434
15	TRA Inspection Fee	330,676	906	*Sch 2*	45.39	*Sch 6*	272.50	(227.11)	(205,762)
16	DOT	13,000	36	*Sch 2*	45.39	*Sch 6*	241.50	(196.11)	(7,060)
17	Total	6,908,756	18,928						(245,783)
18									
19	Federal Income Tax	*3,597,547*							
20	Current Taxes	1,361,887	3,731	*Sch 2*	45.39	*Sch 7*	37.00	8.39	31,303
21	Deferred Taxes	2,235,660	6,125	*Sch 2*	45.39	*Sch 7*	0.00	45.39	278,014
22									
23	State Excise Tax	*730,289*							
24	Current Taxes	0	0	*Sch 2*	45.39	*Sch 8*	37.00	8.39	0
25	Deferred Taxes	730,289	2,001	*Sch 2*	45.39	*Sch 8*	0.00	45.39	90,825
26									
27	Depreciation	7,498,342	20,543	*Sch 2*	45.39		0	45.39	932,447
28									
29	Interest on Customer Deposits	423,512	1,160	*Sch 2*	45.39		15.5	29.89	34,672
30									
31	Interest Expense - LTD	6,709,671	18,383	*Sch 2*	45.39	*Sch 9*	84.18	(38.79)	(713,158)
32									
33	Return on Equity	6,375,701	17,468	*Sch 2*	45.39		0	45.39	792,873
34									
35									
36	TOTAL	173,055,393	474,124						3,989,393
								CAPD	3,989,646
								WC/PP/DRC	4,538,689

Atmos Energy Corporation-Tennessee
Cash Working Capital Lead/Lag Analysis
For Attrition Period Ended October 31, 2008

Adjust CAPD filed position for recommended decrease

Line No.	Description	Test Year Expenses	Average Daily Expense (b) / 365 days		Revenue Lag		Expense Lag	Net Lag (d) - (e)	CWC Requirement (c) x (f)
	(a)	(b)	(c)		(d)		(e)	(f)	(g)
1	Gas Supply Expense								
2	Purchased Gas	125,663,964	344,285	*Sch 2*	45.39	*Sch 3*	40.51	4.88	1,680,111
3									
4	Operation and Maintenance Expense								
5	O&M, Labor	6,236,891	17,087	*Sch 2*	45.39	*Sch 4*	14.23	31.16	532,431
6	O&M, Non-Labor	8,361,845	22,909	*Sch 2*	45.39	*Sch 5*	21.81	23.58	540,194
7	Total O&M Expense	14,598,736	39,996						1,072,625
8									
9									
10	Taxes Other Than Income								
11	Ad Valorem	2,829,817	7,753	*Sch 2*	45.39	*Sch 6*	241.50	(196.11)	(1,520,441)
12	State Gross Receipts Tax	2,661,991	7,293	*Sch 2*	45.39	*Sch 6*	(151.50)	196.89	1,435,919
13	Payroll Taxes	532,274	1,458	*Sch 2*	45.39	*Sch 6*	18.55	26.84	39,127
14	State Franchise Tax	540,998	1,482	*Sch 2*	45.39	*Sch 6*	37.00	8.39	12,434
15	TRA Inspection Fee	330,676	906	*Sch 2*	45.39	*Sch 6*	272.50	(227.11)	(205,762)
16	DOT	13,000	36	*Sch 2*	45.39	*Sch 6*	241.50	(196.11)	(7,060)
17	Total	6,908,756	18,928						(245,783)
18									
19	Federal Income Tax	*3,173,194*							
20	Current Taxes	937,534	2,569	*Sch 2*	45.39	*Sch 7*	37.00	8.39	21,554
21	Deferred Taxes	2,235,660	6,125	*Sch 2*	45.39	*Sch 7*	0.00	45.39	278,014
22									
23	State Excise Tax	*646,296*							
24	Current Taxes	0	0	*Sch 2*	45.39	*Sch 8*	37.00	8.39	0
25	Deferred Taxes	646,296	1,771	*Sch 2*	45.39	*Sch 8*	0.00	45.39	80,386
26									
27	Depreciation	7,736,926	21,197	*Sch 2*	45.39		0	45.39	962,132
28									
29	Interest on Customer Deposits	401,369	1,100	*Sch 2*	45.39		15.5	29.89	32,879
30									
31	Interest Expense - LTD	6,510,455	17,837	*Sch 2*	45.39	*Sch 9*	84.18	(38.79)	(691,976)
32									
33	Return on Equity	5,544,307	15,190	*Sch 2*	45.39		0	45.39	689,474
34									
35									
36	TOTAL	171,184,003	468,998						3,879,415
								CAPD	3,989,646
								WC/PP/DRC	4,428,711

**BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE**

IN RE:

PETITION OF ATMOS ENERGY CORPORATION FOR APPROVAL OF ADJUSTMENT OF ITS RATES AND REVISED TARIFF	))))	**DOCKET NO. 07-00105**

REBUTTAL TESTIMONY OF DONALD S. ROFF ON BEHALF OF ATMOS ENERGY CORPORATION

I. PURPOSE OF TESTIMONY

Q. PLEASE STATE YOUR NAME AND BUSINESS AFFILIATION.

A. My name is Donald S. Roff. I am President of Depreciation Specialty Resources ("DSR").

Q. DID YOU FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes. In my direct testimony, I presented the results of the depreciation studies I conducted for the depreciable natural gas distribution properties in Tennessee ("Tennessee System") of Atmos Energy Corporation ("Atmos" or "the Company"), described the depreciation study process, and recommended appropriate depreciation rates for use by the Company reflecting depreciation accounting principles and regulatory rules. I showed that my studies produce fair and reasonable levels of depreciation expense by utilizing sound accounting practices and principles.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my testimony is to refute the position taken by the Office of the Attorney General Consumer Advocate and Protection Division ("CAPD") witness Mr. Charles W. King. Mr. King was asked by the CAPD to review and critique the Company's gas and shared services depreciation rates and proposals. My rebuttal testimony will demonstrate that the Company's depreciation proposals are reasonable and are predicated on sound analysis techniques and principles. I will further show that Mr. King has made several incorrect and unsubstantiated statements, and that his recommendations should be rejected. Lastly, I will demonstrate that Mr. King has introduced a convoluted and unnecessary procedure for estimating removal cost for its inclusion in depreciation expense. My testimony will include discussions of net salvage (salvage less cost of removal), depreciation rates, and depreciation accounting.

Q. **HAVE YOU PREPARED ANY EXHIBITS IN CONNECTION WITH YOUR REBUTTAL TESTIMONY?**

A. Yes. I have prepared Exhibit DSR-R-1, which compares the annual cost of removal accrual included in my depreciation rate recommendations with the proposal of Mr. King. I have also prepared Exhibit DSR-R-2, which calculates the fair value cost of removal correctly.

II. NET SALVAGE

Q. WHAT IS NET SALVAGE?

A. Net salvage is the difference between gross salvage and cost of removal. When cost of removal exceeds gross salvage, the result is referred to as negative net salvage.

Q. CAN YOU CITE ANY AUTHORITATIVE SOURCE THAT DESCRIBES HOW A NET SALVAGE ANALYSIS SHOULD BE CONDUCTED?

A. Yes. One source is a text referred to by Mr. King, the National Association of Regulatory Utility Commissioners ("NARUC") publication *Public Utility Depreciation Practices*. At page 18 of the 1996 edition, the following statement appears: "Net salvage is expressed as a percentage of plant retired by dividing the dollars of net salvage by the dollars of original cost of plant retired". My depreciation study was conducted using exactly this analysis process.

Q. WHAT IS THE ISSUE RAISED BY MR. KING WITH RESPECT TO NET SALVAGE?

A. Essentially, Mr. King is proposing to utilize a convoluted fair value basis for the depreciation of cost of removal. His proposal is based upon his interpretation of

Statement of Financial Account Standard ("SFAS") No. 143 – *Accounting for Asset Retirement Obligations* and Federal Energy Regulatory Commission ("FERC") Order No. 631, which relates to accounting, financial reporting and rate filing requirements for asset retirement obligations. Mr. King spends a great deal of his testimony discussing topics unrelated to his conclusions and proposals.

III. FAIR VALUE BASIS

Q. DO YOU AGREE WITH MR. KING'S PROPOSALS?

A. No. First and foremost, Atmos is required to practice accrual accounting.[1] The fair value basis proposed by Mr. King is not accrual accounting as I understand that term. Second, the fair value basis results in serious intergenerational inequity. Third, Mr. King's fair value basis introduces an element of valuation to depreciation accounting that is inconsistent with principles related to depreciation accounting. Fourth, Mr. King has not even calculated his fair value basis correctly. The proper allocation of the total cost of fixed assets (investment plus net salvage) should be assigned to the customers benefiting from the service of those assets and not delayed to burden future customers. The fair value basis for cost of removal used by Mr. King results in the later generations of customers providing more than their share of cost of removal compared with earlier customer generations. Treating cost of removal differently from the investment is not only inconsistent, it is improper and unfair. This topic will be expanded later in my rebuttal testimony and demonstrated on Exhibit DSR-R-2.

Q. HOW DOES THE FAIR VALUE BASIS CREATE INTERGENERATIONAL INEQUITIES?

A. Quite simply, the fair value basis creates intergenerational inequities by charging the wrong generation of customers for cost of removal of a plant asset. Consider

[1] Federal Energy Regulatory Commission Uniform System of Accounts, CFR 18, Part 201, General Instruction 11. *Accounting to be on accrual basis.* A. The utility is required to keep its accounts on the accrual basis. This requires the inclusion in its accounts of all known transactions of appreciable amount which affect the accounts. If bills covering such transactions have not been received or rendered, the amounts shall be estimated and appropriate adjustments made when the bills are received.

a small building installed in 1962 for $250,000. In 2007, the Company retires and demolishes the building for a cost of $50,000. Under the fair value basis proposed by Mr. King, several assumptions and additional calculations are required to develop the cost of removal accrual component. The accrual accounting approach that I have utilized allocates the entire cost of this asset ($250,000 + $50,000) over the 45-year life of the building, thus correctly charging each and every generation of customers its fair share of depreciation expense.

Q. WHAT IS THE RESULT USING MR. KING'S METHODOLOGY UNDER THE ABOVE EXAMPLE?

A. Under Mr. King's methodology, the $50,000 cost of removal would be discounted at 7.96% to 1962. That amount would be $1,593. He would depreciate that amount over 45 years, producing and annual expense of $35.4. He would then calculate the accretion expense for the year 2005, which is $3,163. The total cost of removal expense he would compute is $3,198. He would add that to the $250,000 depreciable base, then divide that total by 45 years. That amount is $5,627, or an equivalent depreciation rate of 2.25%.

Q. HOW IS THE FAIR VALUE BASIS PROPOSED BY MR. KING INCONSISTENT WITH DEPRECIATION ACCOUNTING PRINCIPLES?

A. The definition of depreciation accounting, quoted by Mr. King at page 4 of his testimony, states that: "It (depreciation accounting) is a process of allocation, not of valuation." Contrary to this definition, however, Mr. King's fair value basis for measuring cost of removal introduces valuation into the depreciation accounting process, and therefore violates fundamental depreciation accounting principles. As will be demonstrated below, his calculation is not even correct. Further, his calculations require the use of a number of questionable assumptions, and create cumbersome tracking requirements. The much simpler process that I utilize not only produces a fairer result but also is less difficult to implement.

Q. DO YOU AGREE THAT THE FIVE-YEAR AVERAGE APPROACH IS FAIRER TO RATEPAYERS?

A. No. I disagree with Mr. King's assertion, made at line 1 on page 38 of his testimony. It is unclear how the five-year approach would be fairer to ratepayers.

It is true that the proposed depreciation rates will result in the recording of $1.85 million annually of depreciation expense related to cost of removal. This is entirely different from the cost of removal Atmos incurs, however.

Q. PLEASE EXPLAIN WHY THE COMPANY'S REQUESTED ACCRUAL FOR COST OF REMOVAL IS DIFFERENT FROM ITS FIVE-YEAR AVERAGE.

A. Under accrual accounting, an allocation of cost is made by recognizing the components of depreciation expense, including cost of removal, over the entire life of the associated assets. In this case, that $1.85 million cost of removal component of depreciation expense is the annual accrual for the *entire* Atmos asset rate base that will, over time, be retired. The $251 thousand cost of removal incurred on an annual basis relates only to *those assets retired in one year*, which amounts to only a fraction of the entire Atmos asset rate base. On average, the annual retirements total $686 thousand. So the comparison made by Mr. King, while reflecting the correct dollar amounts for unrelated items, is comparing an amount for one year to an amount for the total life of long-lived assets, which provides an "apples to oranges" comparison.

Q. CAN YOU PROVIDE A MORE APPROPRIATE COMPARISON?

A. I believe so. Exhibit DSR-R-1 has been prepared to show the development of the annual cost of removal accrual. Exhibit DSR-R-1 provides a table of only those accounts for which a cost of removal allowance is recommended. This Exhibit shows that, based upon recent experience, the total cost of removal for Atmos' assets in service at the time of the study would be $91.8 million and the annual component of this total is roughly $1.85 million. Thus, the fact that Atmos only incurs $251 thousand annually is somewhat irrelevant, as it does not account for the accrual of amounts to be incurred for cost of removal over the life of the assets, as is required by regulatory Generally Accepted Accounting Principles ("GAAP"). The testimony of Mr. King is misleading.

Q. WHAT IS YOUR INTERPRETATION OF PARAGRAPH 33 OF FERC ORDER NO. 631?

A. With respect to Order No. 631, paragraph 33 simply states that "The Commission did not propose to change its accounting under Parts 101, 201 and 352 for the cost of removal for amounts that result from other than asset retirement obligations." In effect, this paragraph did not change depreciation accounting for cost of removal. Paragraph 36 similarly reaffirms traditional depreciation accounting. The interpretation expressed by Mr. King is completely incorrect.

Q. YOU MENTIONED THAT MR. KING PROVIDED AN INCORRECT FAIR VALUE CALCULATION. HAVE YOU CORRECTED HIS WORK?

A. Yes. Exhibit DSR-R-2 has been prepared to correct Mr. King's error. I should point out that his Schedule 6 of Exhibit CWK-1 develops a cost of removal estimate for the year 2005. This makes no sense to me, as the depreciation study is as of the end of fiscal year 2006.

Q. PLEASE DESCRIBE THE INFORMATION AND METHODOLOGY USED TO CREATE EXHIBIT DSR-R-2.

A. First, you can see that Exhibit DSR-R-2 contains several columns, illustrating the complexity and number of assumptions associated with Mr. King's fair value cost of removal proposal. This example has been prepared for Account 376, Distribution – Mains, the largest depreciable asset category. Listed at the top of the Exhibit are the assumptions needed to make the calculation. Clearly, there is a considerable range of possibilities, making this proposed approach questionable at best.

The first step is to estimate the current level of removal cost. This is developed by multiplying the cost of removal allowance (35%) by the plant balance ($151,083,809). This amount is shown at Column [2] for the year 2006 and is $52,879,333. This amount must be escalated to the year of retirement, in this case 2046 (the current year 2006 plus the remaining life (39.81 years, rounded to 40 years). This is the future cost of removal estimate.

The next step is to discount the future cost of removal to original installation. The discount rate is 7.96%, and the effective year is 1991 (2046 – 55), with 55 years being the average service life. This amount, shown in Column [3], is $2,102,725. Under Mr. King's proposal, this would also be the amount of the asset retirement cost ("ARC") to be depreciated over the 55-year service life. The annual depreciation expense associated with the ARC is $38,231 as shown in Column [4]. This number should be compared with the incorrect amount of $14,239 shown on Schedule 6.

The next step is to "unwind" the discounting, which takes the form of accretion expense (Column [5]). Column [5] is the difference between successive years show in Column [3]. I compute a year 2007 total cost of removal expense of $566,237, more than twice the erroneous $213,767 result of Mr. King's calculation.

Q. DO YOU HAVE ANY OTHER CONCERNS WITH THIS FAIR VALUE APPROACH?

A. Yes. The fair value approach is back-end loaded. That is, customers in later years are charged a much higher removal cost expense. For example, the removal cost expense in year 2046 is over $10.5 million, or roughly 20 times the amount in 2007. This is clearly inequitable, even when considering the net present value of money. I would conclude by saying that it is evident from Exhibit DSR-2R that Mr. King's fair value cost of removal proposal is quite onerous, involves numerous assumptions and produces an ever-increasing pattern of expense. Such an approach should NOT be required by this Authority, as he recommends.

IV. EQUAL LIFE GROUP DEPRECIATION

Q. WHAT IS THE EQUAL LIFE GROUP DEPRECIATION PROCEDURE?

A. The Equal Life Group ("ELG") depreciation procedure recognizes that individual components within an asset group have different lives. The ELG procedure results in the depreciation of the components over their respective lives. In essence, the ELG procedure replicates item depreciation for group assets. In other words, if one could depreciate each asset component separately, a more appropriate matching of depreciation with asset consumption would occur.

Q. HAS MR. KING CORRECTLY CHARACTERIZED THE ELG PROCEDURE?

A. Yes and no. Mr. King's discussion of ELG depreciation at page 13, lines 5 through 19 is accurate. His discussion at page 14, lines 7 and 8 is somewhat misleading. There is no acceleration or deceleration of depreciation associated with ELG. Rather, each separate-lived component is depreciated on a straight-line basis over its respective life. His statement at page 14, lines 15 and 16 that "ELG virtually always increases depreciation rates and accruals" is entirely incorrect. In fact, for certain accounts, the ALG rate is higher than the ELG rate.

Q. HAS THE ELG PROCEDURE BEEN APPROVED IN ANY OF ATMOS' JURISDICTIONS?

A. Yes. ELG rates have been approved in Kentucky, Texas and Louisiana.

Q. MR. KING SUGGESTS THAT THERE WOULD BE IMPLEMENTATION ISSUES WITH ELG. DO YOU AGREE?

A. No. I disagree with Mr. King's assertions, contained in his testimony at page 15, line 28 through page 17, line 3. An ELG rate functions the same as an ALG rate. It would be valid until subsequent studies indicate the need for revision. It is my understanding that Atmos policy is to review depreciation on a periodic basis. The Tennessee Regulatory Authority would be under no additional administrative burden. Atmos' goal is to have comparable depreciation practices in all of its jurisdictions.

V. OTHER ISSUES

Q. WHAT RECOMMENDATIONS HAS MR. KING MADE WITH RESPECT TO SERVICE LIVES?

A. Mr. King ultimately adopted all of the service life parameters I put forth in my testimony.

Q. MR. KING RECOMMENDS THAT ATMOS BE DIRECTED TO CREDIT ALL FUTURE THIRD PARTY REIMBURSEMENTS TO THE DEPRECIATION RESERVE. DO YOU AGREE?

A. No. For the most part, third party reimbursements are payments for the replacement assets, not for the cost of removal. Such a payment is no different than a contribution from a customer, which is correctly credited to the construction work order. This is merely an attempt to introduce an artificial salvage component into the depreciation analysis, and thereby reduce current depreciation expense. Mr. King's recommendation should be dismissed.

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Mr. King's fair value basis treatment of cost of removal is unfair to both Tennessee customers and Atmos. It operates to artificially lower depreciation expense and creates serious intergenerational inequity. His testimony contains many misleading or untrue assertions. My depreciation studies were conducted using sound analytical principles to produce a fair and reasonable level of depreciation expense. The results of my analysis should be adopted in this proceeding.

Q. DOES THIS COMPLETE YOUR REBUTTAL TESTIMONY?

A. Yes.

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:	)	
	)	
PETITION OF ATMOS ENERGY CORPORATION FOR APPROVAL OF ADJUSTMENT OF ITS RATES AND REVISED TARIFF	))))	**DOCKET NO. 07-00105**

VERIFICATION

STATE OF TEXAS)
)
COUNTY OF DALLAS)

I, Donald S. Roff, being first duly sworn, state that I am President of Depreciation Specialty Resources, that I am authorized to testify on behalf of Atmos Energy Corporation in the above referenced docket, that the Rebuttal Testimony of Donald S. Roff pre-filed in this docket on the date of filing herein is true and correct to the best of my knowledge, information and belief.

Donald S. Roff
Donald S. Roff

Sworn and subscribed before me this 20TH day of SEPTEMBER, 2007.

Ethel Z. Taylor
Notary Public

My Commission Expires: August 13, 2010

ETHEL Z TAYLOR
My Commission Expires
August 13, 2010

ATMOS ENERGY CORPORATION - TENNESSEE PROPERTIES

Book Depreciation Study as of September 30, 2006

Development of Cost of Removal Accrual

Exhibit DSR-1R

[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Account Number	Description	9/30/2006 Balance	COR	COR	ROFF COR Rate	Annual Amount	KING COR Rate	Annual Amount
		$	%	$	%	$	%	$
	TRANSMISSION PLANT							
367.0	Mains	11,671,967	35.0	4,085,188	0.64	74,276	0.12	14,499
369.0	M&R Station Equipment	1,629,191	5.0	81,460	0.13	2,036	0.05	880
	Total Transmission	13,301,158		4,166,648	0.57	76,313	0.12	15,379
	DISTRIBUTION PLANT							
376.0	Mains	151,083,809	35.0	52,879,333	0.64	961,442	0.14	213,767
378.0	M&R Station Equipment	6,248,657	5.0	312,433	0.13	7,811	0.06	3,749
379.0	City Gate Equipment	2,381,748	5.0	119,087	0.13	2,977	0.05	1,073
380.0	Services	82,529,059	20.0	16,505,812	0.42	343,871	0.08	62,182
381.0	Meters	11,069,083	55.0	6,087,996	1.53	169,111	0.98	108,425
382.0	Meter Installations	21,126,176	55.0	11,619,397	1.38	290,485	0.39	82,460
385.0	Industrial M&R Equipment	323,828	5.0	16,191	0.13	405	0.03	97
	Total Distribution	274,762,360		87,540,249	0.65	1,776,102	0.17	471,753
	GENERAL PLANT							
390.0	Structures and Improvements	1,014,374	5.0	50,719	0.13	1,268	-	-
	Total General	1,014,374		50,719	0.13	1,268	-	-
	Total Gas Plant	289,077,892		91,757,616	0.64	1,853,683	0.17	487,132

ATMOS ENERGY CORPORATION - TENNESSEE PROPERTIES **EXHIBIT DSR-2R**
FAIR VALUE ESTIMATE OF REMOVAL COST
ACCOUNT 376 - DISTRIBUTION MAINS

ASSUMPTIONS:

Average Service Life = 55 years
Cost of Removal Allowance = 35%
Age of Survivors = 15.58 years
Inflation Rate = 2.5%
Discount Rate = 7.96%
9/30/2006 Plant Balance = $151,083,809
Average Remaining Life = 39.81 years

Current Cost of Removal = (.35 x $151,083,809) = $52,879,333

[1]	[2] COR $	[3] Discounted COR $	[4] Annual Amount $	[5] Accretion Expense $	[6] Cumulative Accretion $	[7] 2007 Expense $
1991		2,102,725				
1992		2,270,102	38,231	167,377	167,377	
1993		2,450,802		180,700	348,077	
1994		2,645,885		195,084	543,161	
1995		2,856,498		210,612	753,773	
1996		3,083,875		227,377	981,150	
1997		3,329,352		245,476	1,226,627	
1998		3,594,368		265,016	1,491,643	
1999		3,880,480		286,112	1,777,755	
2000		4,189,366		308,886	2,086,641	
2001		4,522,839		333,474	2,420,115	
2002		4,882,857		360,018	2,780,133	
2003		5,271,533		388,675	3,168,808	
2004		5,691,147		419,614	3,588,422	
2005		6,144,162		453,015	4,041,438	
2006	52,879,333	6,633,238		489,075	4,530,513	
2007	54,201,316	7,161,243		528,006		566,237
2008	55,556,349	7,731,278		570,035		
2009	56,945,258	8,346,688		615,410		
2010	58,368,889	9,011,084		664,396		
2011	59,828,112	9,728,367		717,282		
2012	61,323,814	10,502,745		774,378		
2013	62,856,910	11,338,763		836,018		
2014	64,428,333	12,241,329		902,566		
2015	66,039,041	13,215,738		974,410		
2016	67,690,017	14,267,711		1,051,973		
2017	69,382,267	15,403,421		1,135,710		
2018	71,116,824	16,629,533		1,226,112		
2019	72,894,745	17,953,244		1,323,711		
2020	74,717,113	19,382,322		1,429,078		
2021	76,585,041	20,925,155		1,542,833		
2022	78,499,667	22,590,798		1,665,642		
2023	80,462,159	24,389,025		1,798,227		
2024	82,473,713	26,330,391		1,941,366		
2025	84,535,556	28,426,291		2,095,899		
2026	86,648,944	30,689,023		2,262,733		
2027	88,815,168	33,131,870		2,442,846		
2028	91,035,547	35,769,166		2,637,297		
2029	93,311,436	38,616,392		2,847,226		
2030	95,644,222	41,690,257		3,073,865		
2031	98,035,327	45,008,801		3,318,544		
2032	100,486,211	48,591,502		3,582,701		
2033	102,998,366	52,459,385		3,867,884		
2034	105,573,325	56,635,152		4,175,767		
2035	108,212,658	61,143,311		4,508,158		
2036	110,917,975	66,010,318		4,867,008		
2037	113,690,924	71,264,739		5,254,421		
2038	116,533,197	76,937,413		5,672,673		
2039	119,446,527	83,061,631		6,124,218		
2040	122,432,690	89,673,336		6,611,706		
2041	125,493,507	96,811,334		7,137,998		
2042	128,630,845	104,517,516		7,706,182		
2043	131,846,616	112,837,111		8,319,594		2046
2044	135,142,782	121,818,945		8,981,834		Expense
2045	138,521,351	131,515,733		9,696,788		
2046	141,984,385	141,984,385		10,468,652		10,506,884

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:

PETITION OF ATMOS ENERGY CORPORATION FOR APPROVAL OF ADJUSTMENT OF ITS RATES AND REFISED TARIFF	))))	**DOCKET NO. 07-00105**

REBUTTAL TESTIMONY OF LAURIE M. SHERWOOD
ON BEHALF OF ATMOS ENERGY CORPORATION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS AFFILIATION.

A. My name is Laurie M. Sherwood. I am the Vice President, Corporate Development and Treasurer of Atmos Energy Corporation ("Atmos", "Atmos Energy" or "the Company").

Q. DID YOU FILE DIRECT TESTIMONY ON BEHALF OF THE COMPANY IN THIS PROCEEDING?

A. Yes. In my direct testimony, I addressed the proper capital structure and cost of long-term debt the Tennessee Regulatory Authority (the "Authority") should consider in setting rates in this proceeding. I also addressed the Company's cost of short-term debt in the event the Authority decides to include some level of that component in the Company's capital structure for rate-setting purposes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I am providing this testimony in rebuttal to specific issues raised in the direct cost of capital testimony of Dr. Steve Brown, a witness for the Consumer Advocate and Protection Division ("CAPD") of the Tennessee Attorney General's Office. The areas addressed in my testimony include the Company's capital structure, the issues raised by Dr. Brown concerning the inclusion of short-term debt in the capital structure and the Company's cost of short-term debt. I do not address the cost of long-term debt because Dr. Brown agrees with the Company that the cost of long-term debt for purposes of setting rates in this proceeding is 6.1%. Rebuttal testimony in response to Dr. Brown's testimony regarding the cost of equity and the appropriate return on equity is being provided by Dr. Don Murry.

II. CAPITAL STRUCTURE

Q. WHAT IS THE APPROPRIATE CAPITAL STRUCTURE FOR THE COMPANY IN THIS PROCEEDING?

A. As I explained in my opening testimony, the Company's proper capital structure is 51.5% long-term debt and 48.5% equity. This capital structure is appropriate for use in this proceeding because it is representative of the Company's capital structure for the attrition period.

Q. BY COMPARISON, WHAT CAPITAL STRUCTURE DOES THE CAPD RECOMMEND FOR THE COMPANY IN THIS PROCEEDING?

A. The capital structure recommended by Dr. Brown on behalf of the CAPD is reflected on page 2 of Dr. Brown's cost of capital testimony. His capital structure components are 11.3% short-term debt, 1.7% for current maturities of long-term debt, 46.3% long-term debt and 40.7% equity. For all practical purposes, current maturities of long-term debt should be included as part of total long-term debt, which would bring Dr. Brown's long-term debt percentage, as a component of capital structure, to 48%.[1]

Q. HOW DID DR. BROWN DERIVE HIS CAPITAL STRUCTURE?

A. Apparently he bases his recommended capital structure on a 10-year average of the Company's historical capital structures reported in its annual report on Form 10-K filed with the Securities and Exchange Commission ("SEC"). However, for purposes of his averaging, he states that he has omitted the year in which the Company's acquisition of TXU Gas occurred because I identified this particular period as aberrant in my direct testimony. In reviewing an exhibit attached to his testimony, it appears that Dr. Brown has excluded the Company's capital

[1] The long-term debt component of capital structure proposed by the Company in this proceeding includes current maturities of long-term debt.

structure reported in its Form 10-K for the 2004 fiscal year (*i.e.* the year ended September 30, 2004).

Q. DID DR. BROWN USE ANY OTHER HISTORICAL REPORTS FILED WITH THE SEC BY THE COMPANY IN ARRIVING AT HIS CAPITAL STRUCTURE?

A. No. Dr. Brown has apparently concluded that the only reliable source for determining a publicly traded company's capital structure is its 10-K reports. The rationale he provides for this is that 10-Ks are audited by independent certified public accountants. The last Form 10-K filed by the Company and included in Dr. Brown's analysis was for the Company's fiscal year ended September 30, 2006.

Q. DOES DR. BROWN PROVIDE ANY AUTHORITY FOR HIS CONCLUSION?

A. Yes. He provides some quotes from a 1984 United States Supreme Court opinion rendered in *United States v. Arthur Young & Co.*[2]

Q. DID YOU REVIEW THAT OPINION?

A. Yes. That case involved whether the accounting firm of Arthur Young, as the independent accountant for Amerada Hess Corp., was required to turn over its work papers to the Internal Revenue Service in connection with an audit the IRS was performing regarding Hess' income tax liability for the years 1972 through 1974. While it appears that Dr. Brown's quotes from the Supreme Court's decision are accurate, that case does not say that, for purposes of setting rates for a public utility, a state regulatory agency should rely only on the utility's 10-Ks. My lay reading of that case is that the Court's discussion was in the context of whether any form of privilege attached to the accountant's work papers that would serve as a basis for restricting the IRS' access to those papers. I do not believe that the Supreme Court's decision supports Dr. Brown's conclusion.

Q. DO YOU AGREE WITH DR. BROWN'S CONCLUSION THAT 10-Ks ARE THE ONLY RELIABLE SOURCE OF DATA?

[2] 465 U.S. 805 (1984).

A. No. More frequent and current data is available in the form of quarterly reports on Form 10-Q, which are also filed by the Company with the SEC. The reasons why these reports are reliable information are addressed in the rebuttal testimony of Mr. Christopher Forsythe.

Q. ARE THE COMPANY'S FORMS 10-Q A RELIABLE DATA SOURCE THAT DR. BROWN SHOULD HAVE CONSIDERED?

A. Yes, for the reasons addressed in Mr. Forsythe's rebuttal testimony.

Q. HAS THE AUTHORITY CONSIDERED INFORMATION IN 10-Qs IN OTHER RATE CASES?

A. Yes. In Docket No. 05-00258, the Authority adopted costs for short-term debt as reported by the Company in its June 30, 2006 10-Q.[3] In Docket No. 04-00034, a rate proceeding involving Chattanooga Gas Company, the Authority took official notice of 10-Q filings made by AGL Resources, Chattanooga's parent company[4], in connection with its reconsideration of capital structure issues in that proceeding.

Q. WHAT IS THE EFFECT OF DR. BROWN'S UTILIZATION OF INFORMATION REPORTED ONLY IN THE COMPANY'S 10-K FILINGS?

A. His analysis does not provide an accurate depiction of historical capital structure because the analysis is fixed upon a point in time (September 30) every year when the Company's short-term debt is elevated or beginning to become elevated as a result of funding seasonal natural gas purchases. His single point in time focus, predicated upon an erroneous and unsupported assumption that 10-Ks are the only reliable investor data, produces a skewed result of the Company's capital structure that conveniently supports the CAPD's position advocating a lower equity ratio, weighted cost of capital and rate of return for the Company. Moreover, use of a 10-year average also does not accurately reflect the current state of the Company's actual capital structure because much of the data is stale and is too remote in time.

[3] Motion of Director Miller, *supra.* at p. 13.
[4] *See* Authority's decision dated November 1, 2005, in that docket.

Q. WHY WOULD DR. BROWN'S DATA BE CONSIDERED STALE?

A. Over the last ten years, the Company has undergone dramatic growth by becoming the largest natural-gas-only-distribution utility in the United States. After the acquisition of United Cities Gas Company ("United Cities") in July of 1997, the Company's customer base grew to approximately one million customers with a total capitalization as of September 30, 1997 (excluding short-term debt) of approximately $645 million. Since then, the Company's customer base has grown to almost 3.2 million customers and a total capitalization as of September 30, 2006 (excluding short-term debt) of approximately $3.8 billion. The total number of shares of common stock outstanding has grown from approximately 29.6 million to over 81 million shares over the same period.

Dr. Brown's analysis also fails to consider events that have occurred since September 30, 2006. These are reported in the Company's quarterly reports on Form 10-Q filed with the SEC and are attached as exhibits to Mr. Forsythe's rebuttal testimony. All of these reports are publicly available and can be accessed on-line through the SEC's EDGAR database at www.sec.gov as well as the Company's website at www.atmosenergy.com.

Q. WHAT ARE THE SUBSEQUENT EVENTS TO WHICH YOU REFER?

A. One of these events is described in my direct testimony at pp. 6-7. In December of 2006, and as reported in Exhibit CF-R-1 attached to Mr. Forsythe's rebuttal testimony, the Company issued 6.325 million shares of common stock and the proceeds were used to pay down short-term debt outstanding under the Company's commercial paper program. As a result, the Company's reported capital structure improved to 51.8% long-term debt, 4.5% short-term debt and 43.7% equity.

As reported in Exhibit CF-R-2 attached to Mr. Forsythe's rebuttal testimony, the Company's capital structure further improved because the Company had no outstanding short-term debt because it had paid down the remaining portion. The Company's capital structure as of March 31, 2007, was 51.9% long-term debt and 48.1% equity.

As reported in Exhibit CF-R-3 attached to Mr. Forsythe's rebuttal testimony, the Company redeemed approximately $300 million in long-term debt on July 15, 2007, from the proceeds received through the issuance of $250 million in new long-term debt in June 2007 and approximately $50 million in cash. At June 30, 2007, although the Company already had delivered an irrevocable notice of redemption to the holders of the $300 million of long-term debt, the redemption had not yet occurred and the Company's quarterly financial statements therefore temporarily reflected an additional $250 million in long-term debt (along with a much larger than normal cash balance). This temporary distortion, however, disappeared once the redemption of the old $300 million of long-term debt occurred on July 15, 2007. Taking into effect this transaction and also the fact that the Company had no outstanding short-term debt, the Company's capital structure at June 30, 2007 would have been 51.7% long-term debt and 48.3% equity as shown in the following table:

Amounts shown in thousands

L-T Debt	S-T Debt	Total Debt	Shareholder Equity	Total
$2,130,518	$0	$2,130,518	$1,988,142	$4,118,660
51.7%	0.00%	51.7%	48.3%	100.0%

Q. IS DR. BROWN'S CAPITAL STRUCTURE ANALYSIS IN THIS PROCEEDING CONSISTENT WITH HIS ANALYSIS IN OTHER PROCEEDINGS?

A. No. It appears that Dr. Brown's standard methodology is to employ a hypothetical capital structure based upon a three-year average of comparable company capital structures.

Q. DO YOU AGREE THAT CAPITAL STRUCTURE SHOULD BE BASED UPON AN AVERAGE OF THE CAPITAL STRUCTURES OF COMPARABLE COMPANIES?

A. Not in cases where the actual capital structure of the entity for which rates are being set is already known or can be readily ascertained. If the Company were a wholly-owned utility of a holding company, then such a methodology might prove beneficial in determining an appropriate capital structure for purposes of setting rates for the utility. However, the Company is not a holding company and, as I stated in my direct testimony, the capital structure of the Company (as the entity for which rates are being set in this proceeding) is the appropriate capital structure.

Q. DO YOU AGREE THAT A THREE-YEAR AVERAGE IS APPROPRIATE?

A. No. While I realize that Dr. Brown has in other gas company rate cases advocated a three-year average of a utility's annually reported capital structure as an alternative to his three-year comparable company average[5], a three-year average is not appropriate for purposes of setting rates for the Company in this proceeding because it does not take into account known and measurable changes that have occurred since September 30, 2006. A three-year average for the Company under Dr. Brown's typical, alternative capital structure methodology would be as follows:

Cap Structure Component	*FY2004*	*FY2005*	*FY2006*	*Average*
Short-Term Debt	0.00%	3.70%	9.10%	4.27%
Long-Term Debt	43.30%	55.60%	51.80%	50.23%
Common Equity	56.70%	40.70%	39.10%	45.50%
Total	100.00%	100.00%	100.00%	100.00%

The above results produce an average level of short-term debt where there is currently none, reduce long-term debt below current actual levels and reduce current actual levels of common equity. In other words, averaging merely produces a hypothetical, as opposed to a real capital structure.

Q. DIDN'T THE COMPANY ADVOCATE THE USE OF A HYPOTHETICAL CAPITAL STRUCTURE IN DOCKET NO. 05-00258?

A. No. The Company advocated the use of a 50/50 debt to equity capital structure in that proceeding because that was reflective of the Company's stated capitalization

[5] *See* Direct Testimony of Steve Brown at p. 27 filed in TRA Docket No. 06-00175.

goals.[6] The Authority, however, did not agree because it did not see the Company attaining that goal until several more years beyond the end of the attrition period in that proceeding. Almost a year has passed since the Authority's decision in that docket, however, and the Company has come much closer to its targeted 50/50 capital structure.

Q. WHAT WAS THE METHODOLOGY USED BY THE AUTHORITY STAFF IN FORMULATING A CAPITAL STRUCTURE IN DOCKET NO. 05-00258?

A. Staff began by relying on the Company's capital structure stated in its 2005 10-K as a starting point and then made projections up to September 30, 2006, to account for long-term debt maturities and projected value of new stock issuances.[7] In subsequent rebuttal testimony filed in that proceeding, Staff buttressed its capital structure arguments by referencing data from the Company's 10-Qs filed for the quarters ended March 31, 2006 and June 30, 2006.[8]

Q. DID THE AUTHORITY AGREE WITH STAFF'S PROPOSED CAPITAL STRUCTURE IN THAT PROCEEDING?

A. Yes. In Director Miller's motion filed in that docket, he states "I further find that the TRA Investigative Staff's methodology for estimating long-term debt and equity percentages is the most reasonable and best supported by the record in these proceedings".[9]

Q. IS THE COMPANY'S METHODOLOGY FOR ESTIMATING CAPITAL STRUCTURE IN THIS PROCEEDING COMPARABLE TO THAT EMPLOYED BY THE AUTHORITY STAFF IN DOCKET 05-00258?

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[6] On p. 49 of its annual report on Form 10-K for the period ending September 30, 2005, the Company stated: *Within three to five years from the closing of the TXU Gas acquisition, we intend to reduce our capitalization ratio to a target range of 50 to 55 percent through cash flow generated from operations, continued issuance of new common stock under our Direct Stock Purchase Plan and Retirement Savings Plan, access to the equity capital markets and reduced annual maintenance and capital expenditures.* The Company again stated this goal on p. 52 of its annual report on Form 10-K for the period ending September 30, 2006. The acquisition of TXU Gas closed on October 1, 2004. The Company has achieved its targeted capitalization within three years of that date.

[7] *See* Pre-Filed Direct Testimony of Jerry Kettles, pp. 3-6 dated July 17, 2006 filed in TRA Docket 05-00258.

[8] *See* Pre-Filed Rebuttal Testimony of Jerry Kettles, p. 3 dated August 18, 2006 filed in TRA Docket 05-00258.

[9] Motion of Director Pat Miller, p. 12.

A. Yes. As reflected in my direct testimony filed in this proceeding, the Company's beginning point for its capital structure analysis is the capital structure reported in its annual report on Form 10-K for the fiscal year ended September 30, 2006. I then go on to explain why, based upon subsequent known and measurable events reported in the Company's intervening quarterly report on Form 10-Q, that capital structure is not appropriate for purposes of this proceeding. Instead, after taking into account an equity issuance reported in the Company's December 31, 2006 10-Q, the Company's capital structure, as adjusted, had improved to 51.8% long-term debt, 4.5% short-term debt and 43.7% equity.

Subsequent to the filing of my direct testimony, the Company has filed two more quarterly reports that reflect further known and measurable changes affecting the Company's capital structure. These events include the retirement of outstanding short-term debt and the retirement and partial refinancing of $300 million in long-term debt. All of this has culminated in a capital structure as of June 30, 2007, of 51.7% long-term debt, 0.0% short-term debt and 48.3% equity. This is very close to the Company's projected capital structure of 51.5% long-term debt and 48.5% equity set forth in my direct testimony as the appropriate capital structure to be used for purposes of setting rates for the Company in this proceeding.

Q. IS THE COMPANY'S METHODOLOGY FOR DETERMINING CAPITAL STRUCTURE MORE ACCURATE THAN THE METHOD EMPLOYED BY THE CAPD?

A. Yes. An important fundamental of this rate proceeding is that it is based upon forecasts. However, the CAPD's capital structure methodology focuses entirely on the past and to a large degree on the distant past, and completely ignores subsequent and significant events based upon the erroneous conclusion that the only valid data can be derived from 10-K reports. Conversely, the Company's capital structure methodology focuses on the future and is validated by known and measurable events <u>that have already occurred</u> within the Company's most recent fiscal year, and have been reported on interim reports that the SEC has itself determined are critical to an investor because they provide more timely information.[10]

IV. SHORT-TERM DEBT AS A COMPONENT OF CAPITAL STRUCTURE

Q. ON WHAT BASIS DOES DR. BROWN INCLUDE SHORT-TERM DEBT IN CAPD'S PROPOSED CAPITAL STRUCTURE?

A. Dr. Brown argues that a 10-year history of the Company's 10-K filings with the SEC demonstrates that short-term debt is a permanent component of the Company's capital structure.

Q. WHAT IS WRONG WITH DR. BROWN'S ARGUMENT?

A. I have already explained in my direct testimony filed herein that the Company's normal use of short-term debt is seasonal in nature to fund gas purchases. These purchases typically begin ramping up in the last quarter of each fiscal year (July 1 through September 30) so that, by the time the fiscal year end report is to be made, short-term debt has already become elevated. Dr. Brown's September 30 single-point-in-time focus, as discussed earlier in my testimony, makes it appear that the Company has consistently had short-term debt as a permanent part of its capital structure. Moreover, he relies heavily upon historical data that is stale because it is too remote in time to be properly considered as any sort of benchmark for determining whether short-term debt is a part of the Company's capital structure in setting rates prospectively.

Q. DOES DR. BROWN ADVANCE ANY OTHER ARGUMENTS FOR INCLUSION OF SHORT-TERM DEBT?

A. Yes. Dr. Brown seems to suggest that because other comparable natural gas utilities include short-term debt in their capital structure, then this should be considered evidence that the inclusion of short-term debt in the Company's capital structure is appropriate. However, I believe that Dr. Brown's evaluation of the SEC filings of other gas utilities employs his single point in time analysis and, as with the Company, it could very well be that these other companies are

[10] *See* Rebuttal Testimony of Christopher Forsythe, p. 7.

also beginning to experience elevated levels of short-term debt to fund gas purchases.

Q. DO YOU AGREE WITH DR. BROWN'S CONCLUSION THAT THE COMPANY'S CAPITAL STRUCTURES THAT INCLUDE ELEVATED LEVELS OF SHORT-TERM DEBT FOLLOWING THE ACQUISITION OF TXU GAS ARE NOT ABERRATIONS?

A. No. Dr. Brown attempts to demonstrate this at pp. 7-8 of his testimony, but contrary to his analysis if one evaluates all of the 10-Q and 10-K filings made by the Company over the last three years[11], then short-term debt, expressed as a percentage of capital structure, is as follows:

Data Source	*Short-Term Debt*
9/30/04 10-K	0.00%
12/31/04 10-Q	0.07%
3/31/05 10-Q	0.00%
6/30/05 10-Q	0.00%
9/30/05 10-K	3.70%
12/31/05 10-Q	11.00%
3/31/06 10-Q	6.30%
6/30/06 10-Q	7.20%
9/30/06 10-K	9.10%
12/31/06 10-Q	3.60%
3/31/07 10-Q	0.00%
6/30/07 10-Q	0.00%

Q. WHAT DOES THE ABOVE TABLE ILLUSTRATE?

A. The above table illustrates that for half of the reported periods the Company had little to no short-term debt. However, following Hurricane Katrina in August of 2005, gas prices escalated dramatically as evidenced by the sharp increase in the Company's level of short-term debt as of December 31, 2005. Although the Company made some headway in reducing short-term debt the following quarter, the residual short-term debt from the previous season exacerbated the levels of short-term debt continuing into the fourth quarter of fiscal 2006 as the Company continued to fund seasonal gas purchases.[12] Following the reduction of

[11] Using the three-year historical period that Dr. Brown has advocated in the alternative in the Chattanooga Gas Company 2006 rate case, although inclusive of quarterly periods.

outstanding short-term debt in December of 2006, short-term debt returned to a more seasonal level and ultimately went to zero.

Q. ARE THERE ANY OTHER REASONS, BESIDES WHAT YOU HAVE JUST DESCRIBED, THAT THE COMPANY'S SHORT-TERM DEBT ROSE DURING THE PERIOD BETWEEN SEPTEMBER 2005 AND DECEMBER 2006?

A. Yes. When the Company acquired TXU Gas, it also acquired a 6,200 mile intrastate pipeline system in Texas that is now operated as an unincorporated division of the Company and known as Atmos Pipeline-Texas division ("APT"). APT is the primary transporter of natural gas for the Company's largest natural gas distribution division known as the Mid-Tex Division ("Mid-Tex") and serves the Dallas/Fort Worth Metroplex and surrounding areas of North and Central Texas. In order to address certain deliverability problems that APT had in ensuring firm deliveries of natural gas to the northern sector of the Dallas/Fort Worth Metroplex, the Company undertook a number of projects to reinforce APT's infrastructure including the construction of a 45-mile, 30-inch high pressure transmission pipeline (referred to as the "North Side Loop") and additional compression facilities. In addition, there was increased capital spending in Mid-Tex relating to various projects. All of this is reflected in the Company's Form 10-Q filed with the SEC for the period ending June 30, 2006, wherein the Company stated:

> *For the nine months ended June 30, 2006, we incurred \$322.7 million for capital expenditures compared with \$226.9 million for the nine months ended June 30, 2005. The increase in capital expenditures primarily reflects increased spending associated with our Dallas/Fort Worth Metroplex North Side Loop project and other pipeline expansion projects in our Atmos Pipeline — Texas Division, which were completed during*

[12] As reported in the Company's Form 10-K for the fiscal year ended September 30, 2005, the Company's utility gas cost was approximately \$2.2 billion. By the end of the following fiscal year, the Company's utility gas cost was approximately \$2.7 billion (as reported in the Company's Form 10-K report for the fiscal year ended September 30, 2006).

the fiscal 2006 third quarter. Increased capital spending in our Mid-Tex Division for various projects contributed to the increase in our capital expenditures.[13]

Total capital expenditures for fiscal year 2006 exceeded $425 million compared to approximately $333 million for the previous fiscal year.[14] To cover these increased working capital needs, the Company borrowed over $100 million in additional short-term debt and the total level of short-term debt had risen to approximately $393 million in November of 2006.[15] This short-term debt was ultimately paid down through a combination of the equity issuance in December 2006 and debt payments from cash flow until the end of March of 2007, when short-term debt was reduced to zero.

Q. SO THE COMPANY HAS USED SHORT-TERM DEBT TO FUND MAJOR CAPITAL PROJECTS?

A. Yes, as an interim financing means. However, the Company does not use short-term debt as a permanent source of capital project financing. The use of short-term debt as a means to finance capital projects on an interim basis is not an uncommon practice for utilities, but it does not mean that short-term debt is part of the Company's permanent capital structure. This is borne out by the following statement made by the Company in its most recent Form 10-Q filing with the SEC:

For the nine months ended June 30, 2007, we incurred $263.0 million for capital expenditures compared with $322.7 million for the nine months ended June 30, 2006. The decrease in capital spending primarily reflects the absence of capital expenditures associated with our North Side Loop and other pipeline compression projects, which were completed in the third quarter of fiscal 2006.[16]

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[13] Atmos Energy Form 10-Q for the period ended June 30, 2006, p. 44.
[14] Atmos Energy Form 10-K for the fiscal year ended September 30, 2006, pp. 117-118.
[15] *See* the Company's response to CAPD Data Request 1-68.
[16] *See* Exhibit LMS-R-3, p. 42.

Q. WERE THERE ANY ADDITIONAL FACTORS THAT CONTRIBUTED TO THE ELEVATED LEVELS OF SHORT-TERM DEBT?

A. Yes. For the Company's fiscal year 2006, the Company generated operating cash flow of $311.4 million compared to $386.9 million in fiscal year 2005.[17] Reduced cash flow due to warmer than normal winter weather in non-weather-normalized jurisdictions, in combination with high natural gas prices and increased capital expenditures, all contributed to the Company's elevated short-term debt levels during the period under discussion.

Q. DOES THE CHART OF MONTHLY SHORT-TERM DEBT LEVELS FOR THIS PERIOD ON P. 38 OF DR. BROWN'S TESTIMONY ILLUSTRATE THIS FACT?

A. Yes. Although Dr. Brown seems to think that this is evidence that the Company consistently maintains an elevated level of short-term debt as part of its capitalization, in reality it only demonstrates that the short-term debt levels increased significantly and stayed elevated during this specific period for the reasons I have already discussed.

Q. HOW DO YOU RESPOND TO DR. BROWN'S STATEMENTS BEGINNING ON PAGE 40 OF HIS TESTIMONY REGARDING THE COMPANY'S AVAILABLE SHORT-TERM DEBT FACILITIES?

A. It appears to me that Dr. Brown claims that the Company's ability to borrow $918 million from short-term debt credit facilities indicates that the Company includes short-term debt as part of its permanent capital structure. However, Dr. Brown apparently does not understand the Company's short-term debt borrowing practices.

Q. PLEASE EXPLAIN.

A. The Company maintains three committed short-term debt facilities. The first facility is a $600 million unsecured revolving credit facility which serves as a liquidity backstop for the Company's commercial paper program. Commercial paper is essentially a form of short-term debt security that the Company sells periodically and will typically have a maturity of 3 months or less. If, at the time

[17] *See* Atmos Energy Form 10-K for the fiscal year ended 9/30/06, p. 52.

the commercial paper must be redeemed, the Company does not have sufficient available cash to make the redemption, it will draw down on the revolving credit facility in an amount sufficient to cover the commercial paper redemption. Borrowings under the revolver bear interest at a base rate or at the one-month LIBOR rate plus from 0.30 percent to 0.75 percent based on the Company's credit ratings.

The second short-term debt credit facility is a $300 million unsecured 364-day revolving credit facility expiring November 2007, that bears interest at a base rate or at the LIBOR rate plus from 0.30 percent to 0.75 percent, based on the Company's credit ratings. This facility is typically used as an alternative to or in addition to commercial paper.

The third short-term debt credit facility is an $18 million unsecured revolving credit facility that bears interest at the Federal Funds rate plus 0.5%. This facility may be used from time to time to fund current operation expense obligations such as employee payroll.

At June 30, 2007, there were no borrowings under any of these credit facilities.

Q. WHY DOES THE COMPANY MAINTAIN ALL OF THESE CREDIT FACILITIES?

A. This is the level of short-term borrowing capacity which the Company has reasonably determined to maintain in order to assure that it can meet current obligations, and particularly seasonal gas supply purchases, even during periods of abnormally high natural gas prices and/or extremely cold winter weather. The Company's credit capacity and the amount of unused borrowing capacity are affected by the seasonal nature of the Company's natural gas business and its short-term borrowing requirements, which are typically highest during colder winter months. The Company's working capital needs can vary significantly due to changes in the price of natural gas and the increased gas supplies required to meet customers' needs during periods of cold weather. Therefore, it is prudent for the Company to maintain ample amounts of available credit in order to be prepared for unexpected spikes in its need for short-term funding.

Q. DOES THE LEVEL OF SHORT-TERM FACILITIES MAINTAINED BY THE COMPANY HAVE ANYTHING TO DO WITH DETERMINING THE APPROPRIATE CAPITAL STRUCTURE FOR THE COMPANY IN THIS PROCEEDING?

A. No. Just because the Company has $918 million in available short-term facilities does not mean that it will maintain a consistent level of $918 million or any level even near that in short-term debt for permanent capitalization purposes. Such an argument would be comparable to saying that, since a consumer may have a $10,000 credit line on a credit card but no amount is owed on it, the whole $10,000 is indicative of the fact that the consumer will "max out" the credit line and then maintain that level of debt for a protracted period of time. The availability of ample amounts of short-term credit merely ensures that the Company will always be able to meet its financial obligations when they become due even in extreme, albeit unlikely, circumstances.

Q. HOW DO YOU RESPOND TO DR. BROWN'S CONTENTION THAT THE LANGUAGE OF THE COMPANY'S SHORT-TERM DEBT REVOLVER IS INDICATIVE OF THE COMPANY'S TREATMENT OF SHORT-TERM DEBT AS PART OF ITS PERMANENT CAPITAL STRUCTURE?

A. I have testified in several rate cases for the Company over the years and this is the first time I have ever heard the argument that debt covenants in a credit facility are evidence of a Company's actual capital structure for rate-setting purposes. The provisions of the revolving credit facility that Dr. Brown cites beginning on p. 41 of his direct testimony, are nothing more than customary debt covenants and restrictions that control the level of the Company's borrowing capacity under the revolver. In other words, the aggregate of all Consolidated Funded Debt, which includes a broad category of evidences of indebtedness ranging from borrowed money to letters of credit to guaranties, must, as of the last day of each fiscal quarter, be less than or equal to 0.70 to 1.0 of Consolidated Capitalization (as defined in the credit facility). If Consolidated Funded Debt were to exceed the specified ratios, then the Company would be unable to receive any further advances under the credit facility until such time as the ratio came back into compliance with the credit agreement.

Dr. Brown attempts to buttress this line of argument on p. 43 of his testimony by quoting from testimony filed by Piedmont's treasurer in a prior Authority docket. However, the instant proceeding involves the Company, not Piedmont.

Irrespective of what the terms and conditions of the Company's revolving credit facility may state, they are not evidence of the Company's capital structure. Loan instrument covenants are in large part merely terms and conditions to the Company's eligibility to receive advances.

Q. HAS DR. BROWN MADE PRIOR SIMILAR ARGUMENTS REGARDING SHORT-TERM DEBT TO THOSE HE IS MAKING IN THIS PROCEEDING?

A. Yes. In Docket 05-00258, Dr. Brown advanced several of the same arguments to support his proposed capital structure for the Company which included a short-term debt component of 12.6%.[18]

Q. DID THE AUTHORITY ACCEPT DR. BROWN'S CONCLUSIONS IN DETERMINING A CAPITAL STRUCTURE FOR THE COMPANY IN THAT PROCEEDING?

A. No. Although the Authority did conclude that the Company had short-term debt each month for the then most recent twelve months in the record and each month prior to the summer of 2004, it did conclude that the Company's use of short-term debt was seasonal. As a result, the Authority included a short-term debt component in the Company's capital structure of 3.59% instead of Dr. Brown's recommended 12.6%.

Q. SHOULD THE AUTHORITY INCLUDE A COMPONENT OF SHORT-TERM DEBT IN THE COMPANY'S CAPITAL STRUCTURE FOR PURPOSES OF THIS PROCEEDING?

A. No. As reflected previously in my rebuttal testimony, there has been little or no short-term debt outstanding as of the end of six of the last twelve fiscal quarters.

[18] *See* Pre-Filed Direct Testimony of Dr. Steve Brown dated July 17, 2006, p. 2, filed in TRA Docket 05-00258.

For the period of October 2005 through December 2006, I have already explained why the Company's short-term debt levels were elevated. Additionally, as of June 30, 2007, the Company had no outstanding short-term debt. For these reasons, the Authority should not include short-term debt in the Company's capital structure.

Q. IF THE AUTHORITY SHOULD DECIDE OTHERWISE, WHAT LEVEL OF SHORT-TERM DEBT SHOULD BE INCLUDED?

A. Although the Company is not advocating the inclusion of short-term debt in its capital structure, I recognize that the Authority has shown a tendency to include some element of short-term debt in utility capital structures for ratemaking purposes. This is merely a factual acknowledgement, not an indication that the Company agrees with those results. If the Authority should decide that the record evidence does not support the Company's position regarding short-term debt, then an easy way to determine a level of short-term debt for ratemaking purposes would be to use the average of the last four fiscal periods reported to the SEC. The results are reflected in the following table:

9/30/06 10-K	9.10%
12/31/06 10-Q	3.60%
3/31/07 10-Q	0.00%
6/30/07 10-Q	0.00%
Average	3.175%

Q. DOES DR. BROWN RECOMMEND A COST FOR SHORT-TERM DEBT?

A. Yes. Dr. Brown opines that the appropriate cost of short-term debt is 5.97%. Dr. Brown bases his conclusion on the LIBOR rates effective as of August 1, 2007. This is in contrast to my projected short-term debt cost of 7.05%.

Q. HOW DID YOU CALCULATE THE PROJECTED COST OF SHORT-TERM DEBT?

A. I began by projecting an annualized short-term debt amount of approximately $84 million for the attrition period. I then used the forecasted average LIBOR rate for 2007 and determined an interest rate of 5.58%, for an effective annual interest cost of $4.698 million. I calculated effective annual arrangement fee costs of $429,000 and effective annual commitment fee costs of $806,000, for a total effective annual interest cost of $5.933 million. The effective annual cost is then divided by the average projected short-term debt outstanding ($5.933 million/$84 million) to yield a composite interest rate of 7.05%.

Although the LIBOR rate of 5.35% included in Dr. Brown's analysis on p. 46 of his testimony may be accurate as of August 2007, the 1-month LIBOR rate has actually gone up since then. In fact, as of the close of business on September 13, 2007, the 1-month LIBOR rate was actually 5.75%.[19] If the average of the margins from Column 7 and lines II, III and IV from Dr. Brown's table on p. 46 of his direct testimony, or 0.62%, is added to the current LIBOR rate, then, based upon Dr. Brown's own analysis, the effective short-term debt cost for the Company as of September 13 was 6.37%.

Q. DOES THE COMPANY'S COMPOSITE RATE APPROACH TO FORECASTING SHORT-TERM DEBT COSTS MORE ACCURATELY REFLECT THE ACTUAL COST THE COMPANY WILL INCUR PROSPECTIVELY?

A. Yes. As opposed to taking Dr. Brown's single-point-in-time approach, the Company has provided a projection of what its composite short-term debt costs will be for the forward-looking period.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[19] Obtained from http://investor.wallstreetselect.com/wss?Page=Quote&Ticker=%24LIBOR1M.

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:	)	
	)	
PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	
ADJUSTMENT OF ITS RATES AND	)	
REVISED TARIFF	)	**DOCKET NO. 07-00105**

VERIFICATION

STATE OF TEXAS)
)
COUNTY OF DALLAS)

I, Laurie M. Sherwood, being first duly sworn, state that I am the Vice President, Corporate Development and Treasurer of Atmos Energy Corporation, that I am authorized to testify on behalf of Atmos Energy Corporation in the above referenced docket, that the Rebuttal Testimony of Laurie M. Sherwood pre-filed in this docket on the date of filing herein is true and correct to the best of my knowledge, information and belief.

Laurie M. Sherwood

Sworn and subscribed before me this 19th day of September, 2007.

Patricia D. Clark
Notary Public

My Commission Expires: 6-15-2010

NOTARY PUBLIC STATE OF TEXAS
Patricia D. Clark
Notary Public
State of Texas
Comm. Expires 06-15-2010

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:

PETITION OF ATMOS ENERGY CORPORATION FOR APPROVAL OF ADJUSTMENT OF ITS RATES AND REVISED TARIFF	))))	**DOCKET NO. 07-00105**

REBUTTAL TESTIMONY OF GARY L. SMITH
ON BEHALF OF ATMOS ENERGY CORPORATION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Gary L. Smith. My current position, effective beginning June 1, 2007, is Director, Customer Revenue Management for Atmos Energy Corporation (the "Company") and my current business address is 5430 LBJ Freeway, Dallas, TX 75240. Previously, I served as Vice President – Marketing and Regulatory Affairs for the Company's Kentucky/Mid-States operations.

Q. DID YOU PREVIOUSLY FILE TESTIMONY ON BEHALF OF THE COMPANY IN THIS RATE PROCEEDING?

A. Yes. My direct testimony was filed at the time of and in connection with the Company's rate application.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony addresses certain statements made and conclusions reached by Mr. Michael D. Chrysler, witness for the Consumer Advocate and Protection Division in the Office of the Attorney General for the State of Tennessee, regarding the Company's proposed Customer Utilization Adjustment (CUA) mechanism.

II. DECOUPLING AND THE PROPOSED CUSTOMER UTILIZATION ADJUSTMENT MECHANISM

Q. PLEASE BRIEFLY DESCRIBE THE RECOMMENDATIONS OF MR. CHRYSLER REGARDING THE COMPANY'S PROPOSED CUA MECHANISM.

A. In his testimony dated August 21, 2007, Mr. Chrysler expresses his opposition to the Company's proposed CUA and acknowledges his general opposition to decoupling as a concept, in large part due to its departure from "traditional" regulation.

Q. IS THE CUA A DEPARTURE FROM "TRADITIONAL" RATEMAKING? AND, IF SO, WHY IS THE CUA NECESSARY?

A. Mechanisms, such as those addressing Gas Cost Adjustments and Weather Normalization Adjustments, which are now very common, were not always "traditional" ratemaking practices and were at one time considered "experimental".

The Company's proposal would indeed result in the first CUA mechanism for an LDC in Tennessee operations, and therefore, may represent a departure from "traditional" ratemaking. However, revenue decoupling mechanisms are not unprecedented. Ten state commissions had approved decoupling mechanisms for 18 gas utilities at the time of my pre-filed testimony in this Case. Since that time, Arkansas has approved a decoupling mechanism for the utility Arkansas Western. Eight additional state commissions are currently considering implementation of decoupling mechanisms for 15 additional utilities. Thus, it is clear that "traditional" ratemaking is continuing to evolve as the concept of decoupling gains wider acceptance throughout the United States.

The Company has provided extensive evidence regarding the patterns of usage for its customers. Increased gas supply prices in recent years have accelerated declining customer gas usage trends and have resulted in greater customer retention challenges. Although Atmos Energy wishes to align interests of shareholders and customers, "traditional" ratemaking, specifically the practice of recovering a portion of non-gas revenues through volumetric distribution rates to customers, puts the recovery of the Company's costs and investments performance at odds with customer conservation efforts. "Traditional" ratemaking fails to take this into account and therefore needs to be reassessed. The CUA proposal simply breaks the faulty traditional linkage between Company's non-gas revenue and the quantity of gas consumed by its customers.

Q. MR. CHRYSLER CITES STATEMENTS FROM WITNESSES OPPOSING DECOUPLING MECHANISMS FROM CASES IN OTHER STATES. HOW DO YOU RESPOND TO THOSE STATEMENTS?

A. The Company recognizes that opposition to change will most always exist. Mr. Chrysler has referenced selected statements of opposition from specific cases in which decoupling proposals have been denied. However, the fact is, the number of states in which decoupling mechanisms have been approved is 11 and growing. Numerous endorsements for decoupling, including the National Association of Regulatory Utility Commissioners, have been placed in the case record by Atmos Energy. The Company points to the wide support we have referenced, which recognizes that as the world and market continue to evolve, innovative rate and regulatory model changes are warranted and appropriate.

Q. IN HIS DISCUSSION OF HOW OTHER STATES HAVE ADDRESSED DECOUPLING PROPOSALS, MR. CHRYSLER CITES A NEW MEXICO PUBLIC REGULATION COMMISSION ORDER, WHICH REJECTED A DECOUPLING PROPOSAL. DOES MR. CHRYSLER'S TESTIMONY ACKNOWLEDGE THAT THE NEW MEXICO COMMISSION KEPT THE DOOR OPEN FOR CONSIDERATION OF FUTURE PROPOSALS?

A. No, Mr. Chrylser's testimony fails to acknowledge that the New Mexico Commission left the door open for consideration of future decoupling proposals. The docket in question is Case No. 06-00210-UT. On page 40 of its Final Order Partially Adopting Recommended Decision the Commission stated: "That is not to say, however, that the Commission will not consider a well-designed decoupling proposal that meets the criteria of the Efficient Use of Energy Act. The Commission welcomes appropriate measures to eliminate disincentives to investment by utilities in energy efficiency programs as contemplated by the Act". Thus, the Commission not only left the door open for future decoupling proposals but also explicitly acknowledged the disincentives that exist under "traditional" ratemaking for utilities to invest in conservation and energy efficiency programs.

Q. MR. CHRYSLER STATES THAT THE PROPOSED CUA CALCULATION FAILS TO TAKE INTO ACCOUNT THE REVENUES GENERATED BY CUSTOMER GROWTH. IS THAT TRUE? AND, IF SO, WHY?

A. Yes. The CUA mechanism is proposed to specifically address the impact of changes in weather-normalized usage per customer from the benchmark usage in this Case.

The Company incurs additional capital investment and ongoing expenses to provide service to new customers. Ideally, the incremental revenues for those customers would economically justify those added costs. If one were to impute revenues generated by customer growth into the CUA, the investments by the Company would produce minimal, if any, incremental return. This would result in a deficiency requiring a subsequent rate increase to existing customers to subsidize the unprofitable growth.

Q. MR. CHRSLER CONCLUDES THAT "THE REVENUE GENERATED BY CUSTOMER GROWTH OFFSETS ANY LOSS ATTRIBUTED TO THE DECLINE IN CUSTOMER USAGE." PLEASE RESPOND TO THIS CONCLUSION.

A. First of all, Mr. Chrysler's conclusion is drawn from a model that is based upon a defined set of assumptions. Different assumptions would produce a different result. But, more importantly, Mr. Chrysler's conclusion is not relevant to the issue of decoupling. He ignores the investments and incremental expenses the Company incurs due to customer growth. The purpose of the CUA mechanism is to true-up the Company's non-gas revenue to the per-customer benchmark utilized in this case and to break the traditional linkage between Company's non-gas revenue and the quantity of gas consumed by its customers. Profitability of customer growth is addressed by Company witness Mr. Michael Ellis in the proposed changes to main extension policies.

Q. MR. CHRYSLER PERFORMS A CALCULATION MODELING CUA REVENUES AND GROWTH REVENUES FOR FUTURE PERIODS. PLEASE SHARE YOUR THOUGHTS REGARDING HIS MODEL AND ITS CONCLUSIONS.

A. First, the comparison of CUA revenues to growth revenues is not particularly relevant.

Second, as stated earlier, the model is based upon a certain set of assumptions, which, if changed, would alter the results.

Mr. Chrysler states that Company's example of the CUA calculation provided in response to CAPD Data Request #1, Q. 96 is "an unlikely scenario since it calculates a **credit** to consumers." With reference to Chart GLS-2 of my pre-filed direct testimony in this case, please note that the weather normalized usage in FY 2002 is lower than any of the subsequent 3 years (FY 2003 – FY 2005). Therefore, if CUA had been implemented in FY 2002, the CUA would have resulted in a credit to consumers for the first three years. Thus, it cannot be credibly argued that a scenario resulting in a credit to customers under the Company's proposal is unlikely. This simply demonstrates that the results of the CUA are dependent on future weather-normalized usage patterns, which cannot be predicted with 100% accuracy.

Q. MR. CHRYSLER RAISES DOUBTS THAT THE COMPANY, ABSENT THE CUA, HAS A DISINCENTIVE TO PROMOTE CONSERVATION. DO YOU BELIEVE A DISINCENTIVE EXISTS WITHOUT CUA?

A. Yes, I believe that a disincentive clearly exists. With only minor exceptions, the Company's non-gas costs of service are do not correlate to the level of volumes sold and transported. Despite that, traditional ratemaking places a portion of these largely fixed costs for recovery through a volumetric charge. Clearly, if the Company were to expend resources to promote, encourage, and affect customer conservation, the result would mean less customer usage and lower overall revenues recovered through the volumetric charges. However, the Company's largely fixed costs would remain unchanged resulting in lower net income. To me, this is a clear case of a structural disincentive.

Nevertheless, the Company does undertake certain measures to educate and encourage customers to control their costs and use energy wisely. This effort is undertaken, despite the disincentives of traditional ratemaking, because the Company believes it is in the long-term best interests of our customers and the natural gas industry.

Q. MR. CHRYSLER SUGGESTS THAT THE COMPANY COULD IMPLEMENT ENERGY CONSERVATION PROGRAMS IN TENNESSEE SIMILAR TO THOSE IN KENTUCKY, IOWA AND MISSOURI WITHOUT A CUA. WHAT IS YOUR OPINION?

A. The Company does not have a decoupled rate design in Kentucky and the Kentucky low-income weatherization program is accordingly funded fully by customers. Iowa, too, does not have a decoupled rate design and its energy efficiency program is fully funded by ratepayers. The recently implemented Missouri program, which is funded by the Company, was associated with a settlement, which included a decoupled rate design recovering all residential non-gas costs through the monthly customer charge.

The Tennessee residential energy efficiency pilot program is seeded with funding exclusively from Atmos Energy shareholders. As I stated in my direct testimony, we believe this pilot program will afford an important learning opportunity for the Company on how to craft an effective weatherization effort in Tennessee. And, the Company is certainly willing to engage in discussions with the Authority Staff and the Consumer Advocate to develop specific programs to aid energy efficiency improvements and weatherization efforts in light of its CUA proposal to eliminate the long-standing disincentives associated with customer conservation.

Q. DOES THIS CONCLUDE MATTERS YOU WISH TO ADDRESS IN REBUTTAL TESTIMONY AT THIS TIME?

A. Yes.

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:	)	
	)	
PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	
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VERIFICATION

STATE OF TEXAS)
)
COUNTY OF DALLAS)

I, Gary L. Smith, being first duly sworn, state that I am the Director of Customer Revenue Management for Atmos Energy Corporation, that I am authorized to testify on behalf of Atmos Energy Corporation in the above referenced docket, that the Rebuttal Testimony of Gary L. Smith pre-filed in this docket on the date of filing herein is true and correct to the best of my knowledge, information and belief.

Gary L. Smith
Gary L. Smith

Sworn and subscribed before me this 19th day of September, 2007.

Erikka L. Hise
Notary Public

My Commission Expires: 2-23-10

Erikka L. Hise
Notary Public
STATE OF TEXAS
My Comm. Expires February 23, 2010