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

Form 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2006

or

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

For the transition period from to

Commission File Number 1-10042

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

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

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

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

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

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐

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

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

Class	Shares Outstanding
No Par Value	81,595,723

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
EITF	Emerging Issues Task Force
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
LPSC	Louisiana Public Service Commission
Mcf	Thousand cubic feet
MMcf	Million cubic feet
Moody's	Moody's Investors Services, Inc.
MPSC	Mississippi Public Service Commission
NYMEX	New York Mercantile Exchange, Inc.
RRC	Railroad Commission of Texas
RSC	Rate Stabilization Clause
S&P	Standard & Poor's Corporation
SEC	United States Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
TLGP	Trans Louisiana Gas Pipeline
TRA	Tennessee Regulatory Authority
TXU Gas	TXU Gas Company, which was acquired on October 1, 2004
WNA	Weather Normalization Adjustment

PART I. FINANCIAL INFORMATION

Item 1. *Financial Statements*

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

	June 30, 2006	September 30, 2005
	(Unaudited) (In thousands, except share data)	
ASSETS		
Property, plant and equipment	$4,993,093	$4,765,610
Less accumulated depreciation and amortization	1,414,010	1,391,243
Net property, plant and equipment	3,579,083	3,374,367
Current assets		
Cash and cash equivalents	26,849	40,116
Cash held on deposit in margin account	58,176	80,956
Accounts receivable, net	409,087	454,313
Gas stored underground	437,069	450,807
Other current assets	118,990	238,238
Total current assets	1,050,171	1,264,430
Goodwill and intangible assets	737,349	737,787
Deferred charges and other assets	249,874	276,943
	$5,616,477	$5,653,527
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding:		
June 30, 2006 — 81,538,149 shares; September 30, 2005 — 80,539,401 shares	$ 408	$ 403
Additional paid-in capital	1,456,032	1,426,523
Retained earnings	243,956	178,837
Accumulated other comprehensive loss	(35,840)	(3,341)
Shareholders' equity	1,664,556	1,602,422
Long-term debt	2,180,752	2,183,104
Total capitalization	3,845,308	3,785,526
Current liabilities		
Accounts payable and accrued liabilities	306,805	461,314
Other current liabilities	407,575	503,368
Short-term debt	297,087	144,809
Current maturities of long-term debt	3,331	3,264
Total current liabilities	1,014,798	1,112,755
Deferred income taxes	283,757	292,207
Regulatory cost of removal obligation	275,955	263,424
Deferred credits and other liabilities	196,659	199,615
	$5,616,477	$5,653,527

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended June 30	
	2006	2005
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Utility segment	$ 402,044	$501,735
Natural gas marketing segment	562,447	466,835
Pipeline and storage segment	35,862	33,449
Other nonutility segment	1,413	1,421
Intersegment eliminations	(138,523)	(96,563)
	863,243	906,877
Purchased gas cost		
Utility segment	232,192	326,502
Natural gas marketing segment	563,333	456,440
Pipeline and storage segment	379	(1,733)
Other nonutility segment	—	—
Intersegment eliminations	(137,161)	(95,606)
	658,743	685,603
Gross profit	204,500	221,274
Operating expenses		
Operation and maintenance	104,380	91,443
Depreciation and amortization	46,838	43,448
Taxes, other than income	48,479	46,915
Total operating expenses	199,697	181,806
Operating income	4,803	39,468
Miscellaneous income	963	1,524
Interest charges	35,944	33,689
Income (loss) before income taxes	(30,178)	7,303
Income tax expense (benefit)	(12,033)	2,817
Net income (loss)	$ (18,145)	$ 4,486
Basic net income (loss) per share	$ (0.22)	$ 0.06
Diluted net income (loss) per share	$ (0.22)	$ 0.06
Cash dividends per share	$ 0.315	$ 0.310
Weighted average shares outstanding:		
Basic	80,840	79,683
Diluted	80,840	80,144

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Nine Months Ended June 30	
	2006	2005
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Utility segment	$3,254,674	$2,650,793
Natural gas marketing segment	2,482,921	1,473,527
Pipeline and storage segment	121,057	122,685
Other nonutility segment	4,500	4,058
Intersegment eliminations	(682,243)	(290,477)
	5,180,909	3,960,586
Purchased gas cost		
Utility segment	2,488,906	1,895,181
Natural gas marketing segment	2,413,511	1,425,128
Pipeline and storage segment	590	8,895
Other nonutility segment	—	—
Intersegment eliminations	(678,591)	(287,889)
	4,224,416	3,041,315
Gross profit	956,493	919,271
Operating expenses		
Operation and maintenance	325,295	305,640
Depreciation and amortization	137,174	132,771
Taxes, other than income	158,691	140,537
Total operating expenses	621,160	578,948
Operating income	335,333	340,323
Miscellaneous income (expense)	(1,028)	2,867
Interest charges	107,625	99,304
Income before income taxes	226,680	243,886
Income tax expense	85,002	91,299
Net income	$ 141,678	$ 152,587
Basic net income per share	$ 1.76	$ 1.96
Diluted net income per share	$ 1.75	$ 1.94
Cash dividends per share	$ 0.945	$ 0.930
Weighted average shares outstanding:		
Basic	80,520	78,009
Diluted	81,013	78,478

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended June 30	
	2006	2005
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	$ 141,678	$ 152,587
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization:		
Charged to depreciation and amortization	137,174	132,771
Charged to other accounts	359	634
Deferred income taxes	36,160	17,703
Other	12,063	7,593
Net assets / liabilities from risk management activities	(3,940)	14,276
Net change in operating assets and liabilities	(100,051)	61,846
Net cash provided by operating activities	223,443	387,410
Cash Flows From Investing Activities		
Capital expenditures	(322,691)	(226,851)
Acquisitions	—	(1,916,654)
Other, net	(4,811)	(1,648)
Net cash used in investing activities	(327,502)	(2,145,153)
Cash Flows From Financing Activities		
Net increase in short-term debt	152,278	—
Net proceeds from issuance of long-term debt	—	1,385,847
Repayment of long-term debt	(2,618)	(102,801)
Settlement of Treasury lock agreements	—	(43,770)
Cash dividends paid	(76,559)	(74,048)
Issuance of common stock	17,691	32,206
Net proceeds from equity offering	—	382,014
Net cash provided by financing activities	90,792	1,579,448
Net decrease in cash and cash equivalents	(13,267)	(178,295)
Cash and cash equivalents at beginning of period	40,116	201,932
Cash and cash equivalents at end of period	$ 26,849	$ 23,637

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
June 30, 2006

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 Mid-Tex Division	Texas, including the Dallas/Fort Worth metropolitan area
Atmos Energy Mississippi Division	Mississippi
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, pipeline and storage operations and other nonutility operations. These operations are either organized under or managed by Atmos Energy Holdings, Inc. (AEH), which is wholly-owned by the Company.

Our natural gas marketing operations are managed by Atmos Energy Marketing, LLC (AEM), which is wholly-owned by AEH. AEM provides a variety of natural gas management services to municipalities, natural gas utility systems and industrial natural gas customers, primarily in the southeastern and midwestern states and to our 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 and to third parties, as well as manages five underground storage reservoirs in Texas. Through APS, we own or have an interest in underground storage fields in Kentucky and Louisiana. We also use these storage facilities to reduce the need to contract for additional pipeline capacity to meet customer demand during peak periods.

Our other nonutility businesses consist primarily of the operations of Atmos Energy Services, LLC (AES) and Atmos Power Systems, Inc., which are each wholly-owned by AEH. Through AES, we 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 have constructed electric peaking power-generating plants and associated facilities and have entered into agreements to lease these plants.

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 and nine-month periods ended June 30, 2006 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 nine months ended June 30, 2006.

Additionally, during the second quarter of fiscal 2006, we completed our annual goodwill impairment assessment. Based on the assessment performed, our goodwill was not considered to be impaired.

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, division presidents and other key employees. Non-employee 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 and nine months ended June 30, 2006 included: (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. The impact of adoption on total stock-based compensation expense included in our statement of income for the three and nine months ended June 30, 2006 was less than $0.1 million and $0.4 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 valued at the market price of the Company's common stock on the date of grant. The unearned compensation was amortized as a component of operation and maintenance expense over the vesting period of the restricted stock.

Total stock-based compensation expense for the three and nine months ended June 30, 2006 was $2.1 million and $4.3 million as compared to $0.9 million and $2.4 million for the three and nine months ended June 30, 2005. 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 and nine months ended June 30, 2005 would have been impacted as shown in the following table:

	Three Months Ended June 30, 2005	Nine Months Ended June 30, 2005
	(In thousands, except per share data)	
Net income — as reported	$4,486	$152,587
Restricted stock compensation expense included in income, net of tax	542	1,514
Total stock-based employee compensation expense determined under fair-value-based method for all awards, net of taxes	(676)	(2,114)
Net income — pro forma	$4,352	$151,987
Earnings per share:		
Basic earnings per share — as reported	$ 0.06	$ 1.96
Basic earnings per share — pro forma	$ 0.05	$ 1.95
Diluted earnings per share — as reported	$ 0.06	$ 1.94
Diluted earnings per share — pro forma	$ 0.05	$ 1.94

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 June 30, 2006 and September 30, 2005 included the following:

	June 30, 2006	September 30, 2005
	(In thousands)	
Regulatory assets:		
Merger and integration costs, net	$ 8,895	$ 9,150
Deferred gas cost	24,645	38,173
Environmental costs	1,234	1,357
Rate case costs	8,986	11,314
Deferred franchise fees	1,202	6,710
Other	8,921	9,313
	$ 53,883	$ 76,017
Regulatory liabilities:		
Deferred gas costs	$ 69,542	$134,048
Regulatory cost of removal obligation	290,604	274,989
Deferred income taxes, net	3,185	3,185
Other	6,570	8,084
	$369,901	$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 be included in future rate filings in accordance with rulings received from various state regulatory commissions.

Comprehensive income

The following table presents the components of comprehensive income, net of related tax, for the three and nine-month periods ended June 30, 2006 and 2005:

	Three Months Ended June 30		Nine Months Ended June 30	
	2006	2005	2006	2005
	(In thousands)			
Net income (loss)	$(18,145)	$ 4,486	$141,678	$152,587
Unrealized holding gains (losses) on investments, net of tax expense (benefit) of $(187) and $(7) for the three months ended June 30, 2006 and 2005 and of $355 and $722 for the nine months ended June 30, 2006 and 2005	(304)	(11)	580	1,178
Amortization and unrealized losses on interest rate hedging transactions, net of tax expense (benefit) of $528 and $528 for the three months ended June 30, 2006 and 2005 and $1,583 and $(2,190) for the nine months ended June 30, 2006 and 2005	860	860	2,581	(3,575)
Net unrealized losses on commodity hedging transactions, net of tax benefit of $4,182 and $2,675 for the three months ended June 30, 2006 and 2005 and $21,858 and $2,672 for the nine months ended June 30, 2006 and 2005	(6,821)	(4,366)	(35,660)	(4,361)
Comprehensive income (loss)	$(24,410)	$ 969	$109,179	$145,829

Accumulated other comprehensive loss, net of tax, as of June 30, 2006 and September 30, 2005 consisted of the following unrealized gains (losses):

	June 30, 2006	September 30, 2005
	(In thousands)	
Accumulated other comprehensive loss:		
Unrealized holding gains on investments	$ 1,264	$ 684
Treasury lock agreements	(21,401)	(23,982)
Cash flow hedges	(15,703)	19,957
	$(35,840)	$ (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 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. We will be required to apply the provisions of FIN 47 by September 30, 2006. We are currently evaluating the impact that FIN 47 may have on our financial position, results of operations and cash flows.

In February 2006, the FASB issued SFAS 155, *Accounting for Certain Hybrid Financial Instruments*, which amends SFAS 133, *Accounting for Derivative Instruments and Hedging Activities* and SFAS 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*. SFAS 155 (a) permits fair value remeasurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation, (b) clarifies which interest-only strips and principal-only strips are not subject to the requirements of SFAS 133, (c) establishes a requirement to evaluate interests in securitized financial assets to identify interests that are freestanding derivatives or that are hybrid financial instruments that contain an embedded derivative requiring bifurcation, (d) clarifies that concentrations of credit risk in the form of subordination are not embedded derivatives and (e) amends SFAS 140 to eliminate the prohibition on a qualifying special-purpose entity from holding a derivative financial instrument that pertains to a beneficial interest other than another derivative financial instrument. SFAS 155 is effective for all financial instruments acquired or issued by us after October 1, 2006 but is not expected to have a material impact on our financial position, results of operations and cash flows.

In March 2006, the FASB issued SFAS 156, *Accounting for Servicing Financial Assets*, which amends SFAS 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities.* SFAS 156 (a) revises guidance on when a servicing asset and servicing liability should be recognized, (b) requires all separately recognized servicing assets and servicing liabilities to be initially measured at fair value, if practicable, (c) permits an entity to choose to measure servicing assets and servicing liabilities under the amortization method or fair value measurement method, (d) at initial adoption, permits a one-time reclassification of available-for-sale securities to trading securities by entities with recognized servicing rights, without calling into question the treatment of other available-for-sale securities under SFAS 115, provided that the available-for-sale securities are identified as offsetting the exposure to changes in the fair value of servicing assets or liabilities that the servicer elects to subsequently measure at fair value and (e) requires separate presentation of servicing assets and servicing liabilities subsequently measured at fair value in the statement of financial position and additional footnote disclosure. We will be required to apply the provisions of SFAS 156 beginning October 1, 2006 but such application is not expected to have a material impact on our financial position, results of operations and cash flows.

In March 2006, the FASB issued the exposure draft *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)*. The exposure draft, if adopted in its current form, would make a significant change to the existing rules by requiring recognition in the balance sheet of the overfunded or underfunded positions of defined benefit pension and other postretirement plans, along with a corresponding noncash, after-tax adjustment to stockholders' equity. The proposed standard, if adopted, will be effective for fiscal 2007. We are monitoring the status of the exposure draft and assessing the impact it will have on our financial position, results of operations and cash flows.

In June 2006, the Emerging Issues Task Force (EITF) ratified EITF Issue No. 06-3, *How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation)*. The EITF reached a consensus that the scope of this issue includes any tax assessed by a governmental authority that is directly imposed on a revenue-producing transaction between a seller and a customer and may include sales, use, value added, and some excise taxes. The EITF also reached a consensus that entities may present these taxes on either a gross or net basis. If the taxes are significant, an entity should disclose its policy of presenting taxes and the amounts of taxes that are recognized on a gross basis in interim and annual financial statements. We will be required to apply the provisions of EITF 06-3 beginning January 1, 2007. We are currently evaluating the impact this standard may have on our financial position, results of operations and cash flows.

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

3. Derivative Instruments and Hedging Activities

We conduct risk management activities through both our utility and natural gas marketing segments. We record our derivatives as a component of risk management assets and liabilities, which are classified as current or noncurrent other assets or liabilities based upon the anticipated settlement date of the underlying derivative. Our determination of the fair value of these derivative financial instruments reflects the estimated amounts that we would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains and losses on open contracts. In our determination of fair value, we consider various factors, including closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts. 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. This change did not have a material impact on our financial position on the date of adoption.

The following table shows the fair values of our risk management assets and liabilities by segment at June 30, 2006 and September 30, 2005:

	Utility	Natural Gas Marketing	Total
		(In thousands)	
June 30, 2006:			
Assets from risk management activities, current	$11,930	$ 4,589	$ 16,519
Assets from risk management activities, noncurrent	—	38	38
Liabilities from risk management activities, current	(4,299)	(25,351)	(29,650)
Liabilities from risk management activities, noncurrent	—	(9,073)	(9,073)
Net assets (liabilities)	$ 7,631	$(29,797)	$ (22,166)
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)	$93,310	$(61,898)	$ 31,412

Utility Hedging Activities

We use a combination of storage, fixed physical contracts and fixed financial contracts to partially insulate us and our customers against gas price volatility during the winter heating season. Because the gains or losses of financial derivatives used in our utility segment ultimately will be recovered through our rates, current period changes in the assets and liabilities from these risk management activities are recorded as a component of deferred gas costs in accordance with SFAS 71, *Accounting for the Effects of Certain Types of Regulation*. Accordingly, there is no earnings impact to our utility segment as a result of the use of financial derivatives. 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 and nine-month periods ended June 30, 2006, the change in the deferred hedging position in accumulated other comprehensive loss was attributable to decreases in future commodity prices relative to the commodity prices stipulated in the derivative contracts, and the recognition for the nine months ended June 30, 2006 of $3.4 million in net deferred hedging gains ($4.8 million in net deferred hedging losses during the three months ended June 30, 2006) in net income when the derivative contracts matured according to their terms. The net deferred hedging loss associated with open cash flow hedges remains subject to market price fluctuations until the positions are either settled under the terms of the hedge contracts or terminated prior to settlement. The majority of the deferred hedging balance as of June 30, 2006 is expected to be recognized in net income in fiscal 2006 along with the corresponding hedged purchases and sales of natural gas. The remainder of the deferred hedging balance is expected to be recognized in net income in fiscal 2007 and beyond.

Under our risk management policies, we seek to match our financial derivative positions to our physical storage positions as well as our expected current and future sales and purchase obligations to maintain no open positions at the end of each trading day. The determination of our net open position as of any day, however, requires us to make assumptions as to future circumstances, including the use of gas by our customers in relation to our anticipated storage and market positions. Because the price risk associated with any net open position at the end of each day may increase if the assumptions are not realized, we review these assumptions as part of our daily monitoring activities. We may also be affected by intraday fluctuations of gas prices, since the price of natural gas purchased or sold for future delivery earlier in the day may not be hedged until later in the day. At times, limited net open positions related to our existing and anticipated commitments may occur. At the close of business on June 30, 2006, AEH had no net open positions (including existing storage).

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 then 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 and nine-month periods ended June 30, 2006, we recognized approximately $1.4 million and $4.2 million of this amount as a component of interest expense.

4. Debt

Long-term debt

Long-term debt at June 30, 2006 and September 30, 2005 consisted of the following:

	June 30, 2006	September 30, 2005
	(In thousands)	
Unsecured floating rate Senior Notes, due October 2007	$ 300,000	$ 300,000
Unsecured 4.00% Senior Notes, due 2009	400,000	400,000
Unsecured 7.375% Senior Notes, due 2011	350,000	350,000
Unsecured 10% Notes, due 2011	2,303	2,303
Unsecured 5.125% Senior Notes, due 2013	250,000	250,000
Unsecured 4.95% Senior Notes, due 2014	500,000	500,000
Unsecured 5.95% Senior Notes, due 2034	200,000	200,000
Medium term notes		
Series A, 1995-2, 6.27%, due 2010	10,000	10,000
Series A, 1995-1, 6.67%, due 2025	10,000	10,000
Unsecured 6.75% Debentures, due 2028	150,000	150,000
First Mortgage Bonds Series P, 10.43% due 2013	8,750	10,000
Other term notes due in installments through 2013	6,471	7,839
Total long-term debt	2,187,524	2,190,142
Less:		
Original issue discount on unsecured senior notes and debentures	(3,441)	(3,774)
Current maturities	(3,331)	(3,264)
	$2,180,752	$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 June 30, 2006, the interest rate on our floating rate debt was 5.452 percent.

Short-term debt

At June 30, 2006 and September 30, 2005, there was $297.1 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 banks. Our credit capacity and the amount of unused borrowing capacity are affected by the seasonal nature of the natural gas business and our short-term borrowing requirements, which are typically highest during colder winter months. Our working capital needs can vary significantly due to changes in the price of natural gas and the increased gas supplies required to meet customers' needs during periods of cold weather.

Committed credit facilities

As of June 30, 2006, 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 June 30, 2006, there was $281.9 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 June 30, 2006, there were no borrowings under this facility.

We have a third unsecured facility in place for $18 million that bears interest at the Federal Funds rate plus 0.5 percent. This facility expired on March 31, 2006 and was renewed effective April 1, 2006 for one year with no material changes to its terms and pricing. At June 30, 2006, there was $15.2 million outstanding under this facility.

The availability of funds under our credit facilities is subject to conditions specified in the respective credit agreements, all of which we currently satisfy. These conditions include our compliance with financial covenants and the continued accuracy of representations and warranties contained in these agreements. We are required by the financial covenants in both our $600 million 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 June 30, 2006, our total-debt-to-total-capitalization ratio, as defined, was 62 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. On March 31, 2006, AEM amended and extended this uncommitted demand working capital credit facility to March 31, 2007.

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

AEM is required by the financial covenants in the credit facility to maintain a maximum ratio of total liabilities to tangible net worth of 5 to 1, along with minimum levels of net working capital ranging from $20 million to $120 million. Additionally, AEM must maintain a minimum tangible net worth ranging from $21 million to $121 million, and must not have a maximum cumulative loss from March 30, 2005 exceeding $4 million to $23 million, depending on the total amount of borrowing elected from time to time by AEM. At June 30, 2006, AEM's ratio of total liabilities to tangible net worth, as defined, was 1.00 to 1.

At June 30, 2006, there were no borrowings outstanding under this credit facility. However, at June 30, 2006, AEM letters of credit totaling $70.4 million had been issued under the facility, which reduced the amount available by a corresponding amount. The amount available under this credit facility is also limited by various covenants, including covenants based on working capital. Under the most restrictive covenant, the amount available to AEM under this credit facility was $129.6 million at June 30, 2006. This line of credit is collateralized by substantially all of the assets of AEM and is guaranteed by AEH.

The Company also has an unsecured short-term uncommitted credit line for $25 million that is used for working-capital and letter-of-credit purposes. There were no borrowings under this uncommitted credit facility at June 30, 2006, but letters of credit reduced the amount available by $4.5 million. This uncommitted line is renewed or renegotiated at least annually with varying terms, and we pay no fee for the availability of the line. Borrowings under this line are made on a when-and-as-available basis at the discretion of the bank.

AEH, the parent company of AEM, has a $100 million intercompany uncommitted demand credit facility with the Company which bears interest at LIBOR plus 2.75 percent. This facility has been approved by our state regulators through December 31, 2006. At June 30, 2006, $88.4 million was outstanding under this facility. On July 1, 2006, this facility was renewed for one year with no material changes to its terms.

In addition, AEM has a $120 million intercompany uncommitted demand credit facility with AEH for its nonutility business which bears interest at LIBOR plus 2.75 percent. Any outstanding amounts under this facility are subordinated to AEM's $580 million uncommitted demand credit facility described above. This facility is used to supplement AEM's $580 million credit facility. At June 30, 2006, $82.0 million was outstanding under this facility. On July 1, 2006, this facility was renewed for one year with no material changes to its terms.

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 June 30, 2006 approximately $223.0 million of retained earnings was unrestricted with respect to the payment of dividends.

We were in compliance with all of our debt covenants as of June 30, 2006. If we were unable to comply with our debt covenants, we could be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions. Our two public debt indentures relating to our senior notes and debentures, as well as our $600 million and $300 million revolving credit agreements, each contain a default provision that is triggered if outstanding indebtedness arising out of any other credit agreements in amounts ranging from in excess of $15 million to in excess of $100 million becomes due by acceleration or is not paid at maturity. In addition, AEM's credit agreement contains a cross-default provision whereby AEM would be in default if it defaults on other indebtedness, as defined, by at least $250 thousand in the aggregate. Additionally, this agreement contains a provision that would limit the amount of credit available if Atmos were downgraded below an S&P rating of BBB and a Moody's rating of Baa2.

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

5. 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, 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 June 30, 2006, non-qualified stock options, bonus stock, time-lapse restricted stock, performance-based restricted stock units and stock units had been issued under this plan and 715,699 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:

Valuation Assumptions(1)	Nine Months Ended June 30 2006	Nine Months Ended June 30 2005
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 June 30, 2006, and changes during the nine months then ended, is presented below:

	Number of Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term (In years)	Aggregate Intrinsic Value (In thousands)
Outstanding at September 30, 2005	964,704	$22.20		
Granted	93,196	26.19		
Exercised	(23,186)	22.36		
Forfeited	(166)	21.23		
Outstanding at June 30, 2006	1,034,548	$22.56	5.6	$3,764
Exercisable at June 30, 2006	1,009,174	$22.47	5.5	$3,665

The stock options had a weighted-average fair value per share on the date of grant of $3.74 and $3.69 for the nine months ended June 30, 2006 and 2005. There were no stock options granted during the three months ended June 30, 2006 and 2005. Net cash proceeds from the exercise of stock options during the nine months ended June 30, 2006 and 2005 were $0.5 million and $10.1 million and during the three months ended June 30, 2006 and 2005 were $0.5 and $1.0 million. The associated income tax benefit from stock options exercised during the nine months ended June 30, 2006 and 2005 was less than $0.1 million and $1.1 million, and during the three months ended June 30, 2006 and 2005 was less than $0.1 million and $0.1 million. The total intrinsic value of options exercised during the nine months ended June 30, 2006 and 2005 was less than $0.1 million and $1.7 million, and during the three months ended June 30, 2006 and 2005 was less than $0.1 million and $0.2 million.

As of June 30, 2006, there was less than $0.1 million of total unrecognized compensation cost related to nonvested stock options. That cost is expected to be recognized over a weighted-average period of 1.5 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 June 30, 2006, and changes during the nine months then ended, is presented below:

	Number of Restricted Shares	Weighted-Average Grant-Date Fair Value
Nonvested at September 30, 2005	592,490	$25.32
Granted	440,016	26.80
Vested	(110,347)	22.66
Forfeited	(10,983)	26.79
Nonvested at June 30, 2006	911,176	$26.34

As of June 30, 2006, there was $16.0 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 2.1 years. The total fair value of restricted stock vested during the nine months ended June 30, 2006 and 2005 was $2.5 million and $0.5 million, and during the three months ended June 30, 2006 was $0.9 million. There were no restricted stock grants that vested during the three months ended June 30, 2005.

6. Earnings Per Share

Basic and diluted earnings per share for the three and nine months ended June 30, 2006 and 2005 are calculated as follows:

	For the Three Months Ended June 30		For the Nine Months Ended June 30	
	2006	2005	2006	2005
	(In thousands, except per share amounts)			
Net income (loss)	$(18,145)	$ 4,486	$141,678	$152,587
Denominator for basic income per share — weighted average common shares	80,840	79,683	80,520	78,009
Effect of dilutive securities:				
Restricted and other shares	—	330	394	325
Stock options	—	131	99	144
Denominator for diluted income per share — weighted average common shares	80,840	80,144	81,013	78,478
Income (loss) per share — basic	$ (0.22)	$ 0.06	$ 1.76	$ 1.96
Income (loss) per share — diluted	$ (0.22)	$ 0.06	$ 1.75	$ 1.94

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

There were no out-of-the-money options excluded from the computation of diluted earnings per share for the three and nine months ended June 30, 2006 and 2005 as their exercise price was less than the average market price of the common stock during that period.

7. Interim Pension and Other Postretirement Benefit Plan Information

The components of our net periodic pension cost for our pension and other postretirement benefit plans for the three and nine months ended June 30, 2006 and 2005 are presented in the following tables. All of these costs are recoverable through our gas utility rates; however, a portion of these costs is capitalized into our utility rate base. The remaining costs are recorded as a component of operation and maintenance expense.

	Three Months Ended June 30			
	Pension Benefits		Other Benefits	
	2006	2005	2006	2005
	(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	3,299	1,891	320	151
Net periodic pension cost	$ 6,754	$ 4,158	$5,722	$4,951

	Nine Months Ended June 30			
	Pension Benefits		Other Benefits	
	2006	2005	2006	2005
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 12,351	$ 9,408	$ 9,813	$ 7,434
Interest cost	17,166	18,051	6,630	7,098
Expected return on assets	(19,200)	(20,655)	(1,641)	(1,554)
Amortization of transition asset	—	3	1,134	1,134
Amortization of prior service cost	48	(6)	270	288
Amortization of actuarial loss	9,897	5,673	960	453
Net periodic pension cost	$ 20,262	$ 12,474	$17,166	$14,853

The assumptions used to develop our net periodic pension cost for the three and nine months ended June 30, 2006 and 2005 are as follows:

	Pension Benefits		Other Benefits	
	2006	2005	2006	2005
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 nine months ended June 30, 2006, we contributed $2.8 million to the Atmos Energy Corporation Retirement Plan for Mississippi Valley Gas Union Employees. The current year contribution achieved a desired level of funding by satisfying the minimum funding requirements while maximizing the tax deductible contribution for this plan for plan year 2005. We anticipate making no additional contributions to our pension plans for the remainder of fiscal 2006. However, we contributed $7.9 million to our other postretirement plans, and we expect to contribute approximately $12 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 nine months ended June 30, 2006. We continue to believe that the final outcome of such litigation and environmental-related matters or claims will not have a material adverse effect on our financial condition, results of operations or net cash flows.

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 June 30, 2006, AEM was committed to purchase 64.8 Bcf within one year, 53.7 Bcf within one to three years and 3.1 Bcf after three years under indexed contracts. AEM is committed to purchase 2.7 Bcf within one year and 0.2 Bcf within one to three years under fixed price contracts with prices ranging from $5.45 to $12.00. Purchases under these contracts totaled $398.9 million and $294.0 million for the three months ended June 30, 2006 and 2005 and $1,718.4 million and $999.4 million for the nine months ended June 30, 2006 and 2005.

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

Our Mid-Tex Division maintains long-term supply contracts to ensure a reliable source of gas for our customers in its service area which obligate it to purchase specified volumes at market prices. The estimated fiscal year commitments under these contracts as of June 30, 2006 are as follows (in thousands):

2006	$ 70,864
2007	346,837
2008	115,004
2009	12,795
2010	12,479
Thereafter	39,812
	$597,791

Regulatory Matters

In February 2005, the Attorney General of the State of Kentucky filed a complaint with the Kentucky Public Service Commission (KPSC) alleging that our rates were producing revenues in excess of reasonable levels. We answered the complaint and filed a Motion to Dismiss with the KPSC. On February 2, 2006, the KPSC issued an Order denying our Motion to Dismiss and on March 3, 2006 set a procedural schedule for the case. The Attorney General is currently conducting discovery. A hearing should be scheduled for early 2007. We believe that the Attorney General will not be able to demonstrate that our present rates are in excess of reasonable levels.

In May 2006, the Mid-Tex Division filed a Statement of Intent seeking incremental annual revenues of $60 million and several rate design changes including Weather Normalization Adjustment (WNA), revenue stabilization, and recovery of the gas cost component of bad debt. The Statement of Intent consolidated “show cause” resolutions that had been filed in approximately 80 cities served by the Mid-Tex Division, including the City of Dallas, which requires the Mid-Tex Division to demonstrate that existing distribution rates are just and reasonable.

In July 2006, the Mid-Tex Division and the Railroad Commission of Texas (RRC) agreed to implement WNA on both an interim and permanent basis, effective October 1, 2006. The agreement provided that the interim WNA will use 30 years of weather history, while the permanent WNA would allow the parties to contest the appropriate period of weather data to use in calculating normal weather. The permanent WNA would also be modified or adjusted to conform to the rate design that the RRC ultimately approves in the case, which is anticipated no later than the first quarter of calendar 2007. Any rate increase will be effective prospectively from the date of the final order; however, any rate decrease will be effective from May 31, 2006.

In November 2005, we received a notice from the Tennessee Regulatory Authority (TRA) that it was opening an investigation into allegations by the Consumer Advocate and Protection Division of the Tennessee Attorney General’s Office that we are overcharging customers in parts of Tennessee by approximately $10 million per year. We have responded to numerous data requests from the TRA Staff. On April 24, 2006, the TRA Staff filed a Report and Recommendation in which it recommended that the TRA convene a contested case procedure for the purpose of establishing a fair and reasonable return. The TRA convened to consider the Staff’s recommendation on May 15, 2006 and set a procedural schedule. All parties filed direct testimony on July 17, 2006, with rebuttal due August 18, 2006. A hearing is scheduled for August 29, 2006. We believe that the Consumer Advocate and Protection Division will not be able to demonstrate that our present rates are in excess of reasonable levels.

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

In May 2006, Atmos began receiving “show cause” ordinances from several of the cities in the West Texas Division. The ordinances request a filing to be made no later than September 15, 2006. We believe that we will be able to ultimately demonstrate to the West Texas cities 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 the 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 percent of the costs of the compression facilities. The North Side Loop was fully placed into service in May 2006. As of June 30, 2006, we had spent $46.1 million for the North Side Loop project and expect to spend approximately $5.3 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 installed compression equipment and other pipeline infrastructure. We have spent approximately $30 million in fiscal 2006 for these projects, which were placed in service at the end of the third quarter of fiscal 2006.

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. Although service has been restored for many of our customers, a significant number of 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 they may return. Additionally, we cannot accurately determine what regulatory actions, if any, may be taken by the regulators with respect to these areas. We are implementing new rates, subject to refund, in August 2006 that reflect the reduced customer count and enable us to recoup costs attributable to Hurricane Katrina.

In May 2006, we announced plans to form a joint venture with a local natural gas producer to construct a natural gas gathering system in Eastern Kentucky that will originate in Floyd County, Kentucky, and extend north approximately 65 miles to interconnect with the Tennessee Gas Pipeline in Carter County, Kentucky. Tennessee Gas Pipeline's interstate system delivers natural gas to the northeastern United States, including New York City and Boston. The new system is expected to relieve severe gas gathering and transportation constraints that historically have burdened natural gas producers in the area and should improve delivery reliability to natural gas customers. More than a dozen other producers have signed memoranda of understanding to commit gas volumes to the new system and to enter into agreements on commercially reasonable terms.

The project is expected to cost between $75 million to $80 million. Upon receiving all required regulatory approvals, construction is expected to begin in the first half of fiscal 2007, with operations expected to begin in fiscal 2008. Final terms of the joint venture are still under negotiation; however, we anticipate that we will have the ability to consolidate the joint venture.

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 exposure to credit risk. 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. 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 Investors Service Inc. (Moody's) and/or Standard & Poor's Corporation (S&P). 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 following table shows the percentages related to the investment ratings as of June 30, 2006 and September 30, 2005.

	June 30, 2006	September 30, 2005
Investment grade	41%	49%
Non-investment grade	59%	51%
Total	100%	100%

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 June 30, 2006. Investment grade counterparties have minimum credit ratings of BBB-, assigned by S&P; or Baa3, assigned by Moody's. 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.

	June 30, 2006		
	Utility Segment[(1)]	Natural Gas Marketing Segment	Consolidated
		(In thousands)	
Investment grade counterparties	$11,930	$ 843	$12,773
Non-investment grade counterparties	—	3,784	3,784
	$11,930	$4,627	$16,557

(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, 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.

Income statements for the three and nine-month periods ended June 30, 2006 and 2005 by segment are presented in the following tables:

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

	Three Months Ended June 30, 2005					
	Utility	Natural Gas Marketing	Pipeline and Storage	Other Nonutility	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$501,481	$387,999	$16,854	$ 543	$ —	$906,877
Intersegment revenues	254	78,836	16,595	878	(96,563)	—
	501,735	466,835	33,449	1,421	(96,563)	906,877
Purchased gas cost	326,502	456,440	(1,733)	—	(95,606)	685,603
Gross profit	175,233	10,395	35,182	1,421	(957)	221,274
Operating expenses						
Operation and maintenance	76,862	4,948	9,573	1,067	(1,007)	91,443
Depreciation and amortization	38,775	458	4,189	26	—	43,448
Taxes, other than income	44,555	242	2,064	54	—	46,915
Total operating expenses	160,192	5,648	15,826	1,147	(1,007)	181,806
Operating income	15,041	4,747	19,356	274	50	39,468
Miscellaneous income	3,122	153	613	578	(2,942)	1,524
Interest charges	28,520	957	6,169	935	(2,892)	33,689
Income (loss) before income taxes	(10,357)	3,943	13,800	(83)	—	7,303
Income tax expense (benefit)	(3,689)	1,583	4,958	(35)	—	2,817
Net income (loss)	$ (6,668)	$ 2,360	$ 8,842	$ (48)	$ —	$ 4,486
Capital expenditures	$ 80,336	$ 219	$ 8,830	$ —	$ —	$ 89,385

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

	Nine Months Ended June 30, 2005					
	Utility	Natural Gas Marketing	Pipeline and Storage	Other Nonutility	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$2,649,979	$1,250,507	$ 58,433	$1,667	$ —	$3,960,586
Intersegment revenues	814	223,020	64,252	2,391	(290,477)	—
	2,650,793	1,473,527	122,685	4,058	(290,477)	3,960,586
Purchased gas cost	1,895,181	1,425,128	8,895	—	(287,889)	3,041,315
Gross profit	755,612	48,399	113,790	4,058	(2,588)	919,271
Operating expenses						
Operation and maintenance	259,884	12,410	33,077	3,007	(2,738)	305,640
Depreciation and amortization	119,007	1,436	12,244	84	—	132,771
Taxes, other than income	133,395	412	6,510	220	—	140,537
Total operating expenses	512,286	14,258	51,831	3,311	(2,738)	578,948
Operating income	243,326	34,141	61,959	747	150	340,323
Miscellaneous income	6,068	600	1,220	1,787	(6,808)	2,867
Interest charges	83,841	2,037	18,568	1,516	(6,658)	99,304
Income before income taxes	165,553	32,704	44,611	1,018	—	243,886
Income tax expense	61,547	13,291	16,047	414	—	91,299
Net income	$ 104,006	$ 19,413	$ 28,564	$ 604	$ —	$ 152,587
Capital expenditures	$ 209,392	$ 586	$ 16,873	$ —	$ —	$ 226,851

Balance sheet information at June 30, 2006 and September 30, 2005 by segment is presented in the following tables:

	June 30, 2006					
	Utility	Natural Gas Marketing	Pipeline and Storage	Other Nonutility	Eliminations	Consolidated
	(In thousands)					
ASSETS						
Property, plant and equipment, net	$3,055,306	$ 7,381	$515,076	$ 1,320	$ —	$3,579,083
Investment in subsidiaries	253,289	(2,092)	—	—	(251,197)	—
Current assets						
Cash and cash equivalents	8,865	17,456	—	528	—	26,849
Cash held on deposit in margin account	—	58,176	—	—	—	58,176
Assets from risk management activities	11,930	10,388	2,698	—	(8,497)	16,519
Other current assets	661,342	356,506	37,974	86,003	(193,198)	948,627
Intercompany receivables	555,423	—	—	30,437	(585,860)	—
Total current assets	1,237,560	442,526	40,672	116,968	(787,555)	1,050,171
Intangible assets	—	3,069	—	—	—	3,069
Goodwill	566,800	24,282	143,198	—	—	734,280
Noncurrent assets from risk management activities	—	38	2,405	—	(2,405)	38
Deferred charges and other assets	225,647	1,334	5,232	17,623	—	249,836
	$5,338,602	$476,538	$706,583	$135,911	$(1,041,157)	$5,616,477
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	$1,664,556	$127,682	$ 92,210	$ 33,397	$ (253,289)	$1,664,556
Long-term debt	2,176,362	—	—	4,390	—	2,180,752
Total capitalization	3,840,918	127,682	92,210	37,787	(253,289)	3,845,308
Current liabilities						
Current maturities of long-term debt	1,250	—	—	2,081	—	3,331
Short-term debt	297,087	82,000	—	88,407	(170,407)	297,087
Liabilities from risk management activities	4,299	28,049	5,795	—	(8,493)	29,650
Other current liabilities	460,479	181,275	63,386	293	(20,703)	684,730
Intercompany payables	—	61,236	524,624	—	(585,860)	—
Total current liabilities	763,115	352,560	593,805	90,781	(785,463)	1,014,798
Deferred income taxes	280,987	(15,434)	16,178	2,026	—	283,757
Noncurrent liabilities from risk management activities	—	11,478	—	—	(2,405)	9,073
Regulatory cost of removal obligation	275,955	—	—	—	—	275,955
Deferred credits and other liabilities	177,627	252	4,390	5,317	—	187,586
	$5,338,602	$476,538	$706,583	$135,911	$(1,041,157)	$5,616,477

	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	505,728	—	—	20,133	(525,861)	—
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	249,179	1,461	5,737	19,831	—	276,208
	$5,253,369	$603,745	$627,794	$105,707	$(937,088)	$5,653,527
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	$1,602,422	$144,827	$ 53,426	$ 33,089	$(231,342)	$1,602,422
Long-term debt	2,177,279	—	—	5,825	—	2,183,104
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	—	87,968	437,893	—	(525,861)	—
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	172,777	214	4,979	6,329	—	184,299
	$5,253,369	$603,745	$627,794	$105,707	$(937,088)	$5,653,527

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors
Atmos Energy Corporation

We have reviewed the condensed consolidated balance sheet of Atmos Energy Corporation as of June 30, 2006, and the related condensed consolidated statements of income for the three-month and nine-month periods ended June 30, 2006 and 2005, and the condensed consolidated statements of cash flows for the nine-month periods ended June 30, 2006 and 2005. These financial statements are the responsibility of the Company's management.

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

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

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Atmos Energy Corporation as of September 30, 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
August 7, 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 and other significant events for the nine months ended June 30, 2006:

- Our utility segment net income decreased by $19.9 million during the nine months ended June 30, 2006 compared with the nine months ended June 30, 2005. The decrease reflects the impact of weather, as adjusted for jurisdictions with weather-normalized rates, that was three percent warmer than the prior-year period and 13 percent warmer than normal, coupled with higher operating expenses.
- In May 2006, the Louisiana Public Service Commission (LPSC) approved a settlement that provides for, among other things, a modified Weather Normalization Adjustment (WNA) which provides a partial decoupling mechanism to stabilize margins and renewal of the Rate Stabilization Clause (RSC) with provisions that will reduce regulatory lag. The settlement also allowed the recognition of $6.2 million of margin that had been previously deferred as it was subject to refund.
- In May 2006, the Mid-Tex Division filed a Statement of Intent seeking incremental annual revenues of $60 million and several rate design changes including WNA, revenue stabilization, and recovery of the gas cost component of bad debt. In July 2006, the Railroad Commission of Texas (RRC) approved an interim WNA, effective October 1, 2006.
- Our natural gas marketing segment net income increased $8.8 million during the nine months ended June 30, 2006 compared with the nine months ended June 30, 2005. The increase in natural gas marketing net income primarily reflects our ability to capture higher margins in a volatile natural gas market. These increases were partially offset by a $28.2 million increase in unrealized losses reflected in this segment's gross profit, increased operating expenses and increased interest charges resulting from increased short-term borrowings to fund working capital needs.
- Our pipeline and storage segment net income increased $0.5 million during the nine months ended June 30, 2006 compared with the nine months ended June 30, 2005. Increased gross profit margin resulting from higher transportation and related services margins coupled with increased throughput on our Atmos Pipeline-Texas system and Atmos Pipeline & Storage, LLC's ability to capture more favorable arbitrage spreads in its asset management contracts were essentially offset by higher operating expenses.
- Our total-debt-to-capitalization ratio at June 30, 2006 was 59.9 percent compared with 59.3 percent at September 30, 2005 reflecting the impact of increased short-term debt borrowings to fund working capital needs partially offset by current-year net income.
- For the nine months ended June 30, 2006, we generated $223.4 million in operating cash flow compared with $387.4 million for the nine months ended June 30, 2005, reflecting the adverse impact of high natural gas costs on our working capital.
- Capital expenditures increased to $322.7 million in the nine months ended June 30, 2006 from $226.9 million in the prior-year period, primarily reflecting increased capital spending for various pipeline expansion projects in our Atmos Pipeline — Texas Division, all of which were completed during the third quarter of fiscal 2006.

CRITICAL ACCOUNTING ESTIMATES AND POLICIES

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

Our critical accounting policies used in the preparation of our consolidated financial statements are described in our Annual Report on Form 10-K for the year ended September 30, 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 nine months ended June 30, 2006.

RESULTS OF OPERATIONS

The following table presents our financial highlights for the three-month and nine-month periods ended June 30, 2006 and 2005:

	Three Months Ended June 30		Nine Months Ended June 30	
	2006	2005	2006	2005
	(In thousands, unless otherwise noted)			
Operating revenues	$863,243	$906,877	$5,180,909	$3,960,586
Gross profit	204,500	221,274	956,493	919,271
Operating expenses	199,697	181,806	621,160	578,948
Operating income	4,803	39,468	335,333	340,323
Miscellaneous income (expense)	963	1,524	(1,028)	2,867
Interest charges	35,944	33,689	107,625	99,304
Income (loss) before income taxes	(30,178)	7,303	226,680	243,886
Income tax expense (benefit)	(12,033)	2,817	85,002	91,299
Net income (loss)	$ (18,145)	$ 4,486	$ 141,678	$ 152,587
Utility sales volumes — MMcf	32,653	43,925	239,562	263,077
Utility transportation volumes — MMcf	29,630	28,753	91,384	88,635
Total utility throughput — MMcf	62,283	72,678	330,946	351,712
Natural gas marketing sales volumes — MMcf	66,472	52,739	207,418	179,679
Pipeline transportation volumes — MMcf	104,680	97,567	277,721	254,528
Heating degree days(1)				
Actual (weighted average)	119	167	2,507	2,580
Percent of normal	69%	97%	87%	89%
Consolidated utility average transportation revenue per Mcf	$ 0.46	$ 0.48	$ 0.53	$ 0.53
Consolidated utility average cost of gas per Mcf sold	$ 7.11	$ 7.43	$ 10.39	$ 7.20

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

The following table shows our operating income by segment for the three-month and nine-month periods ended June 30, 2006 and 2005. The presentation of our utility operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Three Months Ended June 30			
	2006		2005	
	Operating Income	Heating Degree Days Percent of Normal[1]	Operating Income	Heating Degree Days Percent of Normal[1]
	(In thousands, except degree day information)			
Colorado-Kansas	$ 163	87%	$ 2,451	105%
Kentucky	(371)	101%	1,260	105%
Louisiana	8,715	14%	4,358	63%
Mid-States	(2,734)	85%	1,600	99%
Mid-Tex	(12,819)	7%	2,432	87%
Mississippi	(1,265)	115%	(2,455)	100%
West Texas	4,383	98%	4,992	100%
Other	1,018	—	403	—
Utility segment	(2,910)	69%	15,041	97%
Natural gas marketing segment	(7,350)	—	4,747	—
Pipeline and storage segment	14,919	—	19,356	—
Other nonutility segment and other	144	—	324	—
Consolidated operating income	$ 4,803	69%	$39,468	97%

	Nine Months Ended June 30			
	2006		2005	
	Operating Income	Heating Degree Days Percent of Normal[1]	Operating Income	Heating Degree Days Percent of Normal[1]
	(In thousands, except degree day information)			
Colorado-Kansas	$ 23,423	98%	$ 26,934	99%
Kentucky	14,876	100%	17,863	98%
Louisiana	25,202	78%	26,941	78%
Mid-States	36,459	95%	37,443	94%
Mid-Tex	67,423	72%	82,002	80%
Mississippi	25,480	102%	24,661	96%
West Texas	24,053	100%	26,080	100%
Other	4,187	—	1,402	—
Utility segment	221,103	87%	243,326	89%
Natural gas marketing segment	51,237	—	34,141	—
Pipeline and storage segment	62,557	—	61,959	—
Other nonutility segment and other	436	—	897	—
Consolidated operating income	$335,333	87%	$340,323	89%

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

Three Months Ended June 30, 2006 compared with Three Months Ended June 30, 2005

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 June 30, 2006, we had, or received regulatory approvals for, WNA covering approximately 1.3 million customer meters in the following service areas for the following periods.

Georgia	October – May
Kansas	October – May
Kentucky	November – April
Louisiana(1)	December – March
Mississippi	November – April
Tennessee	November – April
Amarillo, Texas	October – May
West Texas	October – May
Lubbock, Texas	October – May
Virginia	January – December

(1) Effective beginning for the 2006-2007 winter heating season.

Our Mid-Tex Division did not have WNA as of June 30, 2006. However, its operations benefited from a rate structure that combined 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 provided for the recovery of most of our fixed costs for such operations under most weather conditions. However, this rate structure was not as beneficial during periods where weather was significantly warmer than normal.

In July 2006, the RRC approved an interim WNA, effective October 1, 2006 for the Mid-Tex Division. The approved WNA period will be October through May. After we filed our May 2006 Statement of Intent, the parties to the case reached an agreement to implement WNA on both an interim and permanent basis. The agreement provided that the interim WNA will use 30 years of weather history, while the permanent WNA will allow the parties to contest the appropriate period of weather data to use in calculating normal weather. The permanent WNA will also be modified or adjusted to conform to the rate design that the RRC ultimately approves in the case. With the addition of this interim settlement in the Mid-Tex Division and the LPSC's May 2006 settlement to authorize our Louisiana Division to implement WNA, we will have weather protection for over 90 percent of our residential and commercial meters for the 2006-2007 winter heating season.

Operating income

Utility gross profit margin decreased $5.3 million to $169.9 million for the three months ended June 30, 2006 from $175.2 million for the three months ended June 30, 2005. Total throughput for our utility business was 62.3 billion cubic feet (Bcf) during the current-year period compared to 72.7 Bcf in the prior-year period.

The decrease in utility gross profit margin and throughput primarily reflects continued warmer-than-normal weather, as adjusted for jurisdictions with weather-normalized rates, primarily in our Mid-Tex and Louisiana divisions, where we did not have weather-normalized rates during the third quarter. Although the heating load is typically smaller during the third fiscal quarter, warmer-than-normal weather can still adversely affect gross profit. Weather was 29 percent warmer than the prior-year quarter and 31 percent warmer than normal. The impact of warmer weather resulted in a $16.2 million reduction in gross profit margin compared with the prior-year quarter. Additionally, our Louisiana division experienced a $1.3 million reduction in gross profit margin during the current-year quarter due to the impact of Hurricane Katrina compared with the prior-year quarter. Finally, continued customer conservation contributed to the decrease. These decreases were partially offset by a $3.9 million increase arising from the Company's fiscal 2005 and fiscal 2004 filings under Texas's Gas Reliability Infrastructure Program (GRIP) and the recognition of $6.2 million that had been previously deferred in Louisiana following the LPSC's ratification of our 2003 RSC in May 2006.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes other than income taxes, increased to $172.8 million for the three months ended June 30, 2006 from $160.2 million for the three months ended June 30, 2005.

Operation and maintenance expense, excluding the provision for doubtful accounts, increased $10.4 million primarily due to higher employee costs associated with increased headcount to fill positions that were previously outsourced to a third party, higher medical and dental claims and increased pension and postretirement costs resulting from changes in the assumptions used to determine our fiscal 2006 costs. Increased line locate and facilities costs also contributed to the increase. These increases were partially offset by lower third-party costs associated with formerly outsourced administrative and meter reading functions that were in-sourced during the first quarter of fiscal 2006 and the reversal of a $2.0 million charge for Hurricane Katrina losses that was originally recorded during the first quarter of fiscal 2006. The accrual was reversed based upon the improved outlook to fully recover our losses from insurance recoveries and from increased rates that we are implementing, subject to refund, in August 2006.

The provision for doubtful accounts decreased $1.9 million to $2.1 million for the three months ended June 30, 2006. The decrease primarily was attributable to lower revenues than the prior-year quarter coupled with solid customer account collection efforts. In the utility segment, the average cost of natural gas for the three months ended June 30, 2006 was $7.11 per thousand cubic feet (Mcf), compared with $7.43 per Mcf for the three months ended June 30, 2005.

As a result of the aforementioned factors, our utility segment incurred an operating loss of $2.9 million for the three months ended June 30, 2006 compared to operating income of $15.0 million for the three months ended June 30, 2005.

Interest charges

Interest charges allocated to the utility segment for the three months ended June 30, 2006 increased to $30.9 million from $28.5 million for the three months ended June 30, 2005. 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 June 30, 2006 and 2005 is summarized as follows:

	Three Months Ended June 30	
	2006	**2005**
	(In thousands, except physical position)	
Storage Activities		
Realized margin	$ 7,717	$ (1,777)
Unrealized margin	(21,873)	961
Total Storage Activities	(14,156)	(816)
Marketing Activities		
Realized margin	12,691	12,347
Unrealized margin	579	(1,136)
Total Marketing Activities	13,270	11,211
Gross profit	$ (886)	$10,395
Net physical position (Bcf)	19.0	14.1

Our natural gas marketing segment's gross profit margin was a loss of $0.9 million for the three months ended June 30, 2006 compared to gross profit of $10.4 million for the three months ended June 30, 2005. Gross profit margin from our natural gas marketing segment for the three months ended June 30, 2006 included an unrealized loss of $21.3 million compared with an unrealized loss of $0.2 million in the prior-year period. Natural gas marketing sales volumes were 79.9 Bcf during the three months ended June 30, 2006 compared with 62.8 Bcf for the prior-year period. Excluding intersegment sales volumes, natural gas marketing sales volumes were 66.5 Bcf during the current-year period compared with 52.7 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.

Our storage activities incurred a loss of $14.2 million for the three months ended June 30, 2006 compared to a loss of $0.8 million for the three months ended June 30, 2005. Our marketing activities generated $13.3 million for the three months ended June 30, 2006 compared with $11.2 million for the three months ended June 30, 2005. Higher unrealized losses primarily were attributable to unfavorable movements in market prices used to value our physical storage. These unrealized losses were offset by higher realized storage activities due to captured spread arbitrage opportunities that were realized during the current-year quarter.

The $11.3 million decrease in our natural gas marketing gross profit margin was primarily due to unfavorable movements during the three months ended June 30, 2006 in the forward natural gas prices used to value the financial hedges designated against our physical inventory and our fixed-price forward contracts. These results in our storage operations were magnified by a 4.9 Bcf increase in our net physical position at June 30, 2006 compared to the prior-year quarter. We have elected to exclude the 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.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes other than income taxes, increased to $6.5 million for the three months ended June 30, 2006 from $5.6 million for the three months ended June 30, 2005. The increase in operating expense primarily was attributable to an increase in personnel 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 a loss of $7.4 million for the three months ended June 30, 2006 compared with operating income of $4.7 million for the three months ended June 30, 2005.

Interest charges

Interest charges allocated to the natural gas marketing segment for the three months ended June 30, 2006 increased to $1.7 million from $1.0 million for the three months ended June 30, 2005. The increase was attributable to higher average outstanding debt balances to fund natural gas purchases at significantly higher prices.

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 $35.5 million for the three months ended June 30, 2006 from $35.2 million for the three months ended June 30, 2005. Total pipeline transportation volumes were 133.3 Bcf during the three months ended June 30, 2006 compared with 128.5 Bcf for the prior-year quarter. Excluding intersegment transportation volumes, total pipeline transportation volumes were 104.7 Bcf during the current year quarter compared with 97.6 Bcf in the prior-year quarter. The increase was primarily attributable to higher transportation and related services margins in our Atmos Pipeline-Texas Division partially offset by higher unrealized losses recorded by Atmos Pipeline & Storage, LLC.

Operating expenses increased to $20.6 million for the three months ended June 30, 2006 from $15.8 million for the three months ended June 30, 2005 due to higher employee benefit costs associated with an increase in headcount, higher medical and dental claims and increased pension and postretirement costs resulting from changes in the assumptions used to determine our fiscal 2006 costs. Higher pipeline integrity and facilities costs also contributed to the increased level of operating expenses.

As a result of the aforementioned factors, our pipeline and storage segment operating income for the three months ended June 30, 2006 decreased to $14.9 million from $19.4 million for the three months ended June 30, 2005.

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 have constructed electric peaking power-generating plants and associated facilities and have entered into agreements to lease these plants.

Operating income for this segment primarily reflects the leasing income associated with two sales-type lease transactions completed in 2001 and 2002 and was essentially unchanged for the three months ended June 30, 2006 compared with the prior-year quarter.

Nine Months Ended June 30, 2006 compared with Nine Months Ended June 30, 2005

Utility segment

Operating income

Utility gross profit increased $10.2 million to $765.8 million for the nine months ended June 30, 2006 from $755.6 million for the nine months ended June 30, 2005. Total throughput for our utility business was 330.9 billion cubic feet (Bcf) during the current-year period compared to 351.7 Bcf in the prior-year period.

The increase in utility gross profit, despite lower throughput, primarily reflects higher franchise fees and state gross receipts taxes, which are paid by utility customers and have no permanent effect on net income. Additionally, margins increased $8.3 million due to rate increases received from the Company's fiscal 2005 and fiscal 2004 GRIP filings and the recognition of $6.2 million that had been previously deferred in Louisiana following the LPSC's ratification of our agreement in May 2006. These increases were partially offset by an approximate $4.8 million decrease in the Louisiana Division due to the impact of Hurricane Katrina compared with the prior-year period. For the nine months ended June 30, 2006, weather was 13 percent warmer than normal, as adjusted for jurisdictions with weather-normalized operations and three percent warmer than the prior-year period. In the Mid-Tex and Louisiana Divisions, which did not have weather-normalized rates during the 2005-2006 winter heating season, weather was 28 percent and 22 percent warmer than normal. The impact of the warmer weather resulted in a $22.1 million reduction in gross profit margin compared with the prior-year period.

Operating expenses increased to $544.7 million for the nine months ended June 30, 2006 from $512.3 million for the nine months ended June 30, 2005. The increase reflects a $17.1 million increase in taxes, primarily related to franchise fees and state gross receipts taxes, both of which are calculated as a percentage of revenue, and 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.

Operation and maintenance expense, excluding the provision for bad debt, increased $8.4 million primarily due to higher employee costs associated with increased headcount to fill positions that were previously outsourced to a third party, higher medical and dental claims and increased pension and postretirement costs resulting from changes in the assumptions used to determine our fiscal 2006 costs. Increased line locate and facilities costs also contributed to the overall increase. These increases were partially offset by a reduction in third-party costs for outsourced administrative and meter reading functions that were in-sourced during fiscal 2006. Operation and maintenance expense for the nine months ended June 30, 2006 was also favorably impacted by the absence of $2.1 million of United Cities merger and integration cost amortization, as these costs were fully amortized by December 2004.

The provision for doubtful accounts increased $4.2 million to $17.5 million for the nine months ended June 30, 2006, compared with $13.3 million in the prior-year period. The increase was primarily attributable to increased collection risk associated with higher natural gas prices. In the utility segment, the average cost of natural gas for the nine months ended June 30, 2006 was $10.39 per Mcf, compared with $7.20 per Mcf for the nine months ended June 30, 2005.

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 nine months ended June 30, 2006. This decrease was offset by increased depreciation expense associated with the placement of various capital projects into service during the fiscal year.

As a result of the aforementioned factors, our utility segment operating income for the nine months ended June 30, 2006 decreased to $221.1 million from $243.3 million for the nine months ended June 30, 2005.

Interest charges

Interest charges allocated to the utility segment for the nine months ended June 30, 2006 increased to $92.8 million from $83.8 million for the nine months ended June 30, 2005. 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 $3.6 million of interest savings arising from the early payoff of $72.5 million of our First Mortgage Bonds in June 2005.

Miscellaneous income

Miscellaneous income for the nine months ended June 30, 2006 remained essentially unchanged at $6.0 million compared to $6.1 million for the nine months ended June 30, 2005. However, during the fiscal 2006 second quarter, we recorded a $3.3 million charge associated with an adverse ruling in Tennessee related to the calculation of a performance-based rate mechanism associated with gas purchases. This charge was offset by increased interest income associated with intercompany borrowings to our natural gas marketing segment to fund its working capital needs.

Natural gas marketing segment

Operating income

Our natural gas marketing segment's gross profit margin for the nine months ended June 30, 2006 and 2005 is summarized as follows:

	Nine Months Ended June 30 2006	Nine Months Ended June 30 2005
	(In thousands, except physical position)	
Storage Activities		
Realized margin	$ 44,600	$15,482
Unrealized margin	(42,924)	(7,065)
Total Storage Activities	1,676	8,417
Marketing Activities		
Realized margin	63,263	43,182
Unrealized margin	4,471	(3,200)
Total Marketing Activities	67,734	39,982
Gross profit	$ 69,410	$48,399
Net physical position (Bcf)	19.0	14.1

Our natural gas marketing segment's gross profit margin was $69.4 million for the nine months ended June 30, 2006 compared to gross profit of $48.4 million for the nine months ended June 30, 2005. Gross profit margin from our natural gas marketing segment for the nine months ended June 30, 2006 included an unrealized loss of $38.5 million compared with an unrealized loss of $10.3 million in the prior-year period. Natural gas marketing sales volumes were 250.1 Bcf during the nine months ended June 30, 2006 compared with 203.8 Bcf for the prior-year period. Excluding intersegment sales volumes, natural gas marketing sales volumes were 207.4 Bcf during the current-year period compared with 179.7 Bcf in the prior-year period. The increase in consolidated natural gas marketing sales volumes was primarily due to focusing our marketing efforts on higher margin opportunities partially offset by warmer-than-normal weather across our market areas.

Our storage activities generated $1.7 million in gross profit margin for the nine months ended June 30, 2006 compared to $8.4 million for the nine months ended June 30, 2005. Increased realized margins in our storage operations were primarily due to our ability to capture more favorable arbitrage spreads that arose from increased market volatility. These increases were offset by an increase in the unrealized loss associated with these operations due to an unfavorable movement during the nine months ended June 30, 2006 in the forward natural gas prices used to value the financial hedges designated against our physical inventory and our fixed-price forward contracts. These results were magnified by a 4.9 Bcf increase in our net physical position at June 30, 2006 compared to the prior-year period. As noted above, we have elected to exclude this forward/spot differential from our hedge effectiveness assessment. We continually seek opportunities to increase the amount of our storage capacity. To the extent we obtain and utilize new capacity and experience price volatility, the amount of our unrealized storage contribution could increase in future periods.

Our marketing activities generated $67.7 million for the nine months ended June 30, 2006 compared with $40.0 million for the nine months ended June 30, 2005. This increase reflects increased realized margins coupled with a favorable unrealized margin variance compared with the prior-year period. The increase in our realized marketing operations was primarily attributable to successfully capturing increased margins in certain market areas that experienced higher market volatility. The favorable unrealized margin variance was primarily due to favorable movement during the nine months ended June 30, 2006 in the forward natural gas prices associated with financial derivatives used in these activities.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes other than income taxes, increased to $18.2 million for the nine months ended June 30, 2006 from $14.3 million for the nine months ended June 30, 2005. The increase in operating expense primarily was attributable to an increase in personnel costs due to increased headcount and an increase in regulatory compliance costs.

The improved gross profit margin partially offset by higher operating expenses resulted in an increase in our natural gas marketing segment operating income to $51.2 million for the nine months ended June 30, 2006 compared with operating income of $34.1 million for the nine months ended June 30, 2005.

Interest charges

Interest charges allocated to the natural gas marketing segment for the nine months ended June 30, 2006 increased to $6.6 million from $2.0 million for the nine months ended June 30, 2005. The increase was attributable to higher average outstanding debt balances to fund natural gas purchases at significantly higher prices.

Pipeline and storage segment

Operating income

Pipeline and storage gross profit increased to $120.5 million for the nine months ended June 30, 2006 from $113.8 million for the nine months ended June 30, 2005. Total pipeline transportation volumes were 431.2 Bcf during the nine months ended June 30, 2006 compared with 417.4 Bcf for the prior-year period. Excluding intersegment transportation volumes, total pipeline transportation volumes were 277.7 Bcf during the current year period compared with 254.5 Bcf in the prior-year period. The increase in gross profit was primarily attributable to higher transportation and related services margins coupled with increased throughput on our Atmos Pipeline-Texas system and Atmos Pipeline & Storage, LLC's ability to capture more favorable arbitrage spreads in its asset management contracts. These increases were partially offset by the absence of inventory sales of $3.0 million realized in the prior-year period.

Operating expenses increased to $57.9 million for the nine months ended June 30, 2006 from $51.8 million for the nine months ended June 30, 2005 due to higher employee benefit costs associated with the increase in headcount, increased pension and postretirement costs resulting from changes in the assumptions used to determine our fiscal 2006 costs and higher facilities costs.

As a result of the aforementioned factors, our pipeline and storage segment operating income for the nine months ended June 30, 2006 increased to $62.6 million from $62.0 million for the nine months ended June 30, 2005.

Other nonutility segment

Operating income for this segment primarily reflects the leasing income associated with two sales-type lease transactions completed in 2001 and 2002 and was essentially unchanged for the nine months ended June 30, 2006 compared with the prior-year period.

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. 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. Additionally, from time to time, we raise funds from the public debt and equity capital markets to fund our liquidity needs.

Capitalization

The following table presents our capitalization as of June 30, 2006 and September 30, 2005:

	June 30, 2006		September 30, 2005	
	(In thousands, except percentages)			
Short-term debt	$ 297,087	7.2%	$ 144,809	3.7%
Long-term debt	2,184,083	52.7%	2,186,368	55.6%
Shareholders' equity	1,664,556	40.1%	1,602,422	40.7%
Total capitalization, including short-term debt	$4,145,726	100.0%	$3,933,599	100.0%

Total debt as a percentage of total capitalization, including short-term debt, was 59.9 percent at June 30, 2006, and 59.3 percent at September 30, 2005. The increase in the debt to capitalization ratio was primarily attributable to an increase in our short-term debt borrowings to fund our working capital needs partially offset by current-year net income. 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, prices for our products and services, demand for such products and services, margin requirements resulting from significant changes in commodity prices, operational risks and other factors.

Cash flows from operating activities

Period-over-period changes in our operating cash flows primarily are attributable to changes in net income, working capital changes, particularly within our utility segment resulting from the 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 nine months ended June 30, 2006, we generated operating cash flow of $223.4 million from operating activities compared with $387.4 million for the nine months ended June 30, 2005. Period over period, our operating cash flow was adversely impacted by significantly higher natural gas prices, which have increased the levels of accounts payable and undercollected deferred gas costs recorded on our balance sheet as of June 30, 2006. However, we are beginning to see the adverse impact of this situation decline somewhat as declines in accounts receivable and natural gas inventories improved operating cash flow by $79.7 million compared with the prior-year period. Additionally, favorable movements in the market indices used to value our natural gas marketing segment risk management assets and liabilities reduced the amount that we were required to deposit in a margin account and therefore favorably affected operating cash flow by $45.4 million. However, these improvements in cash flow were offset by an unfavorable timing of payments for accounts payable and other accrued liabilities ($251.4 million) and unfavorable timing differences between when we purchase our natural gas and the period in which we can include this cost in our gas rates ($54.3 million). Finally, other working capital and other changes increased operating cash flow by $16.6 million.

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 earn a return on our investment timely. 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 nine months ended June 30, 2006, we incurred $322.7 million for capital expenditures compared with $226.9 million for the nine months ended June 30, 2005. The increase in capital expenditures primarily reflects increased spending associated with our Dallas/Fort Worth Metroplex North Side Loop project and other pipeline expansion projects in our Atmos Pipeline — Texas Division, which were completed during the fiscal 2006 third quarter. Increased capital spending in our Mid-Tex Division for various projects contributed to the increase in our capital expenditures.

Cash flows from financing activities

For the nine months ended June 30, 2006, our financing activities provided $90.8 million in cash compared with $1.6 billion provided in the prior-year period. Our significant financing activities for the nine months ended June 30, 2006 and 2005 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 shares of common stock, 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, into which we entered 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 nine months ended June 30, 2006 we increased our borrowings under our credit facilities by $152.3 million. All amounts borrowed under our credit facilities were repaid during the nine months ended June 30, 2005. The increase reflects borrowings to fund natural gas purchases and other working capital needs.

- We repaid $2.6 million of long-term debt during the nine months ended June 30, 2006 compared with $102.8 million during the nine months ended June 30, 2005. The prior-year payments reflect the repayment of $72.5 million on our First Mortgage Bonds and a $25.0 million make-whole premium in accordance with the terms of the agreements.

- During the nine months ended June 30, 2006 we paid $76.6 million in cash dividends compared with dividend payments of $74 million for the nine months ended June 30, 2005. The increase in dividends paid over the prior-year period reflects the increase in our dividend rate from $0.930 per share during the nine months ended June 30, 2005 to $0.945 per share during the nine months ended June 30, 2006 combined with new share issuances under our various plans.

• During the nine months ended June 30, 2006 we issued 0.7 million shares of common stock which generated net proceeds of $17.7 million. In addition, we granted 0.3 million shares of common stock under our Long-Term Incentive Plan. The following table summarizes the issuances for the nine months ended June 30, 2006 and 2005.

	Nine Months Ended June 30	
	2006	2005
Shares issued:		
Retirement Savings Plan	344,573	338,520
Direct Stock Purchase Plan	302,501	353,512
Outside Directors Stock-for-Fee Plan	1,865	1,769
Long-Term Incentive Plan	349,509	655,684
Long-Term Stock Plan for Mid-States Division	300	—
Public Offering	—	16,100,000
Total shares issued	998,748	17,449,485

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 banks. Our credit capacity and the amount of unused borrowing capacity are affected by the seasonal nature of the natural gas business and our short-term borrowing requirements, which are typically highest during colder winter months. Our working capital needs can vary significantly due to changes in the price of natural gas charged by suppliers and the increased gas supplies required to meet customers' needs during periods of cold weather. Our cash needs for working capital have increased substantially 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. On March 31, 2006, AEM amended and extended this uncommitted demand working capital credit facility to March 31, 2007. At June 30, 2006, there were no borrowings outstanding under this facility.

On April 1, 2006, our $18 million committed unsecured credit facility was renewed for one year with no material changes to its terms and pricing. At June 30, 2006, there was $15.2 million outstanding under this facility.

As of June 30, 2006, the amount available to us under our credit facilities, net of outstanding letters of credit, was $770.6 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, Ltd. (Fitch). Our current debt ratings are all considered investment grade and are as follows:

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

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

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

Debt Covenants

We were in compliance with all of our debt covenants as of June 30, 2006. Our debt covenants are described in Note 4 to the condensed consolidated financial statements.

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 nine months ended June 30, 2006.

Risk Management Activities

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

We record our derivatives as a component of risk management assets and liabilities, which are classified as current or noncurrent based upon the anticipated settlement date of the underlying derivative. Substantially all of our derivative financial instruments are valued using external market quotes and indices. The following tables show the components of the change in the fair value of our utility and natural gas marketing commodity derivative contracts for the three and nine months ended June 30, 2006 and 2005:

	Three Months Ended June 30, 2006		Three Months Ended June 30, 2005	
	Utility	Natural Gas Marketing	Utility	Natural Gas Marketing
	(In thousands)			
Fair value of contracts at beginning of period	$12,352	$ (3,414)	$24,367	$(5,896)
Contracts realized/settled	(1,099)	(20,923)	163	(7,843)
Fair value of new contracts	(2,577)	—	(155)	—
Other changes in value	(1,045)	(5,460)	1,081	5,684
Fair value of contracts at end of period	$ 7,631	$(29,797)	$25,456	$(8,055)

	Nine Months Ended June 30, 2006		Nine Months Ended June 30, 2005	
	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	25,799	2,099	(45,234)	(24,377)
Fair value of new contracts	(7,337)	—	(3,009)	—
Other changes in value	(104,141)	30,002	82,311	3,304
Fair value of contracts at end of period	$ 7,631	$(29,797)	$ 25,456	$ (8,055)

The fair value of our utility and natural gas marketing derivative contracts at June 30, 2006, is segregated below by time period and fair value source:

	Fair Value of Contracts at June 30, 2006				
	Maturity in Years				
Source of Fair Value	Less than 1	1-3	4-5	Greater Than 5	Total Fair Value
	(In thousands)				
Prices actively quoted	$(15,365)	$(8,715)	$—	$—	$(24,080)
Prices provided by other external sources	2,519	(50)	—	—	2,469
Prices based on models and other valuation methods	(285)	(270)	—	—	(555)
Total Fair Value	$(13,131)	$(9,035)	$—	$—	$(22,166)

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. This change had no material impact to the Company on the date of adoption. Derivatives associated with our natural gas inventory, which are designated as fair value hedges, are marked to market each month based upon the NYMEX price with changes in fair value recognized as unrealized gains and losses in the period of change. The changes in the difference between the indices used to mark to market our physical inventory (Gas Daily) and the related fair-value hedge (NYMEX) is reported as a component of revenue and can result in volatility in our reported net income. Over time, gains and losses on the sale of storage gas inventory will be offset by gains and losses on the fair-value hedges; therefore, the economic gross profit AEM captured in the original transaction remains essentially unchanged.

AEM continually manages its positions to enhance the future economic profit it captured in the original transaction. Therefore, AEM may change its scheduled injection and withdrawal plans from one time period to another based on market conditions or adjust the amount of storage capacity it holds on a discretionary basis in an effort to achieve this objective. AEM monitors the impacts of these profit optimization efforts by estimating the economic gross profit that it captured through the purchase and sale of physical natural gas and the associated financial derivatives. The economic gross profit, combined with the effect of unrealized gains or losses recognized in the financial statements in prior periods, provides a measure of the gross profit that could occur in future periods if AEM's optimization efforts are fully successful. The following table presents, by quarter during fiscal 2006, AEM's economic gross profit and its potential gross profit.

Period Ending	Net Physical Position (Bcf)	Economic Gross Profit	Associated Net Unrealized Losses	Potential Gross Profit
		(In millions)	(In millions)	(In millions)
September 30, 2005	6.9	$13.1	$(14.8)	$27.9
December 31, 2005	12.8	$ 7.1	$(38.6)	$45.7
March 31, 2006	23.6	$30.8	$(35.8)	$66.6
June 30, 2006	19.0	$28.4	$(57.7)	$86.1

As of June 30, 2006, based upon AEM's derivatives position and inventory withdrawal schedule, the economic gross profit was $28.4 million. In addition, $57.7 million of net unrealized losses were recorded in the financial statements as of June 30, 2006. Therefore, the potential gross profit was $86.1 million.

The economic gross profit is based upon planned injection and withdrawal schedules, and the realization of the economic gross profit is contingent upon the execution of this plan, weather and other execution factors. Since AEM actively manages and optimizes its portfolio to enhance the future profitability of its storage position, it may change its scheduled injection and withdrawal plans from one time period to another based on market conditions. Therefore, we cannot ensure that the economic gross profit or the potential gross profit calculated as of June 30, 2006 will be fully realized in the future or in what time period. Further, if we experience operational or other issues which limit our ability to optimally manage our stored gas positions, permanent impacts on earnings could result.

Pension and Postretirement Benefits Obligations

For the nine months ended June 30, 2006 and 2005 our total net periodic pension and other benefits cost was $37.4 million and $27.3 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 nine months ended June 30, 2006, we contributed $2.8 million to the Atmos Energy Corporation Retirement Plan for Mississippi Valley Gas Union Employees. The current year contribution achieved a desired level of funding by satisfying the minimum funding requirements while maximizing the tax deductible contribution for this plan for plan year 2005. We anticipate making no additional contributions to our pension plans for the remainder of fiscal 2006. However, we contributed $7.9 million to our other postretirement plans, and we expect to contribute a total of approximately $12 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 and nine-month periods ended June 30, 2006 and 2005.

Utility Sales and Statistical Data

	Three Months Ended June 30		Nine Months Ended June 30	
	2006	2005	2006	2005
METERS IN SERVICE, end of period				
Residential	2,889,470	2,866,950	2,889,470	2,866,950
Commercial	276,492	275,878	276,492	275,878
Industrial	3,056	3,090	3,056	3,090
Agricultural	8,924	9,822	8,924	9,822
Public-authority and other	8,210	8,172	8,210	8,172
Total meters	3,186,152	3,163,912	3,186,152	3,163,912
INVENTORY STORAGE BALANCE — Bcf	46.7	40.0	46.7	40.0
HEATING DEGREE DAYS[1]				
Actual (weighted average)	119	167	2,507	2,580
Percent of normal	69%	97%	87%	89%
UTILITY SALES VOLUMES — MMcf[2]				
Gas sales volumes				
Residential	13,176	20,528	132,754	149,774
Commercial	11,719	15,148	74,691	80,059
Industrial	4,161	5,995	21,224	23,886
Agricultural	2,759	787	3,115	913
Public authority and other	838	1,467	7,778	8,445
Total gas sales volumes	32,653	43,925	239,562	263,077
Utility transportation volumes	30,735	30,420	95,329	94,006
Total utility throughput	63,388	74,345	334,891	357,083
UTILITY OPERATING REVENUES (000's)[2]				
Gas sales revenues				
Residential	$ 208,164	$ 271,153	$1,875,636	$1,575,186
Commercial	112,100	141,465	944,591	731,762
Industrial	31,417	46,932	237,274	182,854
Agricultural	18,940	5,830	22,576	7,092
Public-authority and other	8,094	13,160	95,305	75,332
Total utility gas sales revenues	378,715	478,540	3,175,382	2,572,226
Transportation revenues	13,662	14,095	48,721	47,839
Other gas revenues	9,667	9,100	30,571	30,728
Total utility operating revenues	$ 402,044	$ 501,735	$3,254,674	$2,650,793
Utility average transportation revenue per Mcf	$ 0.44	$ 0.46	$ 0.51	$ 0.51
Utility average cost of gas per Mcf sold	$ 7.11	$ 7.43	$ 10.39	$ 7.20

See footnotes following these tables.

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

	Three Months Ended June 30		Nine Months Ended June 30	
	2006	2005	2006	2005
CUSTOMERS, end of period				
Industrial	679	659	679	659
Municipal	73	79	73	79
Other	444	431	444	431
Total	1,196	1,169	1,196	1,169
INVENTORY STORAGE BALANCE — Bcf				
Natural gas marketing	20.1	15.2	20.1	15.2
Pipeline and storage	2.5	2.8	2.5	2.8
Total	22.6	18.0	22.6	18.0
NATURAL GAS MARKETING SALES VOLUMES — MMcf(2)	79,850	62,798	250,056	203,770
PIPELINE TRANSPORTATION VOLUMES — MMcf(2)	133,306	128,453	431,185	417,370
OPERATING REVENUES (000's)(2)				
Natural gas marketing	$562,447	$466,835	$2,482,921	$1,473,527
Pipeline and storage	35,862	33,449	121,057	122,685
Other nonutility	1,413	1,421	4,500	4,058
Total operating revenues	$599,722	$501,705	$2,608,478	$1,600,270

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 and nine-month periods ended June 30, 2006 and 2005 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 April 2006, Atmos Pipeline-Texas made a filing under Texas' Gas Reliability Infrastructure Program (GRIP) to include in rate base approximately $22.1 million of pipeline capital expenditures incurred during calendar year 2005, which should result in additional annual revenues of approximately $3.4 million. Atmos Pipeline-Texas subsequently agreed to reduce the capital investment in this filing by approximately $0.5 million. It is anticipated that this reduction will not materially affect the annual revenues. The Railroad Commission of Texas (RRC) approved this filing in July 2006 and these new charges will be included in the monthly customer charge beginning in August 2006.

In September 2005, Atmos Pipeline-Texas made a filing under Texas' GRIP to include in rate base approximately $10.6 million of pipeline capital expenditures incurred during calendar year 2004 which should result in additional annual revenues of approximately $1.9 million. The RRC approved this filing in December 2005 and these new charges were included in the monthly customer charge beginning in January 2006.

Atmos Energy Colorado-Kansas Division. In December 2005, Atmos filed its second annual ad valorem tax surcharge for $1.6 million. The surcharge is designed to collect Kansas property taxes in excess of the amount included in Atmos' most recent general rate case. We began to bill this surcharge in January 2006.

Atmos Energy Kentucky Division. In February 2005, the Attorney General of the State of Kentucky filed a complaint with the Kentucky Public Service Commission (KPSC) alleging that our rates were producing revenues in excess of reasonable levels. We answered the complaint and filed a Motion to Dismiss with the KPSC. On February 2, 2006, the KPSC issued an Order denying our Motion to Dismiss but stated that the Attorney General had not met their burden of proof concerning their complaint. On March 3, 2006, the KPSC set a procedural schedule for the case. The Attorney General is currently conducting discovery. A hearing should be scheduled for early 2007. We believe that the Attorney General will not be able to demonstrate that our present rates are in excess of reasonable levels.

In February 2006, the KPSC approved the Company's request to continue its Performance Based Ratemaking (PBR) mechanism for an additional five year period. The PBR establishes predetermined gas cost benchmarks and provides incentives to the Company for purchasing gas supply below those benchmark costs. This mechanism has produced more than $20 million in gas cost savings since its inception in July 1998, with the Kentucky Division retaining over $8 million during that period. Atmos has filed for KPSC approval of a proposed supply agreement, which resulted from a request for proposal to prospective suppliers.

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 (RSC) filing in 2004 and was subject to refund, pending the final resolution of that filing. As the rate increase was subject to refund, we did not recognize this rate increase in our results of operations during fiscal 2005 or 2006.

In September 2005, the Louisiana Public Service Commission (LPSC) consolidated several then-existing dockets. These dockets included a separate proceeding for the renewal of the RSC for each of the LGS and TransLa Gas service areas; resolution of the outstanding 2003 RSC filing for the LGS service area; and our request for approval of a decoupling mechanism to stabilize margins in both the LGS and TransLa service areas.

A proposed settlement was filed with the LPSC in May 2006. The settlement provided for, among other things, a modified WNA which provides for partial decoupling, renewal of the RSC for both the LGS and TransLa service areas with provisions that will reduce regulatory lag and a refund to customers of approximately $0.4 million for the LGS service areas that had been previously deferred.

On May 25, 2006, the LPSC voted to approve the settlement. The first RSC filing to result will be in August 2006, based on a test year ended December 31, 2005, for the LGS service area. The effective date for any rate adjustment resulting from that filing will be August 12, 2006. The first filing for the TransLa service area will be made by December 31, 2006, for the test period ending September 30, 2006, with an effective rate adjustment of April 1, 2007. WNA for both service areas will be in effect for an initial three-year period beginning with the winter of 2006-2007. In the third quarter of fiscal 2006, $6.2 million in deferred revenue associated with the 2003 RSC rate adjustment was recognized.

Atmos Energy Mid-States Division. During the third quarter of fiscal 2005, Atmos 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 an appeal of the GPSC's decision in the Superior Court of Fulton County. Oral arguments are scheduled for September 7, 2006 before the Fulton County Superior Court.

On April 7, 2006, Atmos filed a rate case in its Missouri service area seeking a rate increase of $3.4 million. The Company is proposing to consolidate the rates for its Missouri properties into three sets of regional rates and consolidate the current purchased gas adjustment (PGA) into one statewide PGA. The Company is also proposing a

WNA mechanism. An evidentiary hearing is scheduled to begin on November 27, 2006, with an order expected to be issued February 22, 2007.

In March 2006, we received notification from the Tennessee Regulatory Authority (TRA) that it disagreed with the way we calculated amounts under its performance-based rate mechanism, which resulted in a $3.3 million charge during the second quarter of fiscal 2006. We believe the original calculations were correct, and we will appeal the TRA's decision.

In November 2005, we received a notice from the TRA that it was opening an investigation into allegations by the Consumer Advocate and Protection Division of the Tennessee Attorney General's Office that we are over-charging customers in parts of Tennessee by approximately $10 million per year. We have responded to numerous data requests from the TRA Staff. On April 24, 2006, the TRA Staff filed a Report and Recommendation in which it recommended that the TRA convene a contested case procedure for the purpose of establishing a fair and reasonable return. The TRA convened to consider the Staff's recommendation on May 15, 2006 and set a procedural schedule. All parties filed direct testimony on July 17, 2006, with rebuttal testimony due August 18, 2006. A hearing is scheduled for August 29, 2006. We believe that the Consumer Advocate and Protection Division will not be able to demonstrate that our present rates are in excess of reasonable levels.

Atmos Energy Mid-Tex Division. In May 2006, the Mid-Tex Division filed a Statement of Intent seeking incremental annual revenues of $60 million and several rate design changes including WNA, revenue stabilization, and recovery of the gas cost component of bad debt. The Statement of Intent consolidated "show cause" resolutions that had been filed in approximately 80 cities served by the Mid-Tex Division, including the City of Dallas, which requires the Mid-Tex Division to demonstrate that existing distribution rates are just and reasonable.

In July 2006, the Mid-Tex Division and the RRC agreed to implement WNA on both an interim and permanent basis, effective October 1, 2006. The agreement provided that the interim WNA will use 30 years of weather history, while the permanent WNA will allow the parties to contest the appropriate period of weather data to use in calculating normal weather. The permanent WNA will also be modified or adjusted to conform to the rate design that the RRC ultimately approves in the case, which is anticipated no later than the first quarter of calendar 2007. Any rate increase will be effective prospectively from the date of the final order; however, any rate decrease will be effective from May 31, 2006.

In March 2006, the Mid-Tex Division made a GRIP filing to include in rate base approximately $63.6 million of distribution capital expenditures incurred during calendar year 2005 which should result in additional annual revenues of approximately $12.1 million. The Mid-Tex Division subsequently agreed to reduce the capital investment in this filing by approximately $1.5 million. It is anticipated that this reduction will not materially affect the annual revenues. The implementation date of this filing has been delayed until September 1, 2006 because of delays related to municipal appeals.

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 annual revenues of approximately $6.7 million. The RRC approved this filing in January 2006, and these new charges were 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 refunded substantially all of the overcollected amounts to customers between December 2005 and March 2006 to help offset higher gas costs for residential, commercial and industrial customers.

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 June 2005. A Proposal for Decision has been issued recommending a disallowance. Exceptions and Replies to Exceptions have been filed. The case is currently scheduled for presentation to the RRC on August 8, 2006, but a decision is not expected until August 22, 2006. Additionally, all parties are currently conducting settlement negotiations.

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.

On June 30, 2006, the MPSC approved a pilot program whereby Trans Louisiana Gas Pipeline (TLGP) will provide asset management services to the Mississippi Division. The asset management pilot allows TLGP to market certain off-peak gas supply assets, such as company-owned or leased storage and pipeline capacity, on a recallable basis. In exchange for this TLGP will share net positive benefits of the asset management program with Mississippi ratepayers. The pilot program runs from June 1, 2006 to April 30, 2007 and may be extended by the MPSC upon application by Atmos.

Atmos Energy West Texas Division. In September 2005, Atmos 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. We filed an appeal of such matters with the RRC, which appeal was granted by the RRC in March 2006. New charges for the approved filings were included in the monthly customer charge beginning May 1, 2006. Atmos expects to make its 2005 GRIP filing for the West Texas Division in September 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. The requested information was provided to the city on February 28, 2006. We believe that we will be able to ultimately demonstrate to the City of Lubbock that our rates are just and reasonable.

In May 2006, Atmos began receiving "show cause" ordinances from several of the cities in the West Texas Division. The ordinances request a filing to be made no later than September 15, 2006. We believe that we will be able to ultimately demonstrate to the West Texas cities 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 June 30, 2006 three-month market strip, would increase our purchased gas cost by approximately $1.8 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. Because AEH had no net open positions (including existing storage and related financial contracts) at June 30, 2006, a $0.50 change in the forward NYMEX price would have no 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 June 30, 2006 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 $6.5 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 $3.7 million during the nine months ended June 30, 2006.

We also assess market risk for our fixed and floating rate 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 $128.6 million.

As of June 30, 2006 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 June 30, 2006. Based on that evaluation, these officers have concluded that the Company's disclosure controls and procedures are effective in ensuring that material information required to be disclosed in this quarterly report is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. In addition, there were no changes during the Company's last fiscal quarter that materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. *Legal Proceedings*

During the nine months ended June 30, 2006, there were no material changes in the status of the litigation and environmental-related matters that were disclosed in Note 13 to our annual report on Form 10-K for the year ended September 30, 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.

SIGNATURES

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

ATMOS ENERGY CORPORATION
(Registrant)

By: /s/ JOHN P. REDDY

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

Date: August 9, 2006

EXHIBITS INDEX
Item 6(a)

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

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