
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.

<u>Class</u>	<u>Shares Outstanding</u>
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**

	<u>June 30, 2007</u>	<u>September 30, 2006</u>
	(Unaudited) (In thousands, except share data)	
ASSETS		
Property, plant and equipment	\$5,289,268	\$5,101,308
Less accumulated depreciation and amortization	<u>1,531,792</u>	<u>1,472,152</u>
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	<u>77,519</u>	<u>169,952</u>
Total current assets	1,334,493	1,117,545
Goodwill and intangible assets	738,065	738,521
Deferred charges and other assets	<u>225,775</u>	<u>234,325</u>
	<u>\$6,055,809</u>	<u>\$5,719,547</u>
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	<u>(16,373)</u>	<u>(43,850)</u>
Shareholders' equity	1,988,142	1,648,098
Long-term debt	<u>2,126,526</u>	<u>2,180,362</u>
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	<u>303,992</u>	<u>3,186</u>
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	<u>218,962</u>	<u>204,378</u>
	<u>\$6,055,809</u>	<u>\$5,719,547</u>

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended June 30	
	2007	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	<u>(223,046)</u>	<u>(138,523)</u>
	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	<u>(222,443)</u>	<u>(137,161)</u>
	<u>990,136</u>	<u>658,743</u>
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	<u>52,881</u>	<u>48,479</u>
Total operating expenses	<u>220,285</u>	<u>199,697</u>
Operating income	7,731	4,803
Miscellaneous income	4,266	963
Interest charges	<u>34,479</u>	<u>35,944</u>
Loss before income taxes	(22,482)	(30,178)
Income tax benefit	<u>(9,122)</u>	<u>(12,033)</u>
Net loss	<u>\$ (13,360)</u>	<u>\$ (18,145)</u>
Basic net loss per share	<u>\$ (0.15)</u>	<u>\$ (0.22)</u>
Diluted net loss per share	<u>\$ (0.15)</u>	<u>\$ (0.22)</u>
Cash dividends per share	<u>\$ 0.320</u>	<u>\$ 0.315</u>
Weighted average shares outstanding:		
Basic	<u>88,366</u>	<u>80,840</u>
Diluted	<u>88,366</u>	<u>80,840</u>

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	<u>(588,193)</u>	<u>(682,243)</u>
	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	<u>(585,971)</u>	<u>(678,591)</u>
	<u>3,864,073</u>	<u>4,224,416</u>
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	<u>149,694</u>	<u>158,691</u>
Total operating expenses	<u>644,391</u>	<u>621,160</u>
Operating income	387,903	335,333
Miscellaneous income (expense)	7,683	(1,028)
Interest charges	<u>109,273</u>	<u>107,625</u>
Income before income taxes	286,313	226,680
Income tax expense	<u>111,907</u>	<u>85,002</u>
Net income	<u>\$ 174,406</u>	<u>\$ 141,678</u>
Basic net income per share	<u>\$ 2.02</u>	<u>\$ 1.76</u>
Diluted net income per share	<u>\$ 2.00</u>	<u>\$ 1.75</u>
Cash dividends per share	<u>\$ 0.960</u>	<u>\$ 0.945</u>
Weighted average shares outstanding:		
Basic	<u>86,378</u>	<u>80,520</u>
Diluted	<u>87,011</u>	<u>81,013</u>

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	<u>161,531</u>	<u>(100,051)</u>
Net cash provided by operating activities	552,670	223,443
Cash Flows From Investing Activities		
Capital expenditures	(263,023)	(322,691)
Other, net	<u>(9,867)</u>	<u>(4,811)</u>
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	<u>191,913</u>	<u>—</u>
Net cash provided by (used in) financing activities	<u>(5,212)</u>	<u>90,792</u>
Net increase (decrease) in cash and cash equivalents	274,568	(13,267)
Cash and cash equivalents at beginning of period	<u>75,815</u>	<u>40,116</u>
Cash and cash equivalents at end of period	<u>\$ 350,383</u>	<u>\$ 26,849</u>

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

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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.

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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.

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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:

	<u>Three Months Ended June 30</u>		<u>Nine Months Ended June 30</u>	
	<u>2007</u>	<u>2006</u>	<u>2007</u>	<u>2006</u>
	(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	<u>(4,621)</u>	<u>(6,821)</u>	<u>20,401</u>	<u>(35,660)</u>
Comprehensive income (loss)	<u><u>\$(14,589)</u></u>	<u><u>\$(24,410)</u></u>	<u><u>\$201,883</u></u>	<u><u>\$109,179</u></u>

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

	<u>June 30, 2007</u>	<u>September 30, 2006</u>
	(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	<u>(4,475)</u>	<u>(24,876)</u>
	<u><u>\$(16,373)</u></u>	<u><u>\$(43,850)</u></u>

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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.

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

	<u>Utility</u>	<u>Natural Gas Marketing</u> (In thousands)	<u>Total</u>
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)	<u>\$ (7,524)</u>	<u>\$15,898</u>	<u>\$ 8,374</u>
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)	<u>\$(27,209)</u>	<u>\$15,003</u>	<u>\$(12,206)</u>

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

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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.

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

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.

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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.

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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.

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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.

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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:

	<u>For the Three Months Ended June 30</u>		<u>For the Nine Months Ended June 30</u>	
	<u>2007</u>	<u>2006</u>	<u>2007</u>	<u>2006</u>
	(In thousands, except per share amounts)			
Net income (loss)	<u>\$(13,360)</u>	<u>\$(18,145)</u>	<u>\$174,406</u>	<u>\$141,678</u>
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	<u>—</u>	<u>—</u>	<u>169</u>	<u>99</u>
Denominator for diluted income per share — weighted average common shares	<u>88,366</u>	<u>80,840</u>	<u>87,011</u>	<u>81,013</u>
Income (loss) per share — basic	<u>\$ (0.15)</u>	<u>\$ (0.22)</u>	<u>\$ 2.02</u>	<u>\$ 1.76</u>
Income (loss) per share — diluted	<u>\$ (0.15)</u>	<u>\$ (0.22)</u>	<u>\$ 2.00</u>	<u>\$ 1.75</u>

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.

	<u>Three Months Ended June 30</u>			
	<u>Pension Benefits</u>		<u>Other Benefits</u>	
	<u>2007</u>	<u>2006</u>	<u>2007</u>	<u>2006</u>
	(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	<u>2,435</u>	<u>3,299</u>	<u>—</u>	<u>320</u>
Net periodic pension cost	<u>\$ 6,903</u>	<u>\$ 6,754</u>	<u>\$5,236</u>	<u>\$5,722</u>

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	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	<u>7,303</u>	<u>9,897</u>	<u>—</u>	<u>960</u>
Net periodic pension cost	<u>\$ 20,709</u>	<u>\$ 20,262</u>	<u>\$15,709</u>	<u>\$17,166</u>

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

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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	<u>22,033</u>
	<u>\$811,508</u>

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.

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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					
	<u>Utility</u>	<u>Natural Gas Marketing</u>	<u>Pipeline and Storage</u>	<u>Other Nonutility</u>	<u>Eliminations</u>	<u>Consolidated</u>
	(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)	<u>\$ (15,690)</u>	<u>\$ (5,610)</u>	<u>\$ 7,672</u>	<u>\$268</u>	<u>\$ —</u>	<u>\$ (13,360)</u>
Capital expenditures	<u>\$ 78,829</u>	<u>\$ 187</u>	<u>\$11,215</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 90,231</u>

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Three Months Ended June 30, 2006

	<u>Utility</u>	<u>Natural Gas Marketing</u>	<u>Pipeline and Storage</u>	<u>Other Nonutility</u>	<u>Eliminations</u>	<u>Consolidated</u>
	(In thousands)					
Operating revenues from external parties	\$401,896	\$441,418	\$19,597	\$ 332	\$ —	\$863,243
Intersegment revenues	<u>148</u>	<u>121,029</u>	<u>16,265</u>	<u>1,081</u>	<u>(138,523)</u>	<u>—</u>
	402,044	562,447	35,862	1,413	(138,523)	863,243
Purchased gas cost	<u>232,192</u>	<u>563,333</u>	<u>379</u>	<u>—</u>	<u>(137,161)</u>	<u>658,743</u>
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	<u>45,853</u>	<u>273</u>	<u>2,272</u>	<u>81</u>	<u>—</u>	<u>48,479</u>
Total operating expenses	<u>172,762</u>	<u>6,464</u>	<u>20,564</u>	<u>1,336</u>	<u>(1,429)</u>	<u>199,697</u>
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	<u>30,892</u>	<u>1,716</u>	<u>6,384</u>	<u>1,181</u>	<u>(4,229)</u>	<u>35,944</u>
Income (loss) before income taxes . . .	(30,780)	(8,510)	8,844	268	—	(30,178)
Income tax expense (benefit)	<u>(11,809)</u>	<u>(3,341)</u>	<u>3,012</u>	<u>105</u>	<u>—</u>	<u>(12,033)</u>
Net income (loss)	<u>\$ (18,971)</u>	<u>\$ (5,169)</u>	<u>\$ 5,832</u>	<u>\$ 163</u>	<u>\$ —</u>	<u>\$ (18,145)</u>
Capital expenditures	<u>\$ 75,973</u>	<u>\$ 500</u>	<u>\$32,988</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$109,461</u>

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Nine Months Ended June 30, 2007					
	<u>Utility</u>	<u>Natural Gas Marketing</u>	<u>Pipeline and Storage</u>	<u>Other Nonutility</u>	<u>Eliminations</u>	<u>Consolidated</u>
	(In thousands)					
Operating revenues from external parties	\$2,973,048	\$1,844,271	\$ 77,863	\$1,185	\$ —	\$4,896,367
Intersegment revenues	<u>480</u>	<u>516,631</u>	<u>69,288</u>	<u>1,794</u>	<u>(588,193)</u>	<u>—</u>
	2,973,528	2,360,902	147,151	2,979	(588,193)	4,896,367
Purchased gas cost	<u>2,174,071</u>	<u>2,275,291</u>	<u>682</u>	<u>—</u>	<u>(585,971)</u>	<u>3,864,073</u>
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	<u>141,292</u>	<u>951</u>	<u>7,286</u>	<u>165</u>	<u>—</u>	<u>149,694</u>
Total operating expenses	<u>561,932</u>	<u>21,126</u>	<u>60,943</u>	<u>2,870</u>	<u>(2,480)</u>	<u>644,391</u>
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	<u>91,164</u>	<u>3,418</u>	<u>24,582</u>	<u>1,735</u>	<u>(11,626)</u>	<u>109,273</u>
Income (loss) before income taxes	152,994	66,883	66,448	(12)	—	286,313
Income tax expense (benefit)	<u>60,530</u>	<u>26,515</u>	<u>24,867</u>	<u>(5)</u>	<u>—</u>	<u>111,907</u>
Net income (loss)	<u>\$ 92,464</u>	<u>\$ 40,368</u>	<u>\$ 41,581</u>	<u>\$ (7)</u>	<u>\$ —</u>	<u>\$ 174,406</u>
Capital expenditures	<u>\$ 222,526</u>	<u>\$ 837</u>	<u>\$ 39,660</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 263,023</u>

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Nine Months Ended June 30, 2006					
	<u>Utility</u>	<u>Natural Gas Marketing</u>	<u>Pipeline and Storage</u>	<u>Other Nonutility</u>	<u>Eliminations</u>	<u>Consolidated</u>
	(In thousands)					
Operating revenues from external parties	\$3,254,078	\$1,866,768	\$ 58,716	\$1,347	\$ —	\$5,180,909
Intersegment revenues	<u>596</u>	<u>616,153</u>	<u>62,341</u>	<u>3,153</u>	<u>(682,243)</u>	<u>—</u>
	3,254,674	2,482,921	121,057	4,500	(682,243)	5,180,909
Purchased gas cost	<u>2,488,906</u>	<u>2,413,511</u>	<u>590</u>	<u>—</u>	<u>(678,591)</u>	<u>4,224,416</u>
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	<u>150,456</u>	<u>864</u>	<u>7,086</u>	<u>285</u>	<u>—</u>	<u>158,691</u>
Total operating expenses	<u>544,665</u>	<u>18,173</u>	<u>57,910</u>	<u>4,215</u>	<u>(3,803)</u>	<u>621,160</u>
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	<u>92,783</u>	<u>6,575</u>	<u>18,978</u>	<u>2,996</u>	<u>(13,707)</u>	<u>107,625</u>
Income before income taxes	134,334	46,416	45,425	505	—	226,680
Income tax expense	<u>50,264</u>	<u>18,201</u>	<u>16,339</u>	<u>198</u>	<u>—</u>	<u>85,002</u>
Net income	<u>\$ 84,070</u>	<u>\$ 28,215</u>	<u>\$ 29,086</u>	<u>\$ 307</u>	<u>\$ —</u>	<u>\$ 141,678</u>
Capital expenditures	<u>\$ 232,137</u>	<u>\$ 1,067</u>	<u>\$ 89,487</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 322,691</u>

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

	June 30, 2007					
	<u>Utility</u>	<u>Natural Gas Marketing</u>	<u>Pipeline and Storage</u>	<u>Other Nonutility</u>	<u>Eliminations</u>	<u>Consolidated</u>
	(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	<u>536,238</u>	<u>—</u>	<u>—</u>	<u>45,400</u>	<u>(581,638)</u>	<u>—</u>
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						
Deferred charges and other assets	—	7,077	—	—	—	7,077
	<u>197,731</u>	<u>1,296</u>	<u>4,936</u>	<u>14,735</u>	<u>—</u>	<u>218,698</u>
	<u>\$5,692,749</u>	<u>\$574,616</u>	<u>\$750,739</u>	<u>\$94,344</u>	<u>\$(1,056,639)</u>	<u>\$6,055,809</u>
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	\$1,988,142	\$154,529	\$145,324	\$83,633	\$ (383,486)	\$1,988,142
Long-term debt	<u>2,124,878</u>	<u>—</u>	<u>—</u>	<u>1,648</u>	<u>—</u>	<u>2,126,526</u>
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	<u>—</u>	<u>111,932</u>	<u>469,706</u>	<u>—</u>	<u>(581,638)</u>	<u>—</u>
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						
Regulatory cost of removal obligation	261,436	—	—	—	—	261,436
Deferred credits and other liabilities	<u>209,935</u>	<u>692</u>	<u>3,654</u>	<u>4,120</u>	<u>—</u>	<u>218,401</u>
	<u>\$5,692,749</u>	<u>\$574,616</u>	<u>\$750,739</u>	<u>\$94,344</u>	<u>\$(1,056,639)</u>	<u>\$6,055,809</u>

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	September 30, 2006					
	<u>Utility</u>	<u>Natural Gas Marketing</u>	<u>Pipeline and Storage</u>	<u>Other Nonutility</u>	<u>Eliminations</u>	<u>Consolidated</u>
	(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	<u>602,809</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>(602,809)</u>	<u>—</u>
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 . . .	<u>204,617</u>	<u>1,315</u>	<u>5,301</u>	<u>16,906</u>	<u>—</u>	<u>228,139</u>
	<u>\$5,462,301</u>	<u>\$396,042</u>	<u>\$731,565</u>	<u>\$47,917</u>	<u>\$(918,278)</u>	<u>\$5,719,547</u>
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	\$1,648,098	\$139,863	\$107,640	\$33,640	\$(281,143)	\$1,648,098
Long-term debt	<u>2,176,473</u>	<u>—</u>	<u>—</u>	<u>3,889</u>	<u>—</u>	<u>2,180,362</u>
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	<u>—</u>	<u>75,665</u>	<u>525,895</u>	<u>1,249</u>	<u>(602,809)</u>	<u>—</u>
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	<u>194,557</u>	<u>434</u>	<u>4,109</u>	<u>5,002</u>	<u>—</u>	<u>204,102</u>
	<u>\$5,462,301</u>	<u>\$396,042</u>	<u>\$731,565</u>	<u>\$47,917</u>	<u>\$(918,278)</u>	<u>\$5,719,547</u>

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	<u>190,578</u>	<u>172,762</u>
Operating income (loss)	65	(2,910)
Miscellaneous income	2,232	3,022
Interest charges	<u>28,987</u>	<u>30,892</u>
Loss before income taxes	(26,690)	(30,780)
Income tax benefit	<u>(11,000)</u>	<u>(11,809)</u>
Net loss	<u><u>\$ (15,690)</u></u>	<u><u>\$ (18,971)</u></u>
Utility sales volumes — MMcf	45,252	32,653
Utility transportation volumes — MMcf	<u>29,311</u>	<u>29,630</u>
Total utility throughput — MMcf	<u><u>74,563</u></u>	<u><u>62,283</u></u>
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	<u>\$ 65</u>	98%	<u>\$ (2,910)</u>	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	<u>\$ (5,610)</u>	<u>\$ (5,169)</u>
Natural gas marketing sales volumes — MMcf	<u>85,413</u>	<u>66,472</u>
Net physical position (Bcf)	<u>21.5</u>	<u>19.0</u>

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	<u>2,292</u>	<u>1,681</u>
Gross profit	37,709	35,483
Operating expenses	<u>22,180</u>	<u>20,564</u>
Operating income	15,529	14,919
Miscellaneous income	3,899	309
Interest charges	<u>7,125</u>	<u>6,384</u>
Income before income taxes	12,303	8,844
Income tax expense	<u>4,631</u>	<u>3,012</u>
Net income	<u>\$ 7,672</u>	<u>\$ 5,832</u>
Pipeline transportation volumes — MMcf	<u>127,491</u>	<u>106,999</u>

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	<u>561,932</u>	<u>544,665</u>
Operating income	237,525	221,103
Miscellaneous income	6,633	6,014
Interest charges	<u>91,164</u>	<u>92,783</u>
Income before income taxes	152,994	134,334
Income tax expense	<u>60,530</u>	<u>50,264</u>
Net income	<u>\$ 92,464</u>	<u>\$ 84,070</u>
Utility sales volumes — MMcf	265,508	239,562
Utility transportation volumes — MMcf	<u>101,572</u>	<u>91,384</u>
Total utility throughput — MMcf	<u>367,080</u>	<u>330,946</u>
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	Heating Degree Days Percent of Normal ⁽¹⁾	2006	Heating Degree Days Percent of Normal ⁽¹⁾
	<u>Operating Income</u>		<u>Operating Income</u>	
	(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	<u>1,468</u>	—	<u>4,187</u>	—
Utility segment	<u>\$237,525</u>	101%	<u>\$221,103</u>	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	<u>\$ 40,368</u>	<u>\$ 28,215</u>
Natural gas marketing sales volumes — MMcf	<u>264,325</u>	<u>207,418</u>
Net physical position (Bcf)	<u>21.5</u>	<u>19.0</u>

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	<u>8,407</u>	<u>4,527</u>
Gross profit	146,469	120,467
Operating expenses	<u>60,943</u>	<u>57,910</u>
Operating income	85,526	62,557
Miscellaneous income	5,504	1,846
Interest charges	<u>24,582</u>	<u>18,978</u>
Income before income taxes	66,448	45,425
Income tax expense	<u>24,867</u>	<u>16,339</u>
Net income	<u>\$ 41,581</u>	<u>\$ 29,086</u>
Pipeline transportation volumes — MMcf	<u>365,503</u>	<u>284,551</u>

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	<u>6,325,000</u>	—
Total shares issued	<u>7,373,069</u>	<u>998,748</u>

- 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:

	<u>S&P</u>	<u>Moody's</u>	<u>Fitch</u>
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.

	<u>June 30, 2007</u>		<u>September 30, 2006</u>		<u>June 30, 2006</u>	
	(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	<u>1,988,142</u>	<u>45.0%</u>	<u>1,648,098</u>	<u>39.1%</u>	<u>1,664,556</u>	<u>40.1%</u>
Total capitalization	<u>\$4,418,660</u>	<u>100.0%</u>	<u>\$4,214,062</u>	<u>100.0%</u>	<u>\$4,145,726</u>	<u>100.0%</u>

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	<u>(5,385)</u>	<u>24,898</u>	<u>(1,045)</u>	<u>(5,460)</u>
Fair value of contracts at end of period	<u><u>\$(7,524)</u></u>	<u><u>\$ 15,898</u></u>	<u><u>\$ 7,631</u></u>	<u><u>\$(29,797)</u></u>

	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	<u>54,405</u>	<u>11,488</u>	<u>(104,141)</u>	<u>30,002</u>
Fair value of contracts at end of period	<u>\$ (7,524)</u>	<u>\$ 15,898</u>	<u>\$ 7,631</u>	<u>\$(29,797)</u>

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:

Source of Fair Value	Fair Value of Contracts at June 30, 2007				Total Fair Value
	Maturity in Years				
	Less than 1	1-3	4-5	Greater Than 5	
	(In thousands)				
Prices actively quoted	\$2,552	\$7,252	\$—	\$—	\$ 9,804
Prices based on models and other valuation methods	<u>(694)</u>	<u>(736)</u>	<u>—</u>	<u>—</u>	<u>(1,430)</u>
Total Fair Value	<u>\$1,858</u>	<u>\$6,516</u>	<u>\$—</u>	<u>\$—</u>	<u>\$ 8,374</u>

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.

<u>Period Ending</u>	<u>Net Physical Position</u>	<u>Economic Gross Profit</u>	<u>Associated Net Unrealized Gains (Losses) At Period End</u>	<u>Potential Future Gross Profit</u>
	(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	<u>3,194,304</u>	<u>3,186,152</u>	<u>3,194,304</u>	<u>3,186,152</u>
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	<u>75,683</u>	<u>63,388</u>	<u>370,633</u>	<u>334,891</u>
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	<u>\$ 548,251</u>	<u>\$ 402,044</u>	<u>\$2,973,528</u>	<u>\$3,254,674</u>
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	<u>1,188</u>	<u>1,196</u>	<u>1,188</u>	<u>1,196</u>
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	<u>27.0</u>	<u>22.6</u>	<u>27.0</u>	<u>22.6</u>
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	<u>\$892,947</u>	<u>\$599,722</u>	<u>\$2,511,032</u>	<u>\$2,608,478</u>

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.

EXHIBITS INDEX

Item 6(a)

<u>Exhibit Number</u>	<u>Description</u>	<u>Page Number or Incorporation by Reference to</u>
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.