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

Form 10-Q

(Mark One)

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

For the quarterly period ended December 31, 2005

or

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

For the transition period from _____ to _____

Commission File Number 1-10042

Atmos Energy Corporation

(Exact name of registrant as specified in its charter)

Texas and Virginia
*(State or other jurisdiction of
incorporation or organization)*

75-1743247
*(IRS employer
identification no.)*

**Three Lincoln Centre, Suite 1800
5430 LBJ Freeway, Dallas, Texas**
(Address of principal executive offices)

75240
(Zip code)

(972) 934-9227

(Registrant's telephone number, including area code)

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

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

Large accelerated filer

Accelerated filer

Non-accelerated filer

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

Number of shares outstanding of each of the issuer's classes of common stock, as of January 31, 2006.

<u>Class</u>	<u>Shares Outstanding</u>
No Par Value	80,922,830

GLOSSARY OF KEY TERMS

AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
AES	Atmos Energy Services, LLC
APB	Accounting Principles Board
APS	Atmos Pipeline and Storage, LLC
Bcf	Billion cubic feet
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation
Fitch	Fitch Ratings, Ltd.
GPSC	Georgia Public Service Commission
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
Mcf	Thousand cubic feet
MMcf	Million cubic feet
Moody's	Moody's Investor Services, Inc.
MPSC	Mississippi Public Service Commission
NYMEX	New York Mercantile Exchange, Inc.
RRC	Railroad Commission of Texas
S&P	Standard & Poor's
SEC	United States Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
TXU Gas	TXU Gas Company, which was acquired on October 1, 2004
WNA	Weather Normalization Adjustment

PART 1. FINANCIAL INFORMATION

Item 1. Financial Statements

**ATMOS ENERGY CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS**

	<u>December 31, 2005</u>	<u>September 30, 2005</u>
	(Unaudited)	
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	\$4,853,016	\$4,765,610
Less accumulated depreciation and amortization	<u>1,413,082</u>	<u>1,391,243</u>
Net property, plant and equipment	3,439,934	3,374,367
Current assets		
Cash and cash equivalents	49,451	40,116
Cash held on deposit in margin account	74,076	80,956
Accounts receivable, net	1,229,190	454,313
Gas stored underground	583,572	450,807
Other current assets	<u>239,992</u>	<u>238,238</u>
Total current assets	2,176,281	1,264,430
Goodwill and intangible assets	737,641	737,787
Deferred charges and other assets	<u>265,146</u>	<u>276,943</u>
	<u><u>\$6,619,002</u></u>	<u><u>\$5,653,527</u></u>
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at \$.005 per share); 200,000,000 shares authorized; issued and outstanding:		
December 31, 2005 — 80,852,898 shares;		
September 30, 2005 — 80,539,401 shares	\$ 404	\$ 403
Additional paid-in capital	1,438,917	1,426,523
Retained earnings	224,435	178,837
Accumulated other comprehensive loss	<u>(26,139)</u>	<u>(3,341)</u>
Shareholders' equity	1,637,617	1,602,422
Long-term debt	<u>2,181,497</u>	<u>2,183,104</u>
Total capitalization	3,819,114	3,785,526
Current liabilities		
Accounts payable and accrued liabilities	1,170,402	461,314
Other current liabilities	401,948	503,368
Short-term debt	474,059	144,809
Current maturities of long-term debt	<u>3,286</u>	<u>3,264</u>
Total current liabilities	2,049,695	1,112,755
Deferred income taxes	284,196	292,207
Regulatory cost of removal obligation	268,999	263,424
Deferred credits and other liabilities	<u>196,998</u>	<u>199,615</u>
	<u><u>\$6,619,002</u></u>	<u><u>\$5,653,527</u></u>

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended December 31	
	2005	2004
	(Unaudited)	
	(In thousands, except per share data)	
Operating revenues		
Utility segment	\$1,405,010	\$ 913,681
Natural gas marketing segment	1,101,845	493,801
Pipeline and storage segment	39,712	43,690
Other nonutility segment	1,492	1,359
Intersegment eliminations	<u>(264,239)</u>	<u>(83,907)</u>
	2,283,820	1,368,624
Purchased gas cost		
Utility segment	1,124,829	656,370
Natural gas marketing segment	1,075,526	466,957
Pipeline and storage segment	—	6,221
Other nonutility segment	—	—
Intersegment eliminations	<u>(263,125)</u>	<u>(83,027)</u>
	<u>1,937,230</u>	<u>1,046,521</u>
Gross profit	346,590	322,103
Operating expenses		
Operation and maintenance	108,217	110,777
Depreciation and amortization	43,260	43,997
Taxes, other than income	<u>45,416</u>	<u>38,655</u>
Total operating expenses	<u>196,893</u>	<u>193,429</u>
Operating income	149,697	128,674
Miscellaneous income	448	385
Interest charges	<u>36,189</u>	<u>32,542</u>
Income before income taxes	113,956	96,517
Income tax expense	<u>42,929</u>	<u>36,918</u>
Net income	<u>\$ 71,027</u>	<u>\$ 59,599</u>
Basic net income per share	<u>\$ 0.88</u>	<u>\$ 0.79</u>
Diluted net income per share	<u>\$ 0.88</u>	<u>\$ 0.79</u>
Cash dividends per share	<u>\$ 0.315</u>	<u>\$ 0.310</u>
Weighted average shares outstanding:		
Basic	<u>80,259</u>	<u>75,306</u>
Diluted	<u>80,722</u>	<u>75,725</u>

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended December 31	
	2005	2004
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	\$ 71,027	\$ 59,599
Adjustments to reconcile net income to net cash (used in) provided by operating activities:		
Depreciation and amortization:		
Charged to depreciation and amortization	43,260	43,997
Charged to other accounts	147	254
Deferred income taxes	20,448	8,308
Other	3,680	977
Net assets/liabilities from risk management activities	13,695	22,088
Net change in operating assets and liabilities	<u>(347,626)</u>	<u>(67,319)</u>
Net cash (used in) provided by operating activities	(195,369)	67,904
Cash Flows From Investing Activities		
Capital expenditures	(102,465)	(67,201)
Acquisitions	—	(1,912,532)
Other, net	<u>(1,121)</u>	<u>(1,051)</u>
Net cash used in investing activities	(103,586)	(1,980,784)
Cash Flows From Financing Activities		
Net increase in short-term debt	329,250	28,797
Net proceeds from issuance of long-term debt	—	1,385,847
Repayment of long-term debt	(1,695)	(3,373)
Settlement of Treasury lock agreements	—	(43,770)
Cash dividends paid	(25,429)	(24,521)
Issuance of common stock	6,164	11,116
Net proceeds from equity offering	<u>—</u>	<u>382,014</u>
Net cash provided by financing activities	<u>308,290</u>	<u>1,736,110</u>
Net increase (decrease) in cash and cash equivalents	9,335	(176,770)
Cash and cash equivalents at beginning of period	<u>40,116</u>	<u>201,932</u>
Cash and cash equivalents at end of period	<u>\$ 49,451</u>	<u>\$ 25,162</u>

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
December 31, 2005

1. Nature of Business

Atmos Energy Corporation (“Atmos” or “the Company”) and its 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 seven regulated natural gas utility divisions, in the service areas described below:

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

⁽¹⁾ Denotes locations where we have more limited service areas.

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

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

Our pipeline and storage business includes the regulated operations of our Atmos Pipeline — Texas Division, a division of Atmos Energy Corporation, and the nonregulated operations of Atmos Pipeline and Storage, LLC (APS), which is wholly-owned by AEH. The Atmos Pipeline — Texas Division transports natural gas to our Atmos Energy Mid-Tex Division, transports natural gas 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 AES, we provide natural gas management services to our utility operations, other than the Mid-Tex Division. These services include aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering the gas to our utility service areas at competitive prices in exchange for revenues that are equal to the costs incurred to provide these services. Through Atmos Power Systems, Inc., we construct gas-fired electric peaking power-generating plants and associated facilities and may enter into agreements to either lease or sell these plants.

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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 and notes 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 in its Annual Report on Form 10-K for the fiscal year ended September 30, 2005. Because of seasonal and other factors, the results of operations for the three-month period ended December 31, 2005 are not indicative of expected results of operations for the full 2006 fiscal year, which ends September 30, 2006.

Basis of Comparison

Certain prior-period amounts have been reclassified to conform with the current year's presentation.

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, 2005. Except for the Company's adoption of Statement of Financial Accounting Standards (SFAS) 123 (revised), *Share-Based Payment*, discussed below, there were no significant changes to our accounting policies during the three months ended December 31, 2005.

Stock-based compensation plans

Our 1998 Long-Term Incentive Plan provides for the granting of incentive stock options, non-qualified stock options, stock appreciation rights, bonus stock, time-lapse restricted stock, performance-based restricted stock units and stock units to officers and key employees. Nonemployee directors are also eligible to receive stock-based compensation under the 1998 Long-Term Incentive Plan. The objectives of this plan include attracting and retaining the best personnel, providing for additional performance incentives and promoting our success by providing employees with the opportunity to acquire our common stock.

On October 1, 2005, the Company adopted SFAS 123 (revised), *Share-Based Payment* (SFAS 123(R)). This standard revises SFAS 123, *Accounting for Stock-Based Compensation* and supersedes Accounting Principles Board (APB) Opinion 25, *Accounting for Stock Issued to Employees*. Under SFAS 123(R), the Company is required to measure the cost of employee services received in exchange for stock options and similar awards based on the grant-date fair value of the award and recognize this cost in the income statement over the period during which an employee is required to provide service in exchange for the award.

We adopted SFAS 123(R) using the modified prospective method. Under this transition method, stock-based compensation expense for the three months ended December 31, 2005 includes: (i) compensation expense for all stock-based compensation awards granted prior to, but not yet vested as of October 1, 2005, based on the grant-date fair value estimated in accordance with the original provisions of SFAS 123; and (ii) compensation expense for all stock-based compensation awards granted subsequent to October 1, 2005, based on the grant-date fair value estimated in accordance with the provisions of SFAS 123(R). We recognize compensation expense on a straight-line basis over the requisite service period of the award. Total stock-based compensation expense included in our statement of income for the three months ended December 31, 2005 was less than \$0.1 million and was recorded as a component of operation and maintenance expense. In accordance with the modified prospective method, financial results for prior periods have not been restated.

Prior to October 1, 2005, we accounted for these plans under the intrinsic-value method described in APB Opinion 25, as permitted by SFAS 123. Under this method, no compensation cost for stock options was recognized for stock-option awards granted at or above fair-market value. Awards of restricted stock were

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

valued at the market price of the Company's common stock on the date of grant. The unearned compensation was amortized to operation and maintenance expense over the vesting period of the restricted stock.

Had compensation expense for our stock-based awards been recognized as prescribed by SFAS 123, our net income and earnings per share for the three months ended December 31, 2004 would have been impacted as shown in the following table:

	<u>Three Months Ended December 31, 2004</u> (In thousands, except per share amounts)
Net income — as reported	\$59,599
Restricted stock compensation expense included in income, net of tax	489
Total stock-based employee compensation expense determined under fair-value-based method for all awards, net of tax	<u>(741)</u>
Net income — pro forma	<u>\$59,347</u>
Earnings per share:	
Basic earnings per share — as reported	<u>\$ 0.79</u>
Basic earnings per share — pro forma	<u>\$ 0.79</u>
Diluted earnings per share — as reported	<u>\$ 0.79</u>
Diluted earnings per share — pro forma	<u>\$ 0.78</u>

Regulatory assets and liabilities

We record certain costs as regulatory assets in accordance with 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 substantially all of our regulatory liabilities are recorded as a component of deferred credits and other liabilities. Deferred gas costs are recorded either in other current assets or liabilities and the regulatory cost of removal obligation is separately reported.

Significant regulatory assets and liabilities as of December 31, 2005 and September 30, 2005 included the following:

	<u>December 31, 2005</u>	<u>September 30, 2005</u>
(In thousands)		
Regulatory assets:		
Merger and integration costs, net	\$ 9,065	\$ 9,150
Deferred gas cost	124,269	38,173
Environmental costs	1,312	1,357
Rate case costs	10,796	11,314
Deferred franchise fees	3,208	6,710
Other	<u>9,168</u>	<u>9,313</u>
	<u>\$157,818</u>	<u>\$ 76,017</u>

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	December 31, 2005	September 30, 2005
	(In thousands)	
Regulatory liabilities:		
Deferred gas costs	\$ 39,143	\$134,048
Regulatory cost of removal obligation	280,564	274,989
Deferred income taxes, net	3,185	3,185
Other	7,580	8,084
	\$330,472	\$420,306

Currently 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 future rate filings in accordance with rulings received from various regulatory commissions.

Comprehensive income

The following table presents the components of comprehensive income, net of related tax, for the three-month periods ended December 31, 2005 and 2004:

	Three Months Ended December 31	
	2005	2004
	(In thousands)	
Net income	\$ 71,027	\$ 59,599
Unrealized holding gains on investments, net of tax expense of \$248 and \$649	405	1,057
Amortization and unrealized losses on interest rate hedging transactions, net of tax expense (benefit) of \$528 and \$(3,245)	860	(5,296)
Net unrealized losses on commodity hedging transactions, net of tax benefit of \$14,749 and \$7,912	(24,063)	(12,908)
Comprehensive income	\$ 48,229	\$ 42,452

Accumulated other comprehensive loss, net of tax, as of December 31, 2005 and September 30, 2005 consisted of the following unrealized gains (losses):

	December 31, 2005	September 30, 2005
	(In thousands)	
Accumulated other comprehensive loss:		
Unrealized holding gains on investments	\$ 1,089	\$ 684
Treasury lock agreements	(23,122)	(23,982)
Cash flow hedges	(4,106)	19,957
	\$(26,139)	\$ (3,341)

Recent accounting pronouncements

In March 2005, the Financial Accounting Standards Board (FASB) issued Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* (FIN 47), which clarifies that an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation when the obligation is

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

incurred — generally upon acquisition, construction or development and/or through the normal operation of the asset, if the fair value of the liability can be reasonably estimated. A conditional asset retirement obligation is a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Uncertainty about the timing and/or method of settlement is required to be factored into the measurement of the liability when sufficient information exists. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. FIN 47 is effective for us by the end of the 2006 fiscal year. We are currently evaluating the impact that FIN 47 may have on our financial position, results of operations and cash flows.

3. Derivative Instruments and Hedging Activities

We conduct risk management activities through both our utility and natural gas marketing segments. We record our derivatives as a component of risk management assets and liabilities, which are classified as current or noncurrent other assets or liabilities based upon the anticipated settlement date of the underlying derivative. Our determination of the fair value of these derivative financial instruments reflects the estimated amounts that we would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains and losses on open contracts. In our determination of fair value, we consider various factors, including closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts. Effective October 1, 2005, the Company changed its mark to market measurement from Inside FERC to Gas Daily to better reflect the prices of our physical commodity.

The following table shows the fair values of our risk management assets and liabilities by segment at December 31, 2005 and September 30, 2005:

	<u>Utility</u>	<u>Natural Gas Marketing</u>	<u>Total</u>
	<u>(In thousands)</u>		
December 31, 2005:			
Assets from risk management activities, current	\$38,780	\$ 6,424	\$ 45,204
Assets from risk management activities, noncurrent	—	653	653
Liabilities from risk management activities, current	(507)	(55,251)	(55,758)
Liabilities from risk management activities, noncurrent	—	(11,194)	(11,194)
Net assets (liabilities)	<u>\$38,273</u>	<u>\$(59,368)</u>	<u>\$(21,095)</u>
September 30, 2005:			
Assets from risk management activities, current	\$93,310	\$ 14,603	\$107,913
Assets from risk management activities, noncurrent	—	735	735
Liabilities from risk management activities, current	—	(61,920)	(61,920)
Liabilities from risk management activities, noncurrent	—	(15,316)	(15,316)
Net assets (liabilities)	<u>\$93,310</u>	<u>\$(61,898)</u>	<u>\$ 31,412</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*

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Regulation. Accordingly, there is no earnings impact to our utility segment as a result of the use of financial derivatives. For the 2005-2006 heating season, we hedged approximately 46 percent of our anticipated winter flowing gas requirements at a weighted average cost of approximately \$9.11 per Mcf. Our utility hedging activities also include the cost of our Treasury lock agreements which are described in further detail below.

Nonutility Hedging Activities

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

For the three-month period ended December 31, 2005, the change in the deferred hedging position in accumulated other comprehensive loss was attributable to decreases in future commodity prices relative to the commodity prices stipulated in the derivative contracts, and the recognition for the three months ended December 31, 2005 of \$15.3 million in net deferred hedging gains in net income when the derivative contracts matured according to their terms. The net deferred hedging loss associated with open cash flow hedges remains subject to market price fluctuations until the positions are either settled under the terms of the hedge contracts or terminated prior to settlement. Substantially all of the deferred hedging balance as of December 31, 2005 is expected to be recognized in net income in fiscal 2006 along with the corresponding hedged purchases and sales of natural gas.

Under our risk management policies, we seek to match our financial derivative positions to our physical storage positions as well as our expected current and future sales and purchase obligations to maintain no open positions at the end of each trading day. The determination of our net open position as of any day, however, requires us to make assumptions as to future circumstances, including the use of gas by our customers in relation to our anticipated storage and market positions. Because the price risk associated with any net open position at the end of each day may increase if the assumptions are not realized, we review these assumptions as part of our daily monitoring activities. We can also be affected by intraday fluctuations of gas prices, since the price of natural gas purchased or sold for future delivery earlier in the day may not be hedged until later in the day. At times, limited net open positions related to our existing and anticipated commitments may occur. At the close of business on December 31, 2005, AEH had a net open position (including existing storage) of 0.1 Bcf.

Treasury Activities

During fiscal 2004, we entered into four Treasury lock agreements to fix the Treasury yield component of the interest cost of financing associated with the anticipated issuance of \$875 million of long-term debt in October 2004. We designated these Treasury lock agreements as cash flow hedges of an anticipated transaction. These Treasury lock agreements were settled in October 2004 with a net \$43.8 million payment to the counterparties. This payment was recorded in accumulated other comprehensive loss and is being recognized as a component of interest expense over a period of five to ten years. During the three-month period ended December 31, 2005, we recognized approximately \$1.4 million of this amount as a component of interest expense.

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

4. Debt

Long-term debt

Long-term debt at December 31, 2005 and September 30, 2005 consisted of the following:

	December 31, 2005	September 30, 2005
(In thousands)		
Unsecured floating rate Senior Notes, due 2007	\$ 300,000	\$ 300,000
Unsecured 4.00% Senior Notes, due 2009	400,000	400,000
Unsecured 7.375% Senior Notes, due 2011	350,000	350,000
Unsecured 10% Notes, due 2011	2,303	2,303
Unsecured 5.125% Senior Notes, due 2013	250,000	250,000
Unsecured 4.95% Senior Notes, due 2014	500,000	500,000
Unsecured 5.95% Senior Notes, due 2034	200,000	200,000
Medium term notes		
Series A, 1995-2, 6.27%, due 2010	10,000	10,000
Series A, 1995-1, 6.67%, due 2025	10,000	10,000
Unsecured 6.75% Debentures, due 2028	150,000	150,000
First Mortgage Bonds		
Series P, 10.43% due 2013	8,750	10,000
Other term notes due in installments through 2013	7,394	7,839
Total long-term debt	2,188,447	2,190,142
Less:		
Original issue discount on unsecured senior notes and debentures	(3,664)	(3,774)
Current maturities	(3,286)	(3,264)
	\$2,181,497	\$2,183,104

Our unsecured floating rate debt bears interest at a rate equal to the three-month LIBOR rate plus 0.375 percent per year. At December 31, 2005, the interest rate on our floating rate debt was 4.525 percent.

Short-term debt

At December 31, 2005 and September 30, 2005, there was \$474.1 million and \$144.8 million outstanding under our commercial paper program and bank credit facilities.

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 bank. 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.

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Committed credit facilities

As of December 31, 2005, we had three short-term committed revolving credit facilities totaling \$918 million. The first facility is a three-year unsecured facility, expiring October 2008, for \$600 million that bears interest at a base rate or at the LIBOR rate plus from 0.40 percent to 1.00 percent, based on the Company's credit ratings, and serves as a backup liquidity facility for our \$600 million commercial paper program. At December 31, 2005, there was \$381.7 million outstanding under our commercial paper program.

We have a second unsecured facility in place which is a 364-day facility expiring November 2006, for \$300 million that bears interest at a base rate or the LIBOR rate plus from 0.40 percent to 1.00 percent, based on the Company's credit ratings. At December 31, 2005, there were no borrowings under this facility.

We have a third unsecured facility in place for \$18 million that bears interest at the Federal Funds rate plus 0.5 percent. This facility expires on March 31, 2006. There was \$17.4 million outstanding under this facility at December 31, 2005.

The availability of funds under our credit facilities is subject to conditions specified in the respective credit agreements, all of which we currently meet. 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 three-year credit facility and \$300 million 364-day credit facility to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At December 31, 2005, our total-debt-to-total-capitalization ratio, as defined, was 61 percent. In addition, the fees that we pay on unused amounts under both the \$600 million and \$300 million credit facilities are subject to adjustment depending upon our credit ratings.

Uncommitted credit facilities

On November 28, 2005, AEM amended its \$250 million uncommitted demand working capital credit facility to increase the amount of credit available from \$250 million to a maximum of \$580 million. The credit facility will expire on March 31, 2006.

Borrowings under the credit facility can be made either as revolving loans or offshore rate loans. Revolving loan borrowings will bear interest at a floating rate equal to a base rate (defined as the higher of 0.50% per annum above the Federal Funds rate or the lender's prime rate) plus 0.50%. 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 1.375% to 1.75% 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 1.125% to 2.00% per annum, depending on the excess tangible net worth of AEM and whether the letters of credit are swap-related standby letters of credit.

AEM is required by the financial covenants in the credit facility to maintain a maximum ratio of total liabilities to tangible net worth of 5 to 1, along with minimum levels of net working capital ranging from \$20 million to \$120 million. Additionally, AEM must maintain a minimum tangible net worth ranging from \$21 million to \$121 million, and must not have a maximum cumulative loss from March 30, 2005 exceeding \$4 million to \$23 million, depending on the total amount of borrowing elected from time to time by AEM. At December 31, 2005, AEM's ratio of total liabilities to tangible net worth, as defined, was 2.68 to 1.

At December 31, 2005, \$75 million was outstanding under this credit facility. In addition, at December 31, 2005, AEM letters of credit totaling \$276.9 million had been issued under the facility, which reduced the amount available by a corresponding amount. The amount available under this credit facility is also limited by various covenants, including covenants based on working capital. Under the most restrictive covenant, the

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

amount available to AEM under this credit facility was \$48.1 million at December 31, 2005. 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 for \$25 million that is used for working-capital and letter-of-credit purposes. There were no borrowings under this uncommitted credit facility at December 31, 2005, but letters of credit reduced the amount available by \$4.4 million. This uncommitted line is renewed or renegotiated at least annually with varying terms, and we pay no fee for the availability of the line. Borrowings under this line are made on a when-and-as-available basis at the discretion of the bank.

AEH, the parent company of AEM, has a \$100 million intercompany uncommitted demand credit facility with the Company which bears interest at LIBOR plus 2.75%. This facility has been approved by our state regulators through December 31, 2006. At December 31, 2005, \$96.4 million was outstanding under this facility.

In addition, AEM has a \$120 million intercompany uncommitted demand credit facility with AEH for its nonutility business which bears interest at the LIBOR rate plus 2.75 percent. Any outstanding amounts under this facility are subordinated to AEM's \$580 million uncommitted demand credit facility described above. This facility is used to supplement AEM's \$580 million credit facility. At December 31, 2005, there was \$94 million outstanding under this facility.

Debt Covenants

We have other covenants in addition to those described above. Our Series P First Mortgage Bonds contain provisions that allow us to prepay the outstanding balance in whole at any time, after November 2007, subject to a prepayment premium. The First Mortgage Bonds provide for certain cash flow requirements and restrictions on additional indebtedness, sale of assets and payment of dividends. Under the most restrictive of such covenants, cumulative cash dividends paid after December 31, 1985 may not exceed the sum of accumulated net income for periods after December 31, 1985 plus \$9 million. At December 31, 2005 approximately \$203.5 million of retained earnings was unrestricted with respect to the payment of dividends.

We were in compliance with all of our debt covenants as of December 31, 2005. If we do not comply with our debt covenants, we may be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions. Our two public debt indentures relating to our senior notes and debentures, as well as our \$600 million and \$300 million revolving credit agreements, each contain a default provision that is triggered if outstanding indebtedness arising out of any other credit agreements in amounts ranging from in excess of \$15 million to in excess of \$100 million becomes due by acceleration or is not paid at maturity. In addition, AEM's credit agreement contains a cross-default provision whereby AEM would be in default if it defaults on other indebtedness, as defined, by at least \$250 thousand in the aggregate. Additionally, this agreement contains a provision that would limit the amount of credit available if Atmos were downgraded below an S&P rating of BBB and a Moody's rating of Baa2.

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

5. Stock-Based Compensation

Stock-Based Compensation Plans

On August 12, 1998, the Board of Directors approved and adopted the 1998 Long-Term Incentive Plan, which became effective October 1, 1998 after approval by our shareholders. The Long-Term Incentive Plan is a comprehensive, long-term incentive compensation plan providing for discretionary awards of incentive stock options, non-qualified stock options, stock appreciation rights, bonus stock, time-lapse restricted stock,

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

performance-based restricted stock units and stock units to certain employees and non-employee directors of Atmos and its subsidiaries. The objectives of this plan include attracting and retaining the best personnel, providing for additional performance incentives and promoting our success by providing employees with the opportunity to acquire common stock. We are authorized to grant awards for up to a maximum of four million shares of common stock under this plan subject to certain adjustment provisions. As of December 31, 2005, non-qualified stock options, bonus stock, time-lapse restricted stock, performance-based restricted stock units and stock units have been issued under this plan and 1,090,754 shares were available for issuance. The option price of the stock options issued under this plan is equal to the market price of our stock at the date of grant. These stock options expire 10 years from the date of the grant and vest annually over a service period ranging from one to three years.

We used the Black-Scholes pricing model to estimate the fair value of each option granted with the following weighted average assumptions:

<u>Valuation Assumptions⁽¹⁾</u>	<u>Three Months Ended December 31</u>	
	<u>2005</u>	<u>2004</u>
Expected Life (years) ⁽²⁾	7	7
Interest rate ⁽³⁾	4.6%	4.2%
Volatility ⁽⁴⁾	20.3%	21.3%
Dividend yield	4.8%	4.8%

⁽¹⁾ Beginning on the date of adoption of SFAS 123(R), forfeitures are estimated based on historical experience. Prior to the date of adoption, forfeitures were recorded as they occurred.

⁽²⁾ The expected life of stock options is estimated based on historical experience.

⁽³⁾ The interest rate is based on the U.S. Treasury constant maturity interest rate whose term is consistent with the expected life of the stock options.

⁽⁴⁾ The volatility is estimated based on historical and current stock data for the Company.

A summary of option activity as of December 31, 2005, and changes during the three months then ended, is presented below:

	<u>Number of Options</u>	<u>Weighted-Average Exercise Price</u>	<u>Weighted-Average Remaining Contractual Term</u> (In years)	<u>Aggregate Intrinsic Value</u> (In thousands)
Outstanding at September 30, 2005	964,704	\$22.20		
Granted	93,196	26.19		
Exercised	(1,334)	22.32		
Forfeited	<u>(166)</u>	<u>21.23</u>		
Outstanding at December 31, 2005	<u>1,056,400</u>	<u>\$22.55</u>	<u>6.1</u>	<u>\$3,843</u>
Exercisable at December 31, 2005	<u>855,044</u>	<u>\$22.22</u>	<u>5.5</u>	<u>\$3,131</u>

The stock options had a weighted-average fair value per share on the date of grant of \$3.74 and \$3.69 for the three months ended December 31, 2005 and 2004. Net cash proceeds from the exercise of stock options during the three months ended December 31, 2005 and 2004 were less than \$0.1 million and \$1.1 million. The associated income tax benefit from stock options exercised during the three months ended December 31, 2005 and 2004 was less than \$0.1 million for both periods. The total intrinsic value of options exercised during the three months ended December 31, 2005 and 2004 was \$4,696 and \$176,354.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

As of December 31, 2005, there was \$0.4 million of total unrecognized compensation cost related to nonvested stock options. That cost is expected to be recognized over a weighted-average period of 0.41 years.

Restricted Stock Plans

As noted above, the 1998 Long-Term Incentive Plan provides for discretionary awards of time-lapse restricted stock and performance-based restricted stock units to help attract, retain and reward employees and non-employee directors of Atmos and its subsidiaries. Certain of these awards vest based upon the passage of time and other awards vest based upon the passage of time and the achievement of specified performance targets. The associated expense is recognized ratably over the vesting period.

A summary of the status of the Company's nonvested restricted shares as of December 31, 2005, and changes during the three months then ended, is presented below:

	<u>Number of Restricted Shares</u>	<u>Weighted-Average Grant-Date Fair Value</u>
Nonvested at September 30, 2005	592,490	\$25.32
Granted	83,941	26.19
Vested	(20,290)	21.59
Forfeited	<u>(1,428)</u>	<u>25.55</u>
Nonvested at December 31, 2005	<u>654,713</u>	<u>\$25.55</u>

As of December 31, 2005, there was \$10.2 million of total unrecognized compensation cost related to nonvested restricted shares granted under the 1998 Long-Term Incentive Plan. That cost is expected to be recognized over a weighted-average period of 1.86 years. The total fair value of restricted stock vested during the three months ended December 31, 2005 and 2004 was \$0.4 million and \$0.5 million.

6. Earnings Per Share

Basic and diluted earnings per share for the three months ended December 31, 2005 and 2004 are calculated as follows:

	<u>Three Months Ended December 31</u>	
	<u>2005</u>	<u>2004</u>
	<u>(In thousands, except per share amounts)</u>	
Net income	<u>\$71,027</u>	<u>\$59,599</u>
Denominator for basic income per share — weighted average common shares	80,259	75,306
Effect of dilutive securities:		
Restricted and other shares	365	275
Stock options	<u>98</u>	<u>144</u>
Denominator for diluted income per share — weighted average common shares	<u>80,722</u>	<u>75,725</u>
Income per share — basic	<u>\$ 0.88</u>	<u>\$ 0.79</u>
Income per share — diluted	<u>\$ 0.88</u>	<u>\$ 0.79</u>

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

There were no out-of-the-money options excluded from the computation of diluted earnings per share for the three months ended December 31, 2005 and 2004 as their exercise price was less than the average market price of the common stock during that period.

7. Interim Pension and Other Postretirement Benefit Plan Information

The components of our net periodic pension cost for our pension and other postretirement benefit plans for the three months ended December 31, 2005 and 2004 are presented in the following table. All of these costs are recoverable through our gas utility rates; however, a portion of these costs is capitalized into our utility rate base. The remaining costs are recorded as a component of operation and maintenance expense.

	Three Months Ended December 31			
	Pension Benefits		Other Benefits	
	2005	2004	2005	2004
	(In thousands)			
Components of net periodic pension cost:				
Service cost	\$4,117	\$3,136	\$3,271	\$2,478
Interest cost	5,722	6,017	2,210	2,366
Expected return on assets	(6,400)	(6,885)	(547)	(518)
Amortization of transition asset	—	1	378	378
Amortization of prior service cost	16	(2)	90	96
Amortization of actuarial loss	<u>3,299</u>	<u>1,891</u>	<u>320</u>	<u>151</u>
Net periodic pension cost	<u>\$6,754</u>	<u>\$4,158</u>	<u>\$5,722</u>	<u>\$4,951</u>

The assumptions used to develop our net periodic pension cost for the three months ended December 31, 2005 and 2004 are as follows:

	Pension Benefits		Other Benefits	
	2005	2004	2005	2004
Discount rate	5.00%	6.25%	5.00%	6.25%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Expected return on plan assets	8.50%	8.75%	5.30%	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. During the three months ended December 31, 2005, we did not make a voluntary contribution to our pension plans. However, we contributed \$2.5 million to our other postretirement plans and we expect to contribute approximately \$11.9 million to these plans during fiscal 2006.

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, 2005, there were no material changes in the status of such litigation and environmental-related matters or claims during the three months ended December 31, 2005. We continue to believe that the final outcome of such litigation and environmental-related matters or claims will not have a material adverse effect on our financial condition, results of operations or net cash flows.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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 net cash flows.

Purchase Commitments

AEM has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At December 31, 2005, AEM was committed to purchase 45.3 Bcf within one year, 23.5 Bcf within one to three years and 17.6 Bcf after three years under indexed contracts. AEM is committed to purchase 1.3 Bcf within one year and 0.3 Bcf within one to three years under fixed price contracts with prices ranging from \$6.00 to \$15.08. Purchases under these contracts totaled \$787.7 million and \$360.1 million for the three months ended December 31, 2005 and 2004.

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 commitments under these contracts as of December 31, 2005 are as follows (in thousands):

2006	\$ 561,927
2007	511,915
2008	139,845
2009	11,806
2010	11,061
Thereafter	<u>36,940</u>
	<u>\$1,273,494</u>

Regulatory Matters

In February 2005, the Attorney General of the State of Kentucky filed a complaint at the Kentucky Public Service Commission (KPSC) alleging that our present rates are producing revenues in excess of reasonable levels. We answered the complaint and filed a Motion to Dismiss with the KPSC. On February 2, 2006, the KPSC issued an Order denying our Motion to Dismiss and establishing an informal conference to be held on February 14, 2006 for the purpose of developing a procedural schedule and simplification of issues. We do not believe that the Attorney General will be able to demonstrate that our present rates are in excess of reasonable levels.

In August 2005, we received a “show cause” order from the City of Dallas, which requires us to provide information that demonstrates good cause for showing that our existing distribution rates charged to customers in the City of Dallas should not be reduced. We filed our response to this order in November 2005 and we are responding to requests for information by the City of Dallas. In addition, during the first quarter of fiscal 2006, approximately 80 other cities in the Mid-Tex Division passed resolutions requesting that we “show cause” why existing distribution rates are just and reasonable and required a filing by us on a system-wide basis. We made the required filing on December 30, 2005. We are responding to requests for information by the cities’

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

consultant. We believe that we will be able to demonstrate in all these “show cause” proceedings that our rates are just and reasonable.

In November 2005, we received a notice from the Tennessee Regulatory Authority that it was opening an investigation into allegations that we are overcharging customers in parts of Tennessee by approximately \$10 million per year. We believe that we are not overcharging our customers and we intend to participate fully in the investigation.

In January 2006, the Lubbock, Texas City Council passed a resolution requiring Atmos to submit copies of all documentation necessary for the city to review the rates of Atmos' West Texas Division to ensure they are just and reasonable. We will provide information to the city on or before February 28, 2006. We believe that we will be able to demonstrate to the City of Lubbock that our rates are just and reasonable.

Other

On November 30, 2005, we entered into an agreement with a third party to jointly construct, own and operate a 45-mile large diameter natural gas pipeline in the northern portion of the Dallas/Fort Worth Metroplex (North Side Loop). Under terms of the agreement, we are responsible for contributing no more than \$42.5 million to the construction costs of the pipeline. We are also responsible for 50% of the costs of the compression facilities. Approximately 21 miles of the pipeline was placed in service by December 31, 2005 with the remainder of the pipeline expected to be placed in service by March 31, 2006. As of December 31, 2005, we have spent \$19.2 million for the North Side Loop project and expect to spend approximately \$29.7 million in the remainder of fiscal 2006 for this project.

During the third quarter of fiscal 2005, we entered into two agreements with third parties to transport natural gas through our Texas intrastate pipeline system beginning in fiscal 2006. To handle the increased volumes for these projects, we will install compression equipment and other pipeline infrastructure. We expect to spend approximately \$32 million in fiscal 2006 for these projects.

On August 29, 2005, Hurricane Katrina struck the Gulf Coast, inflicting significant damage to our eastern Louisiana operations. The hardest hit areas in our service territory were in Jefferson, St. Tammany, St. Bernard and Plaquemines parishes. In total, approximately 230,000 of our natural gas customers were affected in these areas. A significant number of these customers will not require gas service for some time because of sustained damages. We cannot predict with certainty how many of these customers will return to these service areas and over what time period. Additionally, we cannot accurately determine what regulatory actions, if any, may be taken by the regulators with respect to these areas. As of December 31, 2005, we believe adequate provision has been made for any losses that may not be fully recovered through insurance or for which we do not receive rate relief.

9. Concentration of Credit Risk

Credit risk is the risk of financial loss to us if a customer fails to perform its contractual obligations. We engage in transactions for the purchase and sale of products and services with major companies in the energy industry and with industrial, commercial, residential and municipal energy consumers. These transactions principally occur in the southern and midwestern regions of the United States. We believe that this geographic concentration does not contribute significantly to our overall exposure to credit risk. Credit risk associated with trade accounts receivable for the utility segment is mitigated by the large number of individual customers and diversity in our customer base.

Customer diversification also helps mitigate AEM's credit exposure. AEM maintains credit policies with respect to its counterparties that it believes minimizes overall credit risk. Where appropriate, such policies include the evaluation of a prospective counterparty's financial condition, collateral requirements and the use of standardized agreements that facilitate the netting of cash flows associated with a single counterparty.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

AEM also monitors the financial condition of existing counterparties on an ongoing basis. Customers not meeting minimum standards are required to provide adequate assurance of financial performance.

AEM maintains a provision for credit losses based upon factors surrounding the credit risk of customers, historical trends and other information. We believe, based on our credit policies and our provisions for credit losses, that our financial position, results of operations and cash flows will not be materially affected as a result of nonperformance by any single counterparty.

AEM's estimated credit exposure is monitored in terms of the percentage of its customers that are rated as investment grade versus non-investment grade. Credit exposure is defined as the total of (1) accounts receivable, (2) delivered, but unbilled physical sales and (3) mark-to-market exposure for sales and purchases. Investment grade determinations are set internally by AEM's credit department, but are primarily based on external ratings provided by Moody's Investor Service Inc. and/or Standard & Poor's. For non-rated entities, the default rating for municipalities is investment grade, while the default rating for non-guaranteed industrial and commercial customers is non-investment grade. The table below shows the percentages related to the investment ratings as of December 31, 2005 and September 30, 2005.

	December 31, 2005	September 30, 2005
Investment grade	48%	49%
Non-investment grade	<u>52%</u>	<u>51%</u>
Total	<u>100%</u>	<u>100%</u>

The following table presents our derivative counterparty credit exposure by operating segment based upon the unrealized fair value of our derivative contracts that represent assets as of December 31, 2005. Investment grade counterparties have minimum credit ratings of BBB-, assigned by Standard & Poor's; or Baa3, assigned by Moody's Investor Service. Non-investment grade counterparties are composed of counterparties that are below investment grade or that have not been assigned an internal investment grade rating due to the short-term nature of the contracts associated with that counterparty. This category is composed of numerous smaller counterparties, none of which is individually significant.

	December 31, 2005		
	Utility Segment⁽¹⁾	Natural Gas Marketing Segment	Consolidated
	(In thousands)		
Investment grade counterparties	\$38,780	\$2,071	\$40,851
Non-investment grade counterparties	<u>—</u>	<u>5,006</u>	<u>5,006</u>
	<u>\$38,780</u>	<u>\$7,077</u>	<u>\$45,857</u>

⁽¹⁾ Counterparty risk for our utility segment is minimized because hedging gains and losses are passed through to our customers.

10. Segment Information

Atmos Energy Corporation and its 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 seven 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,

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we provide natural gas transportation and storage services to certain of our utility operations and to third parties.

Our operations are divided into four segments:

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

Our determination of reportable segments considers the strategic operating units under which we manage sales of various products and services to customers in differing regulatory environments. Although our utility segment operations are geographically dispersed, they are reported as a single segment as each utility division has similar economic characteristics. The accounting policies of the segments are the same as those described in the summary of significant accounting policies found in our annual report on Form 10-K for the fiscal year ended September 30, 2005. We evaluate performance based on net income or loss of the respective operating units.

Summarized income statements for the three-month period ended December 31, 2005 and 2004 by segment are presented in the following tables:

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

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Three Months Ended December 31, 2004					
	<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	\$913,406	\$432,910	\$21,752	\$ 556	\$ —	\$1,368,624
Intersegment revenues	<u>275</u>	<u>60,891</u>	<u>21,938</u>	<u>803</u>	<u>(83,907)</u>	<u>—</u>
	913,681	493,801	43,690	1,359	(83,907)	1,368,624
Purchased gas cost	<u>656,370</u>	<u>466,957</u>	<u>6,221</u>	<u>—</u>	<u>(83,027)</u>	<u>1,046,521</u>
Gross profit	257,311	26,844	37,469	1,359	(880)	322,103
Operating expenses						
Operation and maintenance	96,553	3,446	10,661	1,047	(930)	110,777
Depreciation and amortization	39,051	504	4,413	29	—	43,997
Taxes, other than income	<u>36,620</u>	<u>(91)</u>	<u>2,048</u>	<u>78</u>	<u>—</u>	<u>38,655</u>
Total operating expenses	<u>172,224</u>	<u>3,859</u>	<u>17,122</u>	<u>1,154</u>	<u>(930)</u>	<u>193,429</u>
Operating income	85,087	22,985	20,347	205	50	128,674
Miscellaneous income	972	246	315	593	(1,741)	385
Interest charges	<u>27,259</u>	<u>401</u>	<u>6,171</u>	<u>402</u>	<u>(1,691)</u>	<u>32,542</u>
Income before income taxes	58,800	22,830	14,491	396	—	96,517
Income tax expense	<u>21,777</u>	<u>9,568</u>	<u>5,407</u>	<u>166</u>	<u>—</u>	<u>36,918</u>
Net income	<u>\$ 37,023</u>	<u>\$ 13,262</u>	<u>\$ 9,084</u>	<u>\$ 230</u>	<u>\$ —</u>	<u>\$ 59,599</u>
Capital expenditures	<u>\$ 65,927</u>	<u>\$ 139</u>	<u>\$ 1,135</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 67,201</u>

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Balance sheet information at December 31, 2005 and September 30, 2005 by segment is presented in the following tables:

	December 31, 2005					Consolidated
	Utility	Natural Gas Marketing	Pipeline and Storage	Other Nonutility	Eliminations	
	(In thousands)					
ASSETS						
Property, plant and equipment, net	\$2,966,223	\$ 7,298	\$465,038	\$ 1,375	\$ —	\$3,439,934
Investment in subsidiaries	229,892	(1,997)	—	—	(227,895)	—
Current assets						
Cash and cash equivalents	18,793	30,248	—	410	—	49,451
Cash held on deposit in margin account	—	74,076	—	—	—	74,076
Assets from risk management activities	38,780	18,316	4,649	—	(16,541)	45,204
Other current assets	1,469,586	672,230	42,134	98,155	(274,555)	2,007,550
Intercompany receivables	509,998	—	—	27,156	(537,154)	—
Total current assets	2,037,157	794,870	46,783	125,721	(828,250)	2,176,281
Intangible assets	—	3,361	—	—	—	3,361
Goodwill	566,800	24,282	143,198	—	—	734,280
Noncurrent assets from risk management activities						
Deferred charges and other assets	238,628	1,454	5,327	19,084	—	264,493
	<u>\$6,038,700</u>	<u>\$830,700</u>	<u>\$661,125</u>	<u>\$146,180</u>	<u>\$(1,057,703)</u>	<u>\$6,619,002</u>
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	\$1,637,617	\$127,180	\$ 72,006	\$ 30,706	\$ (229,892)	\$1,637,617
Long-term debt	2,176,140	—	—	5,357	—	2,181,497
Total capitalization	3,813,757	127,180	72,006	36,063	(229,892)	3,819,114
Current liabilities						
Current maturities of long-term debt	1,250	—	—	2,036	—	3,286
Short-term debt	399,059	169,000	—	96,400	(190,400)	474,059
Liabilities from risk management activities	507	59,900	11,902	—	(16,551)	55,758
Other current liabilities	1,105,783	372,803	116,131	4,023	(82,148)	1,516,592
Intercompany payables	—	96,194	440,960	—	(537,154)	—
Total current liabilities	1,506,599	697,897	568,993	102,459	(826,253)	2,049,695
Deferred income taxes	274,552	(6,578)	14,544	1,678	—	284,196
Noncurrent liabilities from risk management activities						
Regulatory cost of removal obligation	268,999	—	—	—	—	268,999
Deferred credits and other liabilities	174,793	228	4,803	5,980	—	185,804
	<u>\$6,038,700</u>	<u>\$830,700</u>	<u>\$661,125</u>	<u>\$146,180</u>	<u>\$(1,057,703)</u>	<u>\$6,619,002</u>

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	September 30, 2005					
	Utility	Natural Gas Marketing	Pipeline and Storage	Other Nonutility	Eliminations	Consolidated
	(In thousands)					
ASSETS						
Property, plant and equipment, net	\$2,926,096	\$ 7,278	\$439,574	\$ 1,419	\$ —	\$3,374,367
Investment in subsidiaries . . .	231,342	(1,896)	—	—	(229,446)	—
Current assets						
Cash and cash equivalents	10,663	28,949	—	504	—	40,116
Cash held on deposit in margin account	4,170	76,786	—	—	—	80,956
Assets from risk management activities . .	93,310	39,528	1,739	—	(26,664)	107,913
Other current assets	666,081	421,777	36,208	63,820	(152,441)	1,035,445
Intercompany receivables	<u>505,728</u>	<u>—</u>	<u>—</u>	<u>20,133</u>	<u>(525,861)</u>	<u>—</u>
Total current assets	1,279,952	567,040	37,947	84,457	(704,966)	1,264,430
Intangible assets	—	3,507	—	—	—	3,507
Goodwill	566,800	24,282	143,198	—	—	734,280
Noncurrent assets from risk management activities . . .	—	2,073	1,338	—	(2,676)	735
Deferred charges and other assets	<u>249,179</u>	<u>1,461</u>	<u>5,737</u>	<u>19,831</u>	<u>—</u>	<u>276,208</u>
	<u>\$5,253,369</u>	<u>\$603,745</u>	<u>\$627,794</u>	<u>\$105,707</u>	<u>\$(937,088)</u>	<u>\$5,653,527</u>
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	\$1,602,422	\$144,827	\$ 53,426	\$ 33,089	\$(231,342)	\$1,602,422
Long-term debt	<u>2,177,279</u>	<u>—</u>	<u>—</u>	<u>5,825</u>	<u>—</u>	<u>2,183,104</u>
Total capitalization	3,779,701	144,827	53,426	38,914	(231,342)	3,785,526
Current liabilities						
Current maturities of long-term debt	1,250	—	—	2,014	—	3,264
Short-term debt	144,809	60,000	—	51,320	(111,320)	144,809
Liabilities from risk management activities . .	—	63,936	25,038	—	(27,054)	61,920
Other current liabilities . . .	623,300	217,777	95,557	4,963	(38,835)	902,762
Intercompany payables . . .	<u>—</u>	<u>87,968</u>	<u>437,893</u>	<u>—</u>	<u>(525,861)</u>	<u>—</u>
Total current liabilities	769,359	429,681	558,488	58,297	(703,070)	1,112,755
Deferred income taxes	268,108	12,369	9,563	2,167	—	292,207
Noncurrent liabilities from risk management activities	—	16,654	1,338	—	(2,676)	15,316
Regulatory cost of removal obligation	263,424	—	—	—	—	263,424
Deferred credits and other liabilities	<u>172,777</u>	<u>214</u>	<u>4,979</u>	<u>6,329</u>	<u>—</u>	<u>184,299</u>
	<u>\$5,253,369</u>	<u>\$603,745</u>	<u>\$627,794</u>	<u>\$105,707</u>	<u>\$(937,088)</u>	<u>\$5,653,527</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 December 31, 2005, and the related condensed consolidated statements of income and cash flows for the three-month periods ended December 31, 2005 and 2004. 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 interim 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, 2005, 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 16, 2005, 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, 2005, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

ERNST & YOUNG LLP

Dallas, Texas
February 3, 2006

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, 2005.

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 the Company 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 the Company's documents or oral presentations, the words "anticipate", "believe", "expect", "estimate", "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 the Company's strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties include the following: adverse weather conditions, such as warmer than normal weather in the Company's gas utility service territories or colder than normal weather that could adversely affect our natural gas marketing activities; regulatory trends and decisions, including deregulation initiatives and the impact of rate proceedings before various state regulatory commissions; market risks beyond our control affecting our risk management activities including market liquidity, commodity price volatility and counterparty creditworthiness; national, regional and local economic conditions; the Company's 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; risks relating to the acquisition of the TXU Gas operations, including without limitation, the Company's increased indebtedness resulting from the acquisition of the TXU Gas operations; the impact of recent natural disasters on our operations, especially Hurricane Katrina; and other uncertainties, which may be discussed herein, all of which are difficult to predict and many of which are beyond the control of the Company. A more detailed discussion of these risks and uncertainties may be found in the Company's Form 10-K for the year ended September 30, 2005. Accordingly, while the Company believes 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, the Company undertakes no obligation to update or revise any of its forward-looking statements whether as a result of new information, future events or otherwise.

Overview

Atmos Energy Corporation and its 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 seven 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, transportation, storage and marketing services to industrial customers, municipalities and other local distribution companies located in 22 states. Additionally, we provide natural gas transportation and storage services to certain of our utility operations and to third parties.

Our operations are divided into four segments:

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

The following summarizes the results of our operations for the three months ended December 31, 2005:

- Our utility segment net income increased by \$11.4 million during the three months ended December 31, 2005. The increase reflects the impact of weather, as adjusted for jurisdictions with weather-normalized rates, that was seven percent colder than the prior-year quarter coupled with lower O&M expenses.
- Our natural gas marketing segment net income decreased \$1.8 million during the three months ended December 31, 2005 compared with the three months ended December 31, 2004. The decrease in natural gas marketing net income primarily reflects increased unrealized losses which offset increases resulting from improved storage optimization efforts. Also contributing to the decrease in natural gas marketing net income was an increase in interest charges resulting from higher third party borrowings to fund working capital needs.
- Our pipeline and storage segment net income increased \$2.1 million during the three months ended December 31, 2005 compared with the three months ended December 31, 2004, primarily reflecting increased throughput and higher transportation and other related services margins in our Atmos Pipeline — Texas Division.
- Our total-debt-to-capitalization ratio at December 31, 2005 was 61.9 percent compared with 59.3 percent at September 30, 2005 reflecting the impact of increased short-term debt borrowings to fund working capital needs.
- For the three months ended December 31, 2005, we realized a \$195.4 million cash outflow from operating activities compared with a \$67.9 million cash inflow from operations for the three months ended December 31, 2004, reflecting the adverse impact of high natural gas costs on our working capital.
- Capital expenditures increased to \$102.5 million in the current quarter from \$67.2 million in the prior-year quarter primarily reflecting increased capital spending for various pipeline expansion projects in our Atmos Pipeline — Texas Division.

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, 2005 and include the following:

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

Our critical accounting policies are reviewed by the Audit Committee on a quarterly basis. There have been no significant changes to these critical accounting policies during the three months ended December 31, 2005.

Results of Operations

The following table presents our financial highlights for the three-month periods ended December 31, 2005 and 2004:

	Three Months Ended December 31	
	2005	2004
	(In thousands, unless otherwise noted)	
Operating revenues	\$2,283,820	\$1,368,624
Gross profit	346,590	322,103
Operating expenses	196,893	193,429
Operating income	149,697	128,674
Miscellaneous income	448	385
Interest charges	36,189	32,542
Income before income taxes	113,956	96,517
Income tax expense	42,929	36,918
Net income	\$ 71,027	\$ 59,599
Utility sales volumes — MMcf	95,188	90,957
Utility transportation volumes — MMcf	30,602	27,978
Total utility throughput — MMcf	<u>125,790</u>	<u>118,935</u>
Natural gas marketing sales volumes — MMcf	<u>71,496</u>	<u>60,296</u>
Pipeline transportation volumes — MMcf	<u>89,613</u>	<u>72,753</u>
Heating degree days ⁽¹⁾		
Actual (weighted average)	1,056	988
Percent of normal	93%	88%
Consolidated utility average transportation revenue per Mcf	\$ 0.51	\$ 0.58
Consolidated utility average cost of gas per Mcf sold	\$ 11.82	\$ 7.22

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

The following table shows our operating income by segment for the three-month periods ended December 31, 2005 and 2004. The presentation of our utility operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Three Months Ended December 31			
	2005		2004	
	Operating Income	Heating Degree Days Percent of Normal⁽¹⁾	Operating Income	Heating Degree Days Percent of Normal⁽¹⁾
	(In thousands, except degree day information)			
Colorado-Kansas	\$ 8,610	99%	\$ 8,235	99%
Kentucky	6,192	100%	5,845	94%
Louisiana	7,891	95%	6,333	85%
Mid-States	14,298	99%	11,138	91%
Mid-Tex	50,787	83%	38,548	78%
Mississippi	9,993	103%	8,607	89%
West Texas	6,131	100%	5,786	100%
Other	<u>2,347</u>	—	<u>595</u>	—
Utility segment	106,249	93%	85,087	88%
Natural gas marketing segment	21,254	—	22,985	—
Pipeline and storage segment	22,052	—	20,347	—
Other nonutility segment and other	<u>142</u>	—	<u>255</u>	—
Consolidated operating income	<u>\$149,697</u>	93%	<u>\$128,674</u>	88%

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

Three Months Ended December 31, 2005 compared with Three Months Ended December 31, 2004

Utility segment

Our utility segment has historically contributed 65 to 85 percent of our consolidated net income. The primary factors that impact the results of our utility operations are seasonal weather patterns, competitive factors in the energy industry and economic conditions in our service areas. Natural gas sales to residential, commercial and public authority customers are affected by winter heating season requirements. 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. Accordingly, our second fiscal quarter has historically been our most critical earnings quarter with an average of approximately 67 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. Utility sales to industrial customers are much less weather sensitive. Utility sales to agricultural customers, which typically use natural gas to power irrigation pumps during the period from March through September, are primarily affected by rainfall amounts and the price of natural gas.

Changes in the cost of gas impact revenue but do not directly affect our gross profit from utility operations because the fluctuations in gas prices are passed through to our customers. Accordingly, we believe gross profit margin is a better indicator of our financial performance than revenues. However, 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.

The effects of weather that is above or below normal are partially offset through weather normalization adjustments, or WNA, in certain of our service areas. WNA allows us to increase the base rate portion of

customers' bills when weather is warmer than normal and decrease the base rate when weather is colder than normal. As of December 31, 2005, we had WNA in the following service areas for the following periods, which covered approximately 1.0 million customer meters:

Georgia	October – May
Kansas	October – May
Kentucky	November – April
Mississippi	November – April
Tennessee	November – April
Amarillo, Texas	October – May
West Texas	October – May
Lubbock, Texas	October – May
Virginia	January – December

Our Mid-Tex Division does not have WNA. However, its operations benefit from a rate structure that combines a monthly customer charge with a declining block rate schedule to partially mitigate the impact of warmer-than-normal weather on revenue. The combination of the monthly customer charge and the customer billing under the first block of the declining block rate schedule provides for the recovery of most of our fixed costs for such operations under most weather conditions. However, this rate structure is not as beneficial during periods where weather is significantly warmer than normal.

Operating income

Utility gross profit margin increased to \$280.2 million for the three months ended December 31, 2005 from \$257.3 million for the three months ended December 31, 2004. Total throughput for our utility business was 125.8 billion cubic feet (Bcf) during the current-year period compared to 118.9 Bcf in the prior-year period.

The increase in utility gross profit margin and throughput primarily reflects weather, as adjusted for jurisdictions with weather-normalized rates, that was seven percent colder than the prior-year quarter. Additionally, our Mississippi Division benefited from an increase in its WNA coverage during the three months ended December 31, 2005 and colder than normal weather prior to the beginning of its WNA period. Offsetting these increases was a \$2.1 million reduction in gross profit in our Louisiana Division due to the impact of Hurricane Katrina. Additionally, gross profit increases were partially offset by weather that was seven percent warmer than normal primarily as a result of 17 percent warmer than normal weather in our Mid-Tex Division, which does not have weather-normalized rates.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes other than income taxes, increased to \$173.9 million for the three months ended December 31, 2005 from \$172.2 million for the three months ended December 31, 2004. The increase reflects a \$6.3 million increase in taxes, primarily related to franchise fees and state gross receipts taxes, both of which are calculated as a percentage of revenue, which are paid by our customers as a component of their monthly bills. Although these amounts are included as a component of revenue in accordance with our tariffs, timing differences between when these amounts are billed to our customers and when we recognize the associated expense may affect net income favorably or unfavorably on a temporary basis. However, there is no permanent effect on net income.

Offsetting these increases was a \$3.8 million decrease in operation and maintenance expense attributable to a reduction in third-party costs for outsourced administrative and meter reading functions that were incurred during the first quarter of fiscal 2006. Additionally, the decrease in operation and maintenance expense reflects the absence of \$2.1 million of UCG merger and integration cost amortization as these costs were fully amortized by December 2004. These decreases were partially offset by a \$2 million charge for Hurricane Katrina related losses, increased employee headcount and higher benefit costs associated with the

increase in headcount and increased pension and postretirement costs resulting from changes in the assumptions used to determine our fiscal 2006 costs.

Additionally, during the first quarter of fiscal 2006, the Mississippi Public Service Commission, in connection with the modification of our rate design described below under Recent Ratemaking Activity, decided to allow \$2.8 million of deferred costs, which it had originally disallowed in its September 2004 decision. This ruling decreased our depreciation expense during the three months ended December 31, 2005.

As a result of the aforementioned factors, our utility segment operating income for the three months ended December 31, 2005 increased to \$106.2 million from \$85.1 million for the three months ended December 31, 2004.

Interest charges

Interest charges allocated to the utility segment for the three months ended December 31, 2005 increased to \$31.6 million from \$27.3 million for the three months ended December 31, 2004. The increase was attributable to higher average outstanding short-term debt balances to fund natural gas purchases at significantly higher prices coupled with a 200 basis point increase in the interest rate on our \$300 million unsecured floating rate Senior Notes due 2007 due to an increase in the three-month LIBOR rate. These increases were partially offset by \$1.2 million of interest savings arising from the early payoff of \$72.5 million of our First Mortgage Bonds in June 2005.

Natural gas marketing segment

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

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

Operating income

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

Our natural gas marketing segment's gross profit margin for the three months ended December 31, 2005 and 2004 is summarized as follows:

	Three Months Ended December 31	
	2005	2004
	(In thousands, except physical position)	
Storage Activities		
Realized margin	\$ 26,272	\$ 4,776
Unrealized margin	<u>(23,792)</u>	<u>12,519</u>
Total Storage Activities	2,480	17,295
Marketing Activities		
Realized margin	29,567	11,414
Unrealized margin	<u>(5,728)</u>	<u>(1,865)</u>
Total Marketing Activities	<u>23,839</u>	<u>9,549</u>
Gross profit	<u>\$ 26,319</u>	<u>\$26,844</u>
Net physical position (Bcf)	<u>12.8</u>	<u>6.4</u>

Our natural gas marketing segment's gross profit margin was \$26.3 million for the three months ended December 31, 2005 compared to gross profit of \$26.8 million for the three months ended December 31, 2004. Gross profit margin from our natural gas marketing segment for the three months ended December 31, 2005 included an unrealized loss of \$29.5 million compared with an unrealized gain of \$10.7 million in the prior-year period. Natural gas marketing sales volumes were 87.8 Bcf during the three months ended December 31, 2005 compared with 66.1 Bcf for the prior-year period. Excluding intersegment sales volumes, natural gas marketing sales volumes were 71.5 Bcf during the current-year period compared with 60.3 Bcf in the prior-year period. The increase in consolidated natural gas marketing sales volumes primarily was attributable to successfully executed marketing strategies into new market areas.

The contribution to gross profit from our storage activities was a gain of \$2.5 million for the three months ended December 31, 2005 compared to a gain of \$17.3 million for the three months ended December 31, 2004. This \$14.8 million decrease in gross profit from storage activities was comprised of a \$21.5 million increase in realized storage contribution primarily due to our ability to capture more favorable arbitrage spreads that arose from increased market volatility offset by a \$36.3 million decrease in the unrealized storage contribution primarily due to an unfavorable movement during the three months ended December 31, 2005 between the current spot market prices used to mark to fair value the physical inventory designated as a hedged item in a fair value hedge and the forward natural gas prices used to value the offsetting financial hedges. This effect was magnified by a 6.4 Bcf increase in our net physical position at December 31, 2005 compared to the prior-year quarter. We have elected to exclude this forward/spot differential from our hedge effectiveness assessment. Subsequent to the hurricanes, which occurred in the fall of 2005, the forward/spot differential has been volatile and may continue to cause material volatility in our unrealized margin. However, the economic gross profit we have captured in the original transactions will remain essentially unchanged. We may further increase the amount of our storage capacity during the remainder of fiscal 2006; therefore, the impact of price volatility on our unrealized storage contribution could increase in future periods.

Our marketing activities contributed \$23.8 million to our gross profit for the three months ended December 31, 2005 compared to \$9.5 million for the three months ended December 31, 2004. The increase in the marketing contribution primarily was attributable to successfully capturing increased margins in certain market areas that experienced higher market volatility.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes other than income taxes, increased to \$5.1 million for the three months ended December 31, 2005 from \$3.9 million for the three months ended December 31, 2004.

The increase in operating expense was attributable primarily to an increase in labor costs due to increased headcount and an increase in regulatory compliance costs.

The decrease in gross profit margin, combined with higher operating expenses, resulted in a decrease in our natural gas marketing segment operating income to \$21.3 million for the three months ended December 31, 2005 compared with operating income of \$23 million for the three months ended December 31, 2004.

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. The Atmos Pipeline — Texas Division transports natural gas to our Mid-Tex Division, transports natural gas for third parties and manages five underground storage reservoirs in Texas. We also provide ancillary services customary in the pipeline industry including parking arrangements, blending 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. Nine basins located in Texas are believed to contain a substantial portion of the nation's remaining onshore natural gas reserves. This pipeline system provides access to all of these basins.

Atmos Pipeline and Storage, LLC, owns or has an interest in underground storage fields in Kentucky and Louisiana. We also use these storage facilities to reduce the need to contract for additional pipeline capacity to meet customer demand during peak periods.

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

As a regulated pipeline, the operations of the Atmos Pipeline — Texas Division may be impacted by the timing of when costs and expenses are incurred and when these costs and expenses are recovered through its tariffs.

Operating income

Pipeline and storage gross profit increased to \$39.7 million for the three months ended December 31, 2005 from \$37.5 million for the three months ended December 31, 2004. Total pipeline transportation volumes were 147 Bcf during the three months ended December 31, 2005 compared with 130 Bcf for the prior-year quarter. Excluding intersegment transportation volumes, total pipeline transportation volumes were 89.6 Bcf during the current year quarter compared with 72.8 Bcf in the prior-year quarter. The increase in pipeline and storage gross profit margin primarily reflects increased throughput on our Atmos Pipeline — Texas system coupled with higher transportation and related services margins.

Operating expenses increased to \$17.7 million for the three months ended December 31, 2005 from \$17.1 million for the three months ended December 31, 2004 due to higher employee benefit costs associated with the increase in headcount and increased pension and postretirement costs resulting from changes in the assumptions used to determine our fiscal 2006 costs.

As a result of the aforementioned factors, our pipeline and storage segment operating income for the three months ended December 31, 2005 increased to \$22.1 million from \$20.3 million for the three months ended December 31, 2004.

Other nonutility segment

Our other nonutility businesses consist primarily of the operations of Atmos Energy Services, LLC (AES), and Atmos Power Systems, Inc. Through AES, we provide natural gas management services to our utility operations, other than the Mid-Tex Division. These services include aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering the gas to our utility service areas at competitive prices in exchange for revenues that are equal to the costs incurred to provide those services. Through Atmos Power Systems, Inc., we construct gas-fired electric peaking power-generating plants and associated facilities and may enter into agreements to either lease or sell these plants.

Operating income for this segment primarily reflects the leasing income associated with two sales-type lease transactions completed in 2001 and 2002 and was essentially unchanged for the three months ended December 31, 2005 compared with the prior-year quarter.

Liquidity and Capital Resources

Our working capital and liquidity for capital expenditures and other cash needs are provided from internally generated funds, borrowings under our credit facilities and commercial paper program and funds raised from the public debt and equity capital markets. We believe that these sources of funds will provide the necessary working capital and liquidity for capital expenditures and other cash needs for the remainder of fiscal 2006.

Capitalization

The following table presents our capitalization as of December 31, 2005 and September 30, 2005:

	<u>December 31, 2005</u>		<u>September 30, 2005</u>	
	<i>(In thousands, except percentages)</i>			
Short-term debt	\$ 474,059	11.0%	\$ 144,809	3.7%
Long-term debt	2,184,783	50.9%	2,186,368	55.6%
Shareholders' equity	<u>1,637,617</u>	<u>38.1%</u>	<u>1,602,422</u>	<u>40.7%</u>
Total capitalization, including short-term debt	<u>\$4,296,459</u>	<u>100.0%</u>	<u>\$3,933,599</u>	<u>100.0%</u>

Total debt as a percentage of total capitalization, including short-term debt, was 61.9 percent at December 31, 2005, and 59.3 percent at September 30, 2005. The increase in the debt to capitalization ratio was primarily attributable to seasonal increases in our short-term debt borrowings to fund our natural gas purchases. 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. Within two to four years, we intend to reduce our capitalization ratio to a target range of 50 to 55 percent through cash flow generated from operations, continued issuance of new common stock under our Direct Stock Purchase Plan and Retirement Savings Plan, access to the equity capital markets and reduced annual maintenance and capital expenditures.

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, the prices for our products and services, the 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

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

For the three months ended December 31, 2005, we realized a \$195.4 million cash outflow from operating activities compared with a \$67.9 million cash inflow from operations for the three months ended December 31, 2004. Overall, our operating cash flow was adversely impacted by significantly higher natural gas prices, which have increased the levels of accounts receivable, natural gas inventories, accounts payable and undercollected deferred gas costs recorded on our balance sheet as of December 31, 2005. Specifically, working capital management efforts, which affected the timing of payments for accounts payable and other accrued liabilities, favorably affected operating cash flow by \$284.2 million. However, these efforts were offset by cash outflow of \$427.1 million arising from accounts receivable changes, an outflow of \$84.9 million arising from a 42 percent increase in our weighted average cost of gas held in inventory coupled with a 4.2 Bcf increase in natural gas stored underground and a \$55.1 million cash outflow related to deferred gas costs arising from timing differences between when we purchase our natural gas and the period in which we can include this cost in our gas rates. Finally, other working capital and other changes improved operating cash flow by \$19.6 million. The changes primarily related to increased net income and deferred tax expense partially offset by various other working capital changes.

Cash flows from investing activities

During the last three years, a substantial portion of our cash resources was used to fund acquisitions, our ongoing construction program and improvements to information systems. Our ongoing construction program enables us to provide natural gas distribution services to our existing customer base, to expand our natural gas distribution services into new markets, to enhance the integrity of our pipelines and, more recently, to expand our intrastate pipeline network. In executing our current rate strategy, we are directing discretionary capital spending to jurisdictions that permit us to recover our investment in a timely manner. 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 2006 are expected to range from \$400 million to \$415 million. For the three months ended December 31, 2005, we incurred \$102.5 million for capital expenditures compared with \$67.2 million for the three months ended December 31, 2004. The increase in capital expenditures primarily reflects increased spending associated with our Dallas/Fort Worth Metroplex North Side Loop project and other pipeline expansion projects in our Atmos Pipeline — Texas Division and various capital projects in our Mid-Tex Division.

Cash flows from financing activities

For the three months ended December 31, 2005, our financing activities provided \$308.3 million in cash compared with \$1.7 billion provided in the prior-year period. Our significant financing activities for the three months ended December 31, 2005 and 2004 are summarized as follows. The adoption of SFAS 123(R) did not materially affect our cash flows from financing activities.

- In October 2004, we sold 16.1 million common shares, including the underwriters' exercise of their overallotment option of 2.1 million shares, under a new shelf registration statement declared effective in September 2004, generating net proceeds of \$382 million. Additionally, we issued \$1.39 billion of senior unsecured debt under our shelf registration statement. The net proceeds from these issuances, combined with the net proceeds from our July 2004 offering were used to finance the acquisition of our Mid-Tex and Atmos Pipeline — Texas divisions and settle Treasury lock agreements we entered into to fix the Treasury yield component of the interest cost of financing associated with \$875 million of the \$1.39 billion long-term debt we issued in October 2004 to fund the acquisition.
- During the three months ended December 31, 2005 we increased our borrowings under our credit facilities by \$329.3 million compared with \$28.8 million in the prior-year quarter. The increase reflects seasonal borrowings to fund natural gas purchases, including \$75 million by our natural gas marketing segment.

- We repaid \$1.7 million of long-term debt during the three months ended December 31, 2005 compared with \$3.4 million during the three months ended December 31, 2004. The decreased payments during the current quarter reflected the timing of our various debt obligations.
- During the three months ended December 31, 2005 we paid \$25.4 million in cash dividends compared with dividend payments of \$24.5 million for the three months ended December 31, 2004. The increase in dividends paid over the prior-year period reflects the increase in our dividend rate from \$0.31 per share during the three months ended December 31, 2004 to \$0.315 per share during the three months ended December 31, 2005.
- During the three months ended December 31, 2005 we issued 0.3 million shares of common stock which generated net proceeds of \$6.2 million. The following table summarizes the issuances for the three months ended December 31, 2005 and 2004.

	Three Months Ended December 31	
	2005	2004
Shares issued:		
Retirement Savings Plan	105,875	115,399
Direct Stock Purchase Plan	103,202	114,839
Outside Directors Stock-for-Fee Plan.....	667	571
Long-Term Incentive Plan	103,753	127,237
Public Offering	—	<u>16,100,000</u>
Total shares issued	<u>313,497</u>	<u>16,458,046</u>

Shelf Registration

In August 2004, we filed a registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to \$2.2 billion in new common stock and/or debt, which became effective on September 15, 2004. In October 2004, we sold 16.1 million common shares and issued \$1.4 billion in unsecured senior notes to partially finance the acquisition of our Mid-Tex and Atmos Pipeline — Texas divisions. After these issuances, we have approximately \$401.5 million of availability remaining under the registration statement.

Credit Facilities

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

In October 2005, our \$600 million 364-day committed credit facility expired and was replaced with a new \$600 million three-year revolving credit facility that became effective October 18, 2005. In addition, on November 10, 2005, we entered into a new \$300 million 364-day revolving credit facility with substantially the same terms as our \$600 million credit facility.

On November 28, 2005, AEM amended its uncommitted demand working capital credit facility to increase the amount of credit available from \$250 million to a maximum of \$580 million. At December 31, 2005 AEM had \$75 million outstanding under this facility.

As of December 31, 2005, the amount available to us under our credit facilities, net of outstanding letters of credit, was \$587.2 million. We believe these credit facilities, combined with our operating cash flows will be

sufficient to fund our increased working capital needs. These facilities are described in further detail in Note 4 to the condensed consolidated financial statements.

Credit Ratings

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

Our debt is rated by three rating agencies: Standard & Poor’s Corporation (S&P), Moody’s Investors Service (Moody’s) and Fitch Ratings, Inc. (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>
Long-term debt	BBB	Baa3	BBB+
Commercial paper	A-2	P-3	F-2

Currently, with respect to our long-term debt, S&P and Moody’s maintain their stable outlook. Additionally, during the second quarter of fiscal 2006, Fitch upgraded their outlook from negative to stable. None of our ratings are currently under review.

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

Debt Covenants

We are required by the financial covenants in 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 December 31, 2005, our total-debt-to-total-capitalization ratio, as defined in such facility, was 61 percent.

AEM is required by the financial covenants in its uncommitted demand working capital facility to maintain a maximum ratio of total liabilities to tangible net worth of 5 to 1, along with minimum levels of net working capital ranging from \$20 million to \$120 million. Additionally, AEM must maintain a minimum tangible net worth ranging from \$21 million to \$121 million, and its maximum cumulative loss from March 30, 2005 cannot exceed \$4 million to \$23 million, depending on the total amount of borrowing elected from time to time by AEM. At December 31, 2005, AEM’s ratio of total liabilities to tangible net worth, as defined in such facility, was 2.68 to 1.

Our Series P 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 our accumulated net income for periods after December 31, 1985, plus \$9 million. At December 31, 2005, approximately \$203.5 million of retained earnings was unrestricted with respect to the payment of dividends.

We were in compliance with all of our debt covenants as of December 31, 2005. If we do not comply with our debt covenants, we may be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions. Our two public debt indentures relating to our senior notes and

debentures, as well as our 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.

Contractual Obligations and Commercial Commitments

Significant commercial commitments are described in Note 8. There were no significant changes in our contractual obligations and commercial commitments during the three months ended December 31, 2005.

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 protect us and our customers against 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 table shows the components of the change in the fair value of our utility and natural gas marketing commodity derivative contracts for the three months ended December 31, 2005 and 2004:

	Three Months Ended December 31, 2005		Three Months Ended December 31, 2004	
	Utility	Natural Gas Marketing	Utility	Natural Gas Marketing
	(In thousands)			
Fair value of contracts at beginning of period	\$ 93,310	\$(61,898)	\$ (8,612)	\$ 13,018
Contracts realized/settled	29,955	(27,669)	(39,121)	(11,627)
Fair value of new contracts	(2,101)	—	(2,681)	—
Other changes in value	<u>(82,891)</u>	<u>30,199</u>	<u>41,002</u>	<u>3,823</u>
Fair value of contracts at end of period	<u>\$ 38,273</u>	<u>\$(59,368)</u>	<u>\$ (9,412)</u>	<u>\$ 5,214</u>

The fair value of our utility and natural gas marketing derivative contracts at December 31, 2005, is segregated below by time period and fair value source:

<u>Source of Fair Value</u>	<u>Fair Value of Contracts at December 31, 2005</u>				<u>Total Fair Value</u>
	<u>Maturity in Years</u>				
	<u>Less than 1</u>	<u>1-3</u>	<u>4-5</u>	<u>Greater Than 5</u>	
	(In thousands)				
Prices actively quoted	\$ (14,784)	\$ (10,449)	\$ —	\$ —	\$ (25,233)
Prices provided by other external sources	4,323	388	—	—	4,711
Prices based on models and other valuation methods	(93)	(480)	—	—	(573)
Total Fair Value	<u>\$ (10,554)</u>	<u>\$ (10,541)</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ (21,095)</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. AEM is able to capture gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time.

Natural gas inventory is marked to market at the end of each month with changes in fair value recognized as unrealized gains and losses in the period of change. Effective October 1, 2005, the Company changed its mark to market measurement from Inside FERC to Gas Daily to better reflect the prices of our physical commodity. Derivatives associated with our natural gas inventory, which are designated as fair value hedges, are marked to market each month based upon the NYMEX price with changes in fair value recognized as unrealized gains and losses in the period of change. The changes in the difference between the indices used to mark to market our physical inventory (Gas Daily) and the related fair-value hedge (NYMEX) is reported as a component of revenue and can result in volatility in our reported net income. Over time, gains and losses on the sale of storage gas inventory will be offset by gains and losses on the fair-value hedges; therefore, the economic gross profit AEM captured in the original transaction remains essentially unchanged.

AEM continually manages its positions to enhance the future economic profit it captured in the original transaction. Therefore, AEM may change its scheduled injection and withdrawal plans from one time period to another based on market conditions or adjust the amount of storage capacity it holds on a discretionary basis in an effort to achieve this objective. AEM monitors the impacts of these profit optimization efforts by estimating the forecasted gross profit margin that it captured through the purchase and sale of physical natural gas and the associated financial derivatives. The forecasted gross profit margin, less the effect of unrealized gains or losses recognized in the financial statements, provides a measure of the net increase or decrease in the gross profit margin that could occur in future periods if AEM's optimization efforts are fully successful.

As of December 31, 2005, based upon AEM's derivatives position and inventory withdrawal schedule, the forecasted gross profit margin was approximately \$7.1 million. Approximately \$38.6 million of net unrealized losses were recorded in the financial statements as of December 31, 2005. Therefore, the projected increase in future gross profit margin is approximately \$45.7 million.

The forecasted gross profit margin calculation is based upon planned injection and withdrawal schedules, and the realization of the forecasted gross profit margin 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 assure that the forecasted gross profit margin or the projected increase in future gross profit margin calculated as of December 31, 2005 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, permanent impacts on earnings may result.

Pension and Postretirement Benefits Obligations

For the three months ended December 31, 2005 and 2004 our total net periodic pension and other benefits cost was \$12.5 million and \$9.1 million. All of these costs are recoverable through our gas utility rates; however, a portion of these costs is capitalized into our utility rate base. The remaining costs are recorded as a component of operation and maintenance expense.

The increase 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, 2005. 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, 2005 measurement date, these interest rates were declining, which resulted in a 125 basis point reduction in our discount rate to 5.0 percent. This reduction has the effect of increasing the present value of our plan liabilities and associated expenses. Additionally, we reduced the expected return on our pension plan assets by 25 basis points to 8.5 percent, which also has the effect of increasing our pension and postretirement benefit cost.

During the three months ended December 31, 2005, we did not make a voluntary contribution to our pension plans. However, we contributed \$2.5 million to our other postretirement plans and we expect to contribute a total of \$11.9 million to these plans during fiscal 2006.

Operating Statistics and Other Information

The following tables present certain operating statistics for our utility, natural gas marketing, pipeline and storage and other nonutility segments for the three-month periods ended December 31, 2005 and 2004.

Utility Sales and Statistical Data

	Three Months Ended December 31	
	2005	2004
METERS IN SERVICE, end of period		
Residential	2,910,467	2,886,511
Commercial	279,263	277,531
Industrial	3,074	2,298
Agricultural	9,470	8,299
Public authority and other	8,202	10,088
Total meters	<u>3,210,476</u>	<u>3,184,727</u>
HEATING DEGREE DAYS⁽¹⁾		
Actual (weighted average)	1,056	988
Percent of normal	93%	88%
UTILITY SALES VOLUMES — MMcf⁽²⁾		
Gas sales volumes		
Residential	53,709	50,769
Commercial	29,139	27,863
Industrial	9,009	8,243
Agricultural	40	66
Public authority and other	3,291	4,016
Total gas sales volumes	95,188	90,957
Utility transportation volumes	31,756	29,741
Total utility throughput	<u>126,944</u>	<u>120,698</u>
UTILITY OPERATING REVENUES (000's)⁽²⁾		
Gas sales revenues		
Residential	\$ 783,346	\$ 523,143
Commercial	424,338	264,992
Industrial	128,471	66,500
Agricultural	786	675
Public authority and other	43,971	32,430
Total utility gas sales revenues	1,380,912	887,740
Transportation revenues	15,867	16,432
Other gas revenues	8,231	9,509
Total utility operating revenues	<u>\$1,405,010</u>	<u>\$ 913,681</u>
Utility average transportation revenue per Mcf	\$ 0.50	\$ 0.55
Utility average cost of gas per Mcf sold	\$ 11.82	\$ 7.22

See footnotes following these tables.

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

	Three Months Ended December 31	
	2005	2004
CUSTOMERS, end of period		
Industrial	657	625
Municipal	71	77
Other	395	389
Total	<u>1,123</u>	<u>1,091</u>
NATURAL GAS MARKETING SALES VOLUMES — MMcf⁽²⁾	87,822	66,138
PIPELINE TRANSPORTATION VOLUMES — MMcf⁽²⁾	146,954	129,994
OPERATING REVENUES (000's)⁽²⁾		
Natural gas marketing	\$1,101,845	\$493,801
Pipeline and storage	39,712	43,690
Other nonutility	1,492	1,359
Total operating revenues	<u>\$1,143,049</u>	<u>\$538,850</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. Degree day information for the three-month periods ended December 31, 2005 and 2004 is adjusted for the Kentucky Division, the Mississippi Division and certain service areas included within the Colorado-Kansas Division, the Mid-States Division and the West Texas Division, which have weather-normalized operations.
- (2) Sales volumes and revenues reflect segment operations, including intercompany sales and transportation amounts.

Recent Ratemaking Activity

Our ratemaking activities during fiscal 2006 are described in the following discussion. 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 September 2005, Atmos Pipeline — Texas made a filing under Texas' Gas Reliability Infrastructure Program (GRIP) to include in rate base approximately \$10.6 million of pipeline capital expenditures incurred during calendar year 2004 which should result in additional revenues of approximately \$1.9 million. The Railroad Commission of Texas (RRC) approved this filing in December 2005 and these new charges will be included in the monthly customer charge beginning in January 2006.

Atmos Energy Kentucky Division. In February 2005, the Attorney General of the State of Kentucky filed a complaint at the Kentucky Public Service Commission (KPSC) alleging that our present rates are producing revenues in excess of reasonable levels. We answered the complaint and filed a Motion to Dismiss with the KPSC. On February 2, 2006, the KPSC issued an Order denying our Motion to Dismiss and establishing an informal conference to be held on February 14, 2006 for the purpose of developing a procedural schedule and simplification of issues. We do not believe that the Attorney General will be able to demonstrate that our present rates are in excess of reasonable levels.

Atmos Energy Louisiana Division. During the second quarter of fiscal 2005, the Louisiana Division implemented a rate increase in its LGS service area. This increase resulted from our Rate Stabilization Clause filing in 2004 and is subject to refund, pending the final resolution of that filing. As the rate increase is subject to refund, we have not recognized the effects of this increase in our results of operations during the first quarter of fiscal 2006. As of December 31, 2005, the total amount of the deferred rate increase subject to final approval is approximately \$5 million.

Atmos Energy Mid-States Division. During the third quarter of fiscal 2005, the Mid-States Division filed a rate case in its Georgia service area seeking a rate increase of \$4 million. In December 2005, the Georgia Public Service Commission (GPSC) approved a \$0.4 million increase. In January 2006, we filed a Petition for Review of the GPSC's decision in the Superior Court of Fulton County. The parties are awaiting a procedural schedule from the court.

Atmos Energy Mid-Tex Division. In September 2005, the Mid-Tex Division made a GRIP filing to include in rate base approximately \$29.4 million of distribution capital expenditures incurred during calendar year 2004, which should result in additional revenues of approximately \$6.7 million. The RRC approved this filing in January 2006 and these new charges will be included in the monthly customer charge beginning in February 2006.

On September 1, 2005, the Mid-Tex Division filed its annual gas cost reconciliation with the RRC. The filing reflects approximately \$14 million in refunds of amounts that were overcollected from customers between July 1, 2004 and June 30, 2005. The Mid-Tex Division has received approval from the RRC to accelerate the refunds to December through March rather than during the usual refund period of October through June to help offset higher gas costs for residential, commercial and industrial customers during the 2005 - 2006 heating season.

In August 2005, we received a "show cause" order from the City of Dallas, which requires us to provide information that demonstrates good cause for showing that our existing distribution rates charged to customers in the City of Dallas should not be reduced. We filed our response to this order in November 2005 and we are responding to requests for information by the City of Dallas. In addition, during the first quarter of fiscal 2006, approximately 80 other cities in the Mid-Tex Division passed resolutions requesting that we "show cause" why existing distribution rates are just and reasonable and required a filing by us on a system-wide basis. We made the required filing on December 30, 2005. We are responding to requests for information by the cities' consultant. We believe that we will be able to demonstrate in all these "show cause" proceedings that our rates are just and reasonable.

In September 2004, the Mid-Tex Division filed its 36-Month Gas Contract Review with the RRC. This proceeding involves a prudency review of gas purchases totaling \$2.2 billion made by the Mid-Tex Division from November 1, 2000 through October 31, 2003. A hearing on this matter was held before the RRC in late June 2005. We are currently waiting for a decision from the RRC.

Atmos Energy Mississippi Division. Through the first quarter of fiscal 2005, the Mississippi Public Service Commission (MPSC) required that we file for rate adjustments every six months. Rate filings were made in May and November of each year and the rate adjustments typically became effective in the following July and January.

Effective October 1, 2005, our rate design was modified to substitute the original agreed-upon benchmark with a sharing mechanism to allow the sharing of cost savings above an allowed return on equity level. Further, we moved from a semi-annual filing process to an annual filing process. Additionally, our WNA period now begins on November 1 instead of November 15, and will end on April 30 instead of May 15. Also, we now have a fixed monthly customer base charge which makes a portion of our earnings less susceptible to variations in usage. We will make our first annual filing under this new structure in September 2006.

In September 2004, the MPSC originally disallowed certain deferred costs totaling \$2.8 million. In connection with the modification of our rate design described above, the MPSC decided to allow these costs, and we included these costs in our rates in October 2005.

Atmos Energy West Texas Division. In September 2005, the West Texas Division made a GRIP filing to include in rate base approximately \$22.6 million of distribution capital costs incurred during calendar year 2004, which should result in additional annual revenues of approximately \$3.8 million. The filings were approved for all jurisdictions except for the inside city limits customers in the West Texas service area, who rejected the filings. An appeal was subsequently filed with the RRC, which is currently pending. New charges for the approved filings will be included in the monthly customer charge beginning in January 2006. We expect the inside city limit filing in the West Texas service area to be approved by the RRC in March 2006.

In January 2006, the Lubbock, Texas City Council passed a resolution requiring Atmos to submit copies of all documentation necessary for the city to review the rates of Atmos' West Texas Division to ensure they are just and reasonable. We will provide information to the city on or before February 28, 2006. We believe that we will be able to demonstrate to the City of Lubbock that our rates are just and reasonable.

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 condensed consolidated financial statements.

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

We are exposed to risks associated with commodity prices and interest rates. Commodity price risk is the potential loss that we may incur as a result of changes in the fair value of a particular instrument or commodity. Interest-rate risk results from our portfolio of debt and equity instruments that we issue to provide financing and liquidity for our business 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 protect us and our customers against 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. Our risk management activities and related accounting treatment are described in further detail in Note 3 to the condensed consolidated financial statements. Additionally, our earnings are affected by changes in short-term interest rates as a result of our issuance of short-term commercial paper, the issuance of floating rate debt and our other short-term borrowings.

Commodity Price Risk

Utility segment

We purchase natural gas for our utility operations. Substantially all of the cost of gas purchased for utility operations is recovered from our customers through purchased gas adjustment mechanisms. However, our utility operations have commodity price risk exposure to fluctuations in spot natural gas prices related to purchases for sales to our nonregulated energy services customers at fixed prices.

For our utility segment, we use a sensitivity analysis to estimate commodity price risk. For purposes of this analysis, we estimate commodity price risk by applying a hypothetical 10 percent increase in the portion of our gas cost related to fixed-price nonregulated sales. Based on projected nonregulated gas sales for the remainder of fiscal 2006, a hypothetical 10 percent increase in fixed prices, based upon the December 31, 2005 three month market strip, would increase our purchased gas cost by approximately \$4.6 million for the remainder of fiscal 2006.

Natural gas marketing and pipeline and storage segments

Our natural gas marketing segment is also exposed to risks associated with changes in the market price of natural gas. For our natural gas marketing segment, we use a sensitivity analysis to estimate commodity price risk. For purposes of this analysis, we estimate commodity price risk by applying a \$0.50 change in the forward

NYMEX price to our net open position (including existing storage and related financial contracts) at the end of each period. Based on AEH's net open position (including existing storage and related financial contracts) at December 31, 2005 of 0.1 Bcf, a \$0.50 change in the forward NYMEX price would have had less than a \$0.1 million impact on our consolidated net income.

However, changes in the difference between the indices used to mark to market our net physical inventory (Gas Daily) and the related fair-value hedge (NYMEX) can result in volatility in our reported net income; but, over time, gains and losses on the sale of storage gas inventory will be offset by gains and losses on the fair-value hedges. Based upon our net physical position at December 31, 2005 and assuming our hedges would still qualify as highly effective, a \$0.50 change in the difference between the Gas Daily and NYMEX indices could impact our reported net income by approximately \$4.4 million.

Interest Rate Risk

Our earnings are exposed to changes in short-term interest rates associated with our short-term commercial paper program and other short-term borrowings. We use a sensitivity analysis to estimate our short-term interest rate risk. For purposes of this analysis, we estimate our short-term interest rate risk as the difference between our actual interest expense for the period and estimated interest expense for the period assuming a hypothetical average one percent increase in the interest rates associated with our short-term borrowings. Had interest rates associated with our short-term borrowings increased by an average of one percent, our interest expense would have increased by approximately \$3.9 million during the three months ended December 31, 2005.

We also assess market risk for our long-term obligations. We estimate market risk for our long-term obligations as the potential increase in fair value resulting from a hypothetical one percent decrease in interest rates associated with these debt instruments. Fair value is estimated using a discounted cash flow analysis. Assuming this one percent hypothetical decrease, the fair value of our long-term obligations would have increased by approximately \$148.6 million.

As of December 31, 2005 we were not engaged in other activities that would cause exposure to the risk of material earnings or cash flow loss due to changes in interest rates or market commodity prices.

Item 4. *Controls and Procedures*

As indicated in the certifications in Exhibit 31 of this report, the Company's Chief Executive Officer and Chief Financial Officer have evaluated the Company's disclosure controls and procedures as of December 31, 2005. 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 included in this quarterly report is accumulated and communicated to them on a timely basis. In addition, there were no changes during the Company's last fiscal quarter that materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. *Legal Proceedings*

During the three months ended December 31, 2005 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, 2005. We continue to believe that the final outcome of such litigation and environmental-related matters or claims will not have a material adverse effect on our financial condition, results of operations or net cash flows.

Item 6. *Exhibits*

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

EXHIBITS INDEX
Item 6(a)

<u>Exhibit Number</u>	<u>Description</u>	<u>Page Number</u>
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.